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February 15, 2023

VIA ELECTRONIC MAIL

<u>carmen.diaz@bpu.nj.gov</u> <u>board.secretary@bpu.nj.gov</u>

Carmen D. Diaz
Acting Secretary of the Board
Board of Public Utilities
44 South Clinton Avenue, 1st Floor
P.O. Box 350
Trenton, New Jersey 08625-0350

RE: In the Matter of the Petition of Atlantic City Electric Company for Approval of Amendments to Its Tariff to Provide for an Increase in Rates and Charges for Electric Service Pursuant to *N.J.S.A.* 48:2-21 and *N.J.S.A.* 48:2-21.1, and for Other Appropriate Relief (2023) BPU Docket No. ER23020091

Dear Acting Secretary Diaz:

On behalf of Atlantic City Electric Company ("ACE" or the "Company"), enclosed for filing is an electronic copy of a Petition (including numerous exhibits and schedules) initiating the above-entitled matter. Also attached and filed herewith is the Direct Testimony of the following witnesses in support of the Company's Petition and the areas on which each witness is expected to testify:

Jay C. Ziminsky	Policy and Case Overview, Revenue Requirement,	
	Test Year Selection, Consolidated Tax Adjustment	
	Calculation, Capital Structure and Proposed	
	Ratemaking Adjustments	
Gregory W. Brubaker &		
Ryan P. Whitman	Distribution System Capital Investments,	
	Infrastructure Investment Program, PowerAhead and	
	the Smart Energy Network	
Shengrong Chen	Proposed Ratemaking Adjustments, Cash Working	
	Capital and the Lead/Lag Study	

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Dylan D'Ascendis.....Cost of Equity

Joshua L. Masters.....Class Cost of Service Studies

Michael T. Normand......Proposed Rate Design and Tariffs.

As an electric public utility with nearly one hundred years of service to southern New Jersey, the Company recognizes the critical role reliable and affordable electric service plays in lives of its customers and the economy of southern New Jersey. Today, ACE strives to improve service reliability, enhance storm-response capabilities, advance solutions to climate change, provide outstanding customer service, and grow the economy of southern New Jersey. Consistent with these goals, the purpose of this case is to recover the costs of investments ACE has made, and continues to make, to provide improved reliability, a better customer experience, and a cleaner environment. In this filing, the Company requests an annual increase in its current retail base rates for electric service in the amount of approximately \$104.8 million (approximately \$111.7 million, including Sales and Use Tax). The monthly bill impact of this request on a typical ACE residential customer taking Basic Generation Service and using approximately 669 kWhs per month is estimated to be \$12.22 or approximately 8.80 percent of a total monthly bill.

There are a number of factors driving the need for the Company's request. ACE has continued to invest significant sums in its electric distribution system to improve and maintain system reliability and resiliency. In 2022 alone, the Company invested approximately \$251 million in its distribution system. Indeed, in the last five years, ACE has invested \$953 million to provide its customers with the safe and reliable electric service they need and have come to expect. These investments are yielding real and tangible benefits for customers in the form of fewer outages, and when there is an outage, shorter duration times. Importantly, ACE customers recognize and appreciate the improvements the Company has made. For example, customers reported a 95 percent satisfaction score for the Company's reliability performance in 2022.

The Company's investments are also an important economic engine for southern New Jersey. In recognition of this fact, the Company has invested in workforce development programs, engaged in economic development initiatives and implemented supplier diversity programs. In short, ACE's investments in reliability result in both direct service improvements and a multitude of indirect economic benefits to local communities, job-seekers, and women and minority-owned businesses.

The Company has also taken important steps to support realization of New Jersey's climate goals, as set out in the Energy Master Plan, with significant initiatives in electric vehicle charging infrastructure, deployment of advanced metering and enabling further distributed energy resources on its distribution system. The benefits and initial costs of these initiatives are discussed in detail in this filing. In addition, Company witnesses will explain how ACE's approach to these programs has included efforts to design and implement them in a manner that is equitable and provides benefits to all customers. Indeed, the Company is committed to ensuring all customers share in the benefits of New Jersey's transition to a clean energy economy.

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Consistent with the Order issued by the Board in connection with *In the Matter of the New Jersey Board of Public Utilities' Response to the COVID-19 Pandemic for a Temporary Waiver of Requirements for Certain Non-Essential Obligations*, BPU Docket No. EO20030254, Order dated March 19, 2020, these documents are being electronically filed with the Secretary of the Board of Public Utilities (the "Board") and the New Jersey Division of Rate Counsel. No paper copies will follow.

ACE respectfully requests that the Board transmit this matter to the Office of Administrative Law as soon as possible so that the Company's request may be decided within the nine-month statutory period set out in *N.J.S.A.* 48:2-21.

Thank you for your consideration and courtesies. Feel free to contact me with any questions or if I can be of further assistance.

Respectfully submitted,

Ćynthia L.M. Holland An Attorney at Law of the State of New Jersey

Enclosure

cc: Service List

IN THE MATTER OF THE PETITION OF ATLANTIC CITY ELECTRIC COMPANY FOR APPROVAL OF AMENDMENTS TO ITS TARIFF TO PROVIDE FOR AN INCREASE IN RATES AND CHARGES FOR ELECTRIC SERVICE PURSUANT TO N.J.S.A. 48:2-21 AND N.J.S.A. 48:2-21.1, AND FOR OTHER APPROPRIATE RELIEF (2/2023)

STATE OF NEW JERSEY

BOARD OF PUBLIC UTILITIES

BPU DOCKET NO. _ER23020091

CERTIFIED PETITION¹

ATLANTIC CITY ELECTRIC COMPANY (hereinafter referred to as "ACE," "Petitioner" or the "Company"), a corporation organized and existing under the laws of the State of New Jersey, which is subject to the jurisdiction of the Board of Public Utilities (hereinafter referred to as the "Board" or "BPU") and which maintains a regional office at 5100 Harding Highway, Mays Landing, New Jersey 08330, respectfully petitions the Board for an increase in its current retail rates for electric service in the amount of approximately \$104.8 million² and other related relief. In support of this request, ACE provides the information set forth below.

CASE OVERVIEW

The COVID-19 global pandemic made clear the essential role of reliable electric service in the lives of all Americans. As an electric public utility with nearly one hundred years of service to southern New Jersey, ACE has long understood the importance of reliable electric supply to the individuals and communities the Company serves. Today, as a member of the Exelon Corporation ("Exelon")³ family of utilities, ACE strives to improve service reliability, enhance storm-response

¹ In light of the exigencies created by the COVID-19 pandemic and the Executive Orders issues pursuant thereto, this Petition is being submitted under Certification in lieu of an Affidavit of Verification.

² \$111.7 million, including Sales and Use Tax.

³ See I/M/O the Merger of Exelon Corporation and Pepco Holdings, Inc., BPU Docket No. EM14060581, Order Approving Stipulation of Settlement (March 6, 2015), in which the Board approved the merger of Exelon Corporation and Pepco Holdings, Inc., and also authorized ACE to become a direct subsidiary of PHI. As a result of the merger transaction, PHI became Pepco Holdings LLC, a Delaware limited liability company. Throughout this Petition and filing, Pepco Holdings LLC will be referred to as PHI.

capabilities, advance solutions to climate change, provide outstanding customer service, and grow the economy of southern New Jersey. Consistent with these goals, the purpose of this case is to recover the costs of investments ACE has made, and continues to make, to provide improved reliability, a better customer experience, and a cleaner environment. In addition, the Company is subject to broad macroeconomic factors, such as inflationary pressures and increasing interest rates, that must be addressed to enable ACE to continue to provide safe, and reliable service to its customers at reasonable rates.

As will be discussed in detail throughout this filing, the Company has made significant, on-going investments to improve the resiliency of the grid as the region continues to experience severe storms driven by climate change. In 2022 alone, ACE's distribution system construction budget totaled \$251 million. The Company has also completed a multi-year program, known as PowerAhead, that consisted of a suite of projects focused on enhancing grid reliability and resiliency. Taken together, these investments are providing real and tangible benefits to customers as measured by improved reliability metrics and strong customer satisfaction scores. For example, customers reported a 95% percent satisfaction score for the Company's reliability performance in 2022. Clearly, ACE's initiatives are delivering benefits to customers and customers recognize the value of the Company's efforts.

The Company has also embraced technology and the benefits it can provide to customers. ACE has begun the complex task of implementing its Smart Energy Network ("SEN"), a program that will bring Advanced Metering Infrastructure ("AMI") to all customers. The SEN is the backbone network that will enable ACE to provide a host of additional services to customers, including allowing customers to monitor their electricity use in near real-time and better manage their electric bills. Company Witnesses Ziminsky, Brubaker and Whitman will discuss the SEN,

its benefits, cost recovery and implementation in detail in their respective Direct Testimonies. In addition, the Company is actively engaged in efforts to expand electric vehicle ("EV") charging infrastructure through its EVsmart program. As explained in the Direct Testimony of Company Witnesses Ziminsky and Normand, ACE has proposed a new rate schedule EV-ERR, Electric Vehicle Equivalent Residential Rate.⁴ This new tariff rate is intended to encourage EV adoption by ensuring eligible residential customers pay a rate consistent with their current residential dwelling. In addition to the direct customer benefits that the SEN and EVsmart will provide, these programs are part of the Company's continuing efforts to support the Energy Master Plan's overarching goals of addressing climate change and transitioning to a clean energy future.

The Company also recognizes that it has an important role to play in supporting equity in the State's clean energy transition and in New Jersey's future more broadly. ACE fully appreciates that it is an economic engine for southern New Jersey, and that the impact of the Company's investments extends far beyond the hundreds of people employed by ACE to include the Company's purchases of materials, services, and the hiring of skilled contractors. Understanding the importance of its investment to the regional economy, the Company has invested in workforce development programs, engaged in economic development initiatives, and implemented supplier diversity programs. In short, ACE's investments in reliability result in both direct service improvements and a multitude of indirect economic benefits to local communities, job-seekers, and women and minority-owned businesses.

While ACE understands its role in the regional economy, the Company also recognizes that its actions have a financial impact on its customers, particularly low and moderate income

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⁴ If approved, this rate will be available to residential unit-owners in multi-unit dwellings wishing to charge their vehicle in a designated parking space. It is also available for residential customers charging their vehicles in separately metered dwellings not intended for residential occupancy.

("LMI") customers. Consequently, ACE is committed to maintaining affordable service while also providing all customers with equitable access to new initiatives. To that end, Company Witness Normand will discuss the concept of gradualism and the estimated impacts on LMI customers. Company Witness Normand also discusses a proposed one-time refund to customers of a gross receipts tax reserve liability in the amount of \$994,337 (\$1,060,212 with SUT). Finally, Company Witness Ziminsky will also address affordability, including the Company resources and programs to support customers struggling to manage their bill, as well as how ACE will assist LMI customers with the customer-side costs of the SEN and support an equitable deployment of this new technology.

While the Company is justifiably proud of these activities, ACE is also facing challenges that must be addressed in this proceeding. Chief among those challenges is the simple fact that customers' electricity use has continued to decline. While several factors contribute to this result and are discussed in this filing, the expansion of solar facilities, which ACE strongly supports, is a particular financial hurdle for the Company. As of September 2022, approximately 8.2% of ACE customers had installed distributed energy resources ("DER") consisting primary of solar facilities. These assets accounted for approximately 10.4% of the Company's total load. Customer interest in DER remains high, and indeed the Energy Master Plan⁵ seeks to promote the deployment of additional DER, along with renewable energy and energy efficiency initiatives, as part of the State's transition to 100% clean energy. While the increased deployment of renewable energy resources is certainly a positive for New Jersey, it is also important to recognize that the Company must continue to make investments, and so incur significant costs, to serve customers with DER.

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⁵ See e.g., 2019 EMP, at 13 (summarizing Strategy 2 Accelerate Deployment of Renewable Energy and Distributed Energy Resources).

ACE supports clean energy initiatives, but these programs have consequences for the Company—especially when a large percentage of ACE's fixed costs are recovered through volumetric charges as explained by Company Witness Masters. The impact on ACE of DER and related clean energy initiatives is already significant and likely to continue — if not accelerate as the Energy Master Plan initiatives are implemented — and must be addressed in this proceeding.

ACE is firmly of the view that the growth of renewable energy resources is positive, but the transition to a clean energy economy creates particular challenges for the Company. Specifically, although ACE's distribution system is largely fixed-cost in nature, the bulk of the Company's revenues come from volumetric charges. When usage is declining due to DER deployment and other factors, as ACE has experienced in recent years, the reliance on volumetric rates undermines the Company's ability to recover its costs to provide service and earn a reasonable return. Given this, the Company has proposed a modest increase in the fixed monthly customer charge as a way to better align its rate structure with its cost structure, and so mitigate some of the risk and uncertainty of volumetric rates as well as provide cost-based price signals to customers. As explained by Company Witness Normand, an increase in the customer charge could assist many LMI customers, as a significant portion of LMI customers tend to have higher usage levels that makes them more likely to be negatively impacted by larger increases in the volumetric rate.

ACE has continued to invest in its distribution system to improve the customer experience, and to provide the modern, reliable electric system customers need and have come to expect. This spending is dictated by a combination of the Company's assessment of infrastructure needs and Board requirements. To illustrate the magnitude of the Company's on-going distribution system investments, in the last five years ACE invested over \$953 million in its distribution system.

These investments are yielding measurable benefits for customers. Since 2016, customers have seen an improvement of 52 percent in the System Average Interruption Frequency Index ("SAIFI") and 57 percent in the Customer Average Interruption Duration Index ("CAIDI") as of the end of 2022. In short, ACE's customers are experiencing fewer outages — and when there is an outage, the Company has achieved shorter duration times.

REQUESTED RATE RELIEF

- 1. ACE is engaged in the transmission and distribution of electric energy for light, heat, and power to approximately 568,000 residential, commercial, and industrial customers located in southern New Jersey. In this Petition, the Company is requesting an annual increase in its current retail base rates for electric service of \$104.8 million (\$111.7 million including Sales and Use Tax). This increase is based upon a test year ending June 30, 2023, as adjusted for known and measurable changes. The Company's filed test year includes five months of actual data, and seven months of estimated data, and will be updated throughout this proceeding. The net monthly bill impact of this filing on a residential customer taking Basic Generation Service and using 669 kWhs⁶ per month is approximately \$12.22 or approximately 8.80% of a total monthly bill.
- 2. ACE continues to make significant and sustained investments in its distribution system to benefit its customers. Such sustained investment must be subject to timely recovery in rates if the Company is to remain a healthy utility. ACE's present rates, however, are unjust and unreasonable in that they do not and will not: (i) provide sufficient operating revenues to reflect increased investment in the Company's rate base, meet operating expenses, taxes, and fixed charges, and maintain ACE's financial viability; and (ii) provide a fair opportunity to earn a

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⁶ 669 kWhs represents the monthly average consumption of all residential customers.

reasonable rate of return on the fair value of the Company's property used in the provision of utility service.

- 3. ACE's last base rate change was implemented for service rendered on and after July 15, 2021, based on a test year ending December 31, 2020.⁷ Thus, at the time current rates were first implemented, they were already out-of-date because they did not reflect all rate base additions or operations and maintenance cost increases after December 31, 2020, when the test year period concluded. Assuming the present proceeding concludes in 2023, the Company will not have recovered the costs associated with some of its investments for periods of up to 35⁸ months and potentially longer. Failure to fully and accurately reflect a return of, and on, investments made to serve customers is a potential deterrent to future investments, and over the long term may undermine the financial health of the Company.
- 4. The Company has made considerable investments in its electric distribution system to provide safe and reliable electric service to its customers, and continues to make significant annual investments as demonstrated by the projected distribution construction budget of \$274.6 million in 2023 alone. Significant investment is planned to continue over the next several years as discussed in detail in the Direct Testimony of Company Witnesses Brubaker and Whitman. This level of investment is funded on the front end by Petitioner's debt and equity investors with an expectation of receiving a reasonable rate of return on that substantial investment. ACE requests a prompt resolution of this matter as well as recognition of certain post-test year costs and

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⁷ See I/M/O the Petition of Atlantic City Electric Company for Approval of Amendments to Its Tariff to Provide for an Increase in Rates and Charges for Electric Service Pursuant to N.J.S.A. 48:2-21 and N.J.S.A. 48:2-21.1, and for Other Appropriate Relief (12/2020), BPU Docket No. ER20120746, Decision and Order Adopting Initial Decision and Stipulation of Settlement (July 14, 2021).

⁸ The 35 month period was calculated beginning January 2021 (at the conclusion of the prior test period), and assumes a decision effective November 17, 2023. Indeed, if this matter is the subject of protracted litigation, without interim rates, the Company could easily experience delays in cost recovery well in excess of three years for certain costs.

investments so that the Company and its investors may be appropriately compensated for the investments made to serve customers.

POWERAHEAD PRUDENCE REVIEW

5. By Order dated May 31, 2017, the Board authorized the Company to implement the PowerAhead program. As approved, PowerAhead was a \$79 million, five-year initiative to improve the resiliency of the ACE distribution system. PowerAhead concluded in May 2022, and the Company has sought recovery of \$73.98 million in program investments as described in detail in the Direct Testimony of Company Witnesses Brubaker and Whitman. While the Company has filed periodic cost recovery petitions consistent with the provisional cost recovery mechanism approved by the Board, the prudence of the execution of the PowerAhead investments has not been fully and finally determined. Therefore, ACE respectfully requests that the Board review its PowerAhead investments and find that they are prudent. ACE also requests that the Board find that its recovery of certain PowerAhead costs through the approved provisional cost recovery mechanism is final and no longer subject to refund.

SEN COST RECOVERY

6. As explained by Company Witnesses Brubaker and Whitman, the SEN entails the deployment of approximately 568,000 "smart meters" across the ACE service territory. Company Witnesses Brubaker and Whitman describe the detailed implementation process and provide an overview of the benefits of the SEN program to customers, while Company Witness Ziminsky discusses the details of the Company's approach to cost recovery in this filing. Specifically, ACE

⁹ I/M/O the Petition of Atlantic City Electric Company for Approval of Amendments to Its Tariff to Provide for An Increase in Rate and Charges for Electric Service Pursuant to N.J.S.A. 48:2-21.1 and For Approval of a Grid Resiliency Initiative and Cost Recovery Related Thereto; and For Other Appropriate Relief (2016) – Phase II, BPU Docket No. ER16030252, Order Approving Stipulation (May 31, 2017).

is seeking recovery of certain capital investments made and the associated Operations & Maintenance ("O&M") expenses that have been incurred by the Company during the test year period (i.e., June 30, 2023).

EVSMART COST RECOVERY

7. By Order dated February 17, 2021, the Board approved the Company's program (now known as EVsmart) to promote the expansion of EV charging infrastructure in its service territory. As explained by Company Witness Ziminsky, ACE was approved to spend up to \$20.7 million over a 5-year period via a series of program offerings targeted to meet the needs of different segments of the light-duty EV market. In addition to authorizing certain program offerings and spending levels, the Board authorized the Company to defer to a regulatory asset ACE's incremental depreciation associated with capital investments placed into service and ACE's O&M costs associated with EVsmart. In the instant proceeding, ACE is seeking recovery of the regulatory asset balance as of June 30, 2023, to be amortized over a period of three years with the unamortized balance included in rate base.

OTHER REQUESTED RELIEF

8. As explained in the testimony of Company Witnesses Brubaker and Whitman, ACE will deploy exclusively energy efficient light emitting diode ("LED") lighting in response to all new customer requests for Company-owned street lighting. Over time, the Company will replace existing non-LED lighting (i.e., Incandescent, Mercury Vapor, High Pressure Sodium and Metal Halide) with LED lighting. To effectuate this strategy, the Company seeks authority to make certain tariff changes, including the addition of two new LED street lighting options, as discussed

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¹⁰ *I/M/O The Petition of Atlantic City Electric Company for Approval of a Voluntary Program for Plug-In Vehicle Charging*, BPU Docket No. EO18020190, Order Approving Stipulation of Settlement (February 17, 2021).

in further detail in the Direct Testimony of Company Witness Normand. In addition, ACE seeks authority to: (i) add a new tariff offering, EV-ERR, Electric Vehicle Equivalent Residential Rate, to facilitate achievement of the State's EV deployment goals; and (ii) incorporate the results of ACE's Class Cost of Service Study ("CCOSS") contained in the Direct Testimony of Company Witnesses Masters and Normand and consider the unitized rate of return for each customer rate class in the allocation of overall revenue requirements among rate classes.

- 9. Additionally, the Company has complied with the Board's May 26, 2005 Final Order in BPU Docket No. ER03020110, which requires the Company to provide a distribution rate design based on a CCOSS using a Peak and Average Coincident Peak method ("P&A method") proposed by Board Staff. As discussed by Company Witness Masters, the P&A method does not reflect the way in which the Company actually designs and constructs its distribution facilities. As a result, the Company believes it would be inappropriate to use the P&A method to set ACE's rates. Consequently, ACE has not used the P&A method to develop its proposed rates in this proceeding. Moreover, the P&A method has not been adopted in prior proceedings to set the Company's base rates, and the Company asserts that it should not be adopted in this or any other ACE rate case.
- 10. As is more fully developed in the Direct Testimony of Company Witness Normand, the Company proposes to increase the monthly customer charge for Rate Schedule RS (residential service) from the current rate of \$6.25 (including Sales and Use Tax) to \$7.60 (including Sales and Use Tax), an increase of \$1.35, so that the monthly charge recovers a greater portion of residential customer-related fixed charges consistent with the Company's CCOSS. As Mr. Normand explains, the costs of the distribution system serving residential customers are largely fixed in nature. Yet, for residential customers, only a small fraction of the distribution costs are recovered

through the monthly fixed customer charge. While some customers are able to reduce their use through DER or energy efficiency/demand-side management measures, the fixed system costs largely remain, but are then shifted to be recovered from other customers. ACE's proposal for a modest increase in the monthly residential customer charge is intended to address this cost-shifting in a gradual manner, and to recover fixed costs equitably from all residential customers who are using and benefitting from the distribution system. Additionally, Mr. Normand has analyzed the impact of the Company's fixed charge proposal and found that the impact of the proposed increase could be mitigated for a significant portion of LMI customers relative to the other residential customers. Finally, Mr. Normand further discusses a proposed refund to customers on a gross receipts tax reserve liability via a one-time credit per customer or per light in the amount of \$994,337 (\$1,060,212 with SUT) within 90 days of a final Board Order.

- 11. As discussed in the Direct Testimony of Company Witness Ziminsky, ACE has included a Consolidated Tax Adjustment calculation in this filing that is consistent with the Board's regulations. ¹¹ The calculation has resulted in no adjustment to the Company's requested revenue requirement in this case.
- 12. In this Petition and supporting Direct Testimony, the Company has requested a Return on Equity ("ROE") of 10.50 percent and utilized a capital structure consisting of 50.20 percent common equity and 49.80 percent long-term debt. As Company Witness Ziminsky states in his Direct Testimony, this capital structure is consistent with industry standard capital structures and supports ACE's current credit ratings.
- 13. The Company has also submitted an alternative capital structure in compliance with the Board's Order in the Conectiv-PHI merger case (BPU Docket No. EM01050306) and the

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¹¹ See N.J.A.C. 14:1-5.12(a)(11).

Exelon merger case (BPU Docket No. EM14060581). As explained in detail by Company Witness Ziminsky, it is the Company's view that use of this alternative capital structure is inappropriate for setting rates, and it has not been used in setting rates in any prior proceeding.

REVISED TARIFF

14. Attached as **Exhibit A** is a revised tariff containing updates to certain provisions in the Company's tariff, as well as new tariffs for ACE's LED Street Lighting offerings and tariff EV-ERR, Electric Vehicle Equivalent Residential Rate.

PROCEDURAL SCHEDULE

15. Set out below is a proposed procedural schedule consistent with the provisions of *N.J.S.A.* 48:2-21(d). Delays in the recovery of investments made to serve customers undermine the Company's ability to earn its authorized rate of return. Thus, it is vital that this case proceed at the pace contemplated by the Legislature when it enacted *N.J.S.A.* 48:2-21. The Company will fully cooperate with the parties to efficiently process the case. Indeed, ACE has identified approximately 100 data requests routinely propounded in prior cases, and will provide the information sought in those data requests on, or about, March 15, 2023. The Company's proactive approach is intended to help the parties move this matter along expeditiously. However, should the Board not have reached a final decision in this matter by the end of the eight-month suspension period, then ACE reserves the right to implement its proposed rates on November 17, 2023, on an interim basis subject to interest and refund, consistent with *N.J.A.C.* 14:1-5.12(e).

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¹² To assist the parties and avoid duplication, the questions the Company will voluntarily respond to are included in **Exhibit H** to this Petition.

Proposed Procedural Schedule		
February 15, 2023	Case filed.	
February 2023	Discovery commences and will be on-going as noted below.	
March 2023	Pre-Hearing Conference with Administrative Law Judge.	
April 3, 2023	All final discovery requests propounded on the Company.	
April 18, 2023	All final discovery responses provided by ACE.	
April TBD, 2023	Two virtual public comment hearings (at 4:30 PM and 5:30 PM)	
April 20, 2023	Discovery conference/Settlement discussions.	
May 8, 2023	Rate Counsel/Intervenor Direct Testimony is due.	
May 17, 2023	Discovery propounded on Rate Counsel/Intervenor Direct Testimony.	
June 1, 2023	Rate Counsel/Intervenor responses to discovery requests are due.	
June 8, 2023	Rebuttal Testimony filed by parties as appropriate.	
June 20, 2023	Discovery requests propounded on Rebuttal Testimony.	
July 6, 2023	Responses to discovery requests on Rebuttal Testimony are due.	
July 10-14, 2023	Five days of evidentiary hearings.	
July 31, 2023	Initial Briefs due.	
August 14, 2023	Reply Briefs due.	
September 29, 2023	Initial Decision due.	
October 2023	Exceptions to Initial Decision & replies to Exceptions filed at the BPU	
November 17, 2023	BPU final decision and rates effective thereafter	

INTERIM RATES

16. Pursuant to *N.J.A.C.* 14:1-5.12(e), ACE hereby advises the Board that it reserves the right to implement its proposed rates for service rendered on and after November 17, 2023, on an interim basis subject to refund, if the Board has suspended the effective date of new rates pursuant to *N.J.S.A.* 48:2-21, but has not finally determined a just and reasonable tariff schedule prior to that date. Consistent with the requirements of *N.J.A.C.* 14:1-5.12(f)(1), ACE will provide notices to all required parties of its intention to implement its proposed rates on an interim basis.

SUPPORTING TESTIMONY AND FILING REQUIREMENTS

17. The proposed increased revenue requirement and proposed rates described in this Petition are supported by the Direct Testimony and supporting schedules of the following witnesses for the Company, each of which is attached hereto and made a part hereof:

Jay C. ZiminskyPolicy and Case Overview, Revenue Requirement,

Test Year Selection, Consolidated Tax Adjustment

Calculation, Capital Structure and Proposed

Ratemaking Adjustments

Gregory W. Brubaker &
Ryan P. WhitmanDistribution System Capital Investments,
Infrastructure Investment Program, and SEN
Shengrong ChenProposed Ratemaking Adjustments and Cash
Working Capital, Lead/Lag Study

Dylan W. D'Ascendis.....Cost of Equity

Joshua L. Masters......Class Cost of Service Studies

Michael T. Normand......Proposed Rate Design and Tariffs

18. As required by *N.J.A.C.* 14:1-5.12(a), the following Exhibits are attached to this Petition:

Exhibit A: a revised Tariff;

Exhibit B: a proposed Public Notice;

Exhibit C: Comparative Balance Sheets for the most recent three year period

and Balance Sheet for September 30, 2022;

Exhibit D: Comparative Income Statements for the most recent three year

period;

Exhibit E: Statement of Revenue derived for the 12 months ending December

31, 2022, from the rates that are the subject matter of this Petition;

Exhibit F: Pro Forma Rate Base/Income Statement for the partially projected

12 month period ending December 31, 2022. **Exhibit F** also provides a listing of all adjustments thereon, as well as a calculation showing the indicated rate of return on average net investment under

present and proposed rates;

Exhibit G: a Schedule of Payments or Accruals to Affiliated Companies;

Exhibit H: a List of Voluntary Data Requests ACE will provide; and

Exhibit I: an Analysis of the EDGE Rider and the Veteran's Rate Law.

19. Notice of this filing, including a statement of the overall impact thereof on customers of the Company, and Petitioner's intention to implement proposed rates on an interim basis subject to refund at the conclusion of any Board-ordered suspension period(s), will be combined with notice of the date and times of the public comment hearings to be scheduled thereon, and will appear in newspapers published and/or in general circulation in Petitioner's service area, after the date and times of such public hearings have been scheduled by the Board or the Office of Administrative Law. Said notice will also be served by mail upon the municipal clerks and the County representatives within the Company's service territory, as required by law. Such notice will be duly mailed following the scheduling of the hearings and will be substantially

in the form of the notice attached hereto as **Exhibit B.** Information regarding this filing will also be posted on the Company's website and a reference to the hearings will be available on ACE's social media outlets, including Facebook and Twitter. In addition, ACE's monthly invoices will contain a bill message referring customers to the Company's "Public Postings" page where the full text of the public notice can be found.

- 20. Due to the on-going nature of the COVID-19 global pandemic, ACE respectfully requests that the public comment hearings be conducted virtually to permit the public to participate in the hearings while also observing social distancing protocols. Virtual public comment hearings have been conducted in other ACE matters, and the Company believes it would be in the public interest to do so in this instance as well.
- 21. Notice of this filing along with all testimony, schedules, exhibits, and attachments (as appropriately redacted), shall be sent to the Deputy Attorneys General at the Department of Law and Public Safety, and to the Director of the Division of Rate Counsel by electronic mail only. Electronic copies of the Petition, along with all testimony, schedules, Exhibits, and attachments (as appropriately redacted), shall be sent to the persons identified in the Service List attached hereto. This is consistent with the Order issued by the Board in connection with *In the Matter of the New Jersey Board of Public Utilities' Response to the COVID-19 Pandemic for a Temporary Waiver of Requirements for Certain Non-Essential Obligations*, BPU Docket No. EO20030254 (March 19, 2020).
- 22. During the course of this proceeding, ACE will submit any confidential, proprietary or competitively sensitive information not covered by privilege once a mutually agreed-upon Agreement of Non-Disclosure (herein, the "NDA") has been executed by and among the Company, Board Staff, the Division of Rate Counsel and its and/or their consultants, and any

permitted intervenors. A form of NDA that is consistent in form and substance with NDAs used in prior base rate cases filed by ACE has been included as part of this filing package.

COMMUNICATIONS

23. Communications and correspondence concerning this proceeding should be sent to the following representatives of the Company:

> Cynthia L.M. Holland, Esquire Assistant General Counsel Atlantic City Electric Company – 92DC42 500 North Wakefield Drive Post Office Box 6066 Newark, Delaware 19714-6066 Telephone: 267.533.1671 (Teams)

E-Mail: cynthia.holland@exeloncorp.com

And

Heather Hall Manager, New Jersey Regulatory Affairs Atlantic City Electric Company – 92DC42 500 North Wakefield Drive P.O. Box 6066 Newark, Delaware 19714-6066 Telephone: 302.373.6727

E-Mail: <u>heather.hall@pepcoholdings.com</u>

And

Mary Anne Phillips Sr. Rate Analyst, Regulatory Services Atlantic City Electric Company – 92DC42 500 North Wakefield Drive P.O. Box 6066 Newark, Delaware 19714-6066

Telephone: 856.832.5177

E-Mail: mary.phillips@atlanticcityelectric.com

CONCLUSION

WHEREFORE, the Petitioner, ATLANTIC CITY ELECTRIC COMPANY, respectfully requests that the Board make the following determinations:

- A. that the Company's present rates and charges for electric service, as set forth in its present tariff, are inadequate to recover the operating expenses and capital costs of the Company and are below the level of just and reasonable rates;
- B. that the increased rates and charges for electric service that would result from the proposed amendments to the Company's tariff are just and reasonable, in the public interest, and shall be approved for service rendered on and after March 17, 2023, but in no event later than November 17, 2023 (the end of the anticipated Board ordered suspension periods);
- C. that the proposed amendments to the Petitioner's tariff for electric service are necessary to provide operating revenues sufficient to meet the Company's operating expenses and cost of capital;
 - D. that Petitioner's requested ROE of 10.50% is just and reasonable;
- F. that Petitioner's execution of its PowerAhead program, and the costs associated therewith, are reasonable and prudent and all previously authorized rates are final;
- G. that Petitioner shall be permitted to recover the costs of the SEN as described in the Direct Testimony of Company Witness Ziminsky;
- H. that Petitioner shall be permitted to recover the costs of the EVsmart initiative as described in the Direct Testimony of Company Witness Ziminsky;

I. that Petitioner shall be permitted to refund to customers a gross receipts tax reserve liability via a one-time credit in the amount of \$994,337 (\$1,060,212 with SUT) within 90 days of a final Board Order in this proceeding, as described in the Direct Testimony of Company Witness Normand; and

J. that Petitioner shall have such other and further relief as the Board may determine to be reasonable and appropriate.

Respectfully submitted,

Dated: February 15, 2023

CYNTHIA L. M. HOLLAND Assistant General Counsel

Atlantic City Electric Company – 92DC42

500 North Wakefield Drive

Post Office Box 6066

Newark, Delaware 19714-6066 Telephone: 267.533.1671 (Teams)

E-Mail: cynthia.holland@exeloncorp.com

IN THE MATTER OF THE PETITION OF ATLANTIC CITY ELECTRIC COMPANY FOR APPROVAL OF AMENDMENTS TO ITS TARIFF TO PROVIDE FOR AN INCREASE IN RATES AND CHARGES FOR ELECTRIC SERVICE PURSUANT TO N.J.S.A. 48:2-21 AND N.J.S.A. 48:2-21.1, AND FOR OTHER APPROPRIATE RELIEF (2/2023)

STATE OF NEW JERSEY BOARD OF PUBLIC UTILITIES

CERTIFICATION IN SUPPORT OF PETITION

WILLIAM D. MOKOID, of full age, certifies as follows:

- 1. I am a Vice President of Atlantic City Electric Company ("ACE") and am Region President for the ACE region, the Petitioner named in the foregoing Petition. I am duly authorized to make this Certification on ACE's behalf.
- 2. I hereby certify that I have read the contents of the foregoing Petition for approval of amendments to ACE's tariff to provide for an increase in rates and charges for electric service and supporting documents thereto.
- 3. I further and finally certify that the foregoing statements made by me are true to the best of my knowledge, information, and belief. I am aware that, if any of the foregoing statements made by me are willfully false, I am subject to punishment.

Dated: 2-9-23

WILLIAM D MOKOID

Exhibit A

Clean Tariff Sheets

ATLANTIC CITY ELECTRIC COMPANY

TARIFF FOR ELECTRIC SERVICE

SECTION I - GENERAL INFORMATION AND TERRITORY SERVED

SECTION II - STANDARD TERMS AND CONDITIONS

SECTION III - RATE SCHEDULE RUE - RESIDENTIAL

UNDERGROUND EXTENSIONS AND CLE - CONTRIBUTED LIGHTING EXTENSIONS

SECTION IV - SERVICE CLASSIFICATIONS AND RIDERS

ATLANTIC CITY ELECTRIC COMPANY Regional Headquarters

5100 Harding Highway Mays Landing, New Jersey 08330-2239

Date of Issue:	Effective Date:
Issued by:	

ATLANTIC CITY ELECTRIC COMPANY

TARIFF FOR ELECTRIC SERVICE

SECTION I GENERAL INFORMATION AND TERRITORY SERVED

ATLANTIC CITY ELECTRIC COMPANY

Regional Headquarters 5100 Harding Highway Mays Landing, NJ 08330-2239

Date of Issue:	Effective Date:

TERRITORY SERVED BY ATLANTIC CITY ELECTRIC COMPANY



Date of Issue: Effective Date: July 15, 2021

RESERVED FOR FUTURE USE

Date of Issue: Effective Date:

LIST OF MUNICIPALITIES SERVED BY ATLANTIC CITY ELECTRIC COMPANY

ATLANTIC COUNTY

Absecon, Atlantic City, Brigantine, Buena Boro, Buena Vista Township, Corbin City, Egg Harbor City, Egg Harbor Township, Estell Manor, Folsom Boro, Galloway Township, Hamilton Township, Hammonton, Linwood, Longport Boro, Margate City, Mullica Township, Northfield, Pleasantville, Port Republic, Somers Point, Ventnor City, Weymouth Township

BURLINGTON COUNTY

Bass River Township, Evesham Township*, Medford Township, Shamong Township, Southhampton Township*, Tabernacle Township, Washington Township, Woodland Township*.

CAMDEN COUNTY

Berlin Boro, Berlin Township, Chesilhurst Boro, Clementon Boro, Gibbsboro Boro, Gloucester Township*, Hi Nella Boro*, Laurel Springs Boro, Lindenwold Boro, Pine Hill Boro, Pine Valley Boro, Somerdale Boro*, Stratford, Voorhees Township*, Waterford Township, Winslow Township.

CAPE MAY COUNTY

Avalon Boro, Cape May, Cape May Point Boro, Dennis Township, Lower Township, Middle Township, North Wildwood, Ocean City, Sea Isle City, Stone Harbor Boro, Upper Township, West Cape May Boro, West Wildwood Boro, Wildwood, Wildwood Crest Boro, Woodbine Boro.

CUMBERLAND COUNTY

Bridgeton, Commercial Township, Deerfield Township, Downe Township, Fairfield Township, Greenwich Township, Hopewell Township, Lawrence Township, Maurice River Township, Millville, Shiloh Boro, Stow Creek Township, Upper Deerfield Township, Vineland*.

Date of Issue:	Effective Date:
Issued hv:	

GLOUCESTER COUNTY

Clayton Boro, Deptford Township*, East Greenwich Township, Elk Township, Franklin Township, Glassboro Boro, Greenwich Township, Harrison Township, Logan Township, Mantua Township, Monroe Township, Newfield Boro, Paulsboro Boro, Pitman Boro, South Harrison Township, Swedesboro Boro, Washington Township, Wenonah Boro, West Deptford Township*, Woolwich Township.

OCEAN COUNTY

Barnegat Light Boro, Barnegat Township*, Beach Haven Boro, Eagleswood Township, Harvey Cedars Boro, Lacey Township*, Little Egg Harbor Township, Long Beach Township, Ocean Township*, Ship Bottom Boro, Stafford Township, Surf City Boro, Tuckerton Boro

SALEM COUNTY

Alloway Township, Carney's Point Township, Elmer Boro, Elsinboro Township, Lower Alloways Creek Township, Mannington Township, Oldmans Township, Penns Grove Boro, Pennsville Township, Pilesgrove Township, Pittsgrove Township, Quinton Township, Salem, Upper Pittsgrove Township, Woodstown Boro.

* Served in I	rart
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Date of Issue:	Effective Date:
Issued by:	

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RESERVED FOR FUTURE USE Date of Issue: Effective Date: Issued by:

ATLANTIC CITY ELECTRIC COMPANY

TARIFF FOR ELECTRIC SERVICE

SECTION III - RATE SCHEDULE RUE - RESIDENTIAL UNDERGROUND EXTENSIONS AND CLE - CONTRIBUTED LIGHTING EXTENSIONS

ATLANTIC CITY ELECTRIC COMPANY Regional Headquarters

5100 Harding Highway Mays Landing, New Jersey 08330-2239

Date of leaves	Effective Date:
Date of Issue:	Effective Date:
Issued by:	

RATE SCHEDULE RUE (Residential Underground Extensions)

AVAILABILITY OF SERVICE

Available to new residential buildings and mobile homes within an approved subdivision to having 3 or more building lots and to new multiple occupancy buildings in accord with the provisions of Subchapter 4 of Regulations of the Board of Public Utilities.

RATE

All charges under the RUE tariff do not include cost and federal income tax liability pursuant to the Tax Reform Act of 1986. For each building lot being served, the applicant shall pay the utility the amount determined from the following table plus all applicable taxes.

For non-typical situations, including service to multiple family buildings and other situations as detailed below, such charges shall be equal to estimated cost of the underground construction less the total estimated costs of the otherwise applicable overhead construction as set forth in Section II plus applicable taxes.

Such cost estimates shall be based on the allowances for the unit costs as detailed in Section II and shall be based on the necessary construction to supply the same loads and locations utilizing Atlantic City Electric's standard offerings and conditions.

Type of Building

Single Family
Duplex-family, mobile home, & multiple
occupancy buildings, three-phase, high
capacity extensions, lots requiring primary
extensions thereon, transformer capacity
above 8.5 KVA per dwelling unit & other
special conditions.

Charge Per Lot

\$732.27 Plus \$3.14/Front Foot Differential in charges for equivalent underground & overhead construction based on unit charges set forth below.

SPECIAL TERMS AND CONDITIONS

See Section II inclusive for Terms and Conditions of Service.

The supply of electricity to the applicant shall be in accordance with the provisions of the rate schedule chosen by the applicant as applicable to this service.

Date of Issue:	Effective Date:
Issued by:	

ADDITIONAL CHARGES	
Primary Termination - Branch (1/0 A1)\$	1,210.33
Primary Junction Enclosure w/Cable Taps	
Three Phase\$	5,391.57
Single Phase\$	2,281.22
Service Length in Excess of 50 feet, including conduit	
200 AMP\$	
320 AMP\$	5.23/Trench Foot
Additional Street Lights where spacing is less than 200'	
30' Fiberglass Standard\$	
Multi-phase Constructions\$	3.20/Foot/Phase
Pavement cutting and restoration, rock) At actual cost plus	
removal, blasting, difficult digging) with option of appl	
and special backfill) as set for by NJAC	
) 14:3-8.9d et seq.	
CHARGES FOR SINGLE PHASE LINDERGROUND CONSTRUCTION	
CHARGES FOR SINGLE PHASE UNDERGROUND CONSTRUCTION Trenching - Total Charge \$	3 29/Foot
Trenching - Total Charge\$	3.29/Foot
Trenching - Total Charge\$ For calculating differential charge\$	1.89/Foot
Trenching - Total Charge\$ For calculating differential charge\$ Primary Cable (1/0 A1)\$	
Trenching - Total Charge\$ For calculating differential charge\$ Primary Cable (1/0 A1)\$ Secondary Cable	1.89/Foot 2.68/Foot
Trenching - Total Charge\$ For calculating differential charge\$ Primary Cable (1/0 A1)\$ Secondary Cable 4/0 Triplex (A1)\$	1.89/Foot 2.68/Foot 4.04/Foot
Trenching - Total Charge \$ For calculating differential charge \$ Primary Cable (1/0 A1) \$ Secondary Cable 4/0 Triplex (A1) \$ 350 KCMIL Triplex (A1) \$	1.89/Foot 2.68/Foot
Trenching - Total Charge \$ For calculating differential charge \$ Primary Cable (1/0 A1) \$ Secondary Cable 4/0 Triplex (A1) \$ 350 KCMIL Triplex (A1) \$ Service	1.89/Foot 2.68/Foot 4.04/Foot 4.91/Foot
Trenching - Total Charge	1.89/Foot 2.68/Foot 4.04/Foot
Trenching - Total Charge \$ For calculating differential charge \$ Primary Cable (1/0 A1) \$ Secondary Cable 4/0 Triplex (A1) \$ 350 KCMIL Triplex (A1) \$ Service 200 AMP (4/0 A1) \$ Complete \$	1.89/Foot 2.68/Foot 4.04/Foot 4.91/Foot 4.04/Foot
Trenching - Total Charge	1.89/Foot 2.68/Foot 4.04/Foot 4.91/Foot 4.04/Foot 598.93
Trenching - Total Charge \$ For calculating differential charge \$ Primary Cable (1/0 A1) \$ Secondary Cable 4/0 Triplex (A1) \$ 350 KCMIL Triplex (A1) \$ Service 200 AMP (4/0 A1) \$ Complete \$ 320 AMP (350 KCMIL A1) \$	1.89/Foot 2.68/Foot 4.04/Foot 4.91/Foot 4.04/Foot 598.93 4.91/Foot
Trenching - Total Charge \$ For calculating differential charge \$ Primary Cable (1/0 A1) \$ Secondary Cable 4/0 Triplex (A1) \$ 350 KCMIL Triplex (A1) \$ Service 200 AMP (4/0 A1) \$ Complete \$ 320 AMP (350 KCMIL A1) \$ Complete \$	1.89/Foot 2.68/Foot 4.04/Foot 4.91/Foot 4.04/Foot 598.93 4.91/Foot
Trenching - Total Charge \$ For calculating differential charge \$ Primary Cable (1/0 A1) \$ Secondary Cable 4/0 Triplex (A1) \$ 350 KCMIL Triplex (A1) \$ Service \$ 200 AMP (4/0 A1) \$ Complete \$ 320 AMP (350 KCMIL A1) \$ Service Riser	1.89/Foot 2.68/Foot 4.04/Foot 4.91/Foot 4.04/Foot 598.93 4.91/Foot 671.68

Date of Issue:	Effective Date:
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CHARGES FOR SINGLE PHASE UNDERGROUND CONSTRUCTIO	N (Continued	l)
Primary Termination - Branch (1/0 A1)		
Primary Junction enclosure w/Cable Taps	\$ 2,281.22	
Secondary Enclosure		
2" PVC Conduit		t
4" PVC Conduit	\$ 4.98/Foo	t
Street Light Cable		t
Transformers - Including Pad		
25 KVA	\$ 3,486.18	
50 KVA	\$ 4,813.60	
100 KVA	\$ 6,305.41	
167 KVA	\$ 6,926.42	
Special Street Light Poles		
30' Fiberglass		
Street Light Luminare (50 watt HPS)	\$ 319.53	
(50 watt LED)	\$ 626.73	
CHARGES FOR THREE PHASE UNDERGROUND CONSTRUCTION	N	
Primary Cable		
1/0 KCMIL A1	•	t
4/0 KCMIL A1	•	t
1000 KCMIL A1	\$ 34.99/Foo	t
Secondary Cable		
500 KCMIL Cu	•	
350 KCMIL A1		
Primary Termination 1/0		
Primary Termination 4/1		
Primary Termination 1000 KCMIL	\$ 7,043.63	
Primary Switch and Junction 2-600 AMP and		
1-200 AMP terminals	\$ 21,748.18	
Primary Switch and Junction 2-600 AMP and		
2-200 AMP terminals	\$ 28,731.41	
Primary Switch and Junction 3-600 AMP and	•	
1-200 AMP terminals		
5" PVC Conduit	\$ 5.88/Foot	t
Transformers - Including Pad	A 40.070 15	
150 KVA	•	
300 KVA		
500 KVA	\$ 10,812.55	

Date of Issue:

Effective Date:

CHARGES FOR SINGLE AND THREE PHASE OVERHEAD CONSTR	UCTION
Pole Line - Total Charge\$	8.72/Foot
Joint pole line cost\$	4.36/Foot
Primary Wire	
#2 AAAC (Single Phase)\$	3.57/Foot
477 KCMIL A1 (Three Phase)\$	13.97/Foot
Primary Wire Neutral	
#2 AAAC\$	2.32/Foot
#4/0 AAAC\$	2.65/Foot
Secondary Wire	
3-Wire (4/0 AAAC)\$	3.97/Foot
4-Wire (4/0 AAAC)\$	
- ()	
Service - Single Phase	
200 AMP (#2 A1)\$	1.20/Foot
Complete\$	
320 AMP (#42/0 A1)\$	1.57/Foot
Complete\$	217.65
σοιιρισισιιαιιαια φ	211100
Service - Three Phase	
Up to 200 AMP	
4-Wire (4/0 A1Qplex)\$	2.46/Foot
Ψ	2
Over 200 AMP	
4-Wire (500 KCMIL Cu)\$	56.60/Foot
· · · · · · · · · · · · · · · · · · ·	00.007. 001
Transformers	
Single Phase	
25 KVA\$	2,592.40
50 KVA\$,
100 KVA\$	4,489.71
167 KVA\$	6,679.28
Ψ	3,3. 3.20

Date of Issue:

Effective Date:

CHARGES FOR SINGLE AND THREE PHASE OVERHEAD CONSTRUCTION (Continued)

Transformers

Three	Phase	
25	KVA	\$ 6,968.77
50	KVA	\$ 8,233.60
100	KVA	\$ 13,309.87
167	KVA	\$ 19,940.74
Street	Light Luminare (50 watt HPS)	\$ 319.53

Date of Issue: Effective Date:

RATE SCHEDULE CLE (Contributed Lighting Extension)

AVAILABILITY OF SERVICE

Required for new or additional lighting fixtures contracted for under Rate Schedule CSL.

RATE

All charges under the CLE tariff are subject to federal income tax liability pursuant to the Tax Reform Act of 1986 and the Revenue Reconciliation Act of 1993. For each fixture the customer shall pay the Company the amount determined from the following table plus any applicable tax gross up.

HPS lighting fixture & bracket (4' or 8') – Lighting offering will be closed as of March 17, 2023 (installed on existing pole/prepaid facilities):

Standard Up to and including Over	150 watt 150 watt	\$319.53 \$441.33
Shoe Box	All	\$751.01
Post Top	All	\$545.88
Flood/Profile Light	Standard HPS Standard Metal Halide	\$635.00 \$546.69

Date of Issue:	Effective Date:

Light Emitting Diode

Cobra Head	50 W	\$ 626.73
	70 W	\$ 616.87
	100 W	\$ 629.19
	150 W	\$ 762.70
	250 W	\$ 931.59
	400 W	\$ 878.31
Mongoose	250 W	\$ 1,253.95
	400 W	\$ 1,466.18
Acorn (Granville)	70 W	\$ 1,746.33
	100 W	\$ 1,746.33
	150 W	\$ 1,746.33
Acorn (Granville) w/ ribs and bands	100W	\$ 1,955.21
Acorn (Granville) w/ ribs and bands	150W	\$ 1,955.21
Tear Drop Decorative	100 W	\$ 1,389.45
real blop becolative	150 W	\$ 1,677.85
Decorative Post Top	150 W	\$ 1,429.21
Colonial Style Post Top	70 W	\$ 1,429.21
Colorida Ciylo i Cot Top	100 W	· ·
Shoe Box	100 W	7 7
Silve box	150 W	\$ 805.55
		\$ 872.01
	250 W	\$ 1,076.22

^{*}Plus \$73.88 if existing incandescent HID fixture is removed.

26 Ft. Corner Decorative standard

25 Ft. Square aluminum Decorative standard

^{*}Less \$25.14 (bracket credit) if existing HID fixture is removed but existing bracket is reused.

Plus additional charges for:	
14 Ft. Bracket	\$145.47
24 Ft. Decorative standard (single bracket)	\$2,385.98
24 Ft. Decorative standard (double bracket)	\$3,302.20
25 Ft. Bracket	\$1,140.68
26 Ft. Tangent Decorative standard (single bracket)	\$2,989.51
26 Ft. Tangent Decorative standard (double bracket)	\$3,709.66

^{*}These items are considered a reimbursement of capital without any tax liability associated with the Tax Reform Act of 1986 and the Revenue Reconciliation Act of 1993.

\$2,975.48

\$3,001.55

Date of Issue:	Effective Date:

^{*}Plus \$57.03 if existing mercury vapor HID fixture is removed.

SPECIAL TERMS AND CONDITIONS

All equipment covered by this schedule will remain the Company's property unless, under special situation where ownership of the above equipment is advantageous to the state or local governmental entity involved, special contractual arrangements can be made.

Capital costs for specialty lighting applications will be provided upon request.

The "new charge per fixture" applies to all areas. In RUE areas, additional charges are collected under the RUE tariff.

Repavement of concrete broken for installation will be at actual cost or accomplished by the customer.

See Section II inclusive for Terms and Conditions of Service

Date of Issue:	Effective Date:
Issued by:	

RESERVED FOR FUTURE USE

Date of Issue:	Effective Date:
Issued by:	

ATLANTIC CITY ELECTRIC COMPANY

TARIFF FOR ELECTRIC SERVICE

SECTION II - STANDARD TERMS AND CONDITIONS

ATLANTIC CITY ELECTRIC COMPANY
Regional Headquarters

5100 Harding Highway Mays Landing, New Jersey 08330-2239

Date of Issue:	Effective Date:
Issued by:	

1. GENERAL INFORMATION

1.1 Filing:

This tariff, comprising service rules, regulations and rate schedules governing supply of electric service within the service area of the Atlantic City Electric Company, referred to herein sometimes as "ACE" or the "Company," is the official tariff of the Company on file with the Board of Public Utilities of the State of New Jersey, referred to herein as "Board of Public Utilities".

1.2 Scope:

The provisions of this tariff shall apply to all persons, natural or artificial and including, but not limited to, partnerships, associations, corporations (private and public), bodies politic, governmental agencies and any other customer receiving electric service hereunder. These "Terms and Conditions" are subject to modifications embodied in "Special Terms and Conditions" of the particular rate schedule under which such customers may be served.

1.3 Revisions:

No agent, representative or employee of the Company is authorized to waive or change the provisions of this tariff, nor shall any agreement or promise to do so be binding upon the Company. Revisions may be made only in compliance with orders of the Board of Public Utilities.

1.4 Other Publications:

Publications set forth by title in these Terms and Conditions of Service are incorporated in these Terms and Conditions of Service by reference.

This tariff is subject to the lawful Orders of the Board of Public Utilities. Complaints may be directed to: Board of Public Utilities, Division of Customer Assistance, 44 South Clinton Avenue, Trenton, NJ 08625, 609-341-9188 or 1-800-624-0241; www.nj.gov/bpu.

Date of Issue:	Effective Date:
Issued bv:	

2. OBTAINING SERVICE

2.1 Application:

Application for service shall be made at nearest Company District Operating Center or Courtesy Center (see paragraph 6.4 for locations), in person, by mail or by telephone, by facsimile transmission, and/or by electronic mail, where available. At the Company's discretion, a signed application may be required, which, when duly accepted by the Company, shall constitute evidence of the agreement between the Company and the customer. A copy of the application will be furnished to the customer upon request.

District Operating Centers

Cape May Courthouse Operations	420 Rt. 9 North Cape May Courthouse NJ 08210
Pleasantville Operations	2542 Fire Rd. Egg Harbor Twp. NJ 08234
Glassboro Operations	428 Ellis St. Glassboro NJ 08028
Winslow Operations	295 Grove St. Berlin NJ 08009
Bridgeton Operations	10 Cohansey Street Bridgton NJ 08302
West Creek Operations	457 Main St West Creek NJ 08092

All customers shall be given a copy of the "Customer Bill of Rights" approved by the Board of Public Utilities, effective at the time of service initiation. The copy shall be presented no later than at the time of the issuance of the customer's first bill or 30 days after the initiation of service, whichever is later.

2.2 Choice of Schedule:

A copy of the Schedules and "Terms and Conditions" under which service is to be rendered to the customer will be provided upon application, and the customer may choose the appropriate rate schedule applicable to his service, upon which his application shall be based. The customer may not change from one schedule to another except by mutual agreement. If customer so desires, the choice of schedule may be discussed with a designated Company representative, who will assist in explaining the Terms and Conditions of each applicable schedule. On request, a representative will also explain the Company's method and scheduling of reading meters.

2.3 Deposits:

A deposit may be required of a customer before service will be supplied. For a new customer such deposit shall be the estimated average bill of the customer for a billing period based upon the average monthly charge over an estimated 12 month service period increased by one month's average bill. Customers in default in the payment of bills shall be required to furnish a deposit based on the same calculation using actual billing data to the extent it exists, or increase their existing deposit in an amount sufficient to secure the payment of future bills. The Company will pay interest on deposits in accordance with N.J.A.C.14:3-3.5(d). The Company will furnish a receipt to each customer who has made a deposit. If a customer who has made a deposit fails to pay a bill, the Company may apply such deposit insofar as is necessary to liquidate the bill, and may require that the deposit be restored to its original amount. The Company shall review a residential customer's account at least once every year, and a non-residential customer's account at least once every two years and if such review indicates that the customer has established credit satisfactory to the utility, then the outstanding deposit shall be returned to the customer.

Upon refunding a deposit or paying a customer interest on a deposit, the Company shall offer the customer the option of a credit to the customer's account or a separate check.

Upon closing an account, the Company shall refund to the customer the balance of any deposit remaining after the closing bill for service has been settled, including any applicable interest required.

Date of Issue:	Effective Date:
Issued by:	

		TERMS AND CONDITIONS OF SERVICE	
2.	OBTAINING SERVICE		
		Eliminated effective December 21, 2015.	
Date o	of Issue:	Effective Date:	
Issue	d by:		

2. OBTAINING SERVICE (Continued)

2.4 Extension of Service - General

A. Definitions

<u>Applicant for service, developer or customer</u>: For purposes of this Section of the tariff, an applicant for service, a developer, and a customer are treated synonymously and in conformance with how those terms are applied in N.J.A.C. Subchapter 14:3-8 et seq.

<u>Cost</u> means, with respect to the cost of construction of an extension, actual and/or site-specific unitized expenses incurred for materials and labor (including both internal and external labor) employed in the actual design, construction, and/or installation of the extension, including overhead directly attributable to the work, as well as overrides or loading factors such as those for back-up personnel for mapping and design. This term does not include expenses for clerical, supervision, dispatching or general office functions. Cost also includes the tax consequences incurred under the Tax Reform Act of 1986 and New Jersey state income tax law by the regulated entity as a result of receiving deposits or contributions.

Distribution revenue:

Total revenue, plus related Sales and Use Tax, collected by the Company from a customer, minus Basic Generation Service charges, plus Sales and Use Tax on the Basic Generation Service charges, and transmission charges derived from FERC approved Transmission Charges, plus Sales and Use Tax on the transmission charges, assessed in accordance with Section IV of the Company's tariff.

Date of Issue:	Effective Date:
Issued by:	

<u>Extension</u>: For purposes of this section 2 of the tariff, "extension" means: the construction or installation of plant and/or facilities by a regulated entity to convey new service from existing or new plant and/or facilities to serve new development or one or more new customers, and also means the plant and/or facilities themselves. This term includes all plant and/or facilities for transmission and/or distribution, whether located overhead or underground, on a public street or right of way, or on a private property or private right of way, including the wire, poles or supports, cable, pipe, conduit or other means of conveying service from existing plant and/or facilities to each unit or structure to be served, except as excluded at paragraphs 1 through 2 below. An extension begins at the existing infrastructure and ends as follows:

- 1. for an overhead extension of electric service, the extension ends at the point where the service connects to the building, but also includes the meter;
- 2. for an underground extension of electric service, the extension ends at, and includes the meter; unless the applicant and the Company make other arrangements.

In other portions of the tariff, the term "extension" may have a narrower meaning that excludes service lines and metering.

Plant and/or facilities installed to supply the increased load of existing non-residential customers are also considered an extension where either: 1) Company facilities of the required voltage or number of phases did not previously exist, or 2) existing Company facilities are upgraded or replaced due to an applicant's new or additional electrical load being greater than 50% of the total design capacity of the pre-existing facilities.

B. General

To obtain regulated services to serve new developments or new customers, an application must be made with the Company for construction of an extension.

Date of Issue:	Effective Date:
Issued by:	

As set forth more fully in N.J.A.C 14:3-8.3,8.4 and 8.5, the following provisions shall apply to all Extensions of Service:

- (a) Unless otherwise agreed to between the Company and an applicant, the Company shall not pay for or financially contribute to the cost of an extension, except in accordance with the provisions of Paragraph 2.5 of this Section of the tariff.
- (b) An extension shall become the property of and be maintained by the Company upon its completion unless other arrangements have been made.
- (c) The estimated cost of an extension for which the Company receives a deposit, or receives a non-refundable contribution, shall include the tax consequences incurred under the Tax Reform Act of 1986 ("TRA 1986") and New Jersey state income taxes by the regulated entity as a result of receiving deposits or contributions, and shall be calculated consistent with the provisions of N.J.A.C. 14:3-8.6(e). Similarly, any applicable deposit refunds to customers shall be grossed up for the effects of TRA 1986 and applicable New Jersey state income taxes previously paid as part of the deposit
- (d) The Company shall construct each extension with sufficient capacity to provide safe, adequate, and proper service to customers, as determined by the Company. The cost of the extension shall be full cost based on the Company's determination of service requirements, regardless of the requirements specified by the applicant.
- (e) If the Company chooses to construct an extension or portion of an extension with additional capacity, over that which is needed to comply with Paragraph 2.4.B, pursuant to N.J.A.C. 14:3-8.5(h), the Company shall pay for, and shall not require the applicant to contribute financially to, the incremental cost of any additional capacity.
- (f) The Company may contract with an applicant for service to design, construct or maintain an extension on behalf of the applicant. However, the Company shall be paid for the cost of constructing or installing the extension, in accordance with the provisions and charges contained in Section III of the Company's tariff for residential underground extensions.
- (g) In the absence of any safety or other public interest concerns, the Company, in the case for the provision for underground service pursuant to N.J.A.C. 14:3-8.4, shall permit the applicant for service to dig the portion of the trench located on the customer's property to receive the service. In that event, the applicant for service shall be solely responsible for ensuring that the excavation is done and completed in accordance with the Company's standards. The Company shall inspect such excavations to ensure that the trench complies with the Company's standards prior to the installation of any utility lines in the trench. The Company reserves, in its sole discretion, the right to reject any excavation performed by the customer that does not meet its standards for the construction of utility trenching.

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2.5 Extension of Service to Serve a Customer Along Public or Common Rights-of-Way:

A. Single Residential Customer

The Company facilities shall be extended or modified to serve customers along public or common rights-of-way in accordance with Subparagraph 2.4 above and applicable regulations. Where the cost of an extension or modification exceeds ten (10) times the estimated or assured annual distribution, the Company shall construct such extension, provided the customer shall deposit with the Company an amount equal to the difference between estimated actual cost of the extension required to bring service to the customer from the nearest existing infrastructure and the estimated annual distribution revenue that will be derived from the customer, multiplied by ten.

B. Multi-Unit Residential Development and Non-Residential Development

The Company facilities shall be extended to serve customers along public or common rights-of-way in accordance with Subparagraph 2.4 above and applicable regulations. Where the cost of an extension or modification exceeds ten (10) times the estimated or assured annual distribution revenue, the Company shall construct such extension, provided the customer (or developer) shall deposit with the Company an amount equal to the cost of the extension. For purposes of calculating the amount of the deposit, the development for which service is requested shall be determined by reference to the subdivision map approved by the applicable local authorities. If a development is to be approved and constructed in phases, the applicant shall indicate which phases are to be treated as separate developments for purposes of determining the deposit. Such deposit shall remain with the Company without interest until such time as the actual annual distribution revenue from premises abutting upon such extension shall exceed the amount of distribution revenue which was used as a basis for the deposit.

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2.6 Return of Deposits.

A. General Rule:

As provided in N.J.A.C. 14:3-8.9(d) and 8.9(h), the costs of extra work required to provide beyond standard service and the additional costs for providing underground service (including the costs of temporary overhead service) over and above the amount it would cost to serve customers overhead are non-refundable. This includes, but is not limited to, relocation of facilities, special equipment, second or more feeds for dual source arrangements, and facilities and extensions other than low voltage service connections beyond the property line. As provided in N.J.A.C. 14:3-8.4(g) the remainder of the cost of the service, that is the amount which overhead service would have cost, shall be shared between the applicant and the regulated entity in accordance with N.J.A.C. 14:3-8.5.

B. Return of Deposits to Single Residential Customer Extension:

Return of deposits for extensions for single residential customers shall be made as follows:

- (a) One year after the customer begins receiving service, the Company shall calculate the distribution revenue derived from the customer's first year of service. If the year one distribution revenue is less than the estimated annual distribution revenue that was used to determine the deposit, the Company is not required to provide a refund. If the year one distribution revenue exceeds the estimated annual distribution revenue, the Company shall provide a refund to the applicant equal to the difference between the estimated and annual year one distribution revenues, multiplied by ten.
- (b) Two years after the customer begins receiving service, the Company shall calculate the distribution revenue derived from the customer's second year of service. If the year two distribution revenue is less than the year one distribution revenue, the Company is not required to provide a refund. In each annual period from the date of connection, if the actual Distribution Revenue from the customer exceeds the greater of either: (1) the estimated annual Distribution Revenue used as the basis for the initial deposit computation, or (2) the highest actual Distribution Revenue from any prior year, there shall be returned to the applicant an additional amount, equal to ten times such excess. This process shall be repeated annually until the earlier of the following:
 - 1. The Company has refunded the entire deposit to the applicant; or
 - 2. Ten years have passed since the customer began receiving service.
- (c) If, during the ten year period after a single residential customer begins receiving service, additional customers connect to the extension, the Company shall increase the initial customer's annual refund to reflect the additional revenue. In such a case, the Company shall add to the initial customer's refund an amount ten times the distribution revenue derived from the additional customers for that year.

In no event shall more than the original deposit be returned to the depositor nor shall any part of the deposit remaining after ten (10) years from the date of original deposit be returned.

C. Return of Deposits for Multi-Unit Residential or Non-Residential Land Development Extensions:

Return of deposits for extensions for multi-unit or non-residential development shall be made as follows:

- (a) As each customer begins receiving services, the Company entity shall refund a portion of the deposit to the applicant. For each customer, this customer startup refund shall be the estimated annual distribution revenue that will result from the customer, multiplied by ten.
- (b) One year after the Company received the deposit, and each subsequent year thereafter, the Company shall provide an annual refund to the applicant. The first annual refund shall be calculated in accordance with (c) below. Subsequent annual refunds shall be calculated under (d) below.
- (c) The first annual refund shall be calculated by multiplying by ten the difference between:
- 1. The distribution revenue from all customers that were served by the extension for the entire previous year; and
- 2. The estimated annual distribution revenue, upon which the original customer startup refund was based, for all customers that were served by the extension for the entire previous year. If the distribution revenue for the first year, determined under (c)1 above, was less than the estimated annual distribution revenue (upon which the original customer startup refund amount was based), the Company is not required to provide an annual refund.

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- (d) For each subsequent year, the annual refund shall be calculated as follows:
- 1. Sum the distribution revenue from all customers that were served by the extension for the entire previous year;
 - 2. Determine the sum of:
- i. The distribution revenue that was used in calculating the most recent annual refund provided to the applicant. This is the amount determined under (d)1 above when this subparagraph was applied to determine the most recent annual refund; and
- ii. The original estimated annual revenue for all customers that were served by the extension for the entire previous year, but whose revenues were not included in the calculation of the most recent annual refund that the regulated entity provided to the applicant;
- 3. Subtract (d)2 above from (d)1 above. If (d)2 above is greater than (d)1 above, the Company is not required to provide a refund; and
- 4. If (d)2 above is less than (d)1 above, multiply the difference derived under (d)3 above by ten to determine the annual refund.

In no event shall more than the original deposit be returned to the depositor nor shall any part of the deposit remaining after ten (10) years from the date of original deposit be returned.

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2.7 Multiple Service for Non-Residential Customers:

When the Customer desires delivery of energy at more than one point, other rules and regulations may apply, and a separate contract may be required for each separate point of delivery. Service at each point of delivery will be billed separately under the applicable schedule.

2.8 Modification of Service at Current Location:

When it is necessary for the Company to construct, upgrade or install facilities necessary to serve the additional requirements of existing customers and these facilities do not meet the definition of an Extension as defined in Section 2.4 A of these Standard Terms and Conditions, the following shall apply:

. The Company shall modify its facilities without charge to the customer provided the cost of such modification shall not exceed five (5) times the estimated or assured incremental annual distribution revenue received as a result of the modification. Where the cost of a modification exceeds five (5) times the estimated or assured incremental annual distribution revenue, the Company shall construct such modification, provided the customer shall make a non-refundable contribution to the Company an amount equal to the difference between the cost of such modification and five (5) times the assured or estimated incremental annual distribution revenue. The cost of such modification shall include the tax consequences incurred by the Company under the Tax Reform Act of 1986 as a result of receiving contributions.

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2. OBTAINING SERVICE (Continued)

2.9 Initiation of Service at Original Location:

Whenever service is initiated to any customer in an original location (no previous service), a service charge will be made as specified on Rate Schedule CHG. Service shall not be connected until customer has met all requirements called for under this tariff, the Rules and Regulations and the applicable service classification.

2.10 Connection or Reconnection of Service at an Existing Location:

Whenever service is initiated to any customer in an existing location (with previous service), a service charge will be made as specified on Rate Schedule CHG. Service shall not be connected until customer has met all requirements called for under this tariff, the Rules and Regulations and the applicable service classification.

2.11 Reconnection of Service Requirements:

Company shall not reconnect service to customer's premises, where service has been disconnected by reason of any act or default of customer, until such time as customer has rectified the condition or conditions causing discontinuance of service. In cases where the service has been disconnected for a period greater than one year, a reconnect certification by the authority having jurisdiction or by a license electrician will be required to ensure the safety and condition of customer wiring. It shall be provided further that service shall not be reconnected until customer has met all financial requirements called for under the Rules and Regulations and the applicable service classification. A service charge under Subparagraph 2.10 above will also be assessed.

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3. WIRING AND ENTRANCE STANDARDS

3.1 Inspection:

The Company shall not connect with any customer's installation until the customer provides the following documentation to the Company:

- A. A certificate which indicates that such installation has been properly inspected by a duly qualified person, and the installation has been completed in accordance with these "Terms and Conditions" as well as with the National Electrical Code. Such certificate shall be obtained from a county or municipality, or person, agency or organization duly appointed by a county or municipality to make such inspections. When a county or municipality does not provide, in accordance with applicable statutes, for the regulation and inspection of wires and appliances for utilization of electric energy, or has not appointed any person, agency or organization to make such inspection, then an inspection certificate issued by any organization authorized to perform inspections by designation and approval of the State of New Jersey shall be accepted in lieu thereof.
- B. Evidence from the customer that any air conditioning equipment installed to serve the building has a Seasonal Energy Efficiency Ratio equal to or in excess of 10.0 for split systems and 9.7 for single package systems. Any change in, or addition to, the original wiring and equipment of the customer shall be subject to the foregoing requirements to insure continuance of service. No liability shall attach to the Company because of any waiver of these requirements, or failure of customer to comply with these requirements.
- C. A State, County or municipal permit, inspection or approval does not indicate an adherence or compliance to all ACE requirements. Please consult your local company representative for ACE specific requirements.

3.2 Minimum Entrance Requirements:

All construction shall be performed in accordance with the requirements of the National Electrical Code and any applicable governmental codes. The service entrance size shall be determined in accordance with the requirements for the load ultimately to be connected, and not the initial load, in order to avoid subsequent additional modification of the service entrance when additional load or larger devices are connected.

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3. WIRING AND ENTRANCE STANDARDS (Continued)

3.3 Service Connections From Overhead Distribution Lines:

The Company shall designate the location of its service connection. The customer's wiring must be brought outside the building wall nearest the Company's service wires so as to be readily accessible thereto and in such manner that all wires or cables carrying unmetered energy will be in plain view from the exterior of the building. The building wiring shall include not less than eighteen (18) inches of conductors arranged so as to permit connection to the company's service conductors. The building wiring shall comply with the requirements of the National Electrical Code with respect to grounding. All connections between the customer's service equipment and the Company's service wires must be installed as recommended by the National Electrical Code. The Company shall modify or extend its facilities onto private property. Any costs associated with this extension shall be based on approved costs established in the Tariff section III, approved at the time of the customer's application.

3.4 Underground Service Connections From Overhead Lines:

Customers desiring an underground service from overhead wires may obtain such at their expense, which, consistent with the Tax Reform Act of 1986 and N.J.A.C. 14:3-8.5(c) shall include the federal and state income tax consequences of such extension to the Company. In the case of new installations, a customer shall be entitled to a credit equal to the cost of overhead service which the Company otherwise would have installed at no additional cost to the customer.

3.5 Service Connections in Urban Underground Network Areas:

In areas designated by the Company as Urban Underground Network Areas, the customer will install necessary ducts, cables and/or service boxes to locations designated by the Company. The Company should be consulted in advance on all installations to be served in the area to be served designated by the necessary permits to open the street. It shall not be obligated to furnish service where such permit is not granted, nor where the customer refuses to reimburse the Company for any municipal charges it incurs or will incur with respect to obtaining such permit.

3.6 Service Connection Other Than as Specified:

If a customer requests that energy should be delivered at a point or in a manner other than that specified by the Company, and the Company agrees thereto, a charge shall be made equal to the additional cost of such delivery. This cost would be based on an estimate of the time, material, overheads and applicable taxes required to install any additional facilities at the customer's request.

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4. USE OF ENERGY

4.1 Additional Loads:

Each customer shall inform the Company of any plan or intention to make a substantial addition, including, without limitation, adding additional load greater than 50% of the existing load, to the customer's equipment or connected load, in order that the Company may assure that its facilities are adequate to serve the intended increase. All electric vehicle (EV) charging stations installed behind the customer meter shall be reported to ACE to ensure proper equipment sizing prior to use.

4.2 Installation and Use of Motors and Appliances:

The customer shall install only motors, apparatus or appliances which are suitable for operation with the character of the service supplied by the Company, and which shall not be detrimental to the Company or its equipment. The electric power must not be used in such a manner as to cause excessive voltage fluctuations or disturbances in the Company's transmission or distribution system. The Company shall be the sole judge as to the suitability of apparatus or appliances to be connected to its lines, and also as to whether the operation of such apparatus or appliances will be detrimental to its general service. Unless modified by specific agreement, single phase motors shall not exceed 5 horse power for residential customers. Commercial customers can install up to 10 horse power with Company approval.

4.3 Characteristics of Motors and Apparatus:

All apparatus used by the customer shall be of such type as to assure the highest practicable power factor and the proper balancing of phases. The starting characteristics of all motors subject to intermittent operation or automatic control shall be in accordance with standards established by the Company. Motors shall be protected by suitable loss of phase protection where applicable. Welders and other devices with high in-rush currents or undesirable operating characteristics shall not be served except as provided in Subparagraph 9.2 and 9.5A. A violation of this requirement may result in the customer's, service being discontinued by the Company until such time as the customer's use of the electric energy furnished hereunder is restored to be in conformance with these requirements. Such suspension of service by the Company shall not operate as a cancellation of any contract with the customer.

4.4 Resale of Energy:

Resale of energy will be permitted only by electric public utilities and alternate suppliers subject to the jurisdiction of the Board of Public Utilities or any other duly authorized regulatory agency, and only with the written consent of the Company.

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4. USE OF ENERGY (Continued)

4.5 Residential Use:

All individual residences shall be served individually under the appropriate service schedule. Three phase (3ph) service and service for motors in excess of 5 horsepower shall not be allowed for residential service. Service for such loads shall be furnished under the appropriate general service schedule. Customers shall not be allowed to receive service for two (2) or more separate residences through a single meter under any schedule, regardless of common ownership of the affected residences. A residential unit is defined as a dwelling intended for residential occupancy. Any separate building loads may be served from this residential meter that is not intended for commercial purposes. Any additional buildings separately metered not meeting the residential use definition in the administrative code (N.J.A.C. 5:28-1.2, N.J.A.C. 5:28-1.4, N.J.A.C. 14:3-1.1) will not be installed under the residential rate regardless of the property use.

4.6 Commercial Activities Within Residences:

Detached building or buildings appurtenant to the residence, such as a garage, stable or barn, may be served by an extension of the customer's residential service wiring and meter. That portion of a residence which becomes regularly used for commercial or manufacturing purposes shall be served under a general service schedule. A customer shall be authorized to maintain separate wiring so that the residential portion of the premises is served through a separate meter under the appropriate schedule, and the commercial or manufacturing portion of the premises is served through a separate meter or meters under the appropriate general service schedule. In the event that the customer does not elect to utilize this authorization, the appropriate general service schedule shall apply to all service supplied.

4.7 Other Sources of Energy:

The Company will not supply service to customers who have other sources of energy supply except under schedules which specifically provide for such service. A customer shall not be permitted to operate its own generating equipment in parallel with the Company's service, except with the written permission of the Company. In order to avoid undue jeopardy to life and property to the customer's premises, to the Company's system, and in the facilities of third parties, the customer shall not install its own generating equipment without the prior written permission of the Company.

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5. COMPANY'S EQUIPMENT

5.1 Installation on Customer's Property:

The customer shall grant the Company the right to construct required service facilities on the customer's property, and place its meters and other apparatus on the property or within the buildings of the customer, at a point or points mutually agreed to for such purpose, and the customer shall further grant to the Company the right to adequate space for the installation of necessary measuring instruments sufficient that such equipment can be protected from injury by the elements or through the negligence or deliberate acts of the customer, any employee of the customer or a third party. The customer agrees to maintain proper clearances, in accordance with NESC, UCC, NFPA and, or the Electric Service Handbook, to all company owned facilities in all future modifications or additions. The customer has the right to have ACE facilities relocated at customers expense. The Company shall not install transformers within the building(s) of the customer. The installation of meters and connections shall be in accordance with N.J.A.C. 14:3-4.2 and N.J.A.C. 14:5.

5.2 Maintenance of Company's Equipment:

The Company will provide and maintain in proper operating condition the necessary line or service connections, transformers (when same are required by conditions of contract between the parties thereto), meters and other apparatus which may be required for the proper measurement of and protection of the service. All such apparatus shall be and remain the property of the Company.

5.3 Attachment to Company Owned Facilities:

No radio transmitting, receiving, television or other antennae may be connected to the Company's lines, nor attached to its poles, cross arms, structures or other facilities without the written consent of the Company. No signs nor devices of any type may be attached to the Company's poles, structures, or other facilities without the written consent of the Company.

5.4 Right of Entrance to Customer's Premises:

Pursuant to N.J.A.C. 14:3-3.6(a), the Company shall have the right at all reasonable hours to enter and to have reasonable access to the premises of the customer for the purpose of installing, reading, removing, testing, inspecting, replacing or otherwise disposing of its apparatus and property, and the right to remove the Company's property in the event of the termination of the contract for any cause.

A customer shall not under any circumstances provide access to the Company's facilities to any individual or entity, other than authorized employees of the Company or duly authorized government officials.

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5. COMPANY'S EQUIPMENT (Continued)

5.5 Work Near Company Facilities:

Pursuant to N.J.A.C. 14:3-2.8, no construction, maintenance or other work shall be performed in close proximity to the Company's poles, apparatus, or conductors without the written permission of the Company. A Company representative shall, upon request, review such work to assure that conditions under which such work is to be performed do not involve hazards to life, property or continuity of service. Contractors and other entities working in close proximity to the Company's lines must do so in compliance with N.J.S.A. 34:6-47.1 and 2 and any applicable provisions of the Occupational Safety and Health Administration regulations. Any work required to mitigate such hazards or continuity of service shall be undertaken at the sole expense of the party requesting such work.

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6. METERING, BILLING AND PAYMENT FOR SERVICE

6.1 Meters:

Meters shall be owned and maintained by the Company in accordance with Section 5 above. The installation of meters and connections shall be in accordance with N.J.A.C. 14:3-4.2 and N.J.A.C. 14:5.

6.2 Special Testing of Meters:

Meters shall be tested in accordance with regulations of the Board of Public Utilities. Pursuant to N.J.A.C. 14:3-4.5, a customer may request an accuracy test be made by the Company at no charge, provided that the Company shall not be required to perform such test more than once every 12 months. If a Customer requests an accuracy test more than once in a 12 month period, a service charge will be made as specified in Rate Schedule CHG. Whenever a meter is found to register faster than the amount allowed by the Board, the test fee will be waived. Complete reports of the results of such tests will be made available to the customer and will be kept on file by the Company in accordance with Board of Public Utilities' regulations. Customers may also request that a test be made by an inspector of the Board of Public Utilities. There is a fee for such tests which must be paid by the customer to the Board of Public Utilities. If the meter is found to be operating "fast" and beyond the allowable limits, the Company will reimburse the customer for the fee paid.

6.3 Adjustment of Bill:

Whenever a meter is found to be registering "fast" in excess of the allowable limits established by the Board of Public Utilities, an adjustment shall be made corresponding to the percentage error as found in the meter covering the entire period during which the meter registered inaccurately, provided such period can be determined. Where such period cannot be determined, a correction shall be applied to $\frac{1}{2}$ of the total amount of billing affected since the most recent prior 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 shall be in accordance with N.J.A.C. 14:3-4.6.

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6. METERING, BILLING AND PAYMENT FOR SERVICE (Continued)

6.4 Payment of Bills:

Bills are payable upon presentation, at any location identified by the Company as a payment office, Courtesy Center or authorized collection agency, within twenty (20) days of the postmarked date. The Company may require earlier payment to prevent fraud or illegal use of energy or when it is clearly evident that customer is preparing to vacate the premises.

Overdue bills for non-residential customers are subject to a late payment charge as specified on Rate Schedule CHG. This charge will be applied to amounts billed including accounts payable and unpaid late payment charge amounts applied to previous bills, which are not received by the Company within forty-five (45) days for non-residential customers following the due date specified on the bill. The amount of the late payment charge to be added to the unpaid balance for non-residential customers shall be determined by multiplying the unpaid balance by the late payment charge rate as specified in Rate Schedule CHG. When payment is received by the Company from a customer who has an unpaid balance which includes charges for late payment, the payment shall be applied first to such charges and then to the remainder of the unpaid balance.

New Jersey public utility companies, subject to the New Jersey State Excise Tax, shall be billed net of such taxes.

Courtesy Center Locations

Egg Harbor Township	6814 Tilton Rd, Egg Harbor Township, NJ 08234
Ventnor	5014 Wellington Ave, Ventnor City, NJ 08406
Cape May Court House	420 S Main St, Cape May Court House, NJ 08210.
Millville	1101 N. 2nd St , Millville NJ 08332
Turnersville	5101 Rt42 Turnersville NJ 08012

6.5 Billing Period:

Except as hereinafter provided under normal course of business, customers shall be billed monthly. Bills for other than thirty (30) days shall be prorated. Where credit situations require, the Company may read meters and render bills at shorter intervals.

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6. METERING, BILLING AND PAYMENT FOR SERVICE (Continued)

6.6 Bi-Monthly and Quarterly Readings:

Meters will be read monthly except when business conditions or weather prevent it. The Company reserves the right to read meters at bi-monthly or quarterly intervals. When monthly readings are unavailable, interim monthly bills will be rendered on a calculated basis.

6.7 Special Readings or Succession and Billings:

Special readings, successions and billings shall be made at customer's request. The charge for each reading or billing shall be as specified on Rate Schedule CHG.

6.8 Monthly Billings for Annual Charges:

When an annual charge for service is to be billed and paid monthly, the total charge shall be divided by twelve (12) and rounded to the next higher cent.

6.9 Uncollectible Checks:

A charge will be made when a customer's check is returned by the customer's bank as uncollectible as specified on Rate Schedule CHG.

6.10 Check Metering:

Where a customer monitors or evaluates the customer's own consumption of electrical energy or any portion thereof in an effort to promote and stimulate conservation or for accountability by means of individual meters, computer or otherwise, installed, operated and maintained at such customer's expense, such practice will be defined as check metering. Check metering will be permitted in new or existing buildings or premises where the basis characteristic of use is industrial or commercial. Check metering will not be permitted in existing buildings or premises where the basis characteristic of use is residential, except where such buildings or premises are publicly financed or government owned; or are condominiums or cooperative housing. Check metering for the aforementioned purposes and applications shall not adversely affect the ability of the Company to render service to any other customer or cause harm to the Company equipment. The customer shall be responsible for the accuracy of check metering equipment.

6.11 Budget Billing Plan (Equal Payment Plan):

Residential Customers billed under Rate Schedules RS or RSH, or Commercial Customers with less than 300kW of usage shall have the option of paying for their Atlantic City Electric (ACE) charges in equal, estimated monthly installments. Budget plans shall be made in accordance with N.J.A.C 14:3-7.5. The total ACE charges for the previous twelve-month period will be averaged over twelve months into monthly budget installments. A review between the actual cost of service and the monthly budget amount will be made at least once in the budget plan year. A final bill for a budget plan year shall be issued at the end of the budget plan year and shall include the customer's actual energy charges for that month, as well as any standing budget balance.

6.12 Opting out of Smart Meter:

A monthly charge will be assessed for customers who retain a non-AMI meter, as specified on Rate Schedule CHG. A one-time opt-out fee will be assessed for the removal of a Smart Meter (known as AMI meter) and re-installation of a non-AMI meter, as specified on Rate Schedule CHG.

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7. DISCONNECTION AND RECONNECTION

7.1 Disconnection at Customer's Request:

The Company will disconnect service at the request of customer, and will render a final bill in accordance with the applicable rate schedule. At such time as the customer shall request disconnection, a charge as specified on Rate Schedule CHG may be made. Notice to disconnect will not relieve the customer from any minimum or guaranteed payment established by contract or rate schedule.

Within 48 hours of said notice, the Company shall discontinue service or obtain a meter reading for the purpose of determining a final bill.

7.2 Disconnection for Non-Payment or Non-Compliance:

The Company reserves the right to discontinue service when: (i) the customer's arrearage is more than \$100.00 and/or the customer's account is more than three months in arrears; (ii) for failure to comply with these Terms and Conditions; and (iii) to prevent fraud upon the Company, or where use of energy is not in accordance with the Company's schedules. The Company shall, upon due notice to the customer, discontinue service to any customer reported by a duly authorized inspection agency to be in violation of county, municipal or National Electrical Codes, or reported to be in violation of any governmental order or directive concerning the use of energy. Any such disconnection of service shall not terminate the contract for special extensions or special facilities between the Company and the customer. A service charge will be made as specified on Rate Schedule CHG. No charge will be due on those instances performed for the convenience of the Company.

7.3 Disconnection for Other Reasons:

In addition to the provisions of Subparagraph 7.2 above, the Company may disconnect service for any of the following causes:

- A. for the purpose of effecting repairs;
- B. in compliance with governmental order or directive;
- C. for refusal of the customer to contract for service where such contract is provided for in the applicable tariff schedule; and/or
- D. where the condition of the customer's electric facilities are such as to provide a hazard to life or property.
- E. where customer equipment is causing power quality issues that effect company equipment of other customers

A service charge will be made as specified on Rate Schedule CHG. No charge will be due on those instances performed for the convenience of the Company.

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TERMS AND CONDITIONS OF SERVICE

7.	DISCONNECTION AND RECONNECTION	(Continued)

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In cases where the Company has discontinued service for non-payment of a bill or bills or other cause, a charge for reconnection will be made as specified in Rate Schedule CHG; except where such disconnection has been made by the Company in order to effect repairs. Beyond normal working hours charge will be based on actual costs.

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8. LIABILITIES

8.1 Company Liability:

The Company will use reasonable diligence in furnishing a regular and uninterrupted supply of energy, but in the event such supply is interrupted or fails by reason of, including, but not limited to, an act of God, a public enemy, accidents, strikes, legal process, governmental interference, breakdowns of or injury to the machinery, transmission lines or distribution lines of the Company or extraordinary repairs, the Company shall not be liable for damages.

8.2 Emergencies:

- A. If the Company shall deem it necessary to the prevention or alleviation of an emergency condition which threatens the integrity of its system or the systems to which it is directly or indirectly connected, it may curtail or interrupt service or reduce voltage to any customer or customers pursuant to a plan filed with the Board of Public Utilities in accordance with N.J.A.C 14:29-4.2 or as otherwise permitted or provided in N.J.A.C. 14:29-4.
- B. If the Company, in its sole judgment, shall deem it necessary to the prevention or alleviation of an emergency condition resulting from an actual or threatened restriction of energy supplies available to its system or the systems to which it is directly or indirectly connected, it may curtail or interrupt service or reduce voltage to any customer or customers pursuant to a plan filed with the Board of Public Utilities in accordance with N.J.A.C 14:29-4.2 or as otherwise permitted or provided in N.J.A.C. 14:29-4.

Date of Issue:	Effective Date:
Issued by:	

8. LIABILITIES (Continued)

8.3 Tampering with Company Equipment:

The customer shall not allow or permit any individual or entity, other than a duly authorized employee(s) of the Company to make any internal or external adjustments of any meter or any other piece of apparatus belonging to the Company. In the event it is established by a Court of Law, the Board of Public Utilities, or with the customer's consent, that the Company's wires, meters, meter seals, switch boxes, or other equipment on or adjacent to the customer's premises have been tampered with, the responsible party shall be required to bear all of the costs incurred by the Company, including but not limited to the following: (i) investigations; (ii) inspections; (iii) costs of prosecution including legal fees; and (iv) installation of any protective equipment deemed necessary by the Company. The responsible party shall be the party who either tampered with or caused the tampering with a meter or other equipment or knowingly received the benefit of tampering by or caused by another.

Furthermore, where tampering with the Company's or customer's facilities results in the incorrect measurement of the service supplied by the Company, the responsible party, (as defined above) shall pay for such service as the Company shall estimate from available information to have been used on the premises but not registered by the Company's meter or meters. Under certain conditions, tampering with the Company's facilities may also be punishable by fine and/or imprisonment under applicable New Jersey law.

Date of Issue:	Effective Date:
Issued by:	

9. MISCELLANEOUS

9.1 Service Suggestions:

The Company will supply, upon request, "Information and Requirements for Electric Service Installations," covering suggested wiring methods and installations. Similar information may be obtained covering application of electricity for space heating and other purposes, installation of primary voltage equipment, etc. Such information is furnished as a helpful guide, but is not to be considered a substitute for the services of an architect or professional engineer.

9.2 Provision of Special Equipment:

Where, in the judgment of the Company, the provision of voltage regulators, special transformers, heavier conductors, capacitors or other devices are required for satisfactory operation of welders, or other appliances and apparatus, the operation of which would not normally be permitted under the terms of Subparagraph 4.3, the Company shall permit the use of such appliances and equipment provided the customer agrees, in writing, to compensate the Company for all additional costs involved to provide the special distribution facilities required. Service for X-ray equipment and other devices with voltage stability requirements more stringent than normal standards may also be obtained under terms of this Paragraph.

9.3 Special Equipment Rental Charge:

Such a charge may be payable in twelve (12) equal installments coincident with the regular bill for electric service. Customers who elect to take service under any of the several rate schedules which require customer ownership of a substation and related equipment also may rent such facilities from the Company in accordance with these terms.

9.4 Meter Sockets and Current Transformer Cabinets:

It shall be the customer's responsibility to furnish, install, and maintain self-contained meter sockets in accordance with Company specifications. The Company will provide all current transformers, current transformer cabinets, and current transformer meter sockets for the customer to install.

9.5 Power Factor:

The monthly average power factor under operating conditions of customers' load at the point where the electric service is metered shall be not less than 90%.

A. Harmonic Content

Customer shall limit harmonic content so as not to adversely impact the operations of the distribution system. (Refer to Company's rights under Subparagraph 4.3)

Date of Issue:	Effective Date:
Issued by:	

9. MISCELLANEOUS (Continued)

9.6 Underground Relocation or Placement of Company-Owned Facilities:

Whenever the Company shall be requested by a Federal, State, County or local government entity ("Governmental Entity"), to relocate currently existing overhead facilities underground or to design or redesign proposed facilities to use underground rather than overhead construction, the total cost attributable to such relocation/redesign and underground installation shall be the responsibility of the requesting Governmental Entity, unless preempted by law; and the amount of the Company's estimated costs shall be deposited with the Company in advance. This section is intended to apply to all Company owned transmission, sub-transmission, primary, and/or secondary facilities.

In each instance, and consistent with N.J.A.C. 14:3-8.2, 14:3-8.9(d)3., and 14:3-8.9(h), the cost is intended to be all inclusive and to cover the aggregate of all costs and expenses associated with placement of the facilities underground. This is intended to include, but not be limited to, the cost of engineering, construction, permits, design, right-of-way acquisition, materials and labor, overhead directly attributable to the work as well as overrides and loading factors and the federal and state income tax consequences incurred by the Company as a result of receiving such deposits or contributions. Whenever the costs shall exceed the estimate, the excess costs shall be the responsibility of the requesting entity, and shall be payable to the Company within thirty (30) days of demand. If actual costs should be less than estimated costs, the difference will be refunded to the requesting entity by the Company, without interest, following completion of the project. At the discretion of the Company, large projects requiring extensive engineering costs may require an engineering deposit.

Whenever the Company shall be requested by a Non-Governmental Entity or person ("Non-Governmental Entity"), to relocate currently existing overhead facilities underground or to design or redesign proposed facilities to use underground rather than overhead construction, the total cost attributable to such relocation/redesign and underground installation shall be the responsibility of the requesting Non-Governmental Entity, unless preempted by law; and the amount of the Company's estimated costs shall be deposited with the Company in advance. This section is intended to apply to all Company owned transmission, sub-transmission, primary, and/or secondary facilities.

In each instance, and consistent with N.J.A.C. 14:3-8.2, 14:3-8.9(d)3., and 14:3-8.9(h), the cost is intended to be all inclusive and to cover the aggregate of all costs and expenses associated with placement of the facilities underground. This is intended to include, but not be limited to, the cost of engineering, construction, permits, design, right-of-way acquisition, materials and labor, overhead directly attributable to the work as well as overrides and loading factors and the federal and state income tax consequences incurred by the Company as a result of receiving such deposits or contributions. These costs will be collected by the company in advance of construction and are non-refundable

Notwithstanding anything to the contrary contained herein, whenever the Company, in the exercise of its reasonable discretion, shall determine that underground construction is not feasible or practicable for reasons which may include, but not be limited to environmental conditions, subsoil or subsurface conditions, engineering or technical consideration, or for reason pertaining to maintenance, safety, reliability or integrity of the Company's transmission and/or distribution system, then the Company shall not be obligated to place the facilities underground notwithstanding the request.

Date of Issue:	Effective Date:
Issued by:	

BPU NJ No. 11 Electric Service - Section II Fourth Revised Sheet Replaces Third Revised Sheet No. 25

TERMS AND CONDITIONS OF SERVICE

9. MISCELLANEOUS (Continued)

9.7 Overhead Relocation or Placement of Company-Owned Facilities:

Whenever the Company shall be requested by a Federal, State, County or local government entity ("Governmental Entity"), to relocate currently existing overhead facilities or to design or redesign proposed facilities underground rather than overhead, the total cost attributable to such relocation/redesign and installation shall be the responsibility of the requesting Governmental Entity unless preempted by law; and the amount of the Company's estimated costs shall be deposited with the Company in advance. This section is intended to apply to all Company owned transmission, sub-transmission, primary, and/or secondary facilities.

In each instance, and consistent with N.J.A.C. 14:3-8.2, 14:3-8.9(d)3. and 14:3-8.9(h), the cost is intended to be all inclusive and to cover the aggregate of costs and expenses associated with placement of the facilities. This is intended to include, without limitation, all costs as defined in section 9.6 above. Whenever the costs shall exceed the estimate, the excess costs shall be the responsibility of the requesting entity, and if actual costs should be less than estimated costs, the difference will be refunded to the requesting entity by the Company, without interest, following completion of the project.

Whenever the Company shall be requested by a Non-Governmental Entity or person ("Non-Governmental Entity"), to relocate currently existing overhead facilities or to design or redesign proposed facilities to use underground rather than overhead, the total cost attributable to such relocation/redesign and installation shall be the responsibility of the requesting Non-Governmental Entity, unless preempted by law; and the amount of the Company's estimated costs shall be deposited with the Company in advance. This section is intended to apply to all Company owned transmission, sub-transmission, primary, and/or secondary facilities.

In each instance, and consistent with N.J.A.C. 14:3-8.2, 14:3-8.9(d)3., and 14:3-8.9(h), the cost is intended to be all inclusive and to cover the aggregate of all costs and expenses associated with placement of the facilities. This is intended to include, without limitation, all costs as defined in section 9.6 above. These costs will be collected by the company in advance of construction and are non-refundable

At the discretion of the Company, large projects requiring extensive engineering costs may require an engineering deposit. Notwithstanding anything to the contrary contained herein, whenever the Company, in the exercise of its reasonable discretion, shall determine that construction is not feasible or practicable for reasons which may include but not be limited to environmental conditions, subsoil or subsurface conditions, engineering or technical considerations or for reasons pertaining to maintenance, safety, reliability or integrity of the Company's transmission and/or distribution system, then the Company shall not be obligated to relocate or place the facilities notwithstanding the request.

Date of Issue:	Effective Date:
Issued by:	

10. GENERAL INTERCONNECTION REQUIREMENTS FOR CUSTOMER'S GENERATION

The following requirements and standards for interconnection of the customer's generating facilities to the Company's system shall be met to assure the integrity and safe operation of the utility system with no reduction in the quality of service being provided to the other customers. Typical installation guidelines for customer owned generators are outlined in the Company's "Technical Interconnection Requirements" and "Technical Considerations Covering Parallel Operations of Customer Owned Generation". The Tariff's conditions are meant to be general in nature, and may not reflect the latest revisions to these Guidelines. Therefore, cogenerators and small power producers shall obtain and adhere to the latest guidelines.

10.1 General Design Requirements:

- A. The customer's installation must meet all applicable national, state and local construction, safety and electrical codes.
- B. Adequate protection devices (relays, circuit breakers, etc.) for the protection of the Company's system, metering equipment and synchronizing equipment must be installed by the customer.
- C. The customer shall provide a load break disconnecting device with a visible open that can be tagged and locked on the Company's side of the interconnection. For systems over 2 MW, the location and type of disconnect must be mutually agreeable to the Company.
- D. Installations where the customer is to provide protective devices for the protection of the Company's system, the customer shall submit a single-line drawing of this equipment sealed by a licensed professional engineer to the Company for informational purposes only.
- E. All cogeneration/small power producer customers must have a dedicated service transformer. This transformer will decrease voltage variations experienced by other customers, attenuate harmonics, and reduce the effects of fault current.
- F. The cogeneration/small power producer customer has sole responsibility for properly synchronizing its generation equipment with the Company's frequency and voltage.

Date of Issue:	Effective Date:
Issued by:	

GENERAL INTERCONNECTION REQUIREMENTS FOR CUSTOMER'S GENERATION (Continued)

10.2 General Operating Requirements:

The interconnection of the customer's generating equipment with the Company's system shall be designed and operated by the customer to cause no reduction in the quality of service being provided to other customers. No abnormal voltages, frequencies or interruptions shall be permitted. The customer's facility shall produce 60 Hertz sinusoidal output with harmonic distortion no greater than 5%. If the Company receives complaints regarding waveform distortion or high or low voltage flicker due to the operation of the customer's generation, such generating equipment shall be disconnected without notice until the problem has been resolved. There shall be no responsibility on the part of the Company, its directors, officers, agents, servants or employees for disconnection. The customer may not commence parallel operation with the Company's system until final written approval has been granted by the Company. The Company reserves the right to inspect the customer's facility and witness testing of any equipment or devices associated with the interconnection.

Switching of the interface breaker or switch device shall be under the administrative control of the Company. This includes the Company's right to open the interface breaker or switching device with or without prior notice to the supplier for any of the following reasons:

- A. to facilitate maintenance, test or repair of utility facilities;
- B. during system emergencies;
- C. when the customer's generating equipment is interfering with other customers on the system;
- D. when the inspection of the customer's generating equipment reveals a condition hazardous to the Company's system or a lack of scheduled maintenance records for equipment necessary to protect the Company's system; and/or
- E. to ensure the safety of the general public and Company personnel.

Date of Issue:	Effective Date:
Issued by:	

10. GENERAL INTERCONNECTION REQUIREMENTS FOR CUSTOMER'S GENERATION (Continued)

10.2 General Operating Requirements: (Con't.)

Automatic disconnecting device, with appropriate automatic control apparatus, must be provided by the customer to isolate the customer's facility from the Company's system for, but not necessarily limited to, the following abnormal conditions:

- A. a fault on the customer's equipment
- B. a fault on the utility system;
- C. a de-energized utility line to which the customer is connected;
- D. an abnormal operating voltage or frequency;
- E. failure of automatic synchronization with the utility system;
- F. loss of a phase or improper phase sequence;
- G. total harmonic content in excess of 5%;
- H. abnormal power factor; and/or
- I. load flow exceeding an established limit.

The customer will not be permitted to energize a de-energized Company circuit.

Operation of the customer's generator shall not adversely affect the voltage regulation of the Company's system to which it is connected. Adequate voltage control shall be provided, by the customer, to minimize voltage regulation on the Company's system caused by changing generator loading conditions.

Date of Issue:	Effective Date:
Issued by	

GENERAL INTERCONNECTION REQUIREMENTS FOR CUSTOMER'S GENERATION (Continued)

10.3 Design Information:

The Company's high voltage distribution system consists of either 4kV, 12kV, 23kV, 34.5kV or 69kV grounded wye. The customer's generator should be designed to be tripped or isolated from Company's system before the first automatic reclose occurs following a fault. Once the customer's generator is isolated from the Company's system, the customer's generator can be paralleled with the Company's system only after approval of the Company's System Control Center. Customers with three-phase generators should be aware that certain conditions in the utility system may cause negative sequence currents to flow in the generator. It is the sole responsibility of the customer to protect his equipment from excess negative sequence currents.

10.4 Design Considerations:

Parallel Operation

A parallel system is defined as one in which the customer's generation can be connected to a bus common with the utility's system. A consequence of such parallel operation is that the parallel generator becomes an electrical part of the utility system which must be considered in the electrical protection of the utility's facilities.

Reactive Power Requirements

When delivering real power (kilowatts) to the Company, the generator must be capable of operating with a power factor at the Point of Delivery to the Company between .95 leading to .95 lagging power factor, such that the generator would receive lagging reactive power (kilovars) from the Company and be capable of delivering leading reactive power (kilovars) to the Company.

Induction Generators

Installation of induction generators over 200 KVA capacity may, at its discretion, require capacitors or dynamic VAR devices to be installed to limit adverse effects of reactive power flow on the Company's system voltage regulation. Such capacitors will be at the expense of the generating facility.

Inverter System

Reactive power supply requirements for inverter systems are similar to those for induction generators and the general guidelines discussed above will apply.

Date of Issue:	Effective Date:
Issued by:	

10. GENERAL INTERCONNECTION REQUIREMENTS FOR CUSTOMER'S GENERATION (Continued)

10.5 Protection Guidelines:

The required protection equipment to be installed by the customer is selected and installed to meet the following objectives, which are not intended to be all inclusive:

- A. provide adequate protection for faults, overloads or other abnormal conditions on the customer's equipment;
- B. provide adequate protection for faults, overloads on the Company's lines, transformers or other equipment;
- C. prevent outages or other adverse effects to other Company customers;
- D. provide a safe means to control, operate, connect, and disconnect the inter-tie of the customer's generation and the Company's system; and/or
- E. provide a free flow of normal power transfer.

10.6 Information to be Supplied by Cogenerator/Small Power Producer: <u>Drawings</u>

- A. a one line diagram of entire system;
- B. a potential elementary of customer-owned generation system;
- C. a current elementary of customer-owned generation system;
- D. a control elementary of generator breaker and interface breaker; and
- E. a three line diagram of generation system.

Date of Issue:	Effective Date:	
Issued by:		

11. ELECTRIC INDUSTRY RESTRUCTURING STANDARDS

11.1 Change of Alternative Electric Supply

Customers served under any of the applicable rate schedules of this tariff for electric service and who desire to purchase their electric supply of capacity, transmission, and energy, hereinafter referenced as electric supply, from a Third Party Supplier, hereinafter referred to as an Alternative Electric Supplier, must execute a contract with an Alternative Electric Supplier. Customers who are not enrolled with an Alternative Electric Supplier will continue to receive their electric supply from the Company.

11.2 Enrollment

Customers may request an enrollment package from the Company which, in addition to providing general information regarding electric supply, describes the process necessary for a customer to obtain an alternative electric Supplier. This enrollment package will be provided to the customer at no charge and may be obtained by calling or writing the Company or visiting a Customer Service Center. Upon written request of the customer, the Company will provide customer usage information to any number of Alternative Electric Suppliers pursuant to Appendix D of the Company's Third Party Supplier Agreement.

11.3 Alternative Electric Supplier

An Alternative Electric Supplier is a retail energy and capacity provider that has executed a Third Party Supplier Agreement with the Company so as to be able to furnish electric supply to retail customers. The provisions of this tariff shall govern such Agreement, and the same form of Agreement shall be offered to all Alternative Electric Suppliers. Delivery of such electric supply will be by the Company. Alternative Electric Suppliers shall be liable for payment of the fees set forth in such Agreement. Any modifications to these fees shall be set after an evidentiary hearing before the Board of Public Utilities. The Agreement requires that the Alternative Electric Supplier satisfy the creditworthiness standards of the Company, be licensed by the Board of Public Utilities and any other appropriate New Jersey state agencies, and satisfy any and all other legal requirements necessary for participation in the New Jersey retail energy market. By determining an Alternative Electric Supplier to be creditworthy, the Company makes no express or implied warranties or guarantees of any kind with respect to the financial or operational qualifications of such Alternative Electric Supplier. Except with respect to fee changes, the Company may modify such Agreement by filing a proposed modification with the Board of Public Utilities, and transmitting same within 48 hours to the Division of Rate Counsel and to all licensed Alternative Electric Suppliers in New Jersey. Any objection to the requested change must be submitted within 17 days. The proposed modification shall take effect 45 days after the filing, unless the Board of Public Utilities issues a suspension order putting the request on hold. In the event the Board of Public Utilities does not act within 45 days of the filing, it reserves the right to make a determination on the request in the future.

Date of Issue:	Effective Date:
Issued by:	

11. ELECTRIC INDUSTRY RESTRUCTURING STANDARDS (Continued)

11.4 Change of Alternative Electric Supplier

The Company shall not initiate or change a customer's Alternative Electric Supplier unless the requirements set forth by the Board of Public Utilities pursuant to its Orders dated March 17, 1999 and May 5, 1999 (BPU Docket Nos. EX94120585Y, etc.) or future Board of Public Utilities Orders have been complied with by both the customer and the Alternative Electric Supplier.

11.5 Late Payment Charges

In the case of electric supply furnished by an Alternative Electric Supplier, Subparagraph 6.4 of these Terms and Conditions is to be applicable only to Company charges. Customer shut-offs in cases where there is non-payment to the Company for its delivery charges are only performed in accordance with Subparagraph 7.2 of these Terms and Conditions.

Date of Issue:	Effective Date:
Issued by:	

11. ELECTRIC INDUSTRY RESTRUCTURING STANDARDS (Continued)

11.6 Billing Disputes

In the event of a billing dispute between the customer and the Alternative Electric Supplier, the Company's sole duty is to verify its charges and billing determinants. The customer is responsible for the timely payment of all Company charges in accordance with Subparagraph 6.4 of these Terms and Conditions, regardless of Alternative Electric Supplier billing disputes. All questions regarding Alternative Electric Suppliers' charges or other terms of the customer's agreement with the Alternative Electric Supplier are to be resolved between the customer and the Alternative Electric Supplier. The Company will not be responsible for the enforcement, intervention, mediation, or arbitration of agreements entered into between Alternative Electric Suppliers and their customers.

11.7 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.

11.8 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.

Date of Issue:	Effective Date:
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ATLANTIC CITY ELECTRIC COMPANY

TARIFF FOR ELECTRIC SERVICE

SECTION IV - SERVICE CLASSIFICATIONS AND RIDERS

ATLANTIC CITY ELECTRIC COMPANY

Regional Headquarters

5100 Harding Highway Mays Landing, New Jersey 08330-2239

Date of Issue:	Effective Date	_
Date of Issue.	Filective Date	ρ

RATE SCHEDULE CHG (Charges)

APPLICABILITY OF SERVICE

Applicable to all customers in accord with the tariff paragraph noted below

SERVICE CHARGES

1.	Installation of Service at Original Location (See Section II paragraph 2.9)\$65.00
2.	Connection, Reconnection, or Succession of Service at Existing Location (See Section II paragraphs 2.10 and 2.11)\$15.00
3.	Disconnection (See Section II paragraph 7.1, 7.2, or 7.3)\$15.00
4.	Special Reading of Meters (See Section II paragraph 6.7)\$15.00
5.	Opting out of Smart Meter (AMI Meter) (See Section II paragraph 6.12)

LATE PAYMENT CHARGES

(See paragraph 6.4)	. 0.877% Per Month
(Non-residential only)	. (10.52% APR)

UNCOLLECTIBLE CHECKS

"In accordance with P.L. 1997,c.192, the charges in this Rate Schedule include provision for the New Jersey Corporation Business Tax and the New Jersey Sales and Use Tax. When billed to customers exempt from one or more of these taxes, as set forth in Riders CBT and SUT, such charges will be reduced by the relevant amount of such taxes included therein."

Date of Issue:	Effective Date:

Replaces Revised Sheet No. 5

RATE SCHEDULE RS (Residential Service)

AVAILABILITY

Available for full domestic service to individually metered residential customers, including rural domestic customers, engaged principally in agricultural pursuits.

	SUMMER June Through September	WINTER October Through May	
Delivery Service Charges:			
Customer Charge (\$/Month)	\$7.60	\$7.60	
Distribution Rates (\$/kWH)			
First Block	\$0.090162	\$0.082054	
(Summer <= 750 kWh; Winter<= 500kWh)			
Excess kWh	\$0.105853	\$0.082054	
Non-Utility Generation Charge (NGC) (\$/kWH)	See F	Rider NGC	
Societal Benefits Charge (\$/kWh)			
Clean Energy Program	See F	Rider SBC	
Universal Service Fund	See Rider SBC		
Lifeline	See Rider SBC		
Uncollectible Accounts	See Rider SBC		
Transition Bond Charge (TBC) (\$/kWh)	See Rider SEC		
Market Transition Charge Tax (MTC-Tax) (\$/kWh)	See Rider SEC		
Transmission Service Charges (\$/kWh):			
Transmission Rate	\$0.032305	\$0.032305	
Reliability Must Run Transmission Surcharge	\$0.	000000	
Transmission Enhancement Charge (\$/kWh)	See Rider BGS		
Basic Generation Service Charge (\$/kWh) Regional Greenhouse Gas Initiative Recovery Charge	See Rider BGS		
(\$/kWh)	See Rider RGGI		
Infrastructure Investment Program Charge	See Rider IIP		
Conservation Incentive Program Recovery Charge	See F	Rider CIP	

CORPORATE BUSINESS TAX (CBT)

Charges under this rate schedule include a component for Corporate Business Taxes as set forth in Rider CBT.

NEW JERSEY SALES AND USE TAX (SUT)

Charges under this rate schedule include a component for New Jersey Sales and Use Tax as set forth in Rider SUT.

Date of Issue:	Effective Date:	
Issued by:		

Fifth Revised Sheet Replaces Fourth Revised Sheet No. 6

RATE SCHEDULE RS (Continued) (Residential Service)

TERM OF CONTRACT

None, except that reasonable notice of service discontinuance will be required.

TERMS AND CONDITIONS

See Section II inclusive for Terms and Conditions of Service.

"In accordance with P.L. 1997, c. 162, the charges in this Rate Schedule includes provision for the New Jersey Corporation Business Tax and the New Jersey Sales and Use Tax. When billed to customers exempt from one or more of these taxes, as set forth in Riders CBT and SUT, such charges will be reduced by the relevant amount of such taxes included therein."

PRICE TO COMPARE

A customer may choose to receive electric supply from a third party supplier as defined in Section 11 of the Standard Terms and Conditions of this Tariff. A customer who receives electric supply from a third party supplier will not be billed the Basic Generation Service Charges or the Transmission Service Charges. Customers eligible for BGS CIEP who receive supply from a third party supplier will continue to be billed the CIEP Standby Fee.

Date of Issue:	Effective Date:	
Issued by:		

ATLANTIC CITY ELECTRIC COMPANY

RATE SCHEDULE RS TOU-D (Residential Service Time of Use Demand)

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Issued by:

Rate Schedule RS-TOU-D eliminated effective August 1, 2003.

Date of Issue:

RATE SCHEDULE RS TOU-D (Continued) (Residential Service Time of Use Demand)

Rate Schedule RS-TOU-D eliminated effective August 1, 2003.

Date of Issue:	Effective Date:
Issued by:	

Exhibit A Clean Page 62 of 146

ATLANTIC CITY ELECTRIC COMPANY

BPU NJ No. 11 Electric Service - Section IV Eighth Revised Sheet Replaces Seventh Revised Sheet No. 9

RATE SCHEDULE RS TOU-E (Residential Service Time of Use Energy)

AVAILABILITY

Rate Schedule RS-TOU-E eliminated effective August 1, 2003.

Date of Issue:	Effective Date:
Issued by:	

ATLANTIC CITY ELECTRIC COMPANY BPU NJ No. 11 Electric Service - Section IV Second Revised Sheet Replaces First Revised Sheet No. 10

RATE SCHEDULE RS TOU-E (Continued) (Residential Service Time of Use Energy)

	Rate Schedule RS-TOU-E eliminated effective August 1, 2003.			
Date of Issue:		Effective Date:		
Issued by:				

Original Sheet No. 10a

RATE SCHEDULE EV-ERR (Electric Vehicle Equivalent Residential Rate)

AVAILABILITY

Available to residential customers of record who are residential unit owners at a multi-unit dwelling ("MUD"), a planned MUD development, or other separately metered dwelling not intended for residential occupancy, primarily for EV charging. The rate is available for service to Level 2 ("L2") charge stations that are installed in the MUD residential unit owner's designated parking space or for service to Level 1 and L2 chargers installed in the residential customer's non-dwelling structure when a separate meter for service is required. The designated parking space or other non-dwelling structure where the charger will be installed must be located at, upon, or adjacent to the premises of the dwelling or planned MUD development where the owner resides. Wiring and other necessary service equipment past the point of service connection is the responsibility of the customer under the terms and conditions described in Section II, 2.5 A. Single Residential Customer and Section III, Residential Underground Extensions. The customer is responsible for obtaining the necessary permissions and approvals that may be required for the installation of infrastructure, metering, and EV charging equipment on common grounds. The charge station must be intended for the sole use of the residential unit owner and the customer is prohibited from selling electricity in any capacity from the charging station or from connecting loads other than EV charging stations to the meter. This schedule is not available to commercial unit owners.

In instances where a separate meter is not required and all other availability qualifications have been satisfied, the charger may be connected to the residential unit owner's main domestic service meter and receive the Residential Service rate schedule.

	SUMMER June Through September	WINTER October Through May
Delivery Service Charges: Customer Charge (\$/Month) Distribution Rates (\$/kWH) First Block (Summer <= 750 kWh; Winter<= 500kWh) Excess kWh	\$7.60 \$0.090162 \$ 0.105853	\$7.60 \$ 0.082054 \$ 0.082054
Non-Utility Generation Charge (NGC) (\$/kWH)	See R	tider NGC
Societal Benefits Charge (\$/kWh) Clean Energy Program Universal Service Fund Lifeline Uncollectible Accounts Transition Bond Charge (TBC) (\$/kWh) Market Transition Charge Tax (MTC-Tax) (\$/kWh) Transmission Service Charges (\$/kWh):	See Rider SBC See Rider SEC See Rider SEC	
Transmission Rate Reliability Must Run Transmission Surcharge Transmission Enhancement Charge (\$/kWh) Basic Generation Service Charge (\$/kWh) Regional Greenhouse Gas Initiative Recovery Charge (\$/kWh) Infrastructure Investment Program Charge Conservation Incentive Program Recovery Charge	\$0.032305 \$0.032305 \$0.000000 See Rider BGS See Rider BGS See Rider RGGI See Rider IIP See Rider CIP	

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Original Sheet No. 10b

RATE SCHEDULE EV-ERR (Electric Vehicle Equivalent Residential Rate)

CORPORATE BUSINESS TAX (CBT)

Charges under this rate schedule include a component for Corporate Business Taxes as set forth in Rider CBT.

NEW JERSEY SALES AND USE TAX (SUT)

Charges under this rate schedule include a component for New Jersey Sales and Use Tax as set forth in Rider SUT.

RESIDENTIAL UNIT OWNER

The owner of record of a residential dwelling unit located within a development or planned MUD development, or, in the case of cooperative housing corporation, a shareholder of record owning the shares appurtenant to an individual residential dwelling unit. Residential Unit owner does not mean the owner of a commercial unit, space, or interest located within a planned real estate development.

DEVELOPMENT OR PLANNED MUD DEVELOPMENT

Any real property situated within the State, whether contiguous or not, which consists of or will consist of, separately owned areas, irrespective of form, be it lots, parcels, units, or interest, which are offered or disposed of pursuant to a common promotional plan, and which provide for common or shared elements or interests in real property, including, but not limited to, property subject to the "Condominium Act," P.L.1969, c.257 (C.46:8B-1 et seq.), any form of homeowners' association, housing cooperative, or community trust or other trust device. "Planned MUD development" shall not include or apply to any form of timesharing.

DESIGNATED PARKING SPACE

A parking space that is specifically designated for use by a particular residential unit owner, including but not limited to a garage, a deeded parking space, or other parking space/garage located at the resident's premises or upon the premises of the planned MUD development where the resident resides and that is intended for a specific resident's exclusive use.

ELECTRIC VEHICLE CHARGING STATION

A station that is installed in compliance with the State Uniform Construction Code, adopted pursuant to P.L.1975, c.217 (C.52:27D-119 et seq.), that delivers electricity from a source outside an electric vehicle into an electric vehicle.

Level 2 ("L2") Charger Electric Vehicle Service Equipment ("EVSE") that provides a plug-in electric vehicle with single phase alternating current electrical power at 208-240V AC, which is approved for installation for this purpose under the National Electric Code through Underwriters Laboratories Certification or an equivalent certifying organization.

Date of Issue:	Effective Date:
Issued by:	

Original Sheet No. 10c

RATE SCHEDULE EV-ERR (Electric Vehicle Equivalent Residential Rate)

TERM OF CONTRACT

None, except that reasonable notice of service discontinuance will be required.

TERMS AND CONDITIONS

See Section II Inclusive for Terms and Conditions of Service.

"In accordance with P.L. 1997, c. 162, the charges in this Rate Schedule includes provision for the New Jersey Corporation Business Tax and the New Jersey Sales and Use Tax. When billed to customers exempt from one or more of these taxes, as set forth in Riders CBT and SUT, such charges will be reduced by the relevant amount of such taxes included therein."

PRICE TO COMPARE

A customer may choose to receive electric supply from a third-party supplier as defined in Section 11 of the Standard Terms and Conditions of this Tariff. A customer who receives electric supply from a third-party supplier will not be billed the Basic Generation Service Charges or the Transmission Service Charges. Customers eligible for BGS CIEP who receive supply from a third-party supplier will continue to be billed the CIEP Standby Fee.

Date of Issue:	Effective Date:
Issued by:	

RATE SCHEDULE MGS-SECONDARY (Monthly General Service)

AVAILABILITY

Issued by:

Available at any point within the Company's system where facilities of adequate character and capacity exist for the entire electric service requirements of any customer delivered at one point and metered at or compensated to the voltage of delivery. This schedule is not available to residential customers.

	SUMMER June Through September	WINTER October Through May
Delivery Service Charges:	June Through September	October Through May
Customer Charge		
Single Phase	\$14.38	\$14.38
Three Phase	\$16.73	\$16.73
Distribution Demand Charge (per kW)	\$3.96	\$3.24
Reactive Demand Charge	\$0.78	\$0.78
(For each kvar over one-third of kW demand)	Φ0.76	Φυ./Ο
·	\$0.065062	¢ 0 057507
Distribution Rates (\$/kWh)	\$0.065062	\$0.057587
Non-Utility Generation Charge (NGC) (\$/kWH)	See Rider NGC	
Societal Benefits Charge (\$/kWh)		
Clean Energy Program	See Rider SBC	
Universal Service Fund	See Rider SBC	
Lifeline	See Rider SBC	
Uncollectible Accounts	See Rider SBC	
Transition Bond Charge (TBC) (\$/kWh)	See Rider SEC	
Market Transition Charge Tax (MTC-Tax)	See Rider SEC	
(\$/kWh)	Can Diday DCC	
CIEP Standby Fee (\$/kWh)	See Rider BGS	
Transmission Demand Charge (\$/kW for each kW in excess of 3 kW)	\$6.48	\$6.10
Reliability Must Run Transmission Surcharge (\$/kWh)	\$0.000000	
Transmission Enhancement Charge (\$/kWh)	See Rider BGS	
Basic Generation Service Charge (\$/kWh)	See Rider BGS	
Regional Greenhouse Gas Initiative Recovery		
Charge (\$/kWh)	See Rider RGG	I
Infrastructure Investment Program Charge	See Rider IIP	
Conservation Incentive Program Recovery Charge	See Rider CIP	

The minimum monthly bill will be \$14.38 per month plus any applicable adjustment.

Date of Issue:	Effective Date:

RATE SCHEDULE MGS-SECONDARY (Continued) (Monthly General Service)

CORPORATE BUSINESS TAX (CBT)

Charges under this rate schedule include a component for Corporate Business Taxes as set forth in Rider CBT.

NEW JERSEY SALES AND USE TAX (SUT)

Charges under this rate schedule include a component for New Jersey Sales and Use Tax as set forth in Rider SUT.

RELIGIOUS HOUSE OF WORSHIP SERVICE

When electric service is supplied to a customer where the primary use of the service is for public religious services and the customer applies for and is eligible for such service, the customer's monthly bill will be subject to the following credits

Energy Credit

For service rendered June thru September, inclusive: \$0.019677 per kWh for each of the first 300 kWhs used per month.

For service rendered October thru May, inclusive: \$0.015706 per kWh for each of the first 300 kWhs used per month.

Demand Adjustment

For service rendered all months of the year, metered demand will be decreased by 7 kW to arrive at billing demand.

The customer will be required to sign an Application for Religious House of Worship Service certifying eligibility. The customer shall furnish satisfactory proof of eligibility for service under this special provision to the Company, who will determine eligibility.

VETERANS' ORGANIZATION SERVICE

Pursuant to N.J.S.A 48:2-21.41, when electric service is delivered to a customer that is a veterans' organization, and where the primary use of the service is dedicated to serving the needs of veterans of the armed forces, and the customer applies for and is eligible for such service.

Each customer shall be eligible for billing under this Special Provision upon submitting an Application for Veterans' Organization Service under this rate schedule 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, who will determine eligibility.

If a customer's application is approved by the Company, the customer shall be eligible under this Special Provision beginning with the billing cycle that commences after receipt of the Application.

The customer will continue to be billed on this rate schedule. Each month, during the billing process, a comparison will be made to the RS rate schedule, and if the RS rate schedule is lower for the distribution portion of the bill, a credit will be placed on the customer's account. If the RS rate is not lower, the customer will be billed under this rate schedule and no corresponding credit will be placed on the customer's account.

Date of Issue:	Effective Date:	_
Issued by:		

ATLANTIC CITY ELECTRIC COMPANY

BPU NJ No. 11 Electric Service - Section IV Seventh Revised Sheet Replaces Sixth Revised Sheet No. 13

RATE SCHEDULE MGS-SECONDARY (Continued) (Monthly General Service)

DEMAND DETERMINATION FOR BILLING

Demand shall be as shown or computed from the readings of Company's demand meter during the fifteen minute period of customer's greatest use during the month. Demand values used for billing will be rounded to the nearest tenth of a kW.

Where no demand meters are installed, a customer's demand will be calculated for the period June 1st thru September 30th, inclusive. This demand will be estimated by dividing the kWh use by 150.

Where demand is expected to exceed 100 kilowatts, the Company may measure reactive demand as the greatest rate of reactive volt-ampere hour use during a fifteen (15) minute interval during the month.

Reactive demand values used for billing will be rounded to the nearest tenth of a kvar.

The provisions of this paragraph are not available to new service locations connected on or after January 1, 1983. Where a customer has permanently installed electrical space heating equipment of less than the total of all other connected load and where such electrical heating equipment represents the sole source of space and comfort heating, such equipment may be so connected as to exclude its contribution to measured demand.

ENERGY DETERMINATION FOR BILLING

Energy values used for billing will be rounded to the nearest hundredth of a kWh.

TERM OF CONTRACT

A customer may elect to have service discontinued at any time after giving due notice to the Company of its intention to do so, provided that all requirements and obligations under the tariff of the Company have been met.

STANDBY SERVICE

See Rider STB

FIXED LOADS

Customers with fixed attached loads may request to receive service on a computed kilowatt-hour basis. The Company, in its sole discretion, shall determine to grant such request. Such customers shall agree to pay a monthly bill equivalent to the computed kilowatt-hour usage for the billing period, said usage to be determined mutually by the Company and customer and specified in the contract. No changes in attached load may be made by the customer without the written permission of the Company and customer shall allow the Company access to its premises to assure conformance herewith.

TERMS AND CONDITIONS

See Section II inclusive for Terms and Conditions of Service.

"In accordance with P.L. 1997, c. 162, the charges in this Rate Schedule includes provision for the New Jersey Corporation Business Tax and the New Jersey Sales and Use Tax. When billed to customers exempt from one or more of these taxes, as set forth in Riders CBT and SUT, such charges will be reduced by the relevant amount of such taxes included therein."

PRICE TO COMPARE

A customer may choose to receive electric supply from a third party supplier as defined in Section 11 of the Standard Terms and Conditions of this tariff. A customer who receives electric supply from a third party supplier will not be billed the Basic Generation Service Charges or the Transmission Service Charges. Customers eligible for BGS CIEP who receive supply from a third party supplier will continue to be billed the CIEP Standby Fee.

Date of Issue:	Effective Date:
Issued by:	

RATE SCHEDULE MGS-SEVC (Monthly General Service - Secondary Electric Vehicle Charging)

AVAILABILITY

This is a transitional Rate Schedule, available only to publicly-accessible direct current fast charging ("DCFC") stations or sites at any point within the Company's system where facilities of adequate character and capacity exist for the entire electric service requirements of any customer delivered at one point and metered at or compensated to the voltage of delivery. This schedule is for secondary voltage only. The charging location DCFC chargers must be energized and operational for charging greater than 95% up time each calendar year to be eligible for this rate schedule.

This schedule is not available to residential customers. This schedule is not available to commercial and industrial customers who install DCFC chargers that are not publicly-accessible. This schedule is not available to DCFC installations that are installed behind the meter of a new or existing customer premise.

Each Charging Location is limited to 1000 kilowatts ("kW") of service capacity.

This Rate Schedule will be closed as of December 31, 2024. Any customers on this Rate Schedule at that time will be transferred to Monthly General Service Secondary in the following billing cycle.

	SUMMER June Through September	WINTER October Through May	
Delivery Service Charges:			
Customer Charge			
Single Phase	\$9.96	\$9.96	
Three Phase	\$11.59	\$11.59	
Distribution Demand Charge (per kW)	\$0.00	\$0.00	
Reactive Demand Charge	\$0.00	\$0.00	
(For each kvar over one-third of kW demand)			
Distribution Rates (\$/kWh)	\$0.109000	\$0.109000	
Non-Utility Generation Charge (NGC) (\$/kWH)	See Ride	er NGC	
Societal Benefits Charge (\$/kWh)			
Clean Energy Program	See Ride	er SBC	
Universal Service Fund	See Rider SBC		
Lifeline	See Rider SBC		
Uncollectible Accounts	See Rider SBC		
Transition Bond Charge (TBC) (\$/kWh)	See Ride	er SEC	
Market Transition Charge Tax (MTC-Tax) (\$/kWh)	See Ride	er SEC	
CIEP Standby Fee (\$/kWh)	See Ride	er BGS	
Transmission Demand Charge (\$/kW for each kW in excess of 3 kW)	\$6.48	\$6.10	
Reliability Must Run Transmission Surcharge (\$/kWh)	\$0.000	0000	
Transmission Enhancement Charge (\$/kWh)	See Ride	er BGS	
Basic Generation Service Charge (\$/kWh)	See Ride	er BGS	
Regional Greenhouse Gas Initiative Recovery Charge		500	
(\$/kWh)	See Ride See Ride		
Infrastructure Investment Program Charge	See Ride	ei IIF	

The minimum monthly bill will be \$9.96 per month plus any applicable adjustment.

Date of Issue:	Effective Date:
Issued by:	

Original Sheet No. 13b

RATE SCHEDULE MGS-SEVC (Continued) (Monthly General Service - Secondary Electric Vehicle Charging)

CORPORATE BUSINESS TAX (CBT)

Charges under this rate schedule include a component for Corporate Business Taxes as set forth in Rider CBT.

NEW JERSEY SALES AND USE TAX (SUT)

Charges under this rate schedule include a component for New Jersey Sales and Use Tax as set forth in Rider SUT.

DEMAND DETERMINATION FOR BILLING

Demand shall be as shown or computed from the readings of Company's demand meter during the fifteen minute period of customer's greatest use during the month. Demand values used for billing will be rounded to the nearest tenth of a kW.

Where no demand meters are installed, a customer's demand will be calculated for the period June 1st thru September 30th, inclusive. This demand will be estimated by dividing the kWh use by 150. Where demand is expected to exceed 100 kilowatts, the Company may measure reactive demand as the greatest rate of reactive volt-ampere hour use during a fifteen (15) minute interval during the month.

Reactive demand values used for billing will be rounded to the nearest tenth of a kvar.

The provisions of this paragraph are not available to new service locations connected on or after January 1, 1983. Where a customer has permanently installed electrical space heating equipment of less than the total of all other connected load and where such electrical heating equipment represents the sole source of space and comfort heating, such equipment may be so connected as to exclude its contribution to measured demand.

DIRECT CURRENT FAST CHARGER ("DCFC")

Electric vehicle service equipment ("EVSE" or "charger" or "charging stations") that provides at least 50 kilowatts ("kW") of direct current electrical power for charging a plug-in electric vehicle through a connector based on fast charging equipment standards and which is approved for installation for that purpose under the National Electric Code through an Underwriters Laboratories Certification or an equivalent certifying organization.

PUBLICY-ACCESSIBLE DCFC CHARGING

A charger located on public land, a community location, or a travel corridor. Such chargers are owned and operated by the site owner, property manager or management company, EVSE Infrastructure Company or, in limited cases, an Electric Distribution Company 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.

ENERGY DETERMINATION FOR BILLING

Energy values used for billing will be rounded to the nearest hundredth of a kWh.

TERM OF CONTRACT

A customer may elect to have service discontinued at any time after giving due notice to the Company of its intention to do so, provided that all requirements and obligations under the tariff of the Company have been met. A customer may request to take service under Rate Schedule Monthly General Service – Secondary, which would be effective in the following billing cycle.

TERMS AND CONDITIONS

See Section II inclusive for Terms and Conditions of Service.

"In accordance with P.L. 1997, c. 162, the charges in this Rate Schedule includes provision for the New Jersey Corporation Business Tax and the New Jersey Sales and Use Tax. When billed to customers exempt from one or more of these taxes, as set forth in Riders CBT and SUT, such charges will be reduced by the relevant amount of such taxes included therein."

PRICE TO COMPARE

Issued by:

A customer may choose to receive electric supply from a third-party supplier as defined in Section 11 of the Standard Terms and Conditions of this tariff. A customer who receives electric supply from a third-party supplier will not be billed the Basic Generation Service Charges or the Transmission Service Charges. Customers eligible for BGS CIEP who receive supply from a third-party supplier will continue to be billed the CIEP Standby Fee.

Date of Issue:	Effective Date:

Revised Sheet Replaces Revised Sheet No. 14

RATE SCHEDULE MGS-PRIMARY (Monthly General Service)

AVAILABILITY

Available at any point within the Company's system where facilities of adequate character and capacity exist for the entire electric service requirements of any customer delivered at one point and metered at or compensated to the voltage of delivery. This schedule is not available to residential customers.

· ·	SUMMER	WINTER
	June Through September	October Through May
Delivery Service Charges:		
Customer Charge		
Single Phase	\$17.56	\$17.56
Three Phase	\$19.08	\$19.08
Distribution Demand Charge (per kW)	\$1.90	\$1.49
Reactive Demand Charge	\$0.47	\$0.47
(For each kvar over one-third of kW demand)		
Distribution Rates (\$/kWh)	\$0.024715	\$0.023944
Non-Utility Generation Charge (NGC) (\$/kWH)	See Ride	r NGC
The contract of the graph of the contract of t		
Societal Benefits Charge (\$/kWh)		
Clean Energy Program	See Rider SBC	
Universal Service Fund	See Rider SBC	
Lifeline	See Rider SBC	
Uncollectible Accounts	See Rider SBC	
Transition Bond Charge (TBC) (\$/kWh)	See Rider SEC	
Market Transition Charge Tax (MTC-Tax) (\$/kWh)	See Ride	r SEC
CIEP Standby Fee (\$/kWh)	See Ride	r BGS
Transmission Demand Charge	\$3.63	\$3.28
(\$/kW for each kW in excess of 3 kW)		
Reliability Must Run Transmission Surcharge (\$/kWh)	\$0.000	
Transmission Enhancement Charge (\$/kWh)	See Rider BGS	
Basic Generation Service Charge (\$/kWh)	See Rider BGS	
Regional Greenhouse Gas Initiative Recovery Charge (\$/kWh)	See Rider RGGI	
Infrastructure Investment Program Charge	See Rider	
Conservation Incentive Program Recovery Charge	See Rider	

The minimum monthly bill will be \$17.56 per month plus any applicable adjustment.

Date of Issue:	Effective Date:

RATE SCHEDULE MGS-PRIMARY (Continued) (Monthly General Service)

CORPORATE BUSINESS TAX (CBT)

Charges under this rate schedule include a component for Corporate Business Taxes as set forth in Rider CBT.

NEW JERSEY SALES AND USE TAX (SUT)

Charges under this rate schedule include a component for New Jersey Sales and Use Tax as set forth in Rider SUT.

RELIGIOUS HOUSE OF WORSHIP SERVICE

When electric service is supplied to a customer where the primary use of the service is for public religious services and the customer applies for and is eligible for such service, the customer's monthly bill will be subject to the following credits

Energy Credit

For service rendered June thru September, inclusive: \$0.019677 per kWh for each of the first 300 kWhs used per month.

For service rendered October thru May, inclusive: \$0.015706 per kWh for each of the first 300 kWhs used per month.

Demand Adjustment

For service rendered all months of the year, metered demand will be decreased by 7 kW to arrive at billing demand.

The customer will be required to sign an Application for Religious House of Worship Service certifying eligibility. The customer shall furnish satisfactory proof of eligibility for service under this special provision to the Company, who will determine eligibility.

VETERANS' ORGANIZATION SERVICE

Pursuant to N.J.S.A 48:2-21.41, when electric service is delivered to a customer that is a veterans' organization, and where the primary use of the service is dedicated to serving the needs of veterans of the armed forces, and the customer applies for and is eligible for such service.

Each customer shall be eligible for billing under this Special Provision upon submitting an Application for Veterans' Organization Service under this rate schedule 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, who will determine eligibility.

If a customer's application is approved by the Company, the customer shall be eligible under this Special Provision beginning with the billing cycle that commences after receipt of the Application.

The customer will continue to be billed on this rate schedule. Each month, during the billing process, a comparison will be made to the RS rate schedule, and if the RS rate schedule is lower for the distribution portion of the bill, a credit will be placed on the customer's account. If the RS rate is not lower, the customer will be billed under this rate schedule and no corresponding credit will be placed on the customer's account.

Date of Issue:	Effective Date:
Issued by:	

ATLANTIC CITY ELECTRIC COMPANY

BPU NJ No. 11 Electric Service - Section IV Seventh Revised Sheet Replaces Sixth Revised Sheet No. 16

RATE SCHEDULE MGS-PRIMARY (Continued) (Monthly General Service)

DEMAND DETERMINATION FOR BILLING

Demand shall be as shown or computed from the readings of Company's demand meter during the fifteen minute period of customer's greatest use during the month. Demand values used for billing will be rounded to the nearest tenth of a kW.

Where no demand meters are installed, a customer's demand will be calculated for the period June 1st thru September 30th, inclusive. This demand will be estimated by dividing the kWh use by 150.

Where demand is expected to exceed 100 kilowatts, the Company may measure reactive demand as the greatest rate of reactive volt-ampere hour use during a fifteen (15) minute interval during the month.

Reactive demand values used for billing will be rounded to the nearest tenth of a kvar.

The provisions of this paragraph are not available to new service locations connected on or after January 1, 1983. Where a customer has permanently installed electrical space heating equipment of less than the total of all other connected load and where such electrical heating equipment represents the sole source of space and comfort heating, such equipment may be so connected as to exclude its contribution to measured demand.

ENERGY DETERMINATION FOR BILLING

Energy values used for billing will be rounded to the nearest hundredth of a kWh.

TERM OF CONTRACT

Customer may elect to have service discontinued at any time after giving due notice to the Company of his intention to do so, provided that all requirements and obligations under the tariff of the Company have been met.

STANDBY SERVICE

See Rider STB

FIXED LOADS

A customer with fixed attached loads may request to receive service on a computed kilowatt-hour basis. The Company, in its sole discretion, shall decide whether to grant such request. Such customers shall agree to pay a monthly bill equivalent to the computed kilowatt-hour usage for the billing period, said usage to be determined mutually by the Company and customer and specified in the contract. No changes in attached load may be made by the customer without the written permission of the Company and customer shall allow the Company access to its premises to assure conformance herewith.

TERMS AND CONDITIONS

See Section II inclusive for Terms and Conditions of Service.

"In accordance with P.L. 1997, c. 162, the charges in this Rate Schedule includes provision for the New Jersey Corporation Business Tax and the New Jersey Sales and Use Tax. When billed to customers exempt from one or more of these taxes, as set forth in Riders CBT and SUT, such charges will be reduced by the relevant amount of such taxes included therein."

PRICE TO COMPARE

A customer may choose to receive electric supply from a third party supplier as defined in Section 11 of the Standard Terms and Conditions of this Tariff. A customer who receives electric supply from a third party supplier will not be billed the Basic Generation Service Charges or the Transmission Service Charges. Customers eligible for BGS CIEP who receive supply from a third party supplier will continue to be billed the CIEP Standby Fee.

Date of Issue:	Effective Date:
Issued by:	

Revised Sheet Replaces Revised Sheet No. 17

See Rider SBC

RATE SCHEDULE AGS-SECONDARY (Annual General Service)

AVAILABILITY

Available at any point within the Company's system where facilities of adequate character and capacity exist for the entire electric service requirements of any customer contracting for annual service delivered at one point and metered at or compensated to the voltage of delivery.

MONTHLY RATE	MO	NTHL	Y R	ATE
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Delivery :	Service	Charges:
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Customer Charge	\$193.22
Distribution Demand Charge (\$/kW)	\$14.97

Reactive Demand (for each kvar over one-third of kW

demand) \$1.13

Non-Utility Generation Charge (NGC) (\$/kWH) See Rider NGC

Societal Benefits Charge (\$/kWh)

Clean Energy Program

Universal Service Fund
Lifeline
Uncollectible Accounts

Transition Bond Charge (TBC) (\$/kWh)

Market Transition Charge Tax (MTC-Tax) (\$/kWh)

CIEP Standby Fee (\$/kWh)

See Rider SEC

Transmission Demand Charge (\$/kWh)

Reliability Must Run Transmission Surcharge (\$/kWh)

Transmission Enhancement Charge (\$/kWh)

Basic Generation Service Charge (\$/kWh)

See Rider BGS

\$0.000000

See Rider BGS

See Rider BGS

Regional Greenhouse Gas Initiative Recovery Charge

(\$/kWh) See Rider RGGI
Infrastructure Investment Program Charge See Rider IIP
Conservation Incentive Program Recovery Charge See Rider CIP

CORPORATE BUSINESS TAX (CBT)

Charges under this rate schedule include a component for Corporate Business Taxes as set forth in Rider CBT.

NEW JERSEY SALES AND USE TAX (SUT)

Charges under this rate schedule include a component for New Jersey Sales and Use Tax as set forth in Rider SUT.

VETERANS' ORGANIZATION SERVICE

Pursuant to N.J.S.A 48:2-21.41, when electric service is delivered to a customer that is a veterans' organization, and where the primary use of the service is dedicated to serving the needs of veterans of the armed forces, and the customer applies for and is eligible for such service.

Each customer shall be eligible for billing under this Special Provision upon submitting an Application for Veterans' Organization Service under this rate schedule 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, who will determine eligibility.

Date of Issue:	Effective Date:

ATLANTIC CITY ELECTRIC COMPANY

BPU NJ No. 11 Electric Service - Section IV Seventh Revised Sheet Replaces Sixth Revised Sheet No. 18

RATE SCHEDULE AGS-SECONDARY (Continued) (Annual General Service)

VETERANS' ORGANIZATION SERVICE (Cont'd)

If a customer's application is approved by the Company, the customer shall be eligible under this Special Provision beginning with the billing cycle that commences after receipt of the Application.

The customer will continue to be billed on this rate schedule. Each month, during the billing process, a comparison will be made to the RS rate schedule, and if the RS rate schedule is lower for the distribution portion of the bill, a credit will be placed on the customer's account. If the RS rate is not lower, the customer will be billed under this rate schedule and no corresponding credit will be placed on the customer's account.

DEMAND DETERMINATION FOR BILLING

Demand shall be as shown or computed from the readings of Company's demand meter during the fifteen minute period of customer's greatest use during the month, but not less than 80% of the highest such demand in the preceding months of June, July, August or September, nor in any event less than 25 kW.

Where demand is expected to exceed 100 kilowatts, the Company may measure reactive demand as the greatest rate of reactive volt-ampere hour use during a fifteen (15) minute interval during the month.

TERM OF CONTRACT

Contracts hereunder will be for not less than one (1) year with self-renewal provisions for successive periods of one (1) year each, and shall remain in effect until either party gives at least 60 days' written notice to the other of the intention to discontinue at the end of any yearly period.

STANDBY SERVICE

See Rider STB

TERMS AND CONDITIONS

See Section II inclusive for Terms and Conditions of Service.

INTERRUPTIBLE SERVICE

See Rider IS.

"In accordance with P.L. 1997, c. 162, the charges in this Rate Schedule includes provision for the New Jersey Corporation Business Tax and the New Jersey Sales and Use Tax. When billed to customers exempt from one or more of these taxes, as set forth in Riders CBT and SUT, such charges will be reduced by the relevant amount of such taxes included therein."

PRICE TO COMPARE

A customer may choose to receive electric supply from a third party supplier as defined in Section 11 of the Standard Terms and Conditions of this Tariff. A customer who receives electric supply from a third party supplier will not be billed the Basic Generation Service Charges or the Transmission Service Charges. Customers eligible for BGS CIEP who receive supply from a third party supplier will continue to be billed the CIEP Standby Fee.

Date of Issue:	Effective Date:
Issued by:	

ATLANTIC CITY ELECTRIC COMPANY BPU NJ No. 11 Electric Service - Section IV

Revised Sheet Replaces Revised Sheet No. 19

See Rider CIP

RATE SCHEDULE AGS-PRIMARY (Annual General Service)

AVAILABILITY

Available at any point within the Company's system where facilities of adequate character and capacity exist for the entire electric service requirements of any customer contracting for annual service delivered at one point and metered at or compensated to the voltage of delivery.

MONTHLY RATE

Delivery Service Charges:

Customer Charge	\$842.34
Distribution Demand Charge (\$/kW)	\$11.65
Reactive Demand (for each kvar over one-third of kW demand)	\$0.87

Non-Utility Generation Charge (NGC) (\$/kWH) See Rider NGC

Societal Benefits Charge (\$/kWh)

Clean Energy Program See Rider SBC Universal Service Fund See Rider SBC Lifeline See Rider SBC Uncollectible Accounts See Rider SBC Transition Bond Charge (TBC) (\$/kWh) See Rider SEC Market Transition Charge Tax (MTC-Tax) (\$/kWh) See Rider SEC CIEP Standby Fee (\$/kWh) See Rider BGS Transmission Demand Charge (\$/kW) \$5.78 Reliability Must Run Transmission Surcharge (\$/kWh) \$0.00000 Transmission Enhancement Charge (\$/kWh) See Rider BGS **Basic Generation Service Charge (\$/kWh)** See Rider BGS Regional Greenhouse Gas Initiative Recovery Charge (\$/kWh) See Rider RGGI **Infrastructure Investment Program Charge** See Rider IIP

CORPORATE BUSINESS TAX (CBT)

Charges under this rate schedule include a component for Corporate Business Taxes as set forth in Rider CBT.

NEW JERSEY SALES AND USE TAX (SUT)

Conservation Incentive Program Recovery Charge

Charges under this rate schedule include a component for New Jersey Sales and Use Tax as set forth in Rider SUT.

VETERANS' ORGANIZATION SERVICE

Pursuant to N.J.S.A 48:2-21.41, when electric service is delivered to a customer that is a veterans' organization, and where the primary use of the service is dedicated to serving the needs of veterans of the armed forces, and the customer applies for and is eligible for such service.

Each customer shall be eligible for billing under this Special Provision upon submitting an Application for Veterans' Organization Service under this rate schedule 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, who will determine eligibility.

Date of Issue:	Effective Date:

ATLANTIC CITY ELECTRIC COMPANY

BPU NJ No. 11 Electric Service - Section IV Seventh Revised Sheet Replaces Sixth Revised Sheet No. 20

RATE SCHEDULE AGS-PRIMARY (Continued) (Annual General Service)

VETERANS' ORGANIZATION SERVICE (Cont'd)

If a customer's application is approved by the Company, the customer shall be eligible under this Special Provision beginning with the billing cycle that commences after receipt of the Application.

The customer will continue to be billed on this rate schedule. Each month, during the billing process, a comparison will be made to the RS rate schedule, and if the RS rate schedule is lower for the distribution portion of the bill, a credit will be placed on the customer's account. If the RS rate is not lower, the customer will be billed under this rate schedule and no corresponding credit will be placed on the customer's account.

DEMAND DETERMINATION FOR BILLING

Demand shall be as shown or computed from the readings of Company's demand meter during the fifteen minute period of customer's greatest use during the month, but not less than 80% of the highest such demand in the preceding months of June, July, August or September, nor in any event less than 25 kW.

Where demand is expected to exceed 100 kilowatts, the Company may measure reactive demand as the greatest rate of reactive volt-ampere hour use during a fifteen (15) minute interval during the month.

TERM OF CONTRACT

Contracts hereunder will be for not less than one (1) year with self-renewal provisions for successive periods of one (1) year each, and shall remain in effect until either party gives at least 60 days' written notice to the other of the intention to discontinue at the end of any yearly period.

STANDBY SERVICE

See Rider STB

TERMS AND CONDITIONS

See Section II inclusive for Terms and Conditions of Service.

INTERRUPTIBLE SERVICE

See Rider IS.

"In accordance with P.L. 1997, c. 162, the charges in this Rate Schedule includes provision for the New Jersey Corporation Business Tax and the New Jersey Sales and Use Tax. When billed to customers exempt from one or more of these taxes, as set forth in Riders CBT and SUT, such charges will be reduced by the relevant amount of such taxes included therein."

PRICE TO COMPARE

A customer may choose to receive electric supply from a third party supplier as defined in Section 11 of the Standard Terms and Conditions of this Tariff. A customer who receives electric supply from a third party supplier will not be billed the Basic Generation Service Charges or the Transmission Service Charges. Customers eligible for BGS CIEP who receive supply from a third party supplier will continue to be billed the CIEP Standby Fee.

Date of Issue:	Effective Date:
Issued by:	

Date of Issue: Effective Date:

ATLANTIC CITY ELECTRIC COMPANY	
RPILNING 11 Flectric Service - Section	ı IV

Revised Sheet Replaces Revised Sheet No. 22

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Date of Issue:

Effective Date:

Date of Issue: Effective Date:

RATE SCHEDULE TGS (Transmission General Service) (Sub Transmission Service Taken at 23kV and 34.5 kV)

AVAILABILITY

Available at any point within the Company's system where facilities of adequate character and capacity exist for the entire electric service requirements of any customer contracting for annual service delivered at one point and metered at or compensated to the voltage subtransmission level (23 or 34.5 kV).

MONTHLY RATE

Delivery Service Charges	Delivery	Service	Charges:
--------------------------	----------	---------	----------

Customer Charge

Maximum billed demand within the most recent 12 billing months.

Less than 5,000 kW	\$131.75
5,000 – 9,000 kW	\$4,363.57
Greater than 9,000 kW	\$7,921.01

Distribution Demand Charge (\$/kW)

Maximum billed demand within the most recent 12 billing months.

Less than 5,000 kW	\$4.01
5,000 – 9,000 kW	\$3.09
Greater than 9,000 kW	\$1.57

Reactive Demand (for each kvar over one-third of kW

demand)	\$0.54
Non-Utility Generation Charge (NGC) (\$/kWH)	See Rider NGC

Societal Benefits Charge (\$/kWh)

5 (1)	
Clean Energy Program	See Rider SBC
Universal Service Fund	See Rider SBC
Lifeline	See Rider SBC
Uncollectible Accounts	See Rider SBC
Transition Bond Charge (TBC) (\$/kWh)	See Rider SEC
Market Transition Charge Tax (MTC-Tax) (\$/kWh)	See Rider SEC
CIEP Standby Fee (\$/kWh)	See Rider BGS
Transmission Demand Charge (\$/kW)	\$6.85
Reliability Must Run Transmission Surcharge (\$/kWh)	\$0.00000
Transmission Enhancement Charge (\$/kWh)	See Rider BGS
Basic Generation Service Charge (\$/kWh)	See Rider BGS
Regional Greenhouse Gas Initiative Recovery Charge	
(¢/L/N/h)	Soo Didor DCCI

(\$/KWh)	See Rider RGGI
Infrastructure Investment Program Charge	See Rider IIP
Conservation Incentive Program Recovery Charge	See Rider CIP

Data at lasses	Effection Date
Date of Issue:	Effective Date:

See Rider IIP

See Rider CIP

RATE SCHEDULE TGS (Transmission General Service) (Transmission Service Taken at or above 69kV)

AVAILABILITY

Available at any point within the Company's system where facilities of adequate character and capacity exist for the entire electric service requirements of any customer contracting for annual service delivered at one point and metered at or compensated to the voltage at transmission level (69 kV or higher).

MONTHLY RATE

Delivery Service Charges:

Customer Charge

Maximum billed demand within the most recent 12 billing months.

Less than 5,000 kW	\$128.21
5,000 – 9,000 kW	\$4,246.42
Greater than 9,000 kW	\$19,316.15

Distribution Demand Charge (\$/kW)

Maximum billed demand within the most recent 12 billing months.

Less than 5,000 kW	\$2.79
5,000 – 9,000 kW	\$2.17
Greater than 9.000 kW	\$0.17

Reactive Demand (for each kvar over one-third of kW

demand) \$0.50
Non-Utility Generation Charge (NGC) (\$/kWH) See Rider NGC

Societal Benefits Charge (\$/kWh)

Infrastructure Investment Program Charge

Conservation Incentive Program Recovery Charge

Societal Belletits Charge (\$/KWII)	
Clean Energy Program	See Rider SBC
Universal Service Fund	See Rider SBC
Lifeline	See Rider SBC
Uncollectible Accounts	See Rider SBC
Transition Bond Charge (TBC) (\$/kWh)	See Rider SEC
Market Transition Charge Tax (MTC-Tax) (\$/kWh)	See Rider SEC
CIEP Standby Fee (\$/kWh)	See Rider BGS
Transmission Demand Charge (\$/kW)	\$3.42
Reliability Must Run Transmission Surcharge (\$/kWh)	\$0.00000
Transmission Enhancement Charge (\$/kWh)	See Rider BGS
Basic Generation Service Charge (\$/kWh)	See Rider BGS
Regional Greenhouse Gas Initiative Recovery Charge (\$/kWh)	See Rider RGGI

Date of Issue: Effective Date:

ATLANTIC CITY ELECTRIC COMPANY

BPU NJ No. 11 Electric Service - Section IV Fifth Revised Sheet Replaces Fourth Revised Sheet No. 30

RATE SCHEDULE TGS (Continued) (Transmission General Service)

CORPORATE BUSINESS TAX (CBT)

Charges under this rate schedule include a component for Corporate Business Taxes as set forth in Rider CBT.

NEW JERSEY SALES AND USE TAX (SUT)

Charges under this rate schedule include a component for New Jersey Sales and Use Tax as set forth in Rider SUT.

DEMAND DETERMINATION FOR BILLING

Demand shall be as shown or computed from the readings of Company's demand meter during the fifteen minute period of customer's greatest use during the month, but not less than 80% of the highest such demand in the preceding months of June, July, August or September, nor in any event less than 25 kW.

Where demand is expected to exceed 100 kilowatts, the Company may measure reactive demand as the greatest rate of reactive volt-ampere hour use during a fifteen (15) minute interval during the month.

TERM OF CONTRACT

Contracts hereunder will be for not less than one (1) year with self-renewal provisions for successive periods of one (1) year each, and shall remain in effect until either party gives at least 60 days' written notice to the other of the intention to discontinue at the end of any yearly period.

STANDBY SERVICE

See Rider STB

TERMS AND CONDITIONS

See Section II inclusive for Terms and Conditions of Service.

INTERRUPTIBLE SERVICE

See Rider IS.

"In accordance with P.L. 1997, c. 162, the charges in this Rate Schedule includes provision for the New Jersey Corporation Business Tax and the New Jersey Sales and Use Tax. When billed to customers exempt from one or more of these taxes, as set forth in Riders CBT and SUT, such charges will be reduced by the relevant amount of such taxes included therein."

PRICE TO COMPARE

A customer may choose to receive electric supply from a third party supplier as defined in Section 11 of the Standard Terms and Conditions of this Tariff. A customer who receives electric supply from a third party supplier will not be billed the Basic Generation Service Charges or the Transmission Service Charges. Customers eligible for BGS CIEP who receive supply from a third party supplier will continue to be billed the CIEP Standby Fee.

Date of Issue:	Effective Date:
Issued by:	

ATLANTIC CITY ELECTRIC COMPANY

BPU NJ No. 11 Electric Service – Section IV Eighty-First Revised Sheet Replaces Eightieth Revised Sheet No. 31

RATE SCHEDULE DDC (Direct Distribution Connection)

AVAILABILITY

Available at any point within the Company's existing distribution system where facilities of adequate character exist for the connection of fixed, constant and predictable non-residential loads not to exceed one kilowatt

MONTHLY RATES

Distribution:

Service and Demand (per day per connection) Energy (per day for each kW of effective load)	\$0.163982 \$0.789839
Non-Utility Generation Charge (NGC) (\$/kWH) Societal Benefits Charge (\$/kWh)	See Rider NGC
Clean Energy Program	See Rider SBC
Universal Service Fund	See Rider SBC
Lifeline See Rider SBC	
Uncollectible Accounts	See Rider SBC
Transition Bond Charge (TBC) (\$/kWh)	See Rider SEC
Market Transition Charge Tax (MTC-Tax) (\$/kWh)	See Rider SEC
Transmission Rate (\$/kWh)	\$0.009564
Reliability Must Run Transmission Surcharge (\$/kWh)	\$0.00000
Transmission Enhancement Charge (\$/kWh)	See Rider BGS
Basic Generation Service Charge (\$/kWh)	See Rider BGS
Regional Greenhouse Gas Initiative Recovery Charge (\$/kWh)	See Rider RGGI
Infrastructure Investment Program Charge	See Rider IIP

CORPORATE BUSINESS TAX (CBT)

Charges under this rate schedule include a component for Corporate Business Taxes as set forth in Rider CBT.

NEW JERSEY SALES AND USE TAX (SUT)

Charges under this rate schedule include a component for New Jersey Sales and Use Tax as set forth in Rider SUT.

LOAD CONSUMPTION

Effective load shall be determined by the Company and be specified in the contract. Effective load is defined as the sum of the products of the connected load in kilowatts times the percent load on at one time. No changes in attached load may be made by the customer without the permission of the Company and customer shall allow the Company access to his premises to assure conformance with this provision.

Date of Issue:	Effective Date:
Issued by:	

RATE SCHEDULE DDC (Continued) (Direct Distribution Connection)

TERM OF CONTRACT

Contracts hereunder will be for not less than one (1) year with self-renewal provisions for successive periods of one (1) year each, and shall remain in effect until either party gives at least 60 days' written notice to the other of the intention to discontinue at the end of any yearly period.

TERMS AND CONDITIONS

See Section II inclusive for Terms and Conditions of Service.

"In accordance with P.L. 1997, c. 162, the charges in this Rate Schedule includes provision for the New Jersey Corporation Business Tax and the New Jersey Sales and Use Tax. When billed to customers exempt from one or more of these taxes, as set forth in Riders CBT and SUT, such charges will be reduced by the relevant amount of such taxes included therein."

PRICE TO COMPARE

A customer may choose to receive electric supply from a third party supplier as defined in Section 11 of the Standard Terms and Conditions of this Tariff. A customer who receives electric supply from a third party supplier will not be billed the Basic Generation Service Charges or the Transmission Service Charges. Customers eligible for BGS CIEP who receive supply from a third party supplier will continue to be billed the CIEP Standby Fee.

Date of Issue:	Effective Date:
Issued by:	

RATE SCHEDULE TS (Traction Service)

AVAILABILITY OF SERVICE

Available for power service to Street Railway and/or Traction Companies or Authorities. Customers shall contract for a definite amount of electrical capacity in kilowatts which shall be sufficient to meet normal maximum requirements, but in no case shall the capacity contracted for be less than 1,000 kW. The Company may not be required to supply capacity in excess of that contracted for except by mutual agreement. Contracts shall be made in multiples of 100 kW.

T&D MONTHLY RATE

Primary Portion:

\$11,233.72 for the first 1,000 kW of monthly billing demand plus \$9.004473 per kW for monthly billing demand in excess of 1,000 kW. The customer shall be allowed 100 kWhs for each kW of monthly billing demand so billed.

Secondary Portion:

Energy in excess of 100 kWhs per kW of monthly billing demand \$0.069553 per kWh.

Reactive Demand:

\$0.53 per kvar of reactive billing demand in excess of 33% of monthly kW billing demand.

CORPORATE BUSINESS TAX (CBT)

Charges under this rate schedule include a component for Corporate Business Taxes as set forth in Rider CBT.

NEW JERSEY SALES AND USE TAX (SUT)

Charges under this rate schedule include a component for New Jersey Sales and Use Tax as set forth in Rider SUT.

MONTHLY BILLING DEMAND

The billing demand in kW shall be taken each month as the highest 15 minute integrated peak in kW, as registered during the month by a demand meter or indicator corrected to the nearest kW, but the monthly billing demand so established shall in no event be less than 75% of the contract capacity of the customer, nor shall it be less than 1,000 kW. If at the end of any contract year the average of the monthly billing demands for said year is in excess of the contract capacity, then the contract capacity shall be adjusted automatically to the average of the billing demand for the previous twelve months.

DETERMINATION OF REACTIVE DEMAND

Reactive billing demand shall be taken each month as the highest 15-minute integrated peak in kvar, as registered during the month by a reactive demand meter or indicator.

DELIVERY VOLTAGE

The rate set forth in this schedule is based upon the delivery and measurement of energy at primary voltage from lines designated by the Company which are operated at approximately 23,000 volts or over, the customer supplying the complete substation equipment necessary to take service at the said primary voltage.

Date of Issue:	Effective Date:
Issued by:	

RATE SCHEDULE TS (Continued) (Traction Service)

METERING

All energy delivered hereunder shall be measured at the delivery voltage, or at the Company's option, on the low voltage side of the customer's main service transformer bank but corrected by suitable means for measurement of capacity and energy at the delivery point and delivery voltage.

Customer shall mount and/or house the metering equipment, instrument transformers and associated appurtenances which shall be provided by Company.

TERMS OF CONTRACT

Contracts under this schedule will be made for periods of one (1) to five (5) years and either party shall give at least one (1) year's written notice to the other of its intention to discontinue the contract at the end of any contract period.

BREAKDOWN SERVICE

Where the service supplied by the Company under this rate schedule is used to supplement the failure of any other source of electric service or motive power, said service shall constitute Breakdown Service. Said service shall be limited to 96 hours duration for each failure.

Where Breakdown Service is supplied under the provisions of this tariff, the Company will supply a maximum total kW to be mutually agreed upon initially and subsequently revised as required and the customer will pay a fixed monthly amount equal to one-twelfth of \$9.64 per kW as contracted. All energy consumed during this period shall be included in the Energy Component of Monthly Rate. Any excess kW over the agreed upon amount shall be billed at the rates indicated under the Primary Portion of the Monthly Rate.

SPECIAL TERMS AND CONDITIONS

See Section II inclusive for Terms and Conditions of Service.

"In accordance with P.L. 1997, C. 162, the charges in this Rate Schedule include provision for the New Jersey Corporation Business Tax and the New Jersey Sales and Use Tax. When billed to customers exempt from one or more of these taxes, as set forth in Riders CBT and SUT, such charges will be reduced by the relevant amount of such taxes included therein."

PRICE TO COMPARE

A customer may choose to receive electric supply from a third party supplier as defined in Section 11 of the Standard Terms and Conditions of this Tariff. A customer who receives electric supply from a third party supplier will not be billed the Basic Generation Service Charges or the Transmission Service Charges. Customers eligible for BGS CIEP who receive supply from a third party supplier will continue to be billed the CIEP Standby Fee.

Date of Issue:	Effective Date:
Issued by:	

RATE SCHEDULE SPL (Street and Private Lighting)

AVAILABILITY OF SERVICE

Available for general lighting service in the service area of the Company

The Company will provide and maintain a lighting system and provide fixture and electric energy sufficient to operate said fixture continuously, automatically controlled, from approximately one-half hour after sunset until approximately one-half-hour before sunrise, every night and all night, approximately forty-two hundred (4200) hours per annum during the term of years hereinafter set forth.

The following rates shall be applied to the kWh Usage for the particular light type and size to determine the monthly charge per light.

Distribution charges are billed on a monthly per light basis in accordance with the rates specified on the Tables on Sheets 36, 36a and 37.

Non-Utility Generation Charge (NGC) (\$/kWH)	See Rider NGC
Societal Benefits Charge (\$/kWh)	
Clean Energy Program	See Rider SBC
Universal Service Fund	See Rider SBC
Lifeline	See Rider SBC
Uncollectible Accounts	See Rider SBC
Regulatory Assets Recovery Charge (\$/kWh)	See Rider RARC
Transition Bond Charge (TBC) (\$/kWh)	See Rider SEC
Market Transition Charge Tax (MTC-Tax) (\$/kWh)	See Rider SEC
Transmission Rate (\$/kWh)	\$0.000000
Reliability Must Run Transmission Surcharge (\$/kWh)	\$0.000000
Transmission Enhancement Charge (\$/kWh)	See Rider BGS
Basic Generation Service Charge (\$/kWh)	See Rider BGS
Regional Greenhouse Gas Initiative	
Recovery Charge (\$/kWh)	See Rider RGGI
Infrastructure Investment Program Charge	See Rider IIP

CORPORATE BUSINESS TAX (CBT)

Charges under this rate schedule include a component for Corporate Business Taxes as set forth in Rider CBT.

NEW JERSEY SALES AND USE TAX (SUT)

Charges under this rate schedule include a component for New Jersey Sales and Use Tax as set forth in Rider SUT.

PRICE TO COMPARE

A customer may choose to receive electric supply from a third party supplier as defined in Section 11 of the Standard Terms and Conditions of this Tariff. A customer who receives electric supply from a third party supplier will not be billed the Basic Generation Service Charges or the Transmission Service Charges. Customers eligible for BGS CIEP who receive supply from a third party supplier will continue to be billed the CIEP Standby Fee.

Date of Issue:	Effective Date:
Issued by:	

RATE SCHEDULE SPL (Continued) (Street and Private Lighting) RATE (Mounted on Existing Pole)

	<u>WATTS</u>	<u>LUMENS</u>	DIST	NTHLY RIBUTION HARGE	STATUS
INCANDESCENT					
Standard	103	1,000	\$	10.39	Closed
Standard	202	2,500	\$	17.90	Closed
Standard	327	4,000	\$	24.81	Closed
Standard	448	6,000	\$	33.15	Closed
MERCURY VAPOR					
Standard	100	3,500	\$	17.33	Closed
Standard	175	6,800	\$	23.06	Closed
Standard	250	11,000	\$	29.19	Closed
Standard	400	20,000	\$	41.97	Closed
Standard	700	35,000	\$	66.88	Closed
Standard <u>HIGH</u> PRESSURE SODIUM	1,000	55,000	\$	115.37	Closed
Retrofit	150	11,000	\$	21.14	Closed
Retrofit	360	30,000	\$	39.26	Closed

RATE (Overhead/RUE)

	<u>WATTS</u>	<u>LUMENS</u>	DISTE	NTHLY RIBUTION ARGE	STATUS
<u>HIGH</u> <u>PRESSURE</u> <u>SODIUM</u>					
Cobra Head	50	3,600	\$	18.87	Closed
Cobra Head	70	5,500	\$	19.55	Closed
Cobra Head	100	8,500	\$	20.58	Closed
Cobra Head	150	14,000	\$	22.38	Closed
Cobra Head	250	24,750	\$	31.66	Closed
Cobra Head	400	45,000	\$	36.61	Closed
Shoe Box	150	14,000	\$	27.23	Closed
Shoe Box	250	24,750	\$	35.30	Closed
Shoe Box	400	45,000	\$	40.77	Closed
Post Top	50	3,600	\$	20.94	Closed
Post Top	100	8,500	\$	22.81	Closed
Post Top	150	14,000	\$	26.81	Closed
Flood/Profile	150	14,000	\$	21.93	Closed
Flood/Profile	250	24,750	\$	27.65	Closed
Flood/Profile	400	45,000	\$	35.31	Closed
Decorative	50		\$	25.66	Closed
Decorative	70		\$	25.66	Closed
Decorative	100		\$	28.89	Closed
Decorative	150		\$	31.83	Closed
METAL HALIDE					
Flood/Profile	400	31,000	\$	43.38	Closed
Flood/Profile	1,000	96,000	\$	73.87	Closed

Date of Issue: Effective Date:

RATE SCHEDULE SPL (Continued) (Street and Private Lighting) Rate (Underground)

	WATTS	<u>LUMENS</u>	DIST	NTHLY RIBUTION HARGE	STATUS
HIGH PRESSURE SODIUM					
Cobra Head	50	3,600	\$	28.95	Closed
Cobra Head	70	5,500	\$	29.59	Closed
Cobra Head	100	8,500	\$	30.53	Closed
Cobra Head	150	14,000	\$	32.44	Closed
Cobra Head	250	24,750	\$	39.22	Closed
Cobra Head	400	45,000	\$	44.16	Closed
Shoe Box	150	14,000	\$	37.33	Closed
Shoe Box	250	24,750	\$	45.32	Closed
Shoe Box	400	45,000	\$	50.82	Closed
Post Top	50	3,600	\$	25.64	Closed
Post Top	100	8,500	\$	27.47	Closed
Post Top	150	14,000	\$	37.43	Closed
Flood/Profile	150	14,000	\$	34.19	Closed
Flood/Profile	250	24,750	\$	39.90	Closed
Flood/Profile	400	45,000	\$	45.41	Closed
Flood/Profile	400	31,000	\$	53.67	Closed
Flood/Profile	1000	96,000	\$	84.13	Closed
Decorative	50		\$	34.14	Closed
Decorative	70		\$	34.14	Closed
Decorative	100		\$	37.33	Closed
Decorative	150		\$	48.77	Closed

Date of Issue: Effective Date:

RATE SCHEDULE SPL (Continued) (Street and Private Lighting) LIGHT EMITTING DIODE (LED)

LIGITI	LIVIII I IIIVO	DIODE (LLD)	MONTHLY	
	WATTS	<u>LUMENS</u>	MONTHLY DISTRIBUTION CHARGE	STATUS
<u>Overhead</u>				
Cobra Head	50	3,000	\$11.11	Open
Cobra Head	70	4,000	\$11.48	Open
Cobra Head	100	7,000	\$11.76	Open
Cobra Head	150	10,000	\$12.44	Open
Cobra Head	250	17,000	\$14.16	Open
Cobra Head	400	28,000	\$19.21	Open
Decorative	150	10,000	\$25.76	Open
Mongoose	250	15,000	\$23.67	Open
Mongoose	400	17,000	\$26.21	Open
Acorn (Granville)	70	7,000	\$29.54	Open
Acorn (Granville)	100	8,000	\$29.54	Open
Acorn (Granville)	150	10,000	\$29.54	Open
Acorn (Granville) w/ ribs and bands	100	8,000	\$34.63	Open
Acorn (Granville) w/ ribs and bands	150	10,000	\$34.63	Open
Post Top	70	4,000	\$14.48	Open
Post Top	100	7,000	\$15.15	Open
Shoe Box	100	7,000	\$12.90	Open
Shoe Box	150	10,000	\$14.02	Open
Shoe Box	250	17,000	\$14.63	Open
Tear Drop	100	7,000	\$23.82	Open
Tear Drop	150	10,000	\$23.82	Open
Flood	150	6,200	\$21.25	Open
Flood	250	12,100	\$22.12	Open
Flood	400	19,700	\$25.42	Open
Flood	1000	32,900	\$26.45	Open
<u>Underground</u>				
Cobra Head	50	3,000	\$20.79	Open
Cobra Head	70	4,000	\$21.17	Open
Cobra Head	100	7,000	\$21.46	Open
Cobra Head	150	10,000	\$22.13	Open
Cobra Head	250	17,000	\$23.85	Open
Cobra Head	400	28,000	\$24.98	Open
Decorative	150	10,000	\$35.46	Open
Mongoose	250	15,000	\$29.45	Open
Mongoose	400	17,000	\$31.97	Open
Acorn (Granville)	70	7,000	\$35.30	Open
Acorn (Granville)	100	8,000	\$35.30	Open
Acorn (Granville)	150	10,000	\$35.30	Open
Acorn (Granville) w/ ribs and bands	100	8,000	\$39.83	Open
Acorn (Granville) w/ ribs and bands	150	10,000	\$39.83	Open
Post Top	70	4,000	\$24.17	Open
Post Top	100	7,000	\$24.85	Open
Shoe Box	100	7,000	\$22.60	Open
Shoe Box	150	10,000	\$23.72	Open
Shoe Box	250	17,000	\$24.33	Open
Tear Drop	100	7,000	\$33.50	Open
Tear Drop	150	10,000	\$33.50	Open
Flood	150	6,200	\$30.92	Open
Flood	250	12,100	\$31.80	Open
Flood	400	19,700	\$35.12	Open
Flood	1000	32,900	\$36.15	Open

Date of Issue: Issued by:

Effective Date:

ATLANTIC CITY ELECTRIC COMPANY BPU NJ No. 11 Electric Service - Section IV

Revised Sheet Replaces Revised Sheet No. 38

RATE SCHEDULE SPL (Continued) (Street and Private Lighting)

Bill will be rendered monthly and be prorated based on the billing cycle

Lamp sizes listed are standard ratings. Actual output shall be within commercial tolerances. The mercury vapor post standard (no longer available) will be supplied at an annual cost of \$23.09 in addition to the appropriate rate for the facility mounted on an existing pole. For installations on or before January 17, 1986, or lamp sizes 3500 Lumen or greater, an ornamental standard will be supplied at an annual cost of \$76.71 in addition to the appropriate rate for the fixture mounted on an existing pole. For standards installed after January 17, 1986, non-ornamental standards are available at an annual cost of \$112.13 in addition to the appropriate rate for the fixture mounted on an existing pole. Installation charges may be required for new construction. Ornamental standards are available under the CLE rate schedule.

UPGRADES TO EXISTING FIXTURES

Customers may upgrade existing lighting fixtures to fixtures of higher wattage subject to payment of the following charges which provide for labor to replace the light fixture and the differential cost of the light fixture:

Lamp Size up to 150W or equivalent: \$339.80 plus applicable income tax gross up Lamp Size greater than 150W or equivalent: \$430.74 plus applicable income tax gross up

TERM OF CONTRACT

Contracts under this schedule will be made for a period of not less than one (1) year or more than five (5) years and for specified numbers and sizes of fixtures. In all cases where the customer shall authorize additional fixtures within the contract period, the number of lamps shall be increased through the remainder of the contract period.

In no case shall the Company be obliged to furnish additional lighting under any contract for a period of two (2) years or less, or during the last two (2) years of any contract for a longer period unless the customer shall reimburse the Company for all expenses incurred in the running of additional lines for such fixtures, the cost of such fixtures and the cost of the installation.

Removal of fixtures and related facilities shall be at the direction of the customer and the customer shall reimburse the Company for all actual removal costs.

CREDITS

The annual charge per unit reflects an outage allowance based on normal and abnormal operating conditions.

TERMS AND CONDITIONS OF SERVICE

See Section II inclusive for Terms and Conditions of Service.

Customers requiring service under unusual conditions, or whose service requirements are different from those provided for herein may obtain such service under mutually acceptable contractual arrangements.

Service to all incandescent, high pressure sodium, metal halide and mercury vapor lamps of all sizes is in the process of elimination and is limited to lamp replacement

Upon removal of a fixture before the expiration of its service life, the customer will be responsible to reimburse the Company the average undepreciated value per fixture. Refer to Rate Schedule CLE.

Conversion to Rate Schedule CSL

Governmental Agency customers taking service under Rate Schedule SPL who are eligible to take service under Rate Schedule CSL may convert at any time. The customer will be required to pay a rate schedule conversion charge, assessed on a per fixture basis, based on the following conditions:

Lighting Installations less than or equal to five years Full Installation costs per Rate Schedule CLE

Light Installations Greater than five years of age

Labor Costs associated with street light replacement.

(\$271.15, plus applicable federal income tax gross up.)

"In accordance with P.L. 1997, c. 162, the charges in this Rate Schedule include provision for the New Jersey Corporation Business Tax and the New Jersey Sales and Use Tax. When billed to customers exempt from one or more of these taxes, as set forth in Riders CBT and SUT, such charges will be reduced by the relevant amount of such taxes included therein."

Date of Issue:	Effective Date:
Issued by:	

Revised Sheet Replaces Revised Sheet No. 39

RATE SCHEDULE CSL (Contributed Street Lighting)

AVAILABILITY OF SERVICE

Available for general lighting service to Governmental Agencies in the service area of the Company

The Company will install and maintain a lighting system and provide electric energy sufficient to operate fixtures continuously, automatically controlled, for approximately one-half-hour after sunset until approximately one-half-hour before sunrise, every night and all night, approximately forty-two hundred (4200) hours per annum during the term of years hereinafter set forth. The installed cost of the fixtures, standards, and other installed equipment (if necessary) shall be paid by the customer upon installation. All equipment shall be the property of the Company (see Rate Schedule CLE). The rates below provide for ordinary maintenance and replacement of lamps and automatic controls. The rates below do not provide for replacement due to expiration of the service life of installed fixtures, standards or other equipment which may be billed to customer at the time of replacement.

The following rates shall be applied to the kWh Usage for the particular light type and size to determine the monthly charge per light.

Delivery charges are billed on a monthly per light basis in accordance with the rates specified on the Tables on Sheets 40 and 40a.

Non-Utility Generation Charge (NGC) (\$/kWH)	See Rider NGC
Societal Benefits Charge (\$/kWh)	
Clean Energy Program	See Rider SBC
Universal Service Fund	See Rider SBC
Lifeline	See Rider SBC
Uncollectible Accounts	See Rider SBC
Transition Bond Charge (TBC) (\$/kWh)	See Rider SEC
Market Transition Charge Tax (MTC-Tax) (\$/kWh)	See Rider SEC
Transmission Rate (\$/kWh)	\$0.000000
Reliability Must Run Transmission Surcharge (\$/kWh)	\$0.000000
Transmission Enhancement Charge (\$/kWh)	See Rider BGS
Basic Generation Service Charge (\$/kWh)	See Rider BGS
Regional Greenhouse Gas Initiative	
Recovery Charge (\$/kWh)	See Rider RGGI
Infrastructure Investment Program Charge	See Rider IIP

CORPORATE BUSINESS TAX (CBT)

Charges under this rate schedule include a component for Corporate Business Taxes as set forth in Rider CBT.

NEW JERSEY SALES AND USE TAX (SUT)

Charges under this rate schedule include a component for New Jersey Sales and Use Tax as set forth in Rider SUT.

PRICE TO COMPARE

A customer may choose to receive electric supply from a third party supplier as defined in Section 11 of the Standard Terms and Conditions of this Tariff. A customer who receives electric supply from a third party supplier will not be billed the Basic Generation Service Charges or the Transmission Service Charges. Customers eligible for BGS CIEP who receive supply from a third party supplier will continue to be billed the CIEP Standby Fee.

Date of Issue:	Effective Date:	
Issued by:		

RATE SCHEDULE CSL (continued) (Contributed Street Lighting)

	•	•	•	
	WATTS	<u>LUMENS</u>	MONTHLY DISTRIBUTION CHARGE	<u>STATUS</u>
HIGH PRESSURE SODIUM				
All	50	3,600	\$8.32	Closed
All	70	5,500	\$9.02	Closed
All	100	8,500	\$10.09	Closed
All	150	14,000	\$11.96	Closed
All	250	24,750	\$16.24	Closed
All	400	45,000	\$21.42	Closed
METAL HALIDE				
Flood	1000		\$16.24	Closed
Flood	175		\$15.35	Closed
Decorative - Two Lights	175		\$51.46	Closed
Decorative	175		\$36.38	Closed
			<u>MONTHLY</u>	
	<u>WATTS</u>	<u>LUMENS</u>	DISTRIBUTION CHARGE	<u>STATUS</u>
LIGHT EMITTING DIODE (LED)				
Cobra Head	50	3,000	\$4.38	Open
Cobra Head	70	4,000	\$4.38	Open
Cobra Head	100	7,000	\$4.38	Open
Cobra Head	150	10,000	\$4.38	Open
Cobra Head	250	17,000	\$4.38	Open
Cobra Head	400	28,000	\$4.38	Open
Post Top	150	10,000	\$4.38	Open
Colonial Post Top	70	4,000	\$4.38	Open
Colonial Post Top	100	7,000	\$4.38	Open
Mongoose	250	15,000	\$4.38	Open
Mongoose	400	17,000	\$4.38	Open
Acorn (Granville)	70	7,000	\$4.38	Open
Acorn (Granville)	100	8,000	\$4.38	Open
Acorn (Granville)	150	10,000	\$4.38	Open
Acorn (Granville) w/ ribs and bands	100	8,000	\$4.38	Open
Acorn (Granville) w/ ribs and bands	150	10,000	\$4.38	Open
Shoe Box	100	7,000	\$4.38	Open
Shoe Box	150	10,000	\$4.38	Open
Shoe Box	250	17,000	\$4.38	Open
Tear Drop	100	7,000	\$4.38	Open
Tear Drop	150	10,000	\$4.38	Open
Flood	150	6,200	\$4.38	Open
Flood	250	12,100	\$4.38	Open
Flood	400	19,700	\$4.38	Open
			A	

Bill will be rendered monthly and be prorated based on the billing cycle

Flood

Lamp sizes listed are standard ratings. Actual output shall be within commercial tolerances. For fixtures mounted on an existing ornamental standard, the existing standard will continue to be supplied at an annual cost of \$65.81 until the expiration of its service life in addition to the appropriate rate for the fixtures on an existing pole

32,900

1000

Date of Issue: Issued by:

Effective Date:

\$4.38

Open

Revised Sheet Replaces Sheet No. 40a

RATE SCHEDULE CSL (continued) (Contributed Street Lighting)

UPGRADES TO EXISTING FIXTURES

Customers may upgrade existing lighting fixtures to fixtures of higher wattage subject to payment of the following charges which provide for labor to replace the light fixture and the differential cost of the light fixture:

Lamp Size up to 150W or equivalent: \$339.80 plus applicable income tax gross up Lamp Size greater than 150W or equivalent: \$430.74 plus applicable income tax gross up

TERMS OF CONTRACT

Contracts under this schedule will be made for a period of not less than one (1) year or more than five (5) years and for specified numbers and sizes of fixtures. In all cases where the customer shall authorize additional fixtures within the contract period, the number of lamps shall be increased through the remainder of the contract period.

In no case shall the Company be obliged to furnish lighting unless the customer reimburses the Company for all actual expenses incurred to install additional lines for such fixtures, the cost of such fixtures and accessories and the cost of the installation of the fixtures, lines and accessories.

Removal of fixtures and related facilities shall be at the direction of the customer and the customer shall reimburse the Company for all actual removal costs.

CREDITS

The annual charge per unit reflects an outage allowance based on normal and abnormal operating conditions.

TERMS AND CONDITIONS OF SERVICE

See Section II inclusive for Terms and Conditions of Service.

Customers requiring service under unusual conditions, or whose service requirements are different from those provided for herein may obtain such service under mutually acceptable contractual arrangements.

Service to all incandescent, high pressure sodium, metal halide and mercury vapor lamps of all sizes is limited to lamp replacement.

Upon removal of any fixture before the expiration of its service life, the customer will be responsible to reimburse the Company the average undepreciated value per fixture. Refer to Rate Schedule CLE.

"In accordance with P.L. 1997, c. 162, the charges in this Rate Schedule include provision for the New Jersey Corporation Business Tax and the New Jersey Sales and Use Tax. When billed to customers exempt from one or more of these taxes, as set forth in Riders CBT and SUT, such charges will be reduced by the relevant amount of such taxes included therein."

Date of Issue:	Effective Date:

RATE SCHEDULE TP (Temporary Power)

AVAILABILITY OF SERVICE

Available for temporary power service.

MONTHLY RATE

Temporary power service will be supplied under any published rate schedule applicable to the class of business of the customer, when the Company has available unsold capacity of lines, transformers and generating equipment, with an additional charge of the total cost of connection and disconnection on discontinuance of service on an individually determined basis, in addition to the charges under Rate Schedule CHG.

MINIMUM CHARGE

The same minimum charge as set forth in any rate schedule under which temporary service is supplied, shall be applicable to such temporary power service, and in no case less than full monthly minimum.

TERM OF CONTRACT

As determined and set forth in a written agreement between the Company and the customer.

SPECIAL TERMS AND CONDITIONS

"In accordance with P.L. 1997, C. 162, the charges in this Rate Schedule include provision for the New Jersey Corporation Business Tax and the New Jersey Sales and Use Tax. When billed to customers exempt from one or more of these taxes, as set forth in Riders CBT and SUT, such charges will be reduced by the relevant amount of such taxes included therein."

Date of Issue:	Effective Date:	
Issued by:		

ATLANTIC CITY ELECTRIC COMPANY

BPU NJ No. 11 Electric Service - Section IV Fifth Revised Sheet Replaces Fourth Revised Sheet No. 42

RATE SCHEDULE SPP (Small Power Purchase)

AVAILABILITY OF SERVICE

Available to a "Qualifying Facility" (QF) as defined in Section 210 of the Public Utility Regulatory Policies Act of 1978 who also receives service under regular Company Rate Schedules Rate Schedules RS, MGS-Secondary, MGS-SEVC, MGS-Primary, AGS Secondary, AGS Primary, TGS Sub-Transmission, and TGS Transmission. The generation capacity of such facility must be less than 1000 kW.

Qualifying facilities with capacity greater than 1000 kW must negotiate customer specific contracts. These facilities are entitled to a contract at full avoided energy costs and, if eligible, capacity costs. Customer specific contracts are subject to approval by the New Jersey Board of Public Utilities.

MONTHLY RATE

Service Charge:

This amount is deducted prior to payment for delivered energy.

\$36.37

Energy Payment:

The customer will be paid based on the actual load weighted PJM Residual Metered Load Aggregate Locational Marginal Prices (LMPs) in effect during the month energy is received.

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 100kW 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.

TERMS OF PAYMENT

In any month, credit/charge to the Qualifying Facility shall be the Energy Credit plus the Capacity Credit (if eligible) less the Service Charge. Credit/charge shall be made within 60 days of the last customer meter reading date, in each calendar quarter. If the net monthly credit exceeds \$53.67, a credit shall be made on a monthly basis.

Date of Issue:	Effective Date:
Issued by:	

RATE SCHEDULE SPP (Continued) (Small Power Purchase)

SPECIAL PROVISIONS

- 1. The customer must pay all interconnection charges before the Company will purchase electric power.
- 2. A customer's installation must conform to Company specifications for Qualifying Facility interconnection as outlined in the Company's Technical Guidelines for Cogeneration and Small Power Producers.
- 3. Qualifying Facilities with 10 kW or less generating capacity must sign an Electric Interconnection/Small Power Purchase Agreement.
- 4. Purchases from a QF will receive a capacity credit when the capacity exceeds 100 kilowatts and that capacity meets the Company's reliability criteria. The Company will make capacity payments to the QF to the extent that the capacity of the QF reduces any capacity deficiency payments by the Company to PJM or increases any capacity payments to the Company from PJM. Capacity credits, if applicable, will be based on the average on-peak capacity in any billing month, such capacity to be defined as the on-peak kilowatthours divided by the on-peak hours in that month. The seller may be eligible for an additional credit where the presence of the QF allows the deferral of local transmission or distribution capacity cost.
- 5. The Service Charge will be waived for QF's with 10 kW or less generating capacity.
- 6. Due to simplified metering, QF's with 10 kW or less generating capacity will be credited based on the average non-load weighted PJM billing rate for the month the energy is received.

STANDBY SERVICE

Issued by:

See Rider STB.

"In accordance with P.L. 1997, c. 162, the charges in this Rate Schedule include provision for the New Jersey Corporation Business Tax and the New Jersey Sales and Use Tax. When billed to customers exempt from one or more of these taxes, as set forth in Riders CBT and SUT, such charges will be reduced by the relevant amount of such taxes included therein."

Date of Issue:	Effective Date:

RIDER STB-STANDBY SERVICE (Applicable to MGS, AGS, TGS and SPP Rate Schedules)

AVAILABILITY

This rider is available to customers having other sources of electrical energy supply, but who have Standby Service from the Company. The terms of this rider shall not be available in any month when the customer's Generation Availability for the current and preceding five (5) months does not exceed 50%.

DEFINITIONS

Standby Service:

Standby Service is defined as the additional electrical capacity available to a customer in the event of a forced outage and during a mutually agreed upon customer's scheduled maintenance shutdown of the customer owned electrical energy source.

Standby Service Capacity:

The Standby Service Capacity shall be the maximum electrical capacity in kW supplied by the customer owned electrical energy source during the current and preceding five (5) months. Such Standby Service Capacity may be revised with the Company's approval as changes in the customer's load conditions warrant.

Generation Availability:

Generation Availability is defined as the availability of the customer owned electrical energy source during the current and preceding five (5) months and shall be determined by dividing the Kwhrs produced during this period by the product of the Standby Service Capacity times 4380 hours.

MODIFICATION OF DEMAND DETERMINATION

The monthly billing demand shall be as defined under the "Demand Determination" section of the applicable rate schedule.

The Standby Service Demand shall be the "Standby Service Capacity" as defined above.

During the billing months in which a forced outage or mutually agreed upon customer's scheduled maintenance shutdown occurs, the billing demand will be determined by subtracting the Standby Service Capacity from the total demand and waives the minimum charge provision of the applicable rate schedule. Electric service is provided under the terms of the applicable rate schedule. Total demand is defined as the sum of the Company's demand meter plus demand supplied by the other sources of electrical energy, all computed to the nearest whole kilowatt during a fifteen minute period.

STANDBY SERVICE CHARGE

This rider imposes a Standby Service Charge at the following voltage levels:

<u>Tariff</u>	Transmission Stand By Rate	Distribution Stand By Rate
	<u>(\$/kW)</u>	<u>(\$/kW)</u>
MGS-Secondary and	\$0.66	\$0.53
MGS-SEVC		
MGS Primary	\$0.37	\$0.24
AGS Secondary	\$0.57	\$2.25
AGS Primary	\$0.59	\$1.75
TGS Sub Transmission	\$0.35	\$0.00
TGS Transmission	\$0.35	\$0.00

Date of Issue:	Effective Date:
Issued by:	

RIDER STB-STANDBY SERVICE (Continued) (Applicable to MGS, AGS, TGS and SPP Rate Schedules)

TERMS AND CONDITIONS

- 1. A customer shall allow installation, at its sole expense, of suitable metering equipment or other provisions to determine the amount of generation supplied by customer's source of electrical energy on a period by period basis.
- 2. During the initial five-(5) months application of this rider, all calculations based upon data of the current and preceding five-(5) months, shall be based upon data of the current month and the number of months of experience since its initial application.
- 3. These standby provisions may also be modified by mutual written consent between the Company and the potential standby customer.
- 4. If a customer on this rider has multiple generators, then each individual generator must meet the 50% availability requirement.

"In accordance with P.L. 1997, c. 162, the charges in this Rate Schedule include provision for the New Jersey Corporation Business Tax and the New Jersey Sales and Use Tax. When billed to customers exempt from one or more of these taxes, as set forth in Riders CBT and SUT, such charges will be reduced by the relevant amount of such taxes included therein."

Date of Issue:	Effective Date:
Issued by:	

Date of Issue: Effective Date:

Date of Issue: Effective Date:

Date of Issue: Effective Date:

Exhibit A Clean Page 110 of 146

ATLANTIC CITY ELECTRIC COMPANY	
BPILN.I No. 11 Flectric Service - Section	IV

Sixth Revised Sheet Replaces Fifth Revised Sheet No. 49

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Date of Issue: Effective Date:

RIDER RP REDEVELOPMENT PROGRAM SERVICE

APPLICABLE TO:

Customers receiving service under Electric Rate Schedules AGS Secondary, AGS Primary, TGS

CHARACTER OF SERVICE:

Commitments for service under this rider will be made available to qualifying customers on a pilot basis effective August 24, 2016. Customers must commence service hereunder within 24 months of the date of commitment.

CREDIT:

A credit equal to 20% of the customer's distribution charge(s) as described below for the newly constructed, leased or purchased space, as determined by the Company, will be applied to the customer's monthly electric bills for a term of five years, as follows:

New Customer

A new customer for purposes of this Rider RP shall be defined as a customer contract account whose existing, newly constructed, leased or purchased space is separately metered.

The credit shall apply to the customer charge and the distribution demand charge associated with all kilowatts, as billed by the Company.

Existing Customer

An existing customer for purposes of this Rider RP shall be defined as a customer contract account whose existing, newly constructed, leased or purchased space is not separately metered from the existing service.

For existing customers, the credit shall apply only to those kilowatts, as measured by the Company, which are in excess of comparable demands in the same month established in a base year period, which period shall be defined as the 12 calendar months immediately preceding the first month service is provided under the Redevelopment Program. The credit will not be applicable to the customer charge for an existing customer.

ELIGIBILITY:

Each customer will be required to sign an Application for Redevelopment Program Service, which application shall include, an estimate of additional demand. The customer must remain on the same rate schedule as in the base year period throughout the five year term of the program. Upon verification of eligibility, the Company will provide the customer with a written commitment for Redevelopment Program Service.

To be eligible, a customer must construct, lease or purchase, new or vacant space for commercial or industrial services or build, or have added to or expanded to a building on existing property. The effective date of the lease or purchase must have been on or after August 24, 2016, the initial Effective Date of this rate schedule. The total additional leased or purchased building space must equal or exceed 8,000 square feet.

Qualifying building space must be vacant, as determined by the Company, prior to receiving a commitment for the Redevelopment Program.

A customer must add at least two permanent full-time employees to the customer's payroll at the site receiving the benefit of the Redevelopment Program Service Rider. Relocation or consolidation of employees based in the Company's service territory without employment growth will not qualify. Employment growth will be confirmed by the Company in conjunction with the New Jersey Department of Labor and/or affidavit from the customer. The Company reserves the right, in its discretion, to periodically verify employment increases and sustained level of employment. If after verification the required employment level has not been sustained, Rider RP will no longer be applicable.

A customer must qualify for, receive, and provide the Company with suitable documentation substantiating the receipt of a package of economic incentives pursuant to the Economic Opportunity Act of 2013 (P.L. 2013, c.161) conferred by the state or any other applicable economic incentive conferred by the county or local municipality, including financial assistance or a tax incentive program designed to maintain or increase employment levels in the service area.

LIMITATIONS OF SERVICE:

This service is not available to federal, state, county or local governments or governmental entities.

Date of Issue:	Effective Date
Issued by:	

RIDER - SCD SMALL COMMERCIAL DEVELOPMENT

APPLICABLE TO:

Customers receiving service under Electric Rate Schedules MGS Secondary, MGS Primary

CHARACTER OF SERVICE:

Commitments for service under this rider will be made available to qualifying customers on a pilot basis effective August 24, 2016. Customers must commence service hereunder within 24 months of the date of commitment.

CREDIT:

A credit equal to 20% of the customer's distribution charge(s) as described below for the newly constructed, leased or purchased space, as determined by the Company, will be applied to the customer's monthly electric bills for the term of five years, as follows:

New Customer

A new customer for purposes of this Rider SCD shall be defined as a customer contract account whose existing, newly leased, constructed or purchased space is separately metered.

The credit shall apply to the customer charge and the distribution demand charge associated with all kilowatts, as billed by the Company.

Existing Customer

An existing customer for purposes of this Rider SCD service shall be defined as a customer contract account whose existing, newly constructed, leased or purchased space is not separately metered from the existing service.

For existing customers, the credit shall apply only to those kilowatts, as measured by the Company, which are in excess of comparable demands in the same month established in a base year period, which period shall be defined as the 12 calendar months immediately preceding the first month service is provided under the Redevelopment Program. The credit will not be applicable to the customer charge for an existing customer.

ELIGIBILITY:

Each customer will be required to sign an Application for Small Commercial Development Program Service, which application shall include an estimate of additional demand. The customer must remain on the same rate schedule as in the base year period throughout the five year term of the program. Upon verification of eligibility, the Company will provide the customer with a written commitment for Small Commercial Development Program Service.

To be eligible, a customer must construct, lease or purchase new or vacant space for Commercial services or build, have added to or expanded to a building on existing property. The effective date of the lease or purchase must have been on or after August 24, 2016, the initial Effective Date of this rate schedule. The total additional leased or purchased building space must equal or exceed 2,500 square feet.

Qualifying building space must be vacant, as determined by the Company, prior to receiving a commitment for the Small Commercial Development Rider.

Customer must be adding at least one permanent full-time year round employee to the customer's payroll at the site receiving the benefit of the Small Commercial Development Rider. Relocation or consolidation of employees based in the Company's service territory without employment growth will not qualify. Employment growth will be confirmed by the Company in conjunction with the New Jersey Department of Labor and/or affidavit from the customer on a quarterly basis. The Company reserves the right, in its discretion, to periodically verify employment increases and sustained level of employment. If, after verification, the required employment level has not been sustained, Rider SCD will no longer be applicable.

LIMITATIONS OF SERVICE:

This service is not available to federal, state, county or local governments or governmental entities.

Date of Issue:	Effective Date:
Issued by:	

CBT – RIDER (CORPORATE BUSINESS TAX)

In accordance with P.L. 1997, C. 162 (the "energy tax reform statute"), provision for the New Jersey Corporation Business Tax has been included in all charges applicable Riders [tariff designation for LEACs/LGACs] (the "Base Tariff Rates) by multiplying the Base Tariff Rates in effect immediately prior to January 1, 1998 by the factor 1.3518% [1 plus the "a" factor carried out to decimals]. The energy tax reform statute exempts the following customers from the CBT provision, and when billed to such customers, the Base Tariff 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. Operating co-generators, or those 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.
- Special contract customers for which a customer-specific tax classification was approved by a written Order of the Board of Utilities prior to January 1, 1998.

Date of Issue:	Effective Date:
Issued by:	

Fifth Revised Sheet Replaces Fourth Revised Sheet No. 53

RIDER - SUT (SALES AND USE TAX)

- A. In accordance with P.L. 1997, C. 162 (the "energy tax reform statute"), provision for the New Jersey Sales and Use Tax ("SUT") has been included in all charges applicable under Atlantic's tariff by multiplying the charges that would apply before application of the SUT by the factor 1.06875. Pursuant to P.L. 2016, c.57, this factor is changed to 1.06625 effective January 1, 2018. The energy tax reform statute exempts the following customers from the SUT provision:
 - 1. Franchised providers of utility services (gas, electricity, water, wastewater and telecommunications services provided by local exchange carriers) within the State of New Jersey.
 - 2. Operating co-generators, or those which have filed an application for an operating permit or 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 seg.) with the New Jersey Department of Environmental Protection, on or before March 10.
 - 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 gualified 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.

There are, however, other tariff charges provided in the Company's current tariff which are not subject, or are excluded from the SUT calculations in the compliance filing, as follows:

1.	Rate Schedules	
	Residential Underground Extensions (RUE)	Exempt all charges.
	Contributed Lighting Extension (CLE)	Exempt all charges.
2.	Other Tariff Charges	
	Installation of Service at Original Location	\$65.00 - Exempt
	Connect	\$15.00 - Exempt
	Reconnect	\$15.00 - Exempt
	Succession	\$15.00 - Exempt
	Disconnect	\$15.00 - Exempt
	Special Reading of Meters	\$15.00 - Exempt
	Late Payment Charge	Exempt
	Uncollectible Check	\$7.64 - Exempt

Date of Issue: Issued by:

Effective Date:

Date of Issue: Effective Date:

Date of Issue: Effective Date:

ATLANTIC CITY ELECTRIC COMPANY

BPU NJ No. 11 Electric Service - Section IV Twenty-Fourth Revised Sheet Replaces Twenty-Third Revised Sheet No. 56

RIDER (SEC) Securitization

This Rider provides the two charges associated with the securitization of stranded costs. The charges included in this Rider are:

Transition Bond Charge

The Transition Bond Charge (TBC) is designed to insure full and timely recovery of all Bondable Stranded Costs including financing charges and related costs.

MTC-Tax

Issued by:

The Market Transition Charge Tax (MTC-Tax) is designed to recover all income taxes associated with the TBC and MTC-Tax revenues.

These charges are applicable to all kWhs delivered to customers receiving service under all Electric Rate Schedules and any customer taking service under special contractual arrangements.

The Company's TBC and MTC-Tax Charges to be effective on and after the date indicated below are as follows:

Transition Bond Charge: \$(0.001496) per kWh MTC-Tax \$0.000000 per kWh

NEW JERSEY SALES AND USE TAX (SUT)

Charges under this Rider include a component for New Jersey Sales and Use Tax as set forth in Rider SUT.

Date of Issue:	Effective Date:

ATLANTIC CITY ELECTRIC COMPANY

BPU NJ No. 11 Electric Service - Section IV Twenty-Eighth Revised Sheet Replaces Twenty-Seventh Revised Sheet No. 57

Rider (NGC) Non-Utility Generation Charge (NGC)

Applicable to customers receiving service under Electric Rate Schedules RS, MGS, AGS, TS, TGS, DDC, SPL, CSL, STB, SPP are subject to a non-bypassable Non-Utility Generation Charge (NGC).

This charge provided for the full and timely recovery of the following costs:

- 1. Costs associated with the Company's purchase power contracts with non-utility generators, which are intended recover the stranded costs associated with such commitments. The costs recovered via the NGC are based on the difference between the average estimated cost of energy and capacity in the regional market and the associated costs provided in existing power purchase contracts with non-utility generators. Differences between actual and estimated costs occurring under previously approved rates shall be added or subtracted as appropriate to the estimated costs.
- 2. Costs associated with the transition to a competitive electric market and the restructuring of the electric utility industry in the State of New Jersey.
- 3. Costs associated with the Company's generation facilities, net of any revenue received from the sale of energy, capacity and ancillary services associated with these units.

The following table provides the component rates of the NGC charge for each rate schedule based on the cost categories listed above in \$ per kWh.

Rate Schedule	Total NGC
RS	\$ 0.009827
MGS Secondary and MGS-SEVC	\$ 0.009827
MGS Primary	\$ 0.009569
AGS Secondary	\$ 0.009827
AGS Primary	\$ 0.009569
TGS	\$ 0.009368
SPL/CSL	\$ 0.009827
DDC	\$ 0.009827

Date of Issue:	Effective Date:

ATLANTIC CITY ELECTRIC COMPANY BPU NJ No. 11 Electric Service - Section IV Second Revised Sheet Replaces First Sheet No. 57a

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Date of Issue: Effective Date:

ATLANTIC CITY ELECTRIC COMPANY

BPU NJ No. 11 Electric Service - Section IV Forty-Fourth Revised Sheet Replaces Forty-Third Revised Sheet No. 58

RIDER (SBC) Societal Benefits Charge (SBC)

Applicable to customers receiving service under Electric Rate Schedules RS, MGS, AGS, TS, TGS, DDC, SPL, and CSL and any customer taking service under special contractual arrangements.

In accordance with the New Jersey Electric Discount and Energy Competition Act, Societal Benefits Charges include:

- Clean Energy Program Costs
- Uncollectible Accounts
- Universal Service Fund
- Lifeline

The Company's Societal Benefits Charges to be effective on and after the date indicated below are as follows:

Clean Energy Program \$0.003251 per kWh
Uncollectible Accounts \$0.001712 per kWh
Universal Service Fund \$0.003417 per kWh
Lifeline \$0.000784 per kWh

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Date of Issue:	Effective	Date:
Issued by:		

ATLANTIC CITY ELECTRIC COMPANY

BPU NJ No. 11 Electric Service - Section IV Twenty-Seventh Revised Sheet Replaces Twenty-Sixth Revised Sheet No. 60

RIDER (BGS) Basic Generation Service (BGS)

Basic Generation Service (BGS) will be arranged for any customer taking service under Electric Rate Schedules RS, MGS Secondary, MGS-SEVC, MGS Primary, AGS Secondary, AGS Primary, TGS, DDC, SPL, and CSL who has not notified the Company of an Alternative Electric Supplier choice. BGS is also available to customers whose arrangements with Alternative Electric Suppliers have terminated for any reason, including nonpayment.

BGS is offered under two different terms of service; Basic Generation Service-Residential Small Commercial Pricing (BGS-RSCP) and Basic Generation Service -Commercial and Industrial Energy Pricing (BGS-CIEP). BGS-RSCP is offered to customers on Rate Schedules RS, DDC, SPL and CSL. BGS-RSCP is also offered to customers on Rate Schedules MGS Secondary, MGS-SEVC, MGS Primary, AGS Secondary, AGS Primary with an annual peak load share ("PLS") for generation capacity of less than 500 kW as of November 1 or each year. Additionally, BGS customers on Rate Schedule RS have the option of taking BGS-RSCP on a time of use basis.

BGS customers on Rate Schedule TGS and BGS customers on Rate Schedules MGS Secondary, MGS-SEVC, MGS Primary, AGS Secondary or AGS Primary with a PLS for generation capacity equal to or greater than 500 kW as of November 1 of each year are required to take service under BGS-CIEP.

Customers on Rate Schedules MGS Secondary, MGS-SEVC, MGS Primary, AGS Secondary or AGS Primary with a PLS of less than 500 kW, have the option of taking either BGS-RSCP or BGS-CIEP service. Customers who elect BGS-CIEP must notify the Company of their selection no later than the second working day of January of the year they wish to begin BGS-CIEP service. Such election will be effective on June 1 of that year and remain as the customer's default supply for the following twelve months. Customers electing BGS-CIEP as their default supply in a prior procurement period and who are otherwise eligible to return to BGS-RSCP may return to BGS RSCP by notifying the Company no later than the second working day of January of the year that they wish to return to BGS-RSCP service. Such election shall be effective on June 1 of that year.

BGS-RSCP Supply Charges (\$/kWh):	SUMMER		WINTER	
Rate Schedule	June Thr	ough September	October	Through May
RS			\$	0.074368
<=750 kwhs summer	\$	0.069150		
> 750 kwh summer	\$	0.079173		
RS TOU BGS Option				
On Peak (See Note 1)	\$	0.094446	\$	0.100414
Off Peak (See Note 1)	\$	0.054075	\$	0.055403
MGS-Secondary and MGS-SEVC	\$	0.072372	\$	0.070277
MGS-Primary	\$	0.065779	\$	0.063717
AGS-Secondary	\$	0.069409	\$	0.067159
AGS-Primary	\$	0.065038	\$	0.062937
DDC	\$	0.065335	\$	0.063197
SPL/CSL	\$	0.055779	\$	0.056637

Note 1: On Peak hours are considered to be 8:00 AM to 8:00 PM, Monday through Friday.

The above Basic Generation Service Energy Charges reflect costs for Energy, Generation Capacity, Ancillary Services and Administrative Charges pursuant to N.J.S.A. 48:2-60 plus New Jersey Sales and Use Tax as set forth in Rider SUT.

Date of Issue:	Effective Date:

ATLANTIC CITY ELECTRIC COMPANY

BPU NJ No. 11 Electric Service - Section IV Forty-Second Revised Sheet Replaces Forty-First Revised Sheet No. 60a

RIDER (BGS) continued Basic Generation Service (BGS)

BGS Reconciliation Charge (\$/kWh):

The above charge shall recover the difference between the monthly amount paid to Basic Generation Service (BGS) suppliers and the total revenue from customers for BGS for the preceding months for the applicable BGS supply. These charges include New Jersey Sales and Use Tax as set forth in Rider SUT and are changed on June 1 and October 1 of each year.

Rate Schedule

RS

WGS Secondary, MGS-SEVC, AGS Secondary, SPL/CSL, DDC

MGS Primary, AGS Primary

Charge (\$ per kWh)
\$ (0.000262)
\$ (0.000262)
\$ (0.000255)

BGS-CIEP

Energy Charges

BGS Energy Charges for Rate Schedule TGS, AGS and MGS customers with a Peak Load Share (PLS) of 500 kW or more, and AGS and MGS customers with a PLS of less than 500 kW who have elected BGS-CIEP are hourly and are provided at the real time PJM Load Weighted Average Residual Metered Load Aggregate Locational Marginal Prices for the Atlantic Electric Transmission Zone, adjusted for losses, plus administrative charges pursuant to N.J.S.A. 48:2-60 and New Jersey Sales and Use Tax as set forth in Rider SUT.

Generation Capacity Obligation Charge

Charge per kilowatt of Generation Obligation (\$ per kW per day)

Summer

\$0.304540

\$0.304540

This charge is equal to the winning bid price from the BGS-CIEP default service auction plus administrative charges pursuant to N.J.S.A. 48:2-60 and New Jersey Sales and Use Tax as set forth in Rider SUT. The above charge shall be applied to each customer's annual peak load share ("PLS") for generation capacity, adjusted for the applicable PJM-determined Zonal Scaling Factor and the applicable PJM-determined capacity reserve margin factor, on a daily basis for each day in each customer's respective billing cycle.

Ob - - -

Ancillary Service Charge

Cnarge
(\$ per kWh)
\$ 0.006750
\$ 0.006574
\$ 0.006499
\$ 0.006436

This charge represents the average annual cost of Ancillary Services in the Atlantic Electric Transmission zone adjusted for losses, plus administrative charges pursuant to N.J.S.A. 48:2-60 and New Jersey Sales and Use Tax as set forth in Rider SUT.

Charas

BGS Reconciliation Charge:

Charge
(\$ per kWh)
\$ 0.018407
\$ 0.017925
\$ 0.017722
\$ 0.017548

The above charge shall recover the difference between the monthly amount paid to Basic Generation Service (BGS) suppliers and the total revenue from customers for BGS for the preceding months for the applicable BGS supply. These charges include administrative charges pursuant to N.J.S.A. 48:2-60 and New Jersey Sales and Use Tax as set forth in Rider SUT and are changed on June 1 and October 1 of each year.

Date of Issue:	Effective Date:

RIDER (BGS) continued Basic Generation Service (BGS)

CIEP Standby Fee

\$0.000160 per kWh

This charge recovers the costs associated with the winning BGS-CIEP bidders maintaining the availability of the hourly priced default electric supply service plus administrative charges pursuant to N.J.S.A. 48:2-60 and New Jersey Sales and Use Tax as set forth in Rider SUT. This charge is assessed on all kWhs delivered to all CIEP- eligible customers on Rate Schedules MGS Secondary, MGS-SEVC, MGS Primary, AGS Secondary, AGS Primary or TGS.

Transmission Enhancement Charge

This charge reflects Transmission Enhancement Charges ("TECs"), implemented to compensate transmission owners for the annual transmission revenue requirements for "Required Transmission Enhancements" (as defined in Schedule 12 of the PJM OATT) that are requested by PJM for reliability or economic purposes and approved by the Federal Energy Regulatory Commission (FERC). The TEC charge (in \$ per kWh by Rate Schedule), including administrative charges pursuant to N.J.S.A. 48:2-60 and New Jersey Sales and Use Tax as set forth in Rider SUT, is delineated in the following table.

				Rate Class				
	<u>RS</u>	MGS Secondary And MGS- SEVC	MGS Primary	AGS Secondary	AGS Primary	<u>TGS</u>	SPL/ CSL	DDC
VEPCo	0.000367	0.000278	0.000256	0.000179	0.000156	0.000133	-	0.000114
TrAILCo	0.000275	0.000192	0.000131	0.000138	0.000113	0.000104	-	0.000082
PSE&G	0.003256	0.002478	0.002276	0.001591	0.001385	0.001184	-	0.001018
PATH	0.000010	0.000007	0.000006	0.000004	0.000004	0.000003	-	0.000003
PPL	0.000095	0.000066	0.000046	0.000048	0.000039	0.000036	-	0.000029
PECO	0.000216	0.000150	0.000103	0.000109	0.000088	0.000083	-	0.000065
Pepco	0.000022	0.000016	0.000011	0.000012	0.000010	0.000009	-	0.000006
MAIT	0.000042	0.000032	0.000029	0.000020	0.000018	0.000015	-	0.000013
JCP&L	0.000003	0.000002	0.000002	0.000001	0.000001	0.000001	-	0.000001
EL05-121	0.000019	0.000015	0.000013	0.000010	0.000009	0.000006	-	0.000006
Delmarva	0.000010	0.000006	0.000004	0.000004	0.000004	0.000003	-	0.000003
BG&E	0.000041	0.000028	0.000019	0.000020	0.000017	0.000015	-	0.000012
AEP-East	0.000081	0.000062	0.000057	0.000039	0.000034	0.000030	-	0.000026
Silver Run	0.000325	0.000247	0.000227	0.000159	0.000139	0.000118	-	0.000101
NIPSCO	0.000003	0.000002	0.000002	0.000002	0.000001	0.000001	-	0.000001
CW Edison	-	-	-	-	-	-	-	-
ER18-680 & Form 715	-	-	-	-	-	-	-	-
SFC Duquesne Total	0.000004 0.000002 0.004771	0.000003 0.000001 0.003585	0.000003 0.000001 0.003186	0.000002 0.000001 0.002339	0.000002 0.000001 0.002021	0.000002 0.000001 0.001744	- -	0.000001 0.000001 0.001482

Date of Issue: Effective Date:

RIDER NEM Net Energy Metering

AVAILABILITY

This Rider is available to any customer served under the Company's Rate Schedules RS, MGS-Secondary, MGS-SEVC, MGS-Primary, AGS Secondary, AGS Primary, TGS Subtransmission, and TGS Transmission who owns and operates a customer-generator facility that:

- Uses a New Jersey defined Class I renewable resource, including solar technologies, photovoltaic technologies, wind energy, fuel cells powered by renewable fuels, geothermal technologies, wave or tidal action, and/or methane gas from landfills or a biomass facility, provided that the biomass is cultivated and harvested in a sustainable manner, as more specifically defined in Board of Public Utilities Regulations at N.J.A.C. 14:8; and
- 2. Is located on the customer's premises or contiguous property; and
- 3. Is interconnected and operated in parallel with the Company's transmission or distribution facilities; and
- 4. Is intended primarily to offset all or part of the customer's own electricity requirements; and
- 5. Is not a Qualifying Facility (QF) served under the Company's Rate Schedule SPP, Small Power Purchase.

CONNECTION TO THE COMPANY'S SYSTEM

Any customer who elects this Rider must submit a New Jersey Interconnection Application Form with the Company, at least 30 days prior to activating the customer-generator facility. The customer should not install a customer-generator facility without prior approval from the Company and the customer shall not operate a customer-generator facility without final written approval from the Company.

The customer-generator facility shall not be connected to the Company's system unless it meets all applicable safety and performance standards established by the National Electric Code, The Institute of Electrical and Electronics Engineers (IEEE), Underwriters Laboratories, and as currently detailed in the Company's Technical Interconnection Requirements, Technical Considerations Covering Parallel Operations of customer owned generation and interconnected with the Company's Power Delivery System in the State of New Jersey and the applicable codes of the local public authorities. Special attention should be given to IEEE Standard 1547-2018 (or latest amended revision) for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces. The customer must obtain, at the customer's sole expense, all necessary inspections and approvals required by the local public authorities before the customer-generator facility is connected to the Company's electric system.

INTERCONNECTION AND PARALLEL OPERATION

Interconnection with the Company's system requires the installation of protective equipment which provides safety for personnel, affords adequate protection against damage to the Company's system or to the customer's property, and prevents any interference with the Company's supply of service to other customers. Such protective equipment shall be installed, owned and maintained by the customer at the Customer's expense. Generation systems and equipment that comply with the standards established in the previous Section of this Rider shall be deemed by the Company to have generally complied with the requirements of this Section.

CESSATION OF PARALLEL OPERATION

The customer's equipment must be installed and configured so that parallel operation must cease immediately and automatically during system outages or loss of the Company's primary electric source. The customer must also cease parallel operation upon notification by the Company of a system emergency, abnormal condition, or in cases where such operation is determined to be unsafe, interferes with the supply of service to other customers, or interferes with the Company's system maintenance or operation.

DELIVERY VOLTAGE

Issued by:

The delivery voltage of the customer-generator facility shall be at the same voltage level and at the same delivery point as if the Customer were purchasing all of its electricity from the Company.

Date of Issue:	Effective Date:

ATLANTIC CITY ELECTRIC COMPANY

BPU NJ No. 11 Electric Service - Section IV Second Revised Sheet Replaces First Revised Sheet No. 62

RIDER NEM (Continued) Net Energy Metering

TERM OF CONTRACT

The contract term shall be same as that under the customer's applicable Rate Schedule.

MONTHLY RATES, RATE COMPONENTS AND BILLING UNIT PROVISIONS

The monthly rates, rate components and billing unit provisions shall be those as stated under the customer's applicable Rate Schedule. Under this Rider, only the per kilowatt-hour charge components of the customer's bill are affected. The monthly charges shall be based on one of the following conditions:

- a) When the monthly energy meter reading registers that the customer has consumed more energy than the customer delivered to the Company's delivery system by the end of the monthly billing period, the customer shall be charged for the net amount of electricity consumed based on the rates and charges under the customer's applicable Rate Schedule for either Delivery Service when the customer has a third party supplier as its electric supplier, or the combined Delivery, Transmission and Basic Generation Service when the customer has the Company as its electric supplier; or
- b) If the customer is receiving combined Delivery, Transmission and Basic Generation Service, and the monthly energy meter reading registers that the customer has delivered more energy to the Company's delivery system than the customer has consumed by the end of the monthly billing period, the customer shall be charged the Customer Charge and any appropriate demand charges based on the customer's applicable Rate Schedule. In addition, the Company shall receive and take ownership of the delivered energy from the customer and the Company shall credit the customer for that delivered energy. At the end of twelve consecutive monthly billing periods beginning with the first month in which net metering becomes applicable (annualized period), the customer will be compensated for any remaining credits at the average Residual Metered Load Aggregate locational marginal price for energy, for the annualized period, in the Pennsylvania, New Jersey and Maryland Interconnection (PJM) Control Area Transmission Zone for the Company. In the event that a customer leaves Basic Generation Service prior to the end of the annualized period, the end of the service period will be treated as if it were the end of the annualized period; or
- c) If the customer has a third party supplier and the monthly energy meter reading registers that the customer has delivered more energy to the Company's delivery system than the customer has consumed by the end of the monthly billing period, the customer shall be charged the Customer Charge and any appropriate demand charges based on the customer's applicable Rate Schedule. Monthly meter data will be forwarded to the customer's third party supplier in accordance with existing Electronic Data Interchange (EDI) Standards. In the event that a customer changes electric supplier prior to the end of the annualized period, the end of the service period will be treated as if it were the end of the annualized period.

The customer has one opportunity to select an annualized billing period in accordance with the provisions of N.J.A.C. 14:8-4.3.

RENEWABLE ENERGY CERTIFICATES

The Renewable Energy Certificates generated by the customer-generator facility are owned entirely by the customer or the eligible customer's assignee.

METERING

The watt-hour energy meter at the customer's location shall measure the net energy consumed by the customer or the net energy delivered by the customer-generator facility for the monthly billing period. The Company shall furnish, install, maintain and own all the metering equipment needed for measurement of the service supplied.

Date of Issue:	Effective Date:
Issued by:	

First Revised Sheet Replaces Original Sheet No. 63

RIDER NEM (Continued) Net Energy Metering

MODIFICATION OF THE COMPANY'S SYSTEM

If it is necessary for the Company to extend or modify portions of its systems to accommodate the delivery of electricity from the customer-generator facility, the Company at the customer's expense shall perform such extension or modification.

LIABILITY

The Company accepts no responsibility whatsoever for damage or injury to any person or property caused by failure of the customer to operate in compliance with Company's requirements. The Company shall not be liable for any loss, cost, damage or expense to any party resulting from the use or presence of electric current or potential which originates from the customer-generator facility. Connection by the Company under this Rider does not imply that the Company has inspected or certified that the customer-generator facility has complied with any necessary local codes or applicable safety or performance standards. All inspections, certifications and compliance with applicable local codes and safety requirements are the sole responsibility of the customer-generator.

FAILURE TO COMPLY

If the customer fails to comply with any of the requirements set forth in this Rider, the Company may disconnect the customer's service from the Company's electric system until the requirements are met, or the customer-generator facility is disconnected from the customer's electric system.

TERMS AND CONDITIONS

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Date of Issue:	Effective Date:
Issued by:	

RIDER ANEM Aggregated Net Energy Metering

AVAILABILITY

This Rider is available to any customer served under the Company's Rate Schedules RS, MGS-Secondary, MGS-SEVC, MGS-Primary, AGS Secondary, AGS Primary, TGS Sub-Transmission, and TGS Transmission who owns and operates a customer-generator facility that:

- 1) Is a solar electric power generation system; and
- 2) Is not an on-site generation system; and
- 3) Is located on the customer's premises; and
- 4) Is interconnected and operated in parallel with the Company's transmission or distribution facilities; and
- 5) Is intended primarily to offset all or part of the customer's own aggregated electricity requirements; and
- 6) Is not a Qualifying Facility (QF) served under the Company's Rate Schedule SPP, Small Power Purchase; and
- 7) The customer Is a State entity, school district, county, county agency, county authority, municipality, municipal agency, or municipal authority; and have multiple metered accounts including the host account that:
 - a) Must be located within the customer's territorial jurisdiction or, for a State entity, be located within 5 miles of one another; and
 - b) Are served by Basic Generation Service (BGS) under the same eligible rate schedule or be supplied by the same (third-party) energy supplier; and
 - c) None of the accounts to be aggregated have been included in a previous aggregation for another qualified customer facility; and
 - d) is not located on land that has been actively devoted to agricultural or horticultural use and that is valued, assessed, and taxed pursuant to the Farmland Assessment Act of 1964 at any time within the 10 years prior to July 23, 2012. (The municipal planning board of a municipality where the customer-generator facility is to be located may waive this requirement.)

The customer may aggregate the meters for the purpose of net metering regardless of which individual meter receives energy from a customer-generator facility provided that:

1) Before a customer can participate under this rider and activate the customer-generator facility, the customer shall file an application with the Company available at:

http://www.atlanticcityelectric.com/greenpowerconnection/ and include the following information:

- a) For the metered account behind which a customer-generator is net metered ("the host account"), a description of the customer-generator facility including its location, capacity, and description of its generating technology;
- b) A list of the individual metered accounts that the customer seeks to aggregate, identified by name, address, rate schedule, and account number;
- 2) The customer may provide written notice of a change to its list of aggregated metered accounts no more than once annually and should allow for up to 30 days for the change to go into effect; and
- 3) In order to continue under this rider, the customer must notify the Company of any change in ownership of the accounts by providing the Company 30 days written notice.

Customer-generators applying under this rider may be subject to FERC jurisdiction with respect to net sales of excess generation and interconnection requirements.

eligible customer participating aggregated net metering under this Rider can be charged by the Company for incremental costs providing this service.

Date of Issue:	Effective Date:	
Issued by:		

Sheet No. 63b

RIDER ANEM (Continued) Aggregated Net Energy Metering

CONNECTION TO THE COMPANY'S SYSTEM

Any customer who elects this Rider must submit a New Jersey Interconnection Application Form with the Company, at least 30 days prior to activating the customer-generator facility. The customer should not install a customer-generator facility without prior approval from the Company and the customer shall not operate a customer-generator facility without final written approval from the Company.

The customer-generator facility shall not be connected to the Company's system unless it meets all applicable safety and performance standards established by the National Electric Code, The Institute of Electrical and Electronics Engineers (IEEE), Underwriters Laboratories, and as currently detailed in the Company's Technical Interconnection Requirements, Technical Considerations Covering Parallel Operations of Customer Owned Generation and interconnected with the Company's Power Delivery System in the State of New Jersey and the applicable codes of the local public authorities. Special attention should be given to IEEE Standard 1547-2018 (or latest amended revision) for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces. The customer must obtain, at the customer's sole expense, all necessary inspections and approvals required by the local public authorities before the customer-generator facility is connected to the Company's electric system.

INTERCONNECTION AND PARALLEL OPERATION

Interconnection with the Company's system requires the installation of protective equipment which provides safety for personnel, affords adequate protection against damage to the Company's system or to the Customer's property, and prevents any interference with the Company's supply of service to other customers. Such protective equipment shall be installed, owned and maintained by the customer at the customer's sole expense. Generation systems and equipment that comply with the standards established in the previous Section of this Rider shall be deemed by the Company to have generally complied with the requirements of this Section.

CESSATION OF PARALLEL OPERATION

The customer's equipment must be installed and configured so that parallel operation must cease immediately and automatically during system outages or loss of the Company's primary electric source. The customer must also cease parallel operation upon notification by the Company of a system emergency, abnormal condition, or in cases where such operation is determined to be unsafe, interferes with the supply of service to other customers, or interferes with the Company's system maintenance or operation.

DELIVERY VOLTAGE

The delivery voltage of the customer-generator facility shall be at the same voltage level and at the same delivery point as if the customer were purchasing all of its electricity from the Company.

TERM OF CONTRACT

The contract term shall be same as that under the customer's applicable Rate Schedule.

MONTHLY RATES, RATE COMPONENTS AND BILLING UNIT PROVISIONS

The monthly rates, rate components and billing unit provisions shall be those as stated under the customer's applicable Rate Schedule. Under this Rider, only the per kilowatt-hour charge components of the customer's bill for the host account are affected. The monthly charges shall be based on one of the following conditions:

a) When the monthly energy meter reading registers on the host account that the customer has consumed more energy than the customer delivered to the Company's delivery system by the end of the monthly billing period, the customer shall be charged for the net amount of electricity consumed based on the rates and charges under the customer's applicable Rate Schedule for either Delivery Service when the customer has a third party supplier as its electric supplier, or the combined Delivery, Transmission and Basic Generation Service when the customer has the Company as its electric supplier; or

Date of Issue:	Effective Date
Issued by:	

RIDER ANEM (Continued) Aggregated Net Energy Metering

- b) If the customer is receiving combined Delivery, Transmission and Basic Generation Service, and the monthly energy meter reading on the host account registers that the customer has delivered more energy to the Company's delivery system than the customer has consumed by the end of the monthly billing period, the customer shall be charged the Customer Charge and any appropriate demand charges based on the customer's applicable Rate Schedule. In addition, the Company shall receive and take ownership of the delivered energy from the customer and the Company shall credit the customer for that delivered energy on the next monthly billing period. At the end of twelve consecutive monthly billing periods beginning with the first month in which net metering becomes applicable (annualized period), the customer will be compensated for any remaining credits at the average locational marginal price for energy, for the annualized period, in the Pennsylvania, New Jersey and Maryland Interconnection (PJM) Control Area Transmission Zone for the Company. In the event that a customer leaves Basic Generation Service prior to the end of the annualized period, the end of the service period will be treated as if it were the end of the annualized period; or
- c) If the customer has a third party supplier and the monthly energy meter reading on the host account registers that the customer has delivered more energy to the Company's delivery system than the customer has consumed by the end of the monthly billing period, the customer shall be charged the Customer Charge and any appropriate demand charges based on the customer's applicable Rate Schedule. Monthly meter data will be forwarded to the customer's third party supplier in accordance with existing Electronic Data Interchange (EDI) Standards. In the event that a customer changes electric supplier prior to the end of the annualized period, the end of the service period will be treated as if it were the end of the annualized period.

The customer has one opportunity to select an annualized billing period in accordance with the provisions of N.J.A.C. 14:8-4.3.

RENEWABLE ENERGY CREDITS

The Renewable Energy Credits generated by the customer-generator facility are owned entirely by the customer or the eligible customer's assignee.

METERING

The watt-hour energy meter at the customer's location shall measure the net energy consumed by the customer or the net energy delivered by the customer-generator facility for the monthly billing period. The Company shall furnish, install, maintain and own all the metering equipment needed for measurement of the service supplied.

MODIFICATION OF THE COMPANY'S SYSTEM

If it is necessary for the Company to extend or modify portions of its systems to accommodate the delivery of electricity from the customer-generator facility, the Company, at the customer's sole expense, shall perform such extension or modification.

LIABILITY

The Company accepts no responsibility whatsoever for damage or injury to any person or property caused by failure of the customer to operate in compliance with Company's requirements. The Company shall not be liable for any loss, cost, damage or expense to any party resulting from the use or presence of electric current or potential which originates from the customer-generator facility. Connection by the Company under this Rider does not imply that the Company has inspected or certified that the customer-generator facility has complied with any necessary local codes or applicable safety or performance standards. All inspections, certifications and compliance with applicable local codes and safety requirements are the sole responsibility of the customer-generator.

Date of Issue:	Effective Date:
Issued by:	

Original Sheet No. 63d

RIDER ANEM (Continued) Aggregated Net Energy Metering

FAILURE TO COMPLY

If the customer fails to comply with any of the requirements set forth in this Rider, the Company may disconnect the customer's service from the Company's electric system until the requirements are met, or the customer-generator facility is disconnected from the customer's electric system.

TERMS AND CONDITIONS

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The	Lerms and	Conditions	set forth in	this tariff s	shall govern	the provision of	service under this	Rider.

Date of Issue:	Effective Date:
Issued by:	

ATLANTIC CITY ELECTRIC COMPANY

BPU NJ No. 11 Electric Service - Section IV Twenty-Sixth Revised Sheet Replaces Twenty-Fifth Revised Sheet No. 64

RIDER RGGI

Regional Greenhouse Gas Initiative Recovery Charge

A. Applicability

This Rider is applicable to Rate Schedules RS, MGS Secondary, MGS-SEVC, MGS Primary, AGS Secondary, AGS Primary, TGS, DDC, SPL and CSL. Amounts billed to customers shall include a charge to reflect regional greenhouse gas initiative program costs. Except where indicated otherwise, Rider "RGGI" will be determined annually based on projections of program costs (including an adjustment for variances between budgeted and actual prior year expenditures) and forecasts of kilowatt hour sales. The charge (in dollars per kilowatt hour) will be computed by dividing the total annual amount to be recovered for by forecasted retail sales (in kilowatt hours).

RGGI Programs

Solar Renewable Energy Certificate (SREC) (\$/kWh)

\$0.000189

This charge component is intended to recover net costs associated with the Solar Renewable Energy Certificate Program.

Solar Renewable Energy Certificate (SREC II) (\$/kWh)

\$0.00000

This charge component is intended to recover net costs associated with the Solar Renewable Energy Certificate II Program.

Transition Renewable Energy Certificate (TREC) (\$/kWh)

\$0.000988

This charge component is intended to recover net costs associated with the Solar Transition Incentive Program.

Energy Efficiency Surcharge (EE) (\$/kWh)

\$0.000840

This charge component is intended to recover the costs associated with the Energy Efficiency Program.

Successor Solar Incentive Program (SuSI) (\$/kWh)

\$0.000370

This charge component is intended to recover the costs associated with the Successor Solar Incentive Program.

Community Solar Energy Program (CSEP) (\$/kWh)

\$0.000000

This charge component is intended to recover the net costs associated with the Community Solar Energy Program.

Total Rider RGGI Surcharge (\$/kWh)

\$0.002396

Date of Issue:	Effective Date:

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Date of Issue: Effective Date:

RIDER EDIT

Excess Deferred Income Tax Credit

AVAILABILITY

This rider is applicable to Rate Schedules RS, MGS Secondary, MGS Primary, AGS Secondary, AGS Primary, TGS, DDC, SPL and CSL.

Rider "EDIT" is to ensure the full amount of the Tax Cut and Jobs Act (TCJA) tax benefits associated with the non-protected assets are returned to customers over a five (5) year period.

The charge for each Rate Schedule is as follows:

Rate Class	<u>EDIT</u>	Credit (w/ SUT)	
RS	\$	(0.004884)	\$ per kWh
MGS Secondary	\$	(0.000000)	\$ per kWh
MGS Primary	\$	(0.000000)	\$ per kWh
AGS Secondary	\$	(0.002785)	\$ per kWh
AGS Primary	\$	(0.001621)	\$ per kWh
TGS Subtransmission	\$	(0.000605)	\$ per kWh
TGS Transmission	\$	(0.000630)	\$ per kWh
SPL/CSL	\$	(0.019798)	\$ per kWh
DDC	\$	(0.000000)	\$ per kWh

Date of Issue:	Effective Date:

ZERO EMISSION CERTIFICATE ("ZEC") RECOVERY CHARGE

APPLICABILITY: The Zero Emission Certificate Recovery Charge ("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.

Rate Component (\$ per kWh)

	Excluding SUT	Including SUT
ZEC Charge	\$0.004000	\$0.004265
ZEC Reconciliation Charge	\$0.000000	\$0.000000
Total ZEC Charge	\$0.004000	\$0.004265

Pursuant to the BPU's Zero Emission Certificate Charge Order dated November 19, 2018 in BPU Docket No. EO18091003, 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 <u>L.</u> 2018, <u>c.</u> 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, interest-bearing account 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.

The ZEC Charge will become effective upon the issuance of the April 2019 Board Order in BPU Docket No. EO18080899.

Date of Issue:	Effective Date:	
Issued by:		

RIDER IIP Infrastructure Investment Program

APPLICABILITY:

This rider is applicable to Rate Schedules RS, MGS Secondary, MGS Primary, AGS Secondary, AGS Primary, TGS, DDC, SPL and CSL, and Rider STB.

This charge provides for the full and timely recovery of revenue requirements associated with the Infrastructure Investment Program ("IIP") projects subject to the IIP recovery rules, codified at N.J.A.C. 14:3-2A.1 et seq., as approved by the New Jersey Board of Public Utilities.

The following table provides the rates for the IIP, including ("SUT"). For billing presentation purposes these rates are to be added to the base distribution rates for each Rate Schedule. This applies to the distribution charges for the Rate Schedules on the following Tariff Sheets: 5, 11, 14, 17, 19, 29, 29a, 31, 36, 37,37a, 40, and 44. These rates are subject to all other applicable charges and taxes in accordance with the underlying rate schedule's distribution rates.

RATE SCHEDULE	IIP Rate	Billing Units
RS	\$ 0.001282	Per kWh
MGS Secondary	\$ 0.04 \$ 0.001095	Per kW Per kWh
MGS Primary	\$ 0.03 \$ 0.000758	Per kW Per kWh
AGS Secondary	\$ 0.24	Per kW
AGS Primary	\$ 0.17	Per kW
TGS Sub Transmission	\$ 0.06	Per kW
TGS Transmission	\$ 0.04	Per kW
SPL/CSL	\$ 0.27 Per la	mp per month
DDC Service and Demand (per day per connection) Energy (per day for each kW of effective load)	\$ 0.002775 \$ 0.013367	
RIDER STB MGS Secondary MGS Primary AGS Secondary AGS Primary TGS – Sub Transmission TGS – Transmission	\$ 0.00 \$ 0.00 \$ 0.02 \$ 0.02 \$ 0.00 \$ 0.00	Per kW Per kW Per kW Per kW Per kW

Date of Issue:	Effective Date:

RIDER CIP CONSERVATION INCENTIVE PROGRAM RECOVERY CHARGE

APPLICABILITY:

This rider is applicable to Rate Schedules RS, MGS Secondary, MGS Primary, AGS Secondary, AGS Primary, and TGS and TGS Sub Transmission. The Company's CIP shall be based on the differences between actual and allowedrevenue per customer during the preceding annual period. This adjustment will be effectuated through a credit or surcharge applied to customers' bills during the adjustment period. The credit or surcharge will also be adjusted to reflect prior year under or over recoveries pursuant to Rider "CIP". The Company at its discretion will make annual filings.

The Company's CIP Recovery Charge including sales and use tax to be effective on and after the date indicated below is as follows:

Rate Schedule	Rate	
Residential	\$(0.000354)	per kWh
MGS Secondary	\$(0.008526)	per kWh
MGS Primary	\$(0.032302)	per kWh
AGS Secondary	\$0.04	per kW
AGS Primary	\$(0.13)	per kW
TGS Sub Transmission	\$(0.17)	per kW
TGS Transmission	\$Ò.05 [^]	per kW

I. DEFINITION OF TERMS AS USED HEREIN:

1. Actual Number of Customers

- The Actual Number of Customers ("ANC") shall be determined on a monthly basis for each Rate Schedule, to which the CIP applies. The ANC shall equal the aggregate actual monthly customer charge revenue for each classof customers subject to the CIP as recorded on the Company's books, divided by the customer charge rate applicable to such class of customers in each Rate Schedule.

2. Actual Revenue Per Customer

The Actual Revenue per Customer ("ARC") shall be determined in dollars per customer on a monthly basis for each Rate Schedule, to which the CIP applies. The ARC shall equal the aggregate actual booked variable margin revenue per applicable rate schedule for the month as recorded on the Company's books divided by the Actual Number of Customers for the corresponding month. Actual revenues shall include Distribution Kilowatt-hour and Distribution Kilowatt demand charges, as well as any PowerAhead and Infrastructure Investment Program revenues, and shall not include the customer charge and any non-base rate charges such as the Societal Benefits, Non-Utility Generation, Regional Greenhouse Gas Initiative Recovery ("RGGI"), Securitization, or the Zero EmissionCertificate ("ZEC") Charges.

3. Adjustment Period

Shall be the year beginning immediately following the conclusion of the Annual Period.

4. Annual Period

Issued by:

 Shall be the twelve consecutive months from July 1st of one calendar year through June 30th of the followingcalendar year.

5. Average 13 Month Common Equity Balance

Shall be the average of the beginning and ending common equity balances based on the latest publicly available financials available before the end of the Annual Period. The Company shall provide the most recently available actual months plus forecasted data at the time of each Initial Filing. The forecasted data will be updated with actuals once the financial statements for the months have been disclosed.

Date of Issue:	Effective Date:

RIDER CIP (continued) CONSERVATION INCENTIVE PROGRAM RECOVERY CHARGE

6. Baseline Revenue per Customer

The Baseline Revenue per Customer shall be stated in dollars per customer on a monthly basis for each of the Rate Schedules, to which the CIP applies. The Baseline Revenue per Customer shall be calculated as the current variable margin revenue per rate schedule, including any revenue from PowerAhead and Infrastructure Investment Program rate adjustments, divided by the number of customers from the most recent approved base rate case for the rate schedule.

Baseline revenues shall include Distribution Kilowatt-hour and Distribution Kilowatt charges and shall not include the customer charge and any non-base rate charges such as the Societal Benefits, Non-Utility Generation Charge, RGGI, Securitization, or the ZEC Charges.

The table below summaries the Board approved monthly Baseline Revenue per customer:

	<u>RS</u>	MGSS	<u>MGSP</u>	<u>AGSS</u>	<u>AGSP</u>	<u>TGSS</u>	<u>TGS</u>
Jan	\$ 57.52	\$ 127.18	\$ 1,468.61	\$ 2,020.52	\$10,089.63	\$ 8,483.11	\$ 4,322.24
Feb	\$ 51.71	\$ 124.25	\$ 1,451.55	\$ 1,910.07	\$ 9,378.29	\$ 6,833.58	\$ 6,888.56
Mar	\$ 45.05	\$ 121.00	\$ 1,453.05	\$ 1,862.34	\$ 9,863.95	\$ 6,935.47	\$ 5,872.60
Apr	\$ 39.13	\$ 122.78	\$ 1,410.43	\$ 1,911.53	\$10,266.06	\$ 9,929.68	\$ 3,260.78
May	\$ 32.33	\$ 120.94	\$ 1,364.69	\$ 1,853.69	\$ 9,715.06	\$ 9,896.55	\$ 3,649.66
June	\$ 54.27	\$ 160.24	\$ 1,671.81	\$ 1,856.93	\$ 10,711.67	\$ 10,481.30	\$ 4,373.90
July	\$ 86.42	\$ 193.80	\$ 1,388.05	\$ 1,960.94	\$ 10,080.24	\$ 7,433.50	\$ 7,608.31
Aug	\$ 97.51	\$ 208.58	\$ 1,969.53	\$ 1,969.28	\$ 11,297.01	\$ 8,106.62	\$ 6,246.29
Sept	\$ 86.43	\$ 205.86	\$ 1,980.04	\$ 1,956.72	\$ 11,441.59	\$ 8,993.31	\$ 5,400.11
Oct	\$ 45.65	\$ 138.64	\$ 1,614.70	\$ 1,886.04	\$ 10,988.78	\$ 7,939.40	\$ 11,075.30
Nov	\$ 34.29	\$ 118.43	\$ 1,576.18	\$ 1,761.76	\$ 9,714.65	\$ 7,344.54	\$ 6,829.31
Dec	\$ 44.61	\$ 127.89	\$ 1,100.41	\$ 2,003.63	\$ 12,716.64	\$ 8,758.92	\$ 5,156.31

7. Forecast Annual Usage

 The Forecast Annual Usage shall be the projected total annual Kilowatt-hour sales or Kilowatt demand for all customers within the applicable Rate Schedules. The Forecasted Annual Usage shall be estimated based on normal weather.

8. Cooling and Heating Degree Days ("CDD" & "HDD")

- CDD are the difference between 65°F and the mean daily temperature. The mean daily temperature is the simple average of the 24-hourly temperature observations for a day. HDD are used to measure the difference between 35°F and the mean daily temperature during winter weather.

9. Actual Calendar Month CDD and HDD

- The accumulation of the actual CDD and HDD for each day of a calendar month.

10. Normal Calendar Month CDD and HDD

- The level of calendar month CDD and HDD, to which the weather portion of this CIP applies. The normal calendar month CDD and HDD will be based on the twenty-year average of the National Oceanic and Atmospheric Administration (NOAA) First Order Weather Observation Station hourly observations at the Atlantic City Airport and will be updated annually. The base level of normal CDD and HDD for the defined winter and summer period months for the 2021 Periods are set forth in the table below:

Date of Issue:	Effective Date:

RIDER CIP (continued) CONSERVATION INCENTIVE PROGRAM RECOVERY CHARGE

Month	Normal Heating	Normal Cooling
	Degree Days	Degree Days
January	877	0
February	929	0
March	742	0
April	541	0
May	256	35
June	0	138
July	0	306
August	0	369
September	0	248
October	123	83
November	396	0
December	662	0

11. Winter Period

- Shall be the eight consecutive calendar months from October of one calendar year through May of the following calendar year.

12. Summer Period

- Shall be the three consecutive calendar months from July through September of the calendar year and starting June of the following calendar year.

II. DETERMINATION OF THE CONSERVATION INCENTIVE PROGRAM

- 1. At the end of the Annual Period, a calculation shall be made that determines for each Rate Schedule the deficiency or excess to be surcharged or credited to customers pursuant to the CIP mechanism. The deficiency or excess shall be calculated each month by multiplying the result obtained from subtracting the Baseline Revenue per Customer from the Actual Revenue per Customer by the Actual Number of Customers, and then multiplying the resulting usage by the Margin Revenue Factor.
- 2. The weather-related change in customer usage shall be calculated as the difference between actual CDD and HDD and the above CDD and HDD multiplied by the weather normalization factors and multiplying the result by the margin revenue factors of this Rate Schedule to determine the weather-related deficiency or excess. The weather-related amount will be subtracted from the total deficiency or excess to determine the non-weather-related deficiency or excess.
- 3. Recovery of margin deficiency associated with non-weather-related changes in customer usage will be subject to a Basic General Service ("BGS") savings test and a Variable Margin Revenue recovery limitation ("recovery tests"). Recovery of non-weather-related margin deficiency will be limited to the smaller of (1) the level of BGS savings achieved when such savings are less than 75 percent of the non-weather-related margin deficiency, i.e. BGS savings test, and (2) 6.5 percent of variable margins for the CIP Annual Period, i.e., Variable Margin Revenue recovery limitation. Any amount that exceeds the above limitations may be deferred for future recovery and is subject to either or both recovery tests in a future year consistent with the amount by which either or both non-weather-related margin deficiency exceeded the recovery tests. For the purposes of this calculation, the value of the weather-related portion shall be calculated as set forth in Section II.2 of this Rate Schedule.

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RIDER CIP (continued) CONSERVATION INCENTIVE PROGRAM RECOVERY CHARGE

- 4. In addition, if the calculated Return on Equity ("ROE") exceeds the allowed ROE from the utility's last base rate case by 50 basis points or more, recovery of lost revenues through the CIP shall not be allowed for the applicable filing period. For purposes of this section, the Company's rate of return on common equity shall be calculated by dividing the Company's net income for the applicable period as defined in the Average 13-Month Common Equity Balance by the Company's average common equity balance for the same period. The Company's Average 13-Month Common EquityBalance shall be the ratio of Electric Distribution Net Plant (including the Electric Distribution allocation of Common Plant) to the total Company Net Plant for the Average 13 Month Common Equity Balance period multiplied by the Company's total common equity for the same period.
- 5. The amount to be surcharged or credited shall equal the eligible aggregate deficiency or excess for all months during the Annual Period determined in accordance with the provisions herein, divided by the Forecast Annual Usage for the Rate Schedule.

III. TRACKING THE OPERATION OF THE CONSERVATION INCENTIVE PROGRAM

The revenues billed, or credits applied, net of taxes and assessments, through the application of the Conservation Incentive Program Rate shall be accumulated for each month of the Adjustment Period and applied against the CIP excess or deficiency from the Annual Period and any cumulative balancesremaining from prior periods.

NEW JERSEY SALES AND USE TAX (SUT)

Charges under this Rider include a component for New Jersey Sales and Use Tax as set forth in Rider SUT.

CORPORATE BUSINESS TAX (CBT)

Charges under this rate schedule include a component for Corporate Business Taxes as set forth in Rider CBT.

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Issued by:	

RIDER RNEM Remote Net Energy Metering

Limitations and Qualifications for Remote Net Metering (BPU Docket No. QO18070697, Orders dated September 17, 2018 and August 18, 2021)

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. On September 17, 2018, the Board established the application and approval process and defined public entity for Remote Net Metering, in Docket No. QO18070697; this process was further clarified by Order dated August 18, 2021.

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, county community college, 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 in the Atlantic City Electric Co. ("ACE" or the "Company") service territory. The entities designated to receive credits are considered to be receiving customers. Receiving customers must be public entities also located in the ACE service territory. Both the host customer and the receiving customer must be a customer of record of ACE. Receiving customers must maintain positive bill payment practices on their ACE account to remain eligible for credits. There may be no more than 10 receiving customer accounts per host customer. Host customer and receiving customers must be served by Basic Generation Service ("BGS") or be supplied by the same (third-party) energy supplier. None of the accounts can be included in a previous aggregation for another qualified customer facility or be a NEM customer.

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 ACE and the BPU, 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 business 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 Board with a recommendation for approval or denial. The Company, contingent on the cooperation of the Public Entity Applicant(s), will continue to perform any additional technical processing of the eligible public entities' interconnection application, subject to the Board's final approval or denial. ACE is not responsible for resolving disputes which may arise between host customer and receiving customers.

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 applicable host customer's electric account(s) 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 must 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 the number of accounts, if more than one account is used, and 1,200 annual kWh per kilowatt ("kWdc") to arrive at the maximum capacity for the solar electric generation facility in kWs ("kWdc" and "kWac").

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Effective Date:

Original Sheet No. 70a

RIDER RNEM (Continued) Remote Net Energy Metering

Billing and Credits for Remote Net Metering: No more than 10 receiving accounts may be party to a Public Entity Certification Agreement and no less than 10% of the solar electric generating facility output may be allocated to a receiving customer account and intended primarily to offset all or part of the receiving customer's own electricity requirements except to the extent that 10% of the solar electric generating facility output is greater. Receiving customers must maintain positive payment practices on their ACE accounts to remain eligible to receive credits. 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'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 that is specified, owned, and installed by the Company. This revenue grade production meter will 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 approved 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, 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 approved 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 host customers and receiving customers. 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.

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RIDER CSEP Community Solar Energy Pilot Program

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 9.6 MW based upon the Company's 12.8% 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 5 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.

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.

Date of Issue:	Effective Date:
Issued by:	

RIDER CSEP (Continued) Community Solar Energy Pilot Program

Interconnection Application & Requirements

Community solar pilot projects shall comply with all current and future applicable interconnection requirements, as set forth in N.J.A.C. 14:8-9.9(a) and N.J.A.C. 14:8-5 and shall be processed by the Company following normal interconnection procedures.

Although projects are not required to have submitted an interconnection agreement or have an executed interconnection agreement prior to applying to the Pilot Program with the BPU, projects may file an interconnection application with the Company prior to being selected by the BPU at their own risk and cost. Additionally, only projects that have been approved by the BPU to participate in the Pilot Program are eligible to allocate community solar bill credits.

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.

Date of Issue:	Effective Date:
Issued by:	

Original Sheet No. 71b

RIDER CSEP (Continued) Community Solar Energy Pilot Program

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-bypassable 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, the TBC charge, the MTC-Tax charge and the ZEC charge. The value of the bill credit shall be set at the retail rate for their respective service classification. The BGS bill credit for CIEP eligible customers will be set at the average prior calendar year hourly Locational Marginal Price (LMP) of energy in the ACE PJM zone. 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 section on the subscribers' utility bills.

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 prior calendar year hourly Locational Marginal Price (LMP) of energy in the ACE PJM 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 prior calendar year hourly Locational Marginal Price (LMP) of energy in the ACE PJM 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.

Date of Issue:	Effective Date:	
Issued by:		

Original Sheet No. 71c

RIDER CSEP (Continued) Community Solar Energy Pilot Program

Subscription Enrollments & Management

The subscriber organization must provide subscriber information for a project to the Company using the Company's online portal for subscription management, known as the Community Solar Portal ("CSP"). The CSP and informational material can be accessed at

https://www.atlanticcityelectric.com/SmartEnergy/MyGreenPowerConnection/Pages/CommunitySolarResources.aspx.

Subscriber organizations shall indicate in CSP the subscribers that qualify as LMI in accordance with N.J.S.A. 14:8-9.8, and by doing so the subscriber organization confirms that all LMI information entered in CSP has been verified as accurate. Additionally, the subscriber organization shall have obtained authorization from each subscriber for the utility to release that subscriber's account information to the subscriber organization as necessary. Once a project is operational, subscriber organizations shall update their subscriber information for each community solar facility every month unless there is no change from the previous month. Updates to subscriber information must be submitted electronically through CSP. Depending on timing of notification from the subscriber organization of the subscriber's subscription amount, it may take up to two billing cycles before a bill credit is applied to the subscriber's bill. Updates received by the Company on or before the 10th of each month will be effective the following month. Subscriptions may not take effect retroactively.

Date of Issue:	Effective Date:	_
Issued by:		

Exhibit A

Redlined Tariff Sheets

ATLANTIC CITY ELECTRIC COMPANY

TARIFF FOR ELECTRIC SERVICE

SECTION I - GENERAL INFORMATION AND TERRITORY SERVED

SECTION II - STANDARD TERMS AND CONDITIONS

SECTION III - RATE SCHEDULE RUE - RESIDENTIAL UNDERGROUND

EXTENSIONS AND CLE - CONTRIBUTED LIGHTING

EXTENSIONS

SECTION IV - SERVICE CLASSIFICATIONS AND RIDERS

ATLANTIC CITY ELECTRIC COMPANY

Regional Headquarters 5100 Harding Highway Mays Landing, New Jersey 08330-2239

Date of Issue: July 15, 2021 Effective Date: July 15, 2021

Issued by: David M. Velazquez, President and Chief Executive Officer – Atlantic City Electric Company Filed pursuant to Board of Public Utilities of the State of New Jersey directives associated with the BPU Docket No. ER20120746

ATLANTIC CITY ELECTRIC COMPANY

TARIFF FOR ELECTRIC SERVICE

SECTION I

GENERAL INFORMATION AND TERRITORY SERVED

ATLANTIC CITY ELECTRIC COMPANY

Regional Headquarters 5100 Harding Highway Mays Landing, NJ 08330-2239

Date of Issue: July 15, 2021 Effective Date: July 15, 2021

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TERRITORY SERVED BY ATLANTIC CITY ELECTRIC COMPANY



Date of Issue: July 15, 2021 Effective Date: July 15, 2021

Fage 4 of
Original Shoot No. 2
Original Sheet No. 3

Date of Issue: July 15, 2021 _____Effective Date: July 15, 2021

LIST OF MUNICIPALITIES SERVED BY ATLANTIC CITY ELECTRIC COMPANY

ATLANTIC COUNTY

——Absecon, Atlantic City, Brigantine, Buena	a Boro, Bu	uena Vis	ta Towns	ship, Co	rbin City,
Egg Harbor City, Egg Harbor Township,	•				<i>,</i>
Township, Hamilton Township, Hammonton	, Linwood	d, Long	port Bord	o, Marg	ate City,
Mullica Township, Northfield, Pleasantville,	Port Re	epublic,	Somers	Point,	Ventnor
City, Weymouth Township		•			

BURLINGTON COUNTY

——Bass River Township, Evesham Township*, Medford Township, Shamong Township, Southhampton Township*, Tabernacle Township, Washington Township, Woodland Township*.

CAMDEN COUNTY

Berlin Boro, Berlin Township, Chesilhurst Boro, Clementon Boro, Gibbsboro Boro, Gloucester Township*, Hi Nella Boro*, Laurel Springs Boro, Lindenwold Boro, Pine Hill Boro, Pine Valley Boro, Somerdale Boro*, Stratford, Voorhees Township*, Waterford Township, Winslow Township.

CAPE MAY COUNTY

——Avalon Boro, Cape May, Cape May Point Boro, Dennis Township, Lower Township, Middle Township, North Wildwood, Ocean City, Sea Isle City, Stone Harbor Boro, Upper Township, West Cape May Boro, West Wildwood Boro, Wildwood, Wildwood Crest Boro, Woodbine Boro.

CUMBERLAND COUNTY

——Bridgeton, Commercial Township, Deerfield Township, Downe Township, Fairfield Township, Greenwich Township, Hopewell Township, Lawrence Township, Maurice River Township, Millville, Shiloh Boro, Stow Creek Township, Upper Deerfield Township, Vineland*.

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ATLANTIC CITY ELECTRIC COMPANY BPU NJ No. 11 ELECTRIC SERVICE - SECTION I

Original Sheet No. 5

GLOUCESTER COUNTY
——Clayton Boro, Deptford Township*, East Greenwich Township, Elk Township, Franklin Township, Glassboro Boro, Greenwich Township, Harrison Township, Logan Township, Mantua Township, Monroe Township, Newfield Boro, Paulsboro Boro, Pitman Boro, South Harrison Township, Swedesboro Boro, Washington Township, Wenonah Boro, West Deptford Township*, Woolwich Township.
OCEAN COUNTY
——Barnegat Light Boro, Barnegat Township*, Beach Haven Boro, Eagleswood Township, Harvey Cedars Boro, Lacey Township*, Little Egg Harbor Township, Long Beach Township, Ocean Township*, Ship Bottom Boro, Stafford Township, Surf City Boro, Tuckerton Boro
SALEM COUNTY
——Alloway Township, Carney's Point Township, Elmer Boro, Elsinboro Township, Lower Alloways Creek Township, Mannington Township, Oldmans Township, Penns Grove Boro, Pennsville Township, Pilesgrove Township, Pittsgrove Township, Quinton Township, Salem, Upper Pittsgrove Township, Woodstown Boro.
* Served in Part

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ATLANTIC CITY ELECTRIC COMPANY
BPU NJ No. 11 ELECTRIC SERVICE - SECTION

Original Sheet No. 6

RESERVED FOR FUTURE USE

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ATLANTIC CITY ELECTRIC COMPANY BPU NJ No. 11 ELECTRIC SERVICE - SECTION I	Original Sheet No. 7
RESERVED FOR FUTURE USE	

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directives associated with the BPU Docket No. ER20120746 Issued by:

Date of Issue: July 15, 2021

2021

ATLANTIC CITY _ELECTRIC COMPANY

TARIFF

FOR ELECTRIC SERVICE

SECTION III - RATE SCHEDULE RUE - RESIDENTIAL UNDERGROUND EXTENSIONS AND CLE - CONTRIBUTED LIGHTING EXTENSIONS

ATLANTIC CITY ELECTRIC COMPANY
Regional Headquarters

5100 Harding Highway Mays Landing, New Jersey 08330-2239

Date of Issue: July 15, 2021 Effective Date: July 15, 2021

Effective Date: July 15,

ATLANTIC CITY ELECTRIC COMPANY BPU NJ No. 11 ELECTRIC SERVICE - SECTION III Third Revised Sheet Replaces Second Sheet No. 3

RATE SCHEDULE RUE (Residential Underground Extensions)

AVAILABILITY OF SERVICE

Available to new residential buildings and mobile homes within an approved subdivision to having 3 or more building lots and to new multiple occupancy buildings in accord with the provisions of Subchapter 4 of Regulations of the Board of Public Utilities.

RATE

All charges under the RUE tariff do not include cost and federal income tax liability pursuant to the Tax Reform Act of 1986. -For each building lot being served, the applicant shall pay the utility the amount determined from the following table plus all applicable taxes.

For non-typical situations, including service to multiple family buildings and other situations as detailed below, such charges shall be equal to estimated cost of the underground construction less the total estimated costs of the otherwise applicable overhead construction as set forth in Section II plus applicable taxes.

Such cost estimates shall be based on the allowances for the unit costs as detailed in Section II and shall be based on the necessary construction to supply the same loads and locations utilizing Atlantic City Electric's standard offerings and conditions.

Type of Building **Charge Per Lot** \$732.27 Plus \$3.14/Front Foot Single Family -Duplex-family, mobile home, & multiple Differential in charges foroccupancy buildings, three-phase, high equivalent underground & -capacity extensions, lots requiring primary overhead construction based extensions thereon, transformer capacity on unit charges set forth above 8.5 KVA per dwelling unit & other below. special conditions. **SPECIAL TERMS AND CONDITIONS** See Section II inclusive for Terms and Conditions of Service. The supply of electricity to the applicant shall be in accordance with the provisions of the rate

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schedule chosen by the applicant as applicable to this service.

Date of Issue: July 15, 2021

2021

ATLANTIC CITY ELECTRIC COMPANY
BPU NJ No. 11 ELECTRIC SERVICE - SECTION III Third-Revised Sheet Replaces Second-Sheet No. 3

RATE SCHEDULE RUE (Continued) (Residential Underground Extensions)

(Residential Underground Extensions)	
ADDITIONAL CHARGES	
Primary Termination - Branch (1/0 A1)\$	1,210.33
Primary Junction Enclosure w/Cable Taps	
Three Phase\$	5,391.57
Single Phase\$	2,281.22
Service Length in Excess of 50 feet, including conduit	
200 AMP\$	4.73/Trench Foot
320 AMP\$	5.23/Trench Foot
Additional Street Lights where spacing is less than 200'	
30' Fiberglass Standard\$	868.37
Multi-phase Constructions\$	3.20/Foot/Phase
Pavement cutting and restoration, rock) At actual cost plus FI	Т
removal, blasting, difficult digging) with option of appl	icant
and special backfill) as set for by NJAC	
) 14:5 - 4.1 <u>3-8.9d</u> e	t seq.
CHARGES FOR SINGLE PHASE UNDERGROUND CONSTRUCTION	
Trenching - Total Charge\$	3.29/Foot
For calculating differential charge\$	1.89/Foot
Primary Cable (1/0 A1)\$	2.68/Foot
Secondary Cable	
4/0 Triplex (A1)\$	4.04/Foot
350 KCMIL Triplex (A1)\$	4.91/Foot
Service	
200 AMP (4/0 A1)\$	4.04/Foot
Complete\$	598.93
320 AMP (350 KCMIL A1)\$	4.91/Foot
Complete\$	671.68
Service Riser	
2"\$	183.82
3"\$	195.25

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ATLANTIC CITY ELECTRIC COMPANY

BPU NJ No. 11 ELECTRIC SERVICE - SECTION III Third Revised Sheet Replaces Second Sheet No. 4

RATE SCHEDULE RUE (Continued) (Residential Underground Extensions)

CHARGES FOR SINGLE PHASE UNDERGROUND CONSTRUCTION	N (Continued)
Primary Termination - Branch (1/0 A1)\$	1,210.33
Primary Junction enclosure w/Cable Taps\$	2,281.22
Secondary Enclosure\$	277.08
2" PVC Conduit\$	3.91/Foot
4" PVC Conduit\$	4.98/Foot
Street Light Cable\$	3.48/Foot
Transformers - Including Pad	
25 KVA\$	3,486.18
50 KVA\$	4,813.60
100 KVA\$	6,305.41
167 KVA\$	6,926.42
Special Street Light Poles	
30' Fiberglass\$	868.37
Street Light Luminare (50 watt HPS)\$	319.53
(50 watt LED)\$	626.73
CHARGES FOR THREE PHASE UNDERGROUND CONSTRUCTION	
Primary Cable	
1/0 KCMIL A1\$	10.39/Foot
4/0 KCMIL A1\$	
1000 KCMIL A1\$	34.99/Foot
Secondary Cable	
500 KCMIL Cu\$	38.64/Foot
350 KCMIL A1\$	7.00/Foot
Primary Termination 1/0\$	3,427.48
Primary Termination 4/1\$	5,043.38
Primary Termination 1000 KCMIL\$	7,043.63
	,
Primary Switch and Junction 2-600 AMP and	
1-200 AMP terminals\$	21,748.18
Primary Switch and Junction 2-600 AMP and	
2-200 AMP terminals\$	28,731.41
Primary Switch and Junction 3-600 AMP and	
1-200 AMP terminals\$	
5" PVC Conduit\$	5.88/Foot
Transformers - Including Pad	
150 KVA\$	•
300 KVA\$	•
500 KVA\$	10,812.55
Date of Issue: July 15, 2021Effe	ective Date: July 1

Date of Issue: July 15, 2021 _____ Effective Date: July 15, 2021

ATLANTIC CITY ELECTRIC COMPANY
BPU NJ No. 11 ELECTRIC SERVICE - SECTION III Third Revised Sheet Replaces Second Sheet No. 5

RATE SCHEDULE RUE (Continued) (Residential Underground Extensions)

CHARGES FOR SINGLE AND THREE PHASE OVERHEAD CONSTRUCTION

i	COLOT ON CHOCK AND TIMEET HACE OVERHEAD CONCIN	0011011
	Pole Line - Total Charge\$	8.72/Foot
	Joint pole line cost\$	4.36/Foot
	Primary Wire	
	#2 AAAC (Single Phase)\$	3.57/Foot
	477 KCMIL A1 (Three Phase)\$	
	Primary Wire Neutral	
	, #2 AAAC\$	2.32/Foot
	#4/0 AAAC\$	•
	Secondary Wire	,
	3-Wire (4/0 AAAC)\$	3.97/Foot
	4-Wire (4/0 AAAC)\$	
	τ νιιε (τ/ο /ννιε/	4.45/1000
	Service - Single Phase	
	200 AMP (#2 A1)\$	1.20/Foot
	Complete\$	<u>-</u>
	320 AMP (#42/0 A1)\$	
	Complete\$	217.65
	Carrier Throng Phase	
	Service - Three Phase	
	Up to 200 AMP	
	4-Wire (4/0 A1Qplex)\$	2.46/Foot
	0 445	
	Over 200 AMP	
	4-Wire (500 KCMIL Cu)\$	56.60/Foot
	Transformers	
	Single Phase	
	25 KVA\$	•
	50 KVA\$	•
	100 KVA\$	4,489.71
	167 KVA\$	6,679.28

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ATLANTIC CITY ELECTRIC COMPANY BPU NJ No. 11 ELECTRIC SERVICE - SECTION III Third Revised Sheet Replaces Second Sheet No. 6

RATE SCHEDULE RUE (Continued) (Residential Underground Extensions)

CHARGESFORSINGLEANDTHREEPHASEOV (Continued)	ERHEADCONSTRUCTION
Transformers	
Three Phase	
25 KVA	\$ 6,968.77
50 KVA	· · · · · · · · · · · · · · · · · · ·
100 KVA	
167 KVA	
Street Light Luminare (50 watt HPS)	\$ 319.53

Date of Issue: July 15, 2021 _____Effective Date: July 15, 2021

RATE SCHEDULE CLE-(Contributed Lighting Extension)

AVAILABILITY OF SERVICE

Required for new or additional lighting fixtures contracted for under Rate Schedule CSL.

RATE

All charges under the CLE tariff are subject to federal income tax liability pursuant to the Tax Reform Act of 1986 and the Revenue Reconciliation Act of 1993. -For each fixture the customer shall pay the Company the amount determined from the following table plus any applicable tax gross up.

New HP	S lighting fixture & bracket (4	or 8') – <u>Lighting offering v</u> 2023	vill be closed as of March 17,
	-(installed on existing pole/prepa facilities):	aid	
	Standard Up to and including Over	150 watt 150 watt	\$319.53- \$441.33-
	Shoe Box	All	\$751.01-
	Post Top	All	\$545.88-
	Flood/Profile Light	Standard HPS Standard Metal Halide	\$635.00- \$546.69-
Induction	- Cobra Head	40 Watt	\$ <u>-</u>
	Cobra Head	80 Watt	574.61 \$- 618.30
	Cobra Head	150 Watt	\$ 642.18
	Cobra Head	200 Watt	\$- 749.65

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ATLANTIC CITY ELECTRIC COMPANY BPU NJ No. 11 ELECTRIC SERVICE - SECTION III Second Revised Sheet Replaces Frist Revised No. 7a

RATE SCHEDULE CLE (Continued) (Contributed Lighting Extension)

Light	Emitting	Diode-
LIMIT	LIIIIIIII	Dioac

ung biod e-		
Cobra Head	50 W	\$ 626.73
	70 W	\$ 616.87
	100 W	\$ 629.19
	150 W	\$ 762.70
	250 W	\$ 931.59
	400 W	\$ 878.31
Mongoose	250 W	\$1,253.95
_	400 W	\$1,466.18
Acorn (Granville)	70 W	\$1,746.33
	100 W	\$1,746.33
	150 W	\$1,746.33

Acorn (Granville) w/ ribs and bands	<u>100W</u>	<u>\$ 1,955.21</u>
Acorn (Granville) w/ ribs and bands	<u>150W</u>	\$ 1.955.21

Tear Drop Decorative	100 W	\$1,389.45
·	150 W	\$1,677.85
Decorative Post Top	150 W	\$1,429.21
Colonial Style Post Top	70 W	\$1,064.27
	100 W	\$1,066.51
Shoe Box	100 W	\$ 805.55
	150 W	\$ 872.01
	250 W	\$1,076.22

^{*}Plus \$73.88 if existing incandescent HID fixture is removed.

Plus additional charges for:

14 Ft. Bracket	\$145.47
24 Ft. Ornamental Decorative standard (single bracket)	\$2,385.98
24 Ft. Ornamental Decorative standard (double bracket)	\$3,302.20
25 Ft. Bracket	\$1,140.68
26 Ft. Tangent Ornamental Decorative standard (single	\$2,989.51
26 Ft. Tangent Ornamental Decorative standard (double	\$3,709.66
26 Ft. Corner Ornamental Decorative standard	\$2,975.48
25 Ft. Square aluminum Ornamental Decorative standard	\$3,001.55

^{*}These items are considered a reimbursement of capital without—___any tax liability associated with the Tax Reform Act of 1986—___and the Revenue Reconciliation Act of 1993.

^{*}Plus \$57.03 if existing mercury vapor HID fixture is removed.

^{*}Less \$25.14 (bracket credit) if existing HID fixture is removed but existing bracket is reused.

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2021	
ssued by: David M. Velazquez, Preside	ent and Chief Executive Officer - Atlantic City
	ent and Chief Executive Officer – Atlantic City ard of Public Utilities of the State of New Jersey

ATLANTIC CITY ELECTRIC COMPANY BPU NJ No. 11 Electric Service – Section III

First Revised Sheet Replaces Original Sheet No. 8

RATE SCHEDULE CLE (Continued) (Contributed Lighting Extension)

SPECIAL TERMS AND CONDITIONS

All equipment covered by this schedule will remain the Company's property unless, under special situation where ownership of the above equipment is advantageous to the state or local governmental entity involved, special contractual arrangements can be made.

Capital costs for specialty lighting applications will be provided upon request.

The "new charge per fixture" applies to all areas. -In RUE areas, additional charges are collected under the RUE tariff.

Repavement of concrete broken for installation will be at actual cost or accomplished by the customer.	
——See Section II inclusive for Terms and Conditions of Service	

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ATLANTIC CITY ELECTRIC COMPANY	
BPU NJ No. 11 ELECTRIC SERVICE - SECTION	Ш

Original Sheet No. 9

RESERVED FOR FUTURE USE

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Issued by:

ATLANTIC CITY ELECTRIC COMPANY

TARIFF FOR ELECTRIC SERVICE

SECTION II - STANDARD TERMS AND CONDITIONS

ATLANTIC CITY ELECTRIC COMPANY
Regional Headquarters

5100 Harding Highway Mays Landing, New Jersey 08330-2239

Date of Issue: July 15, 2021 Effective Date: July 15, 2021

1. GENERAL INFORMATION

1.1 Filing:

This tariff, comprising service rules, regulations and rate schedules governing supply of electric service within the service area of the Atlantic City Electric Company, referred to herein sometimes as "ACE" or the "Company," is the official tariff of the Company on file with the Board of Public Utilities of the State of New Jersey, referred to herein as "Board of Public Utilities".

1.2 Scope:

The provisions of this tariff shall apply to all persons, natural or artificial and including, but not limited to, partnerships, associations, corporations (private and public), bodies politic, governmental agencies and any other customer receiving electric service hereunder. These "Terms and Conditions" are subject to modifications embodied in "Special Terms and Conditions" of the particular rate schedule under which such customers may be served.

1.3 Revisions:

No agent, representative or employee of the Company is authorized to waive or change the provisions of this tariff, nor shall any agreement or promise to do so be binding upon the Company. Revisions may be made only in compliance with orders of the Board of Public Utilities.

1.4 Other Publications:

Publications set forth by title in these Terms and Conditions of Service are incorporated in these Terms and Conditions of Service by reference.

This tariff is subject to the lawful Orders of the Board of Public Utilities. Complaints may be directed to: Board of Public Utilities, Division of Customer Assistance, 44 South Clinton Avenue, Trenton, NJ 08625, 609-341-9188 or 1-800-624-0241; www.nj.gov/bpu.

2. OBTAINING SERVICE

2.1 Application:

Application for service shall be made at nearest Company District Operating Center or Courtesy Center (see paragraph 6.4 for locations), in person, by mail or by telephone, by facsimile transmission, and/or by electronic mail, where available. At the Company's discretion, a signed application may be required, which, when duly accepted by the Company, shall constitute evidence of the agreement between the Company and the customer. A copy of the application will be furnished to the customer upon request.

District Operating Centers

Cape May Courthouse Operations	420 Rt. 9 North Cape May Courthouse NJ 08210
Pleasantville Operations	2542 Fire Rd. Egg Harbor Twp. NJ 08234
Glassboro Operations	428 Ellis St. Glassboro NJ 08028
Winslow Operations	295 Grove St. Berlin NJ 08009
Bridgeton Operations	10 Cohansey Street Bridgton NJ 08302
West Creek Operations	457 Main St West Creek NJ 08092

All customers shall be given a copy of the "Customer Bill of Rights" approved by the Board of Public Utilities, effective at the time of service initiation. The copy shall be presented no later than at the time of the issuance of the customer's first bill or 30 days after the initiation of service, whichever is later.

2.2 Choice of Schedule:

A copy of the Schedules and "Terms and Conditions" under which service is to be rendered to the customer will be provided upon application, and the customer may choose the appropriate rate schedule applicable to his service, upon which his application shall be based. The customer may not change from one schedule to another except by mutual agreement. If customer so desires, the choice of schedule may be discussed with a designated Company representative, who will assist in explaining the Terms and Conditions of each applicable schedule. On request, a representative will also explain the Company's method and scheduling of reading meters.

2.3 Deposits:

A deposit may be required of a customer before service will be supplied. For a new customer such deposit shall be the estimated average bill of the customer for a billing period based upon the average monthly charge over an estimated 12 month service period increased by one month's average bill. Customers in default in the payment of bills shall be required to furnish a deposit based on the same calculation using actual billing data to the extent it exists, or increase their existing deposit in an amount sufficient to secure the payment of future bills. The Company will pay interest on deposits in accordance with N.J.A.C.14:3-3.5(d). The Company will furnish a receipt to each customer who has made a deposit. If a customer who has made a deposit fails to pay a bill, the Company may apply such deposit insofar as is necessary to liquidate the bill, and may require that the deposit be restored to its original amount. The Company shall review a residential customer's account at least once every year, and a non-residential customer's account at least once every two years and if such review indicates that the customer has established credit satisfactory to the utility, then the outstanding deposit shall be returned to the customer.

Upon refunding a deposit or paying a customer interest on a deposit, the Company shall offer the customer the option of a credit to the customer's account or a separate check.

Upon closing an account, the Company shall refund to the customer the balance of any deposit remaining after the closing bill for service has been settled, including any applicable interest required.

Date of Issue: July 15, 2021 Effective Date: July 15, 2021

2.	OBTAINING	SERVICE
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Eliminated effective December 21, 2015.

Date of Issue: July 15, 2021 Effective Date: July 15, 2021

2. OBTAINING SERVICE (Continued)

2.4 Extension of Service - General

A. Definitions

<u>Applicant for service, developer or customer</u>: For purposes of this Section of the tariff, an applicant for service, a developer, and a customer are treated synonymously and in conformance with how those terms are applied in N.J.A.C. Subchapter 14:3-8 et seq.

<u>Cost</u> means, with respect to the cost of construction of an extension, actual and/or site-specific unitized expenses incurred for materials and labor (including both internal and external labor) employed in the actual design, construction, and/or installation of the extension, including overhead directly attributable to the work, as well as overrides or loading factors such as those for back-up personnel for mapping and design. This term does not include expenses for clerical, supervision, dispatching or general office functions. Cost also includes the tax consequences incurred under the Tax Reform Act of 1986 and New Jersey state income tax law by the regulated entity as a result of receiving deposits or contributions.

Distribution revenue:

Total revenue, plus related Sales and Use Tax, collected by the Company from a customer, minus Basic Generation Service charges, plus Sales and Use Tax on the Basic Generation Service charges, and transmission charges derived from FERC approved Transmission Charges, plus Sales and Use Tax on the transmission charges, assessed in accordance with Section IV of the Company's tariff.

<u>Extension</u>: For purposes of this section 2 of the tariff, "extension" means: the construction or installation of plant and/or facilities by a regulated entity to convey new service from existing or new plant and/or facilities to serve new development or one or more new customers, and also means the plant and/or facilities themselves. This term includes all plant and/or facilities for transmission and/or distribution, whether located overhead or underground, on a public street or right of way, or on a private property or private right of way, including the wire, poles or supports, cable, pipe, conduit or other means of conveying service from existing plant and/or facilities to each unit or structure to be served, except as excluded at paragraphs 1 through 2 below. An extension begins at the existing infrastructure and ends as follows:

- 1. for an overhead extension of electric service, the extension ends at the point where the service connects to the building, but also includes the meter;
- 2. for an underground extension of electric service, the extension ends at, and includes the meter; unless the applicant and the Company make other arrangements.

In other portions of the tariff, the term "extension" may have a narrower meaning that excludes service lines and metering.

Plant and/or facilities installed to supply the increased load of existing non-residential customers are also considered an extension where either: 1) Company facilities of the required voltage or number of phases did not previously exist, or 2) existing Company facilities are upgraded or replaced due to an applicant's new or additional electrical load being greater than 50% of the total design capacity of the pre-existing facilities.

B. General

To obtain regulated services to serve new developments or new customers, an application must be made with the Company for construction of an extension.

As set forth more fully in N.J.A.C 14:3-8.3,8.4 and 8.5, the following provisions shall apply to all Extensions of Service:

- (a) Unless otherwise agreed to between the Company and an applicant, the Company shall not pay for or financially contribute to the cost of an extension, except in accordance with the provisions of Paragraph 2.5 of this Section of the tariff.
- (b) An extension shall become the property of and be maintained by the Company upon its completion unless other arrangements have been made.
- (c) The estimated cost of an extension for which the Company receives a deposit, or receives a non-refundable contribution, shall include the tax consequences incurred under the Tax Reform Act of 1986 ("TRA 1986") and New Jersey state income taxes by the regulated entity as a result of receiving deposits or contributions, and shall be calculated consistent with the provisions of N.J.A.C. 14:3-8.6(e). Similarly, any applicable deposit refunds to customers shall be grossed up for the effects of TRA 1986 and applicable New Jersey state income taxes previously paid as part of the deposit
- (d) The Company shall construct each extension with sufficient capacity to provide safe, adequate, and proper service to customers, as determined by the Company. The cost of the extension shall be full cost based on the Company's determination of service requirements, regardless of the requirements specified by the applicant.
- (e) If the Company chooses to construct an extension or portion of an extension with additional capacity, over that which is needed to comply with Paragraph 2.4.B, pursuant to N.J.A.C. 14:3-8.5(h), the Company shall pay for, and shall not require the applicant to contribute financially to, the incremental cost of any additional capacity.
- (f) The Company may contract with an applicant for service to design, construct or maintain an extension on behalf of the applicant. However, the Company shall be paid for the cost of constructing or installing the extension, in accordance with the provisions and charges contained in Section III of the Company's tariff for residential underground extensions.
- (g) In the absence of any safety or other public interest concerns, the Company, in the case for the provision for underground service pursuant to N.J.A.C. 14:3-8.4, shall permit the applicant for service to dig the portion of the trench located on the customer's property to receive the service. In that event, the applicant for service shall be solely responsible for ensuring that the excavation is done and completed in accordance with the Company's standards. The Company shall inspect such excavations to ensure that the trench complies with the Company's standards prior to the installation of any utility lines in the trench. The Company reserves, in its sole discretion, the right to reject any excavation performed by the customer that does not meet its standards for the construction of utility trenching.

2.5 Extension of Service to Serve a Customer Along Public or Common Rights-of-Way:

A. Single Residential Customer

The Company facilities shall be extended or modified to serve customers along public or common rights-of-way in accordance with Subparagraph 2.4 above and applicable regulations. Where the cost of an extension or modification exceeds ten (10) times the estimated or assured annual distribution, the Company shall construct such extension, provided the customer shall deposit with the Company an amount equal to the difference between estimated actual cost of the extension required to bring service to the customer from the nearest existing infrastructure and the estimated annual distribution revenue that will be derived from the customer, multiplied by ten.

B. Multi-Unit Residential Development and Non-Residential Development

The Company facilities shall be extended to serve customers along public or common rights-of-way in accordance with Subparagraph 2.4 above and applicable regulations. Where the cost of an extension or modification exceeds ten (10) times the estimated or assured annual distribution revenue, the Company shall construct such extension, provided the customer (or developer) shall deposit with the Company an amount equal to the cost of the extension. For purposes of calculating the amount of the deposit, the development for which service is requested shall be determined by reference to the subdivision map approved by the applicable local authorities. If a development is to be approved and constructed in phases, the applicant shall indicate which phases are to be treated as separate developments for purposes of determining the deposit. Such deposit shall remain with the Company without interest until such time as the actual annual distribution revenue from premises abutting upon such extension shall exceed the amount of distribution revenue which was used as a basis for the deposit.

D. Special Rules and Exemptions.

Eliminated effective December 21, 2015.

2.6 Return of Deposits.

A. General Rule:

As provided in N.J.A.C. 14:3-8.9(d) and 8.9(h), the costs of extra work required to provide beyond standard service and the additional costs for providing underground service (including the costs of temporary overhead service) over and above the amount it would cost to serve customers overhead are non-refundable. This includes, but is not limited to, relocation of facilities, special equipment, second or more feeds for dual source arrangements, and facilities and extensions other than low voltage service connections beyond the property line. As provided in N.J.A.C. 14:3-8.4(g) the remainder of the cost of the service, that is the amount which overhead service would have cost, shall be shared between the applicant and the regulated entity in accordance with N.J.A.C. 14:3-8.5.

B. Return of Deposits to Single Residential Customer Extension:

Return of deposits for extensions for single residential customers shall be made as follows:

- (a) One year after the customer begins receiving service, the Company shall calculate the distribution revenue derived from the customer's first year of service. If the year one distribution revenue is less than the estimated annual distribution revenue that was used to determine the deposit, the Company is not required to provide a refund. If the year one distribution revenue exceeds the estimated annual distribution revenue, the Company shall provide a refund to the applicant equal to the difference between the estimated and annual year one distribution revenues, multiplied by ten.
- (b) Two years after the customer begins receiving service, the Company shall calculate the distribution revenue derived from the customer's second year of service. If the year two distribution revenue is less than the year one distribution revenue, the Company is not required to provide a refund. In each annual period from the date of connection, if the actual Distribution Revenue from the customer exceeds the greater of either: (1) the estimated annual Distribution Revenue used as the basis for the initial deposit computation, or (2) the highest actual Distribution Revenue from any prior year, there shall be returned to the applicant an additional amount, equal to ten times such excess. This process shall be repeated annually until the earlier of the following:
 - 1. The Company has refunded the entire deposit to the applicant; or
 - 2. Ten years have passed since the customer began receiving service.
- (c) If, during the ten year period after a single residential customer begins receiving service, additional customers connect to the extension, the Company shall increase the initial customer's annual refund to reflect the additional revenue. In such a case, the Company shall add to the initial customer's refund an amount ten times the distribution revenue derived from the additional customers for that year. In no event shall more than the original deposit be returned to the depositor nor shall any part of the deposit

C. Return of Deposits for Multi-Unit Residential or Non-Residential Land Development Extensions:

remaining after ten (10) years from the date of original deposit be returned.

Return of deposits for extensions for multi-unit or non-residential development shall be made as follows:

- (a) As each customer begins receiving services, the Company entity shall refund a portion of the deposit to the applicant. For each customer, this customer startup refund shall be the estimated annual distribution revenue that will result from the customer, multiplied by ten.
- (b) One year after the Company received the deposit, and each subsequent year thereafter, the Company shall provide an annual refund to the applicant. The first annual refund shall be calculated in accordance with (c) below. Subsequent annual refunds shall be calculated under (d) below.
- (c) The first annual refund shall be calculated by multiplying by ten the difference between:
- 1. The distribution revenue from all customers that were served by the extension for the entire previous year; and
- 2. The estimated annual distribution revenue, upon which the original customer startup refund was based, for all customers that were served by the extension for the entire previous year. If the distribution revenue for the first year, determined under (c)1 above, was less than the estimated annual distribution revenue (upon which the original customer startup refund amount was based), the Company is not required to provide an annual refund.

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- (d) For each subsequent year, the annual refund shall be calculated as follows:
- 1. Sum the distribution revenue from all customers that were served by the extension for the entire previous year;
 - 2. Determine the sum of:
- i. The distribution revenue that was used in calculating the most recent annual refund provided to the applicant. This is the amount determined under (d)1 above when this subparagraph was applied to determine the most recent annual refund; and
- ii. The original estimated annual revenue for all customers that were served by the extension for the entire previous year, but whose revenues were not included in the calculation of the most recent annual refund that the regulated entity provided to the applicant;
- 3. Subtract (d)2 above from (d)1 above. If (d)2 above is greater than (d)1 above, the Company is not required to provide a refund; and
- 4. If (d)2 above is less than (d)1 above, multiply the difference derived under (d)3 above by ten to determine the annual refund.

In no event shall more than the original deposit be returned to the depositor nor shall any part of the deposit remaining after ten (10) years from the date of original deposit be returned.

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TERMS AND CONDITIONS OF SERVICE

2.7 Multiple Service for Non-Residential Customers:

When the Customer desires delivery of energy at more than one point, <u>other rules and regulations</u> <u>may apply, and</u> a separate contract may be required for each separate point of delivery. Service at each point of delivery will be billed separately under the applicable schedule.

2.8 Modification of Service at Current Location:

When it is necessary for the Company to construct, upgrade or install facilities necessary to serve the additional requirements of existing customers and these facilities do not meet the definition of an Extension as defined in Section 2.4 A of these Standard Terms and Conditions, the following shall apply:

. The Company shall modify its facilities without charge to the customer provided the cost of such modification shall not exceed five (5) times the estimated or assured incremental annual distribution revenue received as a result of the modification. Where the cost of a modification exceeds five (5) times the estimated or assured incremental annual distribution revenue, the Company shall construct such modification, provided the customer shall make a non-refundable contribution to the Company an amount equal to the difference between the cost of such modification and five (5) times the assured or estimated incremental annual distribution revenue. The cost of such modification shall include the tax consequences incurred by the Company under the Tax Reform Act of 1986 as a result of receiving contributions.

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TERMS AND CONDITIONS OF SERVICE

2. OBTAINING SERVICE (Continued)

2.9 Initiation of Service at Original Location:

Whenever service is initiated to any customer in an original location (no previous service), a service charge will be made as specified on Rate Schedule CHG. Service shall not be connected until customer has met all requirements called for under this tariff, the Rules and Regulations and the applicable service classification.

2.10 Connection or Reconnection of Service at an Existing Location:

Whenever service is initiated to any customer in an existing location (with previous service), a service charge will be made as specified on Rate Schedule CHG. Service shall not be connected until customer has met all requirements called for under this tariff, the Rules and Regulations and the applicable service classification.

2.11 Reconnection of Service Requirements:

Company shall not reconnect service to customer's premises, where service has been disconnected by reason of any act or default of customer, until such time as customer has rectified the condition or conditions causing discontinuance of service. In cases where the service has been disconnected for a period greater than one year, a reconnect certification by the authority having jurisdiction or by a license electrician will be required to ensure the safety and condition of customer wiring. It shall be provided further that service shall not be reconnected until customer has met all financial requirements called for under the Rules and Regulations and the applicable service classification. A service charge under Subparagraph 2.10 above will also be assessed.

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3. WIRING AND ENTRANCE STANDARDS

3.1 Inspection:

The Company shall not connect with any customer's installation until the customer provides the following documentation to the Company:

- A. A certificate which indicates that such installation has been properly inspected by a duly qualified person, and the installation has been completed in accordance with these "Terms and Conditions" as well as with the National Electrical Code. Such certificate shall be obtained from a county or municipality, or person, agency or organization duly appointed by a county or municipality to make such inspections. When a county or municipality does not provide, in accordance with applicable statutes, for the regulation and inspection of wires and appliances for utilization of electric energy, or has not appointed any person, agency or organization to make such inspection, then an inspection certificate issued by any organization authorized to perform inspections by designation and approval of the State of New Jersey shall be accepted in lieu thereof.
- B. Evidence from the customer that any air conditioning equipment installed to serve the building has a Seasonal Energy Efficiency Ratio equal to or in excess of 10.0 for split systems and 9.7 for single package systems. Any change in, or addition to, the original wiring and equipment of the customer shall be subject to the foregoing requirements to insure continuance of service. No liability shall attach to the Company because of any waiver of these requirements, or failure of customer to comply with these requirements.
- C. A State, County or municipal permit, inspection or approval does not indicate an adherence or compliance to all ACE requirements. Please consult your local company representative for ACE specific requirements.

3.2 Minimum Entrance Requirements:

All construction shall be performed in accordance with the requirements of the National Electrical Code and any applicable governmental codes. The service entrance size shall be determined in accordance with the requirements for the load ultimately to be connected, and not the initial load, in order to avoid subsequent additional modification of the service entrance when additional load or larger devices are connected.

3. WIRING AND ENTRANCE STANDARDS (Continued)

3.3 Service Connections From Overhead Distribution Lines:

The Company shall designate the location of its service connection. The customer's wiring must be brought outside the building wall nearest the Company's service wires so as to be readily accessible thereto and in such manner that all wires or cables carrying unmetered energy will be in plain view from the exterior of the building. The building wiring shall include not less than eighteen (18) inches of conductors arranged so as to permit connection to the company's service conductors. The building wiring shall comply with the requirements of the National Electrical Code with respect to grounding. All connections between the customer's service equipment and the Company's service wires must be installed as recommended by the National Electrical Code. The Company shall modify or extend its facilities onto private property. Any costs associated with this extension shall be based on approved costs established in the Tariff section III, approved at the time of the customer's application.

3.4 Underground Service Connections From Overhead Lines:

Customers desiring an underground service from overhead wires may obtain such at their expense, which, consistent with the Tax Reform Act of 1986 and N.J.A.C. 14:3-8.5(c) shall include the federal and state income tax consequences of such extension to the Company. In the case of new installations, a customer shall be entitled to a credit equal to the cost of overhead service which the Company otherwise would have installed at no additional cost to the customer.

3.5 Service Connections in Urban Underground Network Areas:

In areas designated by the Company as Urban Underground Network Areas, the customer will install necessary ducts, cables and/or service boxes to locations designated by the Company. The Company should be consulted in advance on all installations to be served in the area to be served designated by the necessary permits to open the street. It shall not be obligated to furnish service where such permit is not granted, nor where the customer refuses to reimburse the Company for any municipal charges it incurs or will incur with respect to obtaining such permit.

3.6 Service Connection Other Than as Specified:

If a customer requests that energy should be delivered at a point or in a manner other than that specified by the Company, and the Company agrees thereto, a charge shall be made equal to the additional cost of such delivery. This cost would be based on an estimate of the time, material, overheads and applicable taxes required to install any additional facilities at the customer's request.

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4. USE OF ENERGY

4.1 Additional Loads:

Each customer shall inform the Company of any plan or intention to make a substantial addition, including, without limitation, adding additional load greater than 50% of the existing load, to the customer's equipment or connected load, in order that the Company may assure that its facilities are adequate to serve the intended increase. All electric vehicle (EV) charging stations installed behind the customer meter shall be reported to ACE to ensure proper equipment sizing prior to use.

4.2 Installation and Use of Motors and Appliances:

The customer shall install only motors, apparatus or appliances which are suitable for operation with the character of the service supplied by the Company, and which shall not be detrimental to the Company or its equipment. The electric power must not be used in such a manner as to cause excessive voltage fluctuations or disturbances in the Company's transmission or distribution system. The Company shall be the sole judge as to the suitability of apparatus or appliances to be connected to its lines, and also as to whether the operation of such apparatus or appliances will be detrimental to its general service. Unless modified by specific agreement, single phase motors shall not exceed 5 horse power for residential customers. Commercial customers can install up to 10 horse power with Company approval.

4.3 Characteristics of Motors and Apparatus:

All apparatus used by the customer shall be of such type as to assure the highest practicable power factor and the proper balancing of phases. The starting characteristics of all motors subject to intermittent operation or automatic control shall be in accordance with standards established by the Company. Motors shall be protected by suitable loss of phase protection where applicable. Welders and other devices with high in-rush currents or undesirable operating characteristics shall not be served except as provided in Subparagraph 9.2 and 9.5A. A violation of this requirement may result in the customer's, service being discontinued by the Company until such time as the customer's use of the electric energy furnished hereunder is restored to be in conformance with these requirements. Such suspension of service by the Company shall not operate as a cancellation of any contract with the customer.

4.4 Resale of Energy:

Resale of energy will be permitted only by electric public utilities and alternate suppliers subject to the jurisdiction of the Board of Public Utilities or any other duly authorized regulatory agency, and only with the written consent of the Company.

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4. USE OF ENERGY (Continued)

4.5 Residential Use:

All individual residences shall be served individually under the appropriate service schedule. Three phase (3ph) service and service for motors in excess of 5 horse powerhorsepower shall not be allowed for residential service. Service for such loads shall be furnished under the appropriate general service schedule. Customers shall not be allowed to receive service for two (2) or more separate residences through a single meter under any schedule, regardless of common ownership of the affected residences. A residential unit is defined as a dwelling intended for residential occupancy. Any separate building loads may be served from this residential meter that is not intended for commercial purposes. Any additional buildings separately metered not meeting the residential use definition in the administrative code (N.J.A.C. 5:28-1.2, N.J.A.C. 5:28-1.4, N.J.A.C. 14:3-1.1) will not be installed under the residential rate regardless of the property use.

4.6 Commercial Activities Within Residences:

Detached building or buildings appurtenant to the residence, such as a garage, stable or barn, may be served by an extension of the customer's residential service wiring and meter. That portion of a residence which becomes regularly used for commercial or manufacturing purposes shall be served under a general service schedule. A customer shall be authorized to maintain separate wiring so that the residential portion of the premises is served through a separate meter under the appropriate schedule, and the commercial or manufacturing portion of the premises is served through a separate meter or meters under the appropriate general service schedule. In the event that the customer does not elect to utilize this authorization, the appropriate general service schedule shall apply to all service supplied.

4.7 Other Sources of Energy:

The Company will not supply service to customers who have other sources of energy supply except under schedules which specifically provide for such service. A customer shall not be permitted to operate its own generating equipment in parallel with the Company's service, except with the written permission of the Company. In order to avoid undue jeopardy to life and property to the customer's premises, to the Company's system, and in the facilities of third parties, the customer shall not install its own generating equipment without the prior written permission of the Company.

5. COMPANY'S EQUIPMENT

5.1 Installation on Customer's Property:

The customer shall grant the Company the right to construct required service facilities on the customer's property, and place its meters and other apparatus on the property or within the buildings of the customer, at a point or points mutually agreed to for such purpose, and the customer shall further grant to the Company the right to adequate space for the installation of necessary measuring instruments sufficient that such equipment can be protected from injury by the elements or through the negligence or deliberate acts of the customer, any employee of the customer or a third party. The customer agrees to maintain proper clearances, in accordance with NESC, UCC, NFPA and, or the Electric Service Handbook, to all company owned facilities in all future modifications or additions. The customer has the right to have ACE facilities relocated at customers expense. The Company shall not install transformers within the building(s) of the customer. The installation of meters and connections shall be in accordance with N.J.A.C. 14:3-4.2 and N.J.A.C. 14:5.

5.2 Maintenance of Company's Equipment:

The Company will provide and maintain in proper operating condition the necessary line or service connections, transformers (when same are required by conditions of contract between the parties thereto), meters and other apparatus which may be required for the proper measurement of and protection of the service. All such apparatus shall be and remain the property of the Company.

5.3 Attachment to Company Owned Facilities:

No radio transmitting, receiving, television or other antennae may be connected to the Company's lines, nor attached to its poles, cross arms, structures or other facilities without the written consent of the Company. No signs nor devices of any type may be attached to the Company's poles, structures, or other facilities without the written consent of the Company.

5.4 Right of Entrance to Customer's Premises:

Pursuant to N.J.A.C. 14:3-3.6(a), the Company shall have the right at all reasonable hours to enter and to have reasonable access to the premises of the customer for the purpose of installing, reading, removing, testing, inspecting, replacing or otherwise disposing of its apparatus and property, and the right to remove the Company's property in the event of the termination of the contract for any cause.

A customer shall not under any circumstances provide access to the Company's facilities to any individual or entity, other than authorized employees of the Company or duly authorized government officials.

5. COMPANY'S EQUIPMENT (Continued)

5.5 Work Near Company Facilities:

Pursuant to N.J.A.C. 14:3-2.8, no construction, maintenance or other work shall be performed in close proximity to the Company's poles, apparatus, or conductors without the written permission of the Company. A Company representative shall, upon request, review such work to assure that conditions under which such work is to be performed do not involve hazards to life, property or continuity of service. Contractors and other entities working in close proximity to the Company's lines must do so in compliance with N.J.S.A. 34:6-47.1 and 2 and any applicable provisions of the Occupational Safety and Health Administration regulations. Any work required to mitigate such hazards or continuity of service shall be undertaken at the sole expense of the party requesting such work.

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6. METERING, BILLING AND PAYMENT FOR SERVICE

6.1 Meters:

Meters shall be owned and maintained by the Company in accordance with Section 5 above. The installation of meters and connections shall be in accordance with N.J.A.C. 14:3-4.2 and N.J.A.C. 14:5.

6.2 Special Testing of Meters:

Meters shall be tested in accordance with regulations of the Board of Public Utilities. Pursuant to N.J.A.C. 14:3-4.5, a customer may request an accuracy test be made by the Company at no charge, provided that the Company shall not be required to perform such test more than once every 12 months. If a Customer requests an accuracy test more than once in a 12 month period, a service charge will be made as specified in Rate Schedule CHG. Whenever a meter is found to register faster than the amount allowed by the Board, the test fee will be waived. Complete reports of the results of such tests will be made available to the customer and will be kept on file by the Company in accordance with Board of Public Utilities' regulations. Customers may also request that a test be made by an inspector of the Board of Public Utilities. There is a fee for such tests which must be paid by the customer to the Board of Public Utilities. If the meter is found to be operating "fast" and beyond the allowable limits, the Company will reimburse the customer for the fee paid.

6.3 Adjustment of Bill:

Whenever a meter is found to be registering "fast" in excess of the allowable limits established by the Board of Public Utilities, an adjustment shall be made corresponding to the percentage error as found in the meter covering the entire period during which the meter registered inaccurately, provided such period can be determined. Where such period cannot be determined, a correction shall be applied to $\frac{1}{2}$ of the total amount of billing affected since the most recent prior 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 shall be in accordance with N.J.A.C. 14:3-4.6.

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6. METERING, BILLING AND PAYMENT FOR SERVICE (Continued)

6.4 Payment of Bills:

Bills are payable upon presentation, at any location identified by the Company as a payment office, Courtesy Center or authorized collection agency, within twenty (20) days of the postmarked date. The Company may require earlier payment to prevent fraud or illegal use of energy or when it is clearly evident that customer is preparing to vacate the premises.

Overdue bills for non-residential customers are subject to a late payment charge as specified on Rate Schedule CHG. This charge will be applied to amounts billed including accounts payable and unpaid late payment charge amounts applied to previous bills, which are not received by the Company within forty-five (45) days for non-residential customers, and within sixty (60) days for governmental bodies following the due date specified on the bill. The amount of the late payment charge to be added to the unpaid balance for non-residential and governmental customers shall be determined by multiplying the unpaid balance by the late payment charge rate as specified in Rate Schedule CHG. When payment is received by the Company from a customer who has an unpaid balance which includes charges for late payment, the payment shall be applied first to such charges and then to the remainder of the unpaid balance.

New Jersey public utility companies, subject to the New Jersey State Excise Tax, shall be billed net of such taxes.

Courtesy Center Locations

Egg Harbor Township	6814 Tilton Rd, Egg Harbor Township, NJ 08234
Atlantic City Ventnor	2430 Atlantic5014 Wellington Ave, AtlanticVentnor City, NJ 0840108406
Cape May Court House	420 S Main St, Cape May Court House, NJ 08210.
Millville	1101 N. 2nd St , Millville NJ 08332
Turnersville	5101 Rt42 Turnersville NJ 08012

6.5 Billing Period:

Except as hereinafter provided under normal course of business, customers shall be billed monthly. Bills for other than thirty (30) days shall be prorated. Where credit situations require, the Company may read meters and render bills at shorter intervals.

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TERMS AND CONDITIONS OF SERVICE

6. METERING, BILLING AND PAYMENT FOR SERVICE (Continued)

6.6 Bi-Monthly and Quarterly Readings:

Meters will be read monthly except when business conditions or weather prevent it. The Company reserves the right to read meters at bi-monthly or quarterly intervals. When monthly readings are unavailable, interim monthly bills will be rendered on a calculated basis.

6.7 Special Readings or Succession and Billings:

Special readings, successions and billings shall be made at customer's request. The charge for each reading or billing shall be as specified on Rate Schedule CHG.

6.8 Monthly Billings for Annual Charges:

When an annual charge for service is to be billed and paid monthly, the total charge shall be divided by twelve (12) and rounded to the next higher cent.

6.9 Uncollectible Checks:

A charge will be made when a customer's check is returned by the customer's bank as uncollectible as specified on Rate Schedule CHG.

6.10 Check Metering:

Where a customer monitors or evaluates the customer's own consumption of electrical energy or any portion thereof in an effort to promote and stimulate conservation or for accountability by means of individual meters, computer or otherwise, installed, operated and maintained at such customer's expense, such practice will be defined as check metering. Check metering will be permitted in new or existing buildings or premises where the basis characteristic of use is industrial or commercial. Check metering will not be permitted in existing buildings or premises where the basis characteristic of use is residential, except where such buildings or premises are publicly financed or government owned; or are condominiums or cooperative housing. Check metering for the aforementioned purposes and applications shall not adversely affect the ability of the Company to render service to any other customer or cause harm to the Company equipment. The customer shall be responsible for the accuracy of check metering equipment.

6.11 Budget Billing Plan (Equal Payment Plan):

Residential Customers billed under Rate Schedules RS or RSH, or Commercial Customers with less than 300kW of usage shall have the option of paying for their Atlantic City Electric (ACE) charges in equal, estimated monthly installments. Budget plans shall be made in accordance with N.J.A.C 14:3-7.5. The total ACE charges for the previous twelve-month period will be averaged over twelve months into monthly budget installments. A review between the actual cost of service and the monthly budget amount will be made at least once in the budget plan year. A final bill for a budget plan year shall be issued at the end of the budget plan year and shall include the customer's actual energy charges for that month, as well as any standing budget balance.

6.12 Opting out of Smart Meter:

A monthly charge will be assessed for customers who retain a non-AMI meter, as specified on Rate Schedule CHG. A one-time opt-out fee will be assessed for the removal of a Smart Meter (known as AMI meter) and re-installation of a non-AMI meter, as specified on Rate Schedule CHG.

Date of Issue: July 15, 2021 Effective Date: July 15, 2021

7. DISCONNECTION AND RECONNECTION

7.1 Disconnection at Customer's Request:

The Company will disconnect service at the request of customer, and will render a final bill in accordance with the applicable rate schedule. At such time as the customer shall request disconnection, a charge as specified on Rate Schedule CHG may be made. Notice to disconnect will not relieve the customer from any minimum or guaranteed payment established by contract or rate schedule.

Within 48 hours of said notice, the Company shall discontinue service or obtain a meter reading for the purpose of determining a final bill.

7.2 Disconnection for Non-Payment or Non-Compliance:

The Company reserves the right to discontinue service when: (i) the customer's arrearage is more than \$100.00 and/or the customer's account is more than three months in arrears; (ii) for failure to comply with these Terms and Conditions; and (iii) to prevent fraud upon the Company, or where use of energy is not in accordance with the Company's schedules. The Company shall, upon due notice to the customer, discontinue service to any customer reported by a duly authorized inspection agency to be in violation of county, municipal or National Electrical Codes, or reported to be in violation of any governmental order or directive concerning the use of energy. Any such disconnection of service shall not terminate the contract for special extensions or special facilities between the Company and the customer. A service charge will be made as specified on Rate Schedule CHG. No charge will be due on those instances performed for the convenience of the Company.

7.3 Disconnection for Other Reasons:

In addition to the provisions of Subparagraph 7.2 above, the Company may disconnect service for any of the following causes:

- A. for the purpose of effecting repairs;
- B. in compliance with governmental order or directive;
- C. for refusal of the customer to contract for service where such contract is provided for in the applicable tariff schedule; and/or
- D. where the condition of the customer's electric facilities are such as to provide a hazard to life or property.
- E. where customer equipment is causing power quality issues that effect company equipment of other customers

A service charge will be made as specified on Rate Schedule CHG. No charge will be due on those instances performed for the convenience of the Company.

7. DISCONNECTION AND RECONNECTION (Continued)

7.4 Reconnection:

In cases where the Company has discontinued service for non-payment of a bill or bills or other cause, a charge for reconnection will be made as specified in Rate Schedule CHG; except where such disconnection has been made by the Company in order to effect repairs. Beyond normal working hours charge will be based on actual costs.

8. LIABILITIES

8.1 Company Liability:

The Company will use reasonable diligence in furnishing a regular and uninterrupted supply of energy, but in the event such supply is interrupted or fails by reason of, including, but not limited to, an act of God, a public enemy, accidents, strikes, legal process, governmental interference, breakdowns of or injury to the machinery, transmission lines or distribution lines of the Company or extraordinary repairs, the Company shall not be liable for damages.

8.2 Emergencies:

- A. If the Company shall deem it necessary to the prevention or alleviation of an emergency condition which threatens the integrity of its system or the systems to which it is directly or indirectly connected, it may curtail or interrupt service or reduce voltage to any customer or customers pursuant to a plan filed with the Board of Public Utilities in accordance with N.J.A.C 14:29-4.2 or as otherwise permitted or provided in N.J.A.C. 14:29-4.
- B. If the Company, in its sole judgment, shall deem it necessary to the prevention or alleviation of an emergency condition resulting from an actual or threatened restriction of energy supplies available to its system or the systems to which it is directly or indirectly connected, it may curtail or interrupt service or reduce voltage to any customer or customers pursuant to a plan filed with the Board of Public Utilities in accordance with N.J.A.C 14:29-4.2 or as otherwise permitted or provided in N.J.A.C. 14:29-4.

8. LIABILITIES (Continued)

8.3 Tampering with Company Equipment:

The customer shall not allow or permit any individual or entity, other than a duly authorized employee(s) of the Company to make any internal or external adjustments of any meter or any other piece of apparatus belonging to the Company. In the event it is established by a Court of Law, the Board of Public Utilities, or with the customer's consent, that the Company's wires, meters, meter seals, switch boxes, or other equipment on or adjacent to the customer's premises have been tampered with, the responsible party shall be required to bear all of the costs incurred by the Company, including but not limited to the following: (i) investigations; (ii) inspections; (iii) costs of prosecution including legal fees; and (iv) installation of any protective equipment deemed necessary by the Company. The responsible party shall be the party who either tampered with or caused the tampering with a meter or other equipment or knowingly received the benefit of tampering by or caused by another.

Furthermore, where tampering with the Company's or customer's facilities results in the incorrect measurement of the service supplied by the Company, the responsible party, (as defined above) shall pay for such service as the Company shall estimate from available information to have been used on the premises but not registered by the Company's meter or meters. Under certain conditions, tampering with the Company's facilities may also be punishable by fine and/or imprisonment under applicable New Jersey law.

9. MISCELLANEOUS

9.1 Service Suggestions:

The Company will supply, upon request, "Information and Requirements for Electric Service Installations," covering suggested wiring methods and installations. Similar information may be obtained covering application of electricity for space heating and other purposes, installation of primary voltage equipment, etc. Such information is furnished as a helpful guide, but is not to be considered a substitute for the services of an architect or professional engineer.

9.2 Provision of Special Equipment:

Where, in the judgment of the Company, the provision of voltage regulators, special transformers, heavier conductors, capacitors or other devices are required for satisfactory operation of welders, or other appliances and apparatus, the operation of which would not normally be permitted under the terms of Subparagraph 4.3, the Company shall permit the use of such appliances and equipment provided the customer agrees, in writing, to compensate the Company for all additional costs involved to provide the special distribution facilities required. Service for X-ray equipment and other devices with voltage stability requirements more stringent than normal standards may also be obtained under terms of this Paragraph.

9.3 Special Equipment Rental Charge:

Such a charge may be payable in twelve (12) equal installments coincident with the regular bill for electric service. Customers who elect to take service under any of the several rate schedules which require customer ownership of a substation and related equipment also may rent such facilities from the Company in accordance with these terms.

9.4 Meter Sockets and Current Transformer Cabinets:

It shall be the customer's responsibility to furnish, install, and maintain self-contained meter sockets in accordance with Company specifications. The Company will provide all current transformers, current transformer cabinets, and current transformer meter sockets for the customer to install.

9.5 Power Factor:

The monthly average power factor under operating conditions of customers' load at the point where the electric service is metered shall be not less than 90%.

A. Harmonic Content

Customer shall limit harmonic content so as not to adversely impact the operations of the distribution system. (Refer to Company's rights under Subparagraph 4.3)

9. MISCELLANEOUS (Continued)

9.6 Underground Relocation or Placement of Company-Owned Facilities:

Whenever the Company shall be requested by a Federal, State, County or local government entity ("Governmental Entity"), to relocate currently existing overhead facilities underground or to design or redesign proposed facilities to use underground rather than overhead construction, the total cost attributable to such relocation/redesign and underground installation shall be the responsibility of the requesting Governmental Entity, unless preempted by law; and the amount of the Company's estimated costs shall be deposited with the Company in advance. This section is intended to apply to all Company owned transmission, sub-transmission, primary, and/or secondary facilities.

In each instance, and consistent with N.J.A.C. 14:3-8.2, 14:3-8.9(d)3., and 14:3-8.9(h), the cost is intended to be all inclusive and to cover the aggregate of all costs and expenses associated with placement of the facilities underground. This is intended to include, but not be limited to, the cost of engineering, construction, permits, design, right-of-way acquisition, materials and labor, overhead directly attributable to the work as well as overrides and loading factors and the federal and state income tax consequences incurred by the Company as a result of receiving such deposits or contributions. Whenever the costs shall exceed the estimate, the excess costs shall be the responsibility of the requesting entity, and shall be payable to the Company within thirty (30) days of demand. If actual costs should be less than estimated costs, the difference will be refunded to the requesting entity by the Company, without interest, following completion of the project. At the discretion of the Company, large projects requiring extensive engineering costs may require an engineering deposit.

Whenever the Company shall be requested by a Non-Governmental Entity or person ("Non-Governmental Entity"), to relocate currently existing overhead facilities underground or to design or redesign proposed facilities to use underground rather than overhead construction, the total cost attributable to such relocation/redesign and underground installation shall be the responsibility of the requesting Non-Governmental Entity, unless preempted by law; and the amount of the Company's estimated costs shall be deposited with the Company in advance. This section is intended to apply to all Company owned transmission, sub-transmission, primary, and/or secondary facilities.

In each instance, and consistent with N.J.A.C. 14:3-8.2, 14:3-8.9(d)3., and 14:3-8.9(h), the cost is intended to be all inclusive and to cover the aggregate of all costs and expenses associated with placement of the facilities underground. This is intended to include, but not be limited to, the cost of engineering, construction, permits, design, right-of-way acquisition, materials and labor, overhead directly attributable to the work as well as overrides and loading factors and the federal and state income tax consequences incurred by the Company as a result of receiving such deposits or contributions. These costs will be collected by the company in advance of construction and are non-refundable

Notwithstanding anything to the contrary contained herein, whenever the Company, in the exercise of its reasonable discretion, shall determine that underground construction is not feasible or practicable for reasons which may include, but not be limited to environmental conditions, subsoil or subsurface conditions, engineering or technical consideration, or for reason pertaining to maintenance, safety, reliability or integrity of the Company's transmission and/or distribution system, then the Company shall not be obligated to place the facilities underground notwithstanding the request.

Date of Issue: July 15, 2021

Effective Date: July 15, 2021

9. MISCELLANEOUS (Continued)

9.7 Overhead Relocation or Placement of Company-Owned Facilities:

Whenever the Company shall be requested by a Federal, State, County or local government entity ("Governmental Entity"), to relocate currently existing overhead facilities or to design or redesign proposed facilities underground rather than overhead, the total cost attributable to such relocation/redesign and installation shall be the responsibility of the requesting Governmental Entity unless preempted by law; and the amount of the Company's estimated costs shall be deposited with the Company in advance. This section is intended to apply to all Company owned transmission, sub-transmission, primary, and/or secondary facilities.

In each instance, and consistent with N.J.A.C. 14:3-8.2, 14:3-8.9(d)3. and 14:3-8.9(h), the cost is intended to be all inclusive and to cover the aggregate of costs and expenses associated with placement of the facilities. This is intended to include, without limitation, all costs as defined in section 9.6 above. Whenever the costs shall exceed the estimate, the excess costs shall be the responsibility of the requesting entity, and if actual costs should be less than estimated costs, the difference will be refunded to the requesting entity by the Company, without interest, following completion of the project.

Whenever the Company shall be requested by a Non-Governmental Entity or person ("Non-Governmental Entity"), to relocate currently existing overhead facilities or to design or redesign proposed facilities to use underground rather than overhead, the total cost attributable to such relocation/redesign and installation shall be the responsibility of the requesting Non-Governmental Entity, unless preempted by law; and the amount of the Company's estimated costs shall be deposited with the Company in advance. This section is intended to apply to all Company owned transmission, sub-transmission, primary, and/or secondary facilities.

In each instance, and consistent with N.J.A.C. 14:3-8.2, 14:3-8.9(d)3., and 14:3-8.9(h), the cost is intended to be all inclusive and to cover the aggregate of all costs and expenses associated with placement of the facilities. This is intended to include, without limitation, all costs as defined in section 9.6 above. These costs will be collected by the company in advance of construction and are non-refundable

At the discretion of the Company, large projects requiring extensive engineering costs may require an engineering deposit. Notwithstanding anything to the contrary contained herein, whenever the Company, in the exercise of its reasonable discretion, shall determine that construction is not feasible or practicable for reasons which may include but not be limited to environmental conditions, subsoil or subsurface conditions, engineering or technical considerations or for reasons pertaining to maintenance, safety, reliability or integrity of the Company's transmission and/or distribution system, then the Company shall not be obligated to relocate or place the facilities notwithstanding the request.

Date of Issue: July 15, 2021 Effective Date: July 15, 2021

Issued by: David M. Velazquez, President and Chief Executive Officer – Atlantic City Electric Company Filed pursuant to Board of Public Utilities of the State of New Jersey directives associated with the BPU Docket No. ER20120746|ssued by:

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10. GENERAL INTERCONNECTION REQUIREMENTS FOR CUSTOMER'S GENERATION

The following requirements and standards for interconnection of the customer's generating facilities to the Company's system shall be met to assure the integrity and safe operation of the utility system with no reduction in the quality of service being provided to the other customers. Typical installation guidelines for customer owned generators are outlined in the Company's "Technical Interconnection Requirements" and "Technical Considerations Covering Parallel Operations of Customer Owned Generation". The Tariff's conditions are meant to be general in nature, and may not reflect the latest revisions to these Guidelines. Therefore, cogenerators and small power producers shall obtain and adhere to the latest guidelines.

10.1 General Design Requirements:

- A. The customer's installation must meet all applicable national, state and local construction, safety and electrical codes.
- B. Adequate protection devices (relays, circuit breakers, etc.) for the protection of the Company's system, metering equipment and synchronizing equipment must be installed by the customer.
- C. The customer shall provide a load break disconnecting device with a visible open that can be tagged and locked on the Company's side of the interconnection. For systems over 2 MW, the location and type of disconnect must be mutually agreeable to the Company.
- D. Installations where the customer is to provide protective devices for the protection of the Company's system, the customer shall submit a single-line drawing of this equipment sealed by a licensed professional engineer to the Company for informational purposes only.
- E. All cogeneration/small power producer customers must have a dedicated service transformer. This transformer will decrease voltage variations experienced by other customers, attenuate harmonics, and reduce the effects of fault current.
- F. The cogeneration/small power producer customer has sole responsibility for properly synchronizing its generation equipment with the Company's frequency and voltage.

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10. GENERAL INTERCONNECTION REQUIREMENTS FOR CUSTOMER'S GENERATION (Continued)

10.2 General Operating Requirements:

The interconnection of the customer's generating equipment with the Company's system shall be designed and operated by the customer to cause no reduction in the quality of service being provided to other customers. No abnormal voltages, frequencies or interruptions shall be permitted. The customer's facility shall produce 60 Hertz sinusoidal output with harmonic distortion no greater than 5%. If the Company receives complaints regarding waveform distortion or high or low voltage flicker due to the operation of the customer's generation, such generating equipment shall be disconnected without notice until the problem has been resolved. There shall be no responsibility on the part of the Company, its directors, officers, agents, servants or employees for disconnection. The customer may not commence parallel operation with the Company's system until final written approval has been granted by the Company. The Company reserves the right to inspect the customer's facility and witness testing of any equipment or devices associated with the interconnection.

Switching of the interface breaker or switch device shall be under the administrative control of the Company. This includes the Company's right to open the interface breaker or switching device with or without prior notice to the supplier for any of the following reasons:

- A. to facilitate maintenance, test or repair of utility facilities;
- B. during system emergencies;
- C. when the customer's generating equipment is interfering with other customers on the system;
- D. when the inspection of the customer's generating equipment reveals a condition hazardous to the Company's system or a lack of scheduled maintenance records for equipment necessary to protect the Company's system; and/or
- E. to ensure the safety of the general public and Company personnel.

10. GENERAL INTERCONNECTION REQUIREMENTS FOR CUSTOMER'S GENERATION (Continued)

10.2 General Operating Requirements: (Con't.)

Automatic disconnecting device, with appropriate automatic control apparatus, must be provided by the customer to isolate the customer's facility from the Company's system for, but not necessarily limited to, the following abnormal conditions:

- A. a fault on the customer's equipment
- B. a fault on the utility system;
- C. a de-energized utility line to which the customer is connected;
- D. an abnormal operating voltage or frequency;
- E. failure of automatic synchronization with the utility system;
- F. loss of a phase or improper phase sequence;
- G. total harmonic content in excess of 5%;
- H. abnormal power factor; and/or
- I. load flow exceeding an established limit.

The customer will not be permitted to energize a de-energized Company circuit.

Operation of the customer's generator shall not adversely affect the voltage regulation of the Company's system to which it is connected. Adequate voltage control shall be provided, by the customer, to minimize voltage regulation on the Company's system caused by changing generator loading conditions.

GENERAL INTERCONNECTION REQUIREMENTS FOR CUSTOMER'S GENERATION (Continued)

10.3 Design Information:

The Company's high voltage distribution system consists of either 4kV, 12kV, 23kV, 34.5kV or 69kV grounded wye. The customer's generator should be designed to be tripped or isolated from Company's system before the first automatic reclose occurs following a fault. Once the customer's generator is isolated from the Company's system, the customer's generator can be paralleled with the Company's system only after approval of the Company's System Control Center. Customers with three-phase generators should be aware that certain conditions in the utility system may cause negative sequence currents to flow in the generator. It is the sole responsibility of the customer to protect his equipment from excess negative sequence currents.

10.4 Design Considerations:

Parallel Operation

A parallel system is defined as one in which the customer's generation can be connected to a bus common with the utility's system. A consequence of such parallel operation is that the parallel generator becomes an electrical part of the utility system which must be considered in the electrical protection of the utility's facilities.

Reactive Power Requirements

When delivering real power (kilowatts) to the Company, the generator must be capable of operating with a power factor at the Point of Delivery to the Company between .95 leading to .95 lagging power factor, such that the generator would receive lagging reactive power (kilovars) from the Company and be capable of delivering leading reactive power (kilovars) to the Company.

Induction Generators

Installation of induction generators over 200 KVA capacity may, at its discretion, require capacitors or dynamic VAR devices to be installed to limit adverse effects of reactive power flow on the Company's system voltage regulation. Such capacitors will be at the expense of the generating facility.

Inverter System

Reactive power supply requirements for inverter systems are similar to those for induction generators and the general guidelines discussed above will apply.

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10. GENERAL INTERCONNECTION REQUIREMENTS FOR CUSTOMER'S GENERATION (Continued)

10.5 Protection Guidelines:

The required protection equipment to be installed by the customer is selected and installed to meet the following objectives, which are not intended to be all inclusive:

- A. provide adequate protection for faults, overloads or other abnormal conditions on the customer's equipment;
- B. provide adequate protection for faults, overloads on the Company's lines, transformers or other equipment;
- C. prevent outages or other adverse effects to other Company customers;
- D. provide a safe means to control, operate, connect, and disconnect the inter-tie of the customer's generation and the Company's system; and/or
- E. provide a free flow of normal power transfer.

10.6 Information to be Supplied by Cogenerator/Small Power Producer: <u>Drawings</u>

- A. a one line diagram of entire system;
- B. a potential elementary of customer-owned generation system;
- C. a current elementary of customer-owned generation system;
- D. a control elementary of generator breaker and interface breaker; and
- E. a three line diagram of generation system.

11. ELECTRIC INDUSTRY RESTRUCTURING STANDARDS

11.1 Change of Alternative Electric Supply

Customers served under any of the applicable rate schedules of this tariff for electric service and who desire to purchase their electric supply of capacity, transmission, and energy, hereinafter referenced as electric supply, from a Third Party Supplier, hereinafter referred to as an Alternative Electric Supplier, must execute a contract with an Alternative Electric Supplier. Customers who are not enrolled with an Alternative Electric Supplier will continue to receive their electric supply from the Company.

11.2 Enrollment

Customers may request an enrollment package from the Company which, in addition to providing general information regarding electric supply, describes the process necessary for a customer to obtain an alternative electric Supplier. This enrollment package will be provided to the customer at no charge and may be obtained by calling or writing the Company or visiting a Customer Service Center. Upon written request of the customer, the Company will provide customer usage information to any number of Alternative Electric Suppliers pursuant to Appendix D of the Company's Third Party Supplier Agreement.

11.3 Alternative Electric Supplier

An Alternative Electric Supplier is a retail energy and capacity provider that has executed a Third Party Supplier Agreement with the Company so as to be able to furnish electric supply to retail customers. The provisions of this tariff shall govern such Agreement, and the same form of Agreement shall be offered to all Alternative Electric Suppliers. Delivery of such electric supply will be by the Company. Alternative Electric Suppliers shall be liable for payment of the fees set forth in such Agreement. Any modifications to these fees shall be set after an evidentiary hearing before the Board of Public Utilities. The Agreement requires that the Alternative Electric Supplier satisfy the creditworthiness standards of the Company, be licensed by the Board of Public Utilities and any other appropriate New Jersey state agencies, and satisfy any and all other legal requirements necessary for participation in the New Jersey retail energy market. By determining an Alternative Electric Supplier to be creditworthy, the Company makes no express or implied warranties or guarantees of any kind with respect to the financial or operational gualifications of such Alternative Electric Supplier. Except with respect to fee changes, the Company may modify such Agreement by filing a proposed modification with the Board of Public Utilities, and transmitting same within 48 hours to the Division of Rate Counsel and to all licensed Alternative Electric Suppliers in New Jersey. Any objection to the requested change must be submitted within 17 days. The proposed modification shall take effect 45 days after the filing, unless the Board of Public Utilities issues a suspension order putting the request on hold. In the event the Board of Public Utilities does not act within 45 days of the filing, it reserves the right to make a determination on the request in the future.

11. ELECTRIC INDUSTRY RESTRUCTURING STANDARDS (Continued)

11.4 Change of Alternative Electric Supplier

The Company shall not initiate or change a customer's Alternative Electric Supplier unless the requirements set forth by the Board of Public Utilities pursuant to its Orders dated March 17, 1999 and May 5, 1999 (BPU Docket Nos. EX94120585Y, etc.) or future Board of Public Utilities Orders have been complied with by both the customer and the Alternative Electric Supplier.

11.5 Late Payment Charges

In the case of electric supply furnished by an Alternative Electric Supplier, Subparagraph 6.4 of these Terms and Conditions is to be applicable only to Company charges. Customer shut-offs in cases where there is non-payment to the Company for its delivery charges are only performed in accordance with Subparagraph 7.2 of these Terms and Conditions.

11. ELECTRIC INDUSTRY RESTRUCTURING STANDARDS (Continued)

11.6 Billing Disputes

In the event of a billing dispute between the customer and the Alternative Electric Supplier, the Company's sole duty is to verify its charges and billing determinants. The customer is responsible for the timely payment of all Company charges in accordance with Subparagraph 6.4 of these Terms and Conditions, regardless of Alternative Electric Supplier billing disputes. All questions regarding Alternative Electric Suppliers' charges or other terms of the customer's agreement with the Alternative Electric Supplier are to be resolved between the customer and the Alternative Electric Supplier. The Company will not be responsible for the enforcement, intervention, mediation, or arbitration of agreements entered into between Alternative Electric Suppliers and their customers.

11.7 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.

11.8 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.

TARIFF FOR ELECTRIC SERVICE

SECTION IV - SERVICE CLASSIFICATIONS AND RIDERS

ATLANTIC CITY ELECTRIC COMPANY

Regional Headquarters

5100 Harding Highway Mays Landing, New Jersey 08330-2239

Date of Issue: March 27, 2019 Effective Date: April 1, 2019

Issued by: David M. Velazquez, President and Chief Executive Officer – Atlantic City Electric Company Filed pursuant to Board of Public Utilities of the State of New Jersey directives associated with the BPU Docket No. ER18080925 Issued by:

RATE SCHEDULE CHG (Charges)

APPLICABILITY OF SERVICE

Applicable to all customers in accord with the tariff paragraph noted below

SERVICE CHARGES

1.	Installation of Service at Original Location (See Section II paragraph 2.9)\$65.00
2.	Connection, Reconnection, or Succession of Service at Existing Location (See Section II paragraphs 2.10 and 2.11)\$15.00
0	Discounsation (Con Continue II more much 7.4. 7.0 on 7.0)
3.	Disconnection (See Section II paragraph 7.1, 7.2, or 7.3)\$15.00
4.	Special Reading of Meters (See Section II paragraph 6.7)\$15.00
5.	Opting out of Smart Meter (AMI Meter) (See Section II paragraph 6.12)
	Monthly Opt-Out Charge\$15.00
	Removal of Smart Meter and Reinstallation of a Non-AMI Meter\$45.00

LATE PAYMENT CHARGES

(See paragraph 6.4)	0.877% Per Month
(Non-residential only)	(10.52% APR)

UNCOLLECTIBLE CHECKS

(See paragraph 6.9) \$ 7.64

"In accordance with P.L. 1997,c.192, the charges in this Rate Schedule include provision for the New Jersey Corporation Business Tax and the New Jersey Sales and Use Tax. When billed to customers exempt from one or more of these taxes, as set forth in Riders CBT and SUT, such charges will be reduced by the relevant amount of such taxes included therein."

Date of Issue: March 27, 2019 Effective Date: April 1, 2019

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BPU NJ No. 11 Electric Service - Section IV Fifty-Ninth Revised Sheet Replaces Fifty-Eighth Revised Sheet No. 5

RATE SCHEDULE RS (Residential Service)

SUMMER

WINTER

AVAILABILITY

Available for full domestic service to individually metered residential customers, including rural domestic customers, engaged principally in agricultural pursuits.

	June Through September	October Through May	
Delivery Service Charges:			
Customer Charge (\$/Month)	\$ 6.25 7.60	\$ 6.25 7.60	
Distribution Rates (\$/kWH)			
First Block	\$0. 072877 <u>090162</u>	\$0. 066324 <u>082054</u>	
(Summer <= 750 kWh; Winter<= 500kWh)			
Excess kWh	\$0. 085560 <u>105853</u>	\$0. 066324 <u>082054</u>	
Non-Utility Generation Charge (NGC) (\$/kWH)	See Rider NGC		
Societal Benefits Charge (\$/kWh)			
Clean Energy Program	See Rider SBC		
Universal Service Fund	See Rider SBC		
Lifeline	See Rider SBC		
Uncollectible Accounts	See Rider SBC		
Transition Bond Charge (TBC) (\$/kWh)	See Rider SEC		
Market Transition Charge Tax (MTC-Tax) (\$/kWh)	See Rider SEC		
Transmission Service Charges (\$/kWh):			
Transmission Rate	\$0.032305	\$0.032305	
Reliability Must Run Transmission Surcharge	\$0.0	000000	
Transmission Enhancement Charge (\$/kWh)		Rider BGS	
Basic Generation Service Charge (\$/kWh)	See Rider BGS		
Regional Greenhouse Gas Initiative Recovery Charge		idor PCCI	
(\$/kWh) Infrastructure Investment Program Charge	See Rider RGGI See Rider IIP		
iiii asii actare iiivestillelit i rografii Onarge	Structure investment Frogram Charge See Nidel IIF		

CORPORATE BUSINESS TAX (CBT)

Charges under this rate schedule include a component for Corporate Business Taxes as set forth in Rider CBT.

NEW JERSEY SALES AND USE TAX (SUT)

Conservation Incentive Program Recovery Charge

Charges under this rate schedule include a component for New Jersey Sales and Use Tax as set forth in Rider SUT.

See Rider CIP

Date of Issue: September 29, 2022 Effective Date: October 1, 2022

Issued by: J. Tyler Anthony, President and Chief Executive Officer – Atlantic City Electric Company Filed pursuant to Board of Public Utilities of the State of New Jersey directives associated with the BPU Docket No. ER22050323|ssued by:

Fifth Revised Sheet Replaces Fourth Revised Sheet No. 6

RATE SCHEDULE RS (Continued) (Residential Service)

TERM OF CONTRACT

None, except that reasonable notice of service discontinuance will be required.

TERMS AND CONDITIONS

See Section II inclusive for Terms and Conditions of Service.

"In accordance with P.L. 1997, c. 162, the charges in this Rate Schedule includes provision for the New Jersey Corporation Business Tax and the New Jersey Sales and Use Tax. When billed to customers exempt from one or more of these taxes, as set forth in Riders CBT and SUT, such charges will be reduced by the relevant amount of such taxes included therein."

PRICE TO COMPARE

A customer may choose to receive electric supply from a third party supplier as defined in Section 11 of the Standard Terms and Conditions of this Tariff. A customer who receives electric supply from a third party supplier will not be billed the Basic Generation Service Charges or the Transmission Service Charges. Customers eligible for BGS CIEP who receive supply from a third party supplier will continue to be billed the CIEP Standby Fee.

Date of Issue: March 27, 2019 Effective Date: April 1, 2019

Issued by: David M. Velazquez, President and Chief Executive Officer – Atlantic City Electric Company Filed pursuant to Board of Public Utilities of the State of New Jersey directives associated with the BPU Docket No. ER18080925 Issued by:

Exhibit A Redlined Page 61 of 150

ATLANTIC CITY ELECTRIC COMPANY

BPU NJ No. 11 Electric Service - Section IV__Eighth Revised Sheet Replaces Seventh Revised Sheet No. 7

RATE SCHEDULE RS TOU-D (Residential Service Time of Use Demand)

AVAILABILITY

Rate Schedule RS-TOU-D eliminated effective August 1, 2003.

Date of Issue: March 27, 2019 Effective Date: April 1, 2019

Issued by: David M. Velazquez, President and Chief Executive Officer – Atlantic City Electric Company Filed pursuant to Board of Public Utilities of the State of New Jersey directives associated with the BPU Docket No. ER18080925 Issued by:

Exhibit A Redlined Page 62 of 150

ATLANTIC CITY ELECTRIC COMPANY BPU NJ No. 11 Electric Service - Section IV

Second Revised Sheet Replaces First Revised Sheet No. 8

RATE SCHEDULE RS TOU-D (Continued) (Residential Service Time of Use Demand)

Rate Schedule RS-TOU-D eliminated effective August 1, 2003.

Date of Issue: March 27, 2019 Effective Date: April 1, 2019

Issued by: David M. Velazquez, President and Chief Executive Officer – Atlantic City Electric Company Filed pursuant to Board of Public Utilities of the State of New Jersey directives associated with the BPU Docket No. ER18080925|ssued by:

Exhibit A Redlined Page 63 of 150

ATLANTIC CITY ELECTRIC COMPANY

BPU NJ No. 11 Electric Service - Section IV Eighth Revised Sheet Replaces Seventh Revised Sheet No. 9

RATE SCHEDULE RS TOU-E (Residential Service Time of Use Energy)

AVAILABILITY

Rate Schedule RS-TOU-E eliminated effective August 1, 2003.

Date of Issue: March 27, 2019 Effective Date: April 1, 2019

Issued by: David M. Velazquez, President and Chief Executive Officer – Atlantic City Electric Company Filed pursuant to Board of Public Utilities of the State of New Jersey directives associated with the BPU Docket No. ER18080925 Issued by:

ATLANTIC CITY ELECTRIC COMPANY BPILNI No. 11 Flectric Service - Section IV

BPU NJ No. 11 Electric Service - Section IV Second Revised Sheet Replaces First Revised Sheet No. 10

RATE SCHEDULE RS TOU-E (Continued) (Residential Service Time of Use Energy)

Rate Schedule RS-TOU-E eliminated effective August 1, 2003.

Date of Issue: March 27, 2019 Effective Date: April 1, 2019

Issued by: Issued by: David M. Velazquez, President and Chief Executive Officer - Atlantic City Electric Company

Filed pursuant to Board of Public Utilities of the State of New Jersey directives associated with the BPU Docket No. ER18080925

RATE SCHEDULE EV-ERR (Electric Vehicle Equivalent Residential Rate)

AVAILABILITY

Available to residential customers of record who are residential unit owners at a multi-unit dwelling ("MUD"), a planned MUD development, or other separately metered dwelling not intended for residential occupancy, primarily for EV charging. The rate is available for service to Level 2 ("L2") charge stations that are installed in the MUD residential unit owner's designated parking space or for service to Level 1 and L2 chargers installed in the residential customer's non-dwelling structure when a separate meter for service is required. The designated parking space or other non-dwelling structure where the charger will be installed must be located at, upon, or adjacent to the premises of the dwelling or planned MUD development where the owner resides. Wiring and other necessary service equipment past the point of service connection is the responsibility of the customer under the terms and conditions described in Section II, 2.5 A. Single Residential Customer and Section III, Residential Underground Extensions. The customer is responsible for obtaining the necessary permissions and approvals that may be required for the installation of infrastructure, metering, and EV charging equipment on common grounds. The charge station must be intended for the sole use of the residential unit owner and the customer is prohibited from selling electricity in any capacity from the charging station or from connecting loads other than EV charging stations to the meter. This schedule is not available to commercial unit owners.

In instances where a separate meter is not required and all other availability qualifications have been satisfied, the charger may be connected to the residential unit owner's main domestic service meter and receive the Residential Service rate schedule.

	SUMMER June Through September	WINTER October Through May	
Delivery Service Charges: Customer Charge (\$/Month)	<u>\$7.60</u>	<u>\$7.60</u>	
<u>Distribution Rates (\$/kWH)</u> <u>First Block</u> (Summer <= 750 kWh; Winter<= 500kWh)	\$0.090162	\$ 0.082054	
Excess kWh	\$ 0.105853	\$ 0.082054	
Non-Utility Generation Charge (NGC) (\$/kWH)	See Rider NGC		
Societal Benefits Charge (\$/kWh)			
Clean Energy Program	See F	Rider SBC	
Universal Service Fund	See Rider SBC		
Lifeline	See Rider SBC		
Uncollectible Accounts	See Rider SBC		
Transition Bond Charge (TBC) (\$/kWh)	See Rider SEC		
Market Transition Charge Tax (MTC-Tax) (\$/kWh)	See Rider SEC		
Transmission Service Charges (\$/kWh):	<u> </u>	<u> </u>	
Transmission Rate	\$0.032305	\$0.032305	
Reliability Must Run Transmission Surcharge	\$0.00000		
Transmission Enhancement Charge (\$/kWh)	See Rider BGS		
Basic Generation Service Charge (\$/kWh)	See Rider BGS		
Regional Greenhouse Gas Initiative Recovery Charge			
<u>(\$/kWh)</u>	See Rider RGGI		
Infrastructure Investment Program Charge		Rider IIP	
Conservation Incentive Program Recovery Charge	See Rider CIP		
Date of Issue:	Effect	ive Date:	
<u>Issued by:</u>			

RATE SCHEDULE EV-ERR (Electric Vehicle Equivalent Residential Rate)

CORPORATE BUSINESS TAX (CBT)

Charges under this rate schedule include a component for Corporate Business Taxes as set forth in Rider CBT.

NEW JERSEY SALES AND USE TAX (SUT)

Charges under this rate schedule include a component for New Jersey Sales and Use Tax as set forth in Rider SUT.

RESIDENTIAL UNIT OWNER

The owner of record of a residential dwelling unit located within a development or planned MUD development, or, in the case of cooperative housing corporation, a shareholder of record owning the shares appurtenant to an individual residential dwelling unit. Residential Unit owner does not mean the owner of a commercial unit, space, or interest located within a planned real estate development.

DEVELOPMENT OR PLANNED MUD DEVELOPMENT

Any real property situated within the State, whether contiguous or not, which consists of or will consist of, separately owned areas, irrespective of form, be it lots, parcels, units, or interest, which are offered or disposed of pursuant to a common promotional plan, and which provide for common or shared elements or interests in real property, including, but not limited to, property subject to the "Condominium Act," P.L.1969, c.257 (C.46:8B-1 et seq.), any form of homeowners' association, housing cooperative, or community trust or other trust device. "Planned MUD development" shall not include or apply to any form of timesharing.

DESIGNATED PARKING SPACE

A parking space that is specifically designated for use by a particular residential unit owner, including but not limited to a garage, a deeded parking space, or other parking space/garage located at the resident's premises or upon the premises of the planned MUD development where the resident resides and that is intended for a specific resident's exclusive use.

ELECTRIC VEHICLE CHARGING STATION

A station that is installed in compliance with the State Uniform Construction Code, adopted pursuant to P.L.1975, c.217 (C.52:27D-119 et seq.), that delivers electricity from a source outside an electric vehicle into an electric vehicle.

Level 2 ("L2") Charger Electric Vehicle Service Equipment ("EVSE") that provides a plug-in electric vehicle with single phase alternating current electrical power at 208-240V AC, which is approved for installation for this purpose under the National Electric Code through Underwriters Laboratories Certification or an equivalent certifying organization.

Effective Date:

Issued by:

Exhibit A Redlined Page 67 of 150 Original Sheet No. 10c

RATE SCHEDULE EV-ERR (Electric Vehicle Equivalent Residential Rate)

TERM	M OF CONTRACT
Mono	execut that reasonable notice of convine discontinuous will be required

None, except that reasonable notice of service discontinuance will be required.

TERMS AND CONDITIONS

See Section II Inclusive for Terms and Conditions of Service.

"In accordance with P.L. 1997, c. 162, the charges in this Rate Schedule includes provision for the New Jersey Corporation Business Tax and the New Jersey Sales and Use Tax. When billed to customers exempt from one or more of these taxes, as set forth in Riders CBT and SUT, such charges will be reduced by the relevant amount of such taxes included therein."

PRICE TO COMPARE

A customer may choose to receive electric supply from a third-party supplier as defined in Section 11 of the Standard Terms and Conditions of this Tariff. A customer who receives electric supply from a third-party supplier will not be billed the Basic Generation Service Charges or the Transmission Service Charges. Customers eligible for BGS CIEP who receive supply from a third-party supplier will continue to be billed the CIEP Standby Fee.

Date of Issue:	Effective Date:

Issued by:

Ninth Revised Sheet No. 11

RATE SCHEDULE MGS-SECONDARY (Monthly General Service)

AVAILABILITY

Available at any point within the Company's system where facilities of adequate character and capacity exist for the entire electric service requirements of any customer delivered at one point and metered at or compensated to the voltage of delivery. This schedule is not available to residential customers.

	SUMMER June Through September	WINTER October Through May
Delivery Service Charges:	ound imough copiemise.	• • • • • • • • • • • • • • • • • • •
Customer Charge		
Single Phase	\$ 11.90 14.38	\$ 11.90 14.38
Three Phase	\$ 13.84 16.73	\$ 13.84 16.73
Distribution Demand Charge (per kW)	\$3. 27 96	\$ 2.68 3.24
Reactive Demand Charge	\$0. 64 78	\$0. 6478
(For each kvar over one-third of kW demand)	· —	· —
Distribution Rates (\$/kWh)	\$0. 062158 065062	\$0. 055017 <u>057587</u>
· ,		
Non-Utility Generation Charge (NGC) (\$/kWH)	See Rider NGC	
Societal Benefits Charge (\$/kWh)		
Clean Energy Program	See Rider SBC	
Universal Service Fund	See Rider SBC	
Lifeline	See Rider SBC	
Uncollectible Accounts	See Rider SBC	
Transition Bond Charge (TBC) (\$/kWh)	See Rider SEC	
Market Transition Charge Tax (MTC-Tax) (\$/kWh)	See Rider SEC	
CIEP Standby Fee (\$/kWh)	See Rider BGS	
Transmission Demand Charge (\$/kW for each	\$6.48	\$6.10
kW in excess of 3 kW)	40.10	Ψ00
	Φ0.00000	
Reliability Must Run Transmission Surcharge (\$/kWh)	\$0.000000	
Transmission Enhancement Charge (\$/kWh)	See Rider BGS	
Basic Generation Service Charge (\$/kWh)	See Rider BGS	
Regional Greenhouse Gas Initiative Recovery		
Charge (\$/kWh)	See Rider RGG	il
Infrastructure Investment Program Charge	See Rider IIP	
Conservation Incentive Program Recovery	See Rider CIP	
Charge		

The minimum monthly bill will be \$11.9014.38 per month plus any applicable adjustment.

Date of Issue: September 29, 2022 Effective Date: October 1, 2022

<u>Issued by:</u> <u>J. Tyler Anthony, President and Chief Executive Officer – Atlantic City Electric Company</u>

Filed pursuant to Board of Public Utilities of the State of New Jersey directives associated with the BPU Docket No. ER22050323

Second Revised Sheet Replaces First Sheet No. 12

Page 69 of 150

Exhibit A Redlined

RATE SCHEDULE MGS-SECONDARY (Continued) (Monthly General Service)

CORPORATE BUSINESS TAX (CBT)

Charges under this rate schedule include a component for Corporate Business Taxes as set forth in Rider CBT.

NEW JERSEY SALES AND USE TAX (SUT)

Charges under this rate schedule include a component for New Jersey Sales and Use Tax as set forth in Rider SUT.

RELIGIOUS HOUSE OF WORSHIP SERVICE

When electric service is supplied to a customer where the primary use of the service is for public religious services and the customer applies for and is eligible for such service, the customer's monthly bill will be subject to the following credits

Energy Credit

For service rendered June thru September, inclusive: \$0.019677 per kWh for each of the first 300 kWhs used

For service rendered October thru May, inclusive: \$0.015706 per kWh for each of the first 300 kWhs used per month.

Demand Adjustment

For service rendered all months of the year, metered demand will be decreased by 7 kW to arrive at billing demand.

The customer will be required to sign an Application for Religious House of Worship Service certifying eligibility. The customer shall furnish satisfactory proof of eligibility for service under this special provision to the Company, who will determine eligibility.

VETERANS' ORGANIZATION SERVICE

Pursuant to N.J.S.A 48:2-21.41, when electric service is delivered to a customer that is a veterans' organization, and where the primary use of the service is dedicated to serving the needs of veterans of the armed forces, and the customer applies for and is eligible for such service.

Each customer shall be eligible for billing under this Special Provision upon submitting an Application for Veterans' Organization Service under this rate schedule 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, who will determine eligibility.

If a customer's application is approved by the Company, the customer shall be eligible under this Special Provision beginning with the billing cycle that commences after receipt of the Application.

The customer will continue to be billed on this rate schedule. Each month, during the billing process, a comparison will be made to the RS rate schedule, and if the RS rate schedule is lower for the distribution portion of the bill, a credit will be placed on the customer's account. If the RS rate is not lower, the customer will be billed under this rate schedule and no corresponding credit will be placed on the customer's account.

Date of Issue: March 27, 2019 Effective Date: April 1, 2019 Issued by: David M. Velazquez, President and Chief Executive Officer - Atlantic City Electric Company

Filed pursuant to Board of Public Utilities of the State of New Jersey directives associated with the

BPU Docket No. ER18080925

RATE SCHEDULE MGS-SECONDARY (Continued) (Monthly General Service)

DEMAND DETERMINATION FOR BILLING

Demand shall be as shown or computed from the readings of Company's demand meter during the fifteen minute period of customer's greatest use during the month. Demand values used for billing will be rounded to the nearest tenth of a kW.

Where no demand meters are installed, a customer's demand will be calculated for the period June 1st thru September 30th, inclusive. This demand will be estimated by dividing the kWh use by 150.

Where demand is expected to exceed 100 kilowatts, the Company may measure reactive demand as the greatest rate of reactive volt-ampere hour use during a fifteen (15) minute interval during the month.

Reactive demand values used for billing will be rounded to the nearest tenth of a kvar.

The provisions of this paragraph are not available to new service locations connected on or after January 1, 1983. Where a customer has permanently installed electrical space heating equipment of less than the total of all other connected load and where such electrical heating equipment represents the sole source of space and comfort heating, such equipment may be so connected as to exclude its contribution to measured demand.

ENERGY DETERMINATION FOR BILLING

Energy values used for billing will be rounded to the nearest hundredth of a kWh.

TERM OF CONTRACT

A customer may elect to have service discontinued at any time after giving due notice to the Company of its intention to do so, provided that all requirements and obligations under the tariff of the Company have been met.

STANDBY SERVICE

See Rider STB

FIXED LOADS

Customers with fixed attached loads may request to receive service on a computed kilowatt-hour basis. The Company, in its sole discretion, shall determine to grant such request. Such customers shall agree to pay a monthly bill equivalent to the computed kilowatt-hour usage for the billing period, said usage to be determined mutually by the Company and customer and specified in the contract. No changes in attached load may be made by the customer without the written permission of the Company and customer shall allow the Company access to its premises to assure conformance herewith.

TERMS AND CONDITIONS

See Section II inclusive for Terms and Conditions of Service.

"In accordance with P.L. 1997, c. 162, the charges in this Rate Schedule includes provision for the New Jersey Corporation Business Tax and the New Jersey Sales and Use Tax. When billed to customers exempt from one or more of these taxes, as set forth in Riders CBT and SUT, such charges will be reduced by the relevant amount of such taxes included therein."

PRICE TO COMPARE

A customer may choose to receive electric supply from a third party supplier as defined in Section 11 of the Standard Terms and Conditions of this tariff. A customer who receives electric supply from a third party supplier will not be billed the Basic Generation Service Charges or the Transmission Service Charges. Customers eligible for BGS CIEP who receive supply from a third party supplier will continue to be billed the CIEP Standby Fee.

Date of Issue: March 27, 2019 Effective Date: April 1, 2019

<u>Issued by:</u> David M. Velazquez, President and Chief Executive Officer - Atlantic City Electric

Company

Filed pursuant to Board of Public Utilities of the State of New Jersey directives associated with the BPU Docket No. ER18080925

Page 71 of 150 Second Revised Sheet Replaces First Sheet No. 13a

Exhibit A Redlined

AVAILABILITY

schedule.

This is a transitional Rate Schedule, available only to publicly-accessible direct current fast charging ("DCFC") stations or sites at any point within the Company's system where facilities of adequate character and capacity exist for the entire electric service requirements of any customer delivered at one point and metered at or compensated to the voltage of delivery. This schedule is for secondary voltage only. The charging location DCFC chargers must

RATE SCHEDULE MGS-SEVC
(Monthly General Service - Secondary Electric Vehicle Charging)

This schedule is not available to residential customers. This schedule is not available to commercial and industrial customers who install DCFC chargers that are not publicly-accessible. This schedule is not available to DCFC installations that are installed behind the meter of a new or existing customer premise.

be energized and operational for charging greater than 95% up time each calendar year to be eligible for this rate

Each Charging Location is limited to 1000 kilowatts ("kW") of service capacity.

This Rate Schedule will be closed as of December 31, 2024. Any customers on this Rate Schedule at that time will be transferred to Monthly General Service Secondary in the following billing cycle.

	SUMMER	WINTER	
	June Through September	October Through May	
Delivery Service Charges:			
Customer Charge			
Single Phase	\$9.96	\$9.96	
Three Phase	\$11.59	\$11.59	
Distribution Demand Charge (per kW)	\$0.00	\$0.00	
Reactive Demand Charge	\$0.00	\$0.00	
(For each kvar over one-third of kW demand)			
Distribution Rates (\$/kWh)	\$0.109000	\$0.109000	
Non-Utility Generation Charge (NGC) (\$/kWH)	See Ride	r NGC	
Societal Benefits Charge (\$/kWh)			
Clean Energy Program	See Ride	er SBC	
Universal Service Fund	See Rider SBC		
Lifeline	See Rider SBC		
Uncollectible Accounts	See Rider SBC		
Transition Bond Charge (TBC) (\$/kWh)	See Rider SEC		
Market Transition Charge Tax (MTC-Tax) (\$/kWh)	See Ride	er SEC	
CIEP Standby Fee (\$/kWh)	See Rider BGS		
Transmission Demand Charge (\$/kW for each kW in excess of 3 kW)	\$6.48	\$6.10	
Reliability Must Run Transmission Surcharge (\$/kWh)	\$0.000	000	
Transmission Enhancement Charge (\$/kWh)	See Ride	r BGS	
Basic Generation Service Charge (\$/kWh)	See Ride	r BGS	
Regional Greenhouse Gas Initiative Recovery Charge	0. 5:1	- DOO!	
(\$/kWh)	See Ride		
Infrastructure Investment Program Charge	See Ride	ו וור	
The minimum mentally bill will be \$0.06 per mentally only one	licable adjustment		

The minimum monthly bill will be \$9.96 per month plus any applicable adjustment.

Date of Issue: August 26, 2022
Issued by: J. Tyler Anthony, President and Chief Executive Officer – Atlantic City Electric Company
Filed pursuant to Board of Public Utilities of the State of New Jersey directives associated with the

BPU Docket No. ER22060404

Exhibit A Redlined Page 72 of 150 Original Sheet No. 13b

RATE SCHEDULE MGS-SEVC (Continued) (Monthly General Service - Secondary Electric Vehicle Charging)

CORPORATE BUSINESS TAX (CBT)

Charges under this rate schedule include a component for Corporate Business Taxes as set forth in Rider CBT.

NEW JERSEY SALES AND USE TAX (SUT)

Charges under this rate schedule include a component for New Jersey Sales and Use Tax as set forth in Rider SUT.

DEMAND DETERMINATION FOR BILLING

Demand shall be as shown or computed from the readings of Company's demand meter during the fifteen minute period of customer's greatest use during the month. Demand values used for billing will be rounded to the nearest tenth

Where no demand meters are installed, a customer's demand will be calculated for the period June 1st thru September 30th, inclusive. This demand will be estimated by dividing the kWh use by 150. Where demand is expected to exceed 100 kilowatts, the Company may measure reactive demand as the greatest rate of reactive volt-ampere hour use during a fifteen (15) minute interval during the month.

Reactive demand values used for billing will be rounded to the nearest tenth of a kvar.

The provisions of this paragraph are not available to new service locations connected on or after January 1, 1983. Where a customer has permanently installed electrical space heating equipment of less than the total of all other connected load and where such electrical heating equipment represents the sole source of space and comfort heating, such equipment may be so connected as to exclude its contribution to measured demand.

DIRECT CURRENT FAST CHARGER ("DCFC")

Electric vehicle service equipment ("EVSE" or "charger" or "charging stations") that provides at least 50 kilowatts ("kW") of direct current electrical power for charging a plug-in electric vehicle through a connector based on fast charging equipment standards and which is approved for installation for that purpose under the National Electric Code through an Underwriters Laboratories Certification or an equivalent certifying organization.

PUBLICY-ACCESSIBLE DCFC CHARGING

A charger located on public land, a community location, or a travel corridor. Such chargers are owned and operated by the site owner, property manager or management company, EVSE Infrastructure Company or, in limited cases, an Electric Distribution Company 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.

ENERGY DETERMINATION FOR BILLING

Energy values used for billing will be rounded to the nearest hundredth of a kWh.

TERM OF CONTRACT

A customer may elect to have service discontinued at any time after giving due notice to the Company of its intention to do so, provided that all requirements and obligations under the tariff of the Company have been met. A customer may request to take service under Rate Schedule Monthly General Service - Secondary, which would be effective in the following billing cycle.

TERMS AND CONDITIONS

See Section II inclusive for Terms and Conditions of Service.

"In accordance with P.L. 1997, c. 162, the charges in this Rate Schedule includes provision for the New Jersey Corporation Business Tax and the New Jersey Sales and Use Tax. When billed to customers exempt from one or more of these taxes, as set forth in Riders CBT and SUT, such charges will be reduced by the relevant amount of such taxes included therein."

PRICE TO COMPARE

A customer may choose to receive electric supply from a third-party supplier as defined in Section 11 of the Standard Terms and Conditions of this tariff. A customer who receives electric supply from a third-party supplier will not be billed the Basic Generation Service Charges or the Transmission Service Charges. Customers eligible for BGS CIEP who receive supply from a third-party supplier will continue to be billed the CIEP Standby Fee.

Date of Issue: February 26, 2021

Effective Date: March 1, 2021 Issued by: David M. Velazquez, President and Chief Executive Officer - Atlantic City Electric Company Filed pursuant to Board of Public Utilities of the State of New Jersey directives associated with the BPU Docket No. EO18020190

BPU NJ No. 11 Electric Service - Section IV Fifty-Ninth-Revised Sheet Replaces Fifty-Eighth-Revised Sheet No. 14

RATE SCHEDULE MGS-PRIMARY (Monthly General Service)

AVAILABILITY

Available at any point within the Company's system where facilities of adequate character and capacity exist for the entire electric service requirements of any customer delivered at one point and metered at or compensated to the voltage of delivery. This schedule is not available to residential customers.

	SUMMER	WINTER	
	June Through September	October Through May	
Delivery Service Charges:			
Customer Charge			
Single Phase	\$17.56	\$17.56	
Three Phase	\$19.08	\$19.08	
Distribution Demand Charge (per kW)	\$1.90	\$1.49	
Reactive Demand Charge	\$0.47	\$0.47	
(For each kvar over one-third of kW demand)	·	·	
Distribution Rates (\$/kWh)	\$ 0. 048255 024715	\$ 0. 046750 023944	
,	· ———		
Non-Utility Generation Charge (NGC) (\$/kWH)	See Rider NGC		
Societal Benefits Charge (\$/kWh)			
Clean Energy Program	See Ride	r SBC	
Universal Service Fund	See Rider SBC		
Lifeline	See Rider SBC		
Uncollectible Accounts	See Rider SBC		
Transition Bond Charge (TBC) (\$/kWh)	See Rider SEC		
Market Transition Charge Tax (MTC-Tax) (\$/kWh)	See Rider SEC		
CIEP Standby Fee (\$/kWh)			
Transmission Demand Charge	See Rider BGS \$3.63 \$3.28		
(\$/kW for each kW in excess of 3 kW)	φ3.03	φ3.20	
Reliability Must Run Transmission Surcharge (\$/kWh)	\$0.000	000	
Transmission Enhancement Charge (\$/kWh)	See Rider		
Basic Generation Service Charge (\$/kWh)	See Rider		
Regional Greenhouse Gas Initiative	555 Main 255		
Recovery Charge (\$/kWh)	See Rider	RGGI	
Infrastructure Investment Program Charge	See Rider IIP		
Conservation Incentive Program Recovery Charge	See Rider CIP		

The minimum monthly bill will be \$17.56 per month plus any applicable adjustment.

Date of Issue: September 29, 2022

Effective Date: October 1, 2022

<u>Issued by:</u> <u>J. Tyler Anthony, President and Chief Executive Officer – Atlantic City Electric Company</u>

Filed pursuant to Board of Public Utilities of the State of New Jersey directives associated with the BPU Docket No. ER22050323

Second Revised Sheet Replaces First Sheet No. 15

Page 74 of 150

Exhibit A Redlined

RATE SCHEDULE MGS-PRIMARY (Continued) (Monthly General Service)

CORPORATE BUSINESS TAX (CBT)

Charges under this rate schedule include a component for Corporate Business Taxes as set forth in Rider CBT.

NEW JERSEY SALES AND USE TAX (SUT)

Charges under this rate schedule include a component for New Jersey Sales and Use Tax as set forth in Rider SUT.

RELIGIOUS HOUSE OF WORSHIP SERVICE

When electric service is supplied to a customer where the primary use of the service is for public religious services and the customer applies for and is eligible for such service, the customer's monthly bill will be subject to the following credits

Energy Credit

For service rendered June thru September, inclusive: \$0.019677 per kWh for each of the first 300 kWhs used per month.

For service rendered October thru May, inclusive: \$0.015706 per kWh for each of the first 300 kWhs used per month.

Demand Adjustment

For service rendered all months of the year, metered demand will be decreased by 7 kW to arrive at billing demand.

The customer will be required to sign an Application for Religious House of Worship Service certifying eligibility. The customer shall furnish satisfactory proof of eligibility for service under this special provision to the Company, who will determine eligibility.

VETERANS' ORGANIZATION SERVICE

Pursuant to N.J.S.A 48:2-21.41, when electric service is delivered to a customer that is a veterans' organization, and where the primary use of the service is dedicated to serving the needs of veterans of the armed forces, and the customer applies for and is eligible for such service.

Each customer shall be eligible for billing under this Special Provision upon submitting an Application for Veterans' Organization Service under this rate schedule 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, who will determine eligibility.

If a customer's application is approved by the Company, the customer shall be eligible under this Special Provision beginning with the billing cycle that commences after receipt of the Application.

The customer will continue to be billed on this rate schedule. Each month, during the billing process, a comparison will be made to the RS rate schedule, and if the RS rate schedule is lower for the distribution portion of the bill, a credit will be placed on the customer's account. If the RS rate is not lower, the customer will be billed under this rate schedule and no corresponding credit will be placed on the customer's account.

Date of Issue: March 27, 2019 Effective Date: April 1, 2019

<u>Issued by:</u> David M. Velazquez, President and Chief Executive Officer - Atlantic City Electric Company

Filed pursuant to Board of Public Utilities of the State of New Jersey directives associated with the BPU Docket No. ER18080925

RATE SCHEDULE MGS-PRIMARY (Continued) (Monthly General Service)

DEMAND DETERMINATION FOR BILLING

Demand shall be as shown or computed from the readings of Company's demand meter during the fifteen minute period of customer's greatest use during the month. Demand values used for billing will be rounded to the nearest tenth of a kW.

Where no demand meters are installed, a customer's demand will be calculated for the period June 1st thru September 30th, inclusive. This demand will be estimated by dividing the kWh use by 150.

Where demand is expected to exceed 100 kilowatts, the Company may measure reactive demand as the greatest rate of reactive volt-ampere hour use during a fifteen (15) minute interval during the month.

Reactive demand values used for billing will be rounded to the nearest tenth of a kvar.

The provisions of this paragraph are not available to new service locations connected on or after January 1, 1983. Where a customer has permanently installed electrical space heating equipment of less than the total of all other connected load and where such electrical heating equipment represents the sole source of space and comfort heating, such equipment may be so connected as to exclude its contribution to measured demand.

ENERGY DETERMINATION FOR BILLING

Energy values used for billing will be rounded to the nearest hundredth of a kWh.

TERM OF CONTRACT

Customer may elect to have service discontinued at any time after giving due notice to the Company of his intention to do so, provided that all requirements and obligations under the tariff of the Company have been met.

STANDBY SERVICE

See Rider STB

FIXED LOADS

A customer with fixed attached loads may request to receive service on a computed kilowatt-hour basis. The Company, in its sole discretion, shall decide whether to grant such request. Such customers shall agree to pay a monthly bill equivalent to the computed kilowatt-hour usage for the billing period, said usage to be determined mutually by the Company and customer and specified in the contract. No changes in attached load may be made by the customer without the written permission of the Company and customer shall allow the Company access to its premises to assure conformance herewith.

TERMS AND CONDITIONS

See Section II inclusive for Terms and Conditions of Service.

"In accordance with P.L. 1997, c. 162, the charges in this Rate Schedule includes provision for the New Jersey Corporation Business Tax and the New Jersey Sales and Use Tax. When billed to customers exempt from one or more of these taxes, as set forth in Riders CBT and SUT, such charges will be reduced by the relevant amount of such taxes included therein."

PRICE TO COMPARE

A customer may choose to receive electric supply from a third party supplier as defined in Section 11 of the Standard Terms and Conditions of this Tariff. A customer who receives electric supply from a third party supplier will not be billed the Basic Generation Service Charges or the Transmission Service Charges. Customers eligible for BGS CIEP who receive supply from a third party supplier will continue to be billed the CIEP Standby Fee.

Date of Issue: March 27, 2019

Issued by: David M. Velazquez, President and Chief Executive Officer — Atlantic City Electric Company
Filed pursuant to Board of Public Utilities of the State of New Jersey directives associated with the
BPU Docket No. ER18080925

BPU NJ No. 11 Electric Service - Section IV Sixtieth-Revised Sheet Replaces Fifty-Ninth-Revised Sheet No. 17

RATE SCHEDULE AGS-SECONDARY (Annual General Service)

AVAILABILITY

Available at any point within the Company's system where facilities of adequate character and capacity exist for the entire electric service requirements of any customer contracting for annual service delivered at one point and metered at or compensated to the voltage of delivery.

MONTHLY RATE

Delivery Service Charges:

Customer Charge \$193.22 Distribution Demand Charge (\$/kW) \$12.4414.97 Reactive Demand (for each kvar over one-third of kW

demand) \$0.941.13 Non-Utility Generation Charge (NGC) (\$/kWH) See Rider NGC

Societal Benefits Charge (\$/kWh)

Clean Energy Program See Rider SBC Universal Service Fund See Rider SBC See Rider SBC Lifeline See Rider SBC **Uncollectible Accounts** Transition Bond Charge (TBC) (\$/kWh) See Rider SEC Market Transition Charge Tax (MTC-Tax) (\$/kWh) See Rider SEC CIEP Standby Fee (\$/kWh) See Rider BGS Transmission Demand Charge (\$/kW) \$5.62 Reliability Must Run Transmission Surcharge (\$/kWh) \$0.000000 Transmission Enhancement Charge (\$/kWh) See Rider BGS **Basic Generation Service Charge (\$/kWh)** See Rider BGS

Regional Greenhouse Gas Initiative Recovery Charge

(\$/kWh) See Rider RGGI **Infrastructure Investment Program Charge** See Rider IIP **Conservation Incentive Program Recovery Charge** See Rider CIP

CORPORATE BUSINESS TAX (CBT)

Charges under this rate schedule include a component for Corporate Business Taxes as set forth in Rider CBT.

NEW JERSEY SALES AND USE TAX (SUT)

Charges under this rate schedule include a component for New Jersey Sales and Use Tax as set forth in Rider SUT.

VETERANS' ORGANIZATION SERVICE

Pursuant to N.J.S.A 48:2-21.41, when electric service is delivered to a customer that is a veterans' organization, and where the primary use of the service is dedicated to serving the needs of veterans of the armed forces, and the customer applies for and is eligible for such service.

Each customer shall be eligible for billing under this Special Provision upon submitting an Application for Veterans' Organization Service under this rate schedule 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, who will determine eligibility.

Date of Issue: September 29, 2022

Effective Date: October 1, 2022 Issued by: Issued by: J. Tyler Anthony, President and Chief Executive Officer - Atlantic City Electric

Filed pursuant to Board of Public Utilities of the State of New Jersey directives associated with the BPU Docket No. ER22050323

BPU NJ No. 11 Electric Service - Section IV Seventh Revised Sheet Replaces Sixth Revised Sheet No. 18

RATE SCHEDULE AGS-SECONDARY (Continued) (Annual General Service)

VETERANS' ORGANIZATION SERVICE (Cont'd)

If a customer's application is approved by the Company, the customer shall be eligible under this Special Provision beginning with the billing cycle that commences after receipt of the Application.

The customer will continue to be billed on this rate schedule. Each month, during the billing process, a comparison will be made to the RS rate schedule, and if the RS rate schedule is lower for the distribution portion of the bill, a credit will be placed on the customer's account. If the RS rate is not lower, the customer will be billed under this rate schedule and no corresponding credit will be placed on the customer's account.

DEMAND DETERMINATION FOR BILLING

Demand shall be as shown or computed from the readings of Company's demand meter during the fifteen minute period of customer's greatest use during the month, but not less than 80% of the highest such demand in the preceding months of June, July, August or September, nor in any event less than 25 kW.

Where demand is expected to exceed 100 kilowatts, the Company may measure reactive demand as the greatest rate of reactive volt-ampere hour use during a fifteen (15) minute interval during the month.

TERM OF CONTRACT

Contracts hereunder will be for not less than one (1) year with self-renewal provisions for successive periods of one (1) year each, and shall remain in effect until either party gives at least 60 days' written notice to the other of the intention to discontinue at the end of any yearly period.

STANDBY SERVICE

See Rider STB

TERMS AND CONDITIONS

See Section II inclusive for Terms and Conditions of Service.

INTERRUPTIBLE SERVICE

See Rider IS.

"In accordance with P.L. 1997, c. 162, the charges in this Rate Schedule includes provision for the New Jersey Corporation Business Tax and the New Jersey Sales and Use Tax. When billed to customers exempt from one or more of these taxes, as set forth in Riders CBT and SUT, such charges will be reduced by the relevant amount of such taxes included therein."

PRICE TO COMPARE

A customer may choose to receive electric supply from a third party supplier as defined in Section 11 of the Standard Terms and Conditions of this Tariff. A customer who receives electric supply from a third party supplier will not be billed the Basic Generation Service Charges or the Transmission Service Charges. Customers eligible for BGS CIEP who receive supply from a third party supplier will continue to be billed the CIEP Standby Fee.

Date of Issue: March 27, 2019 Effective Date: April 1, 2019

Issued by: Issued by: David M. Velazquez, President and Chief Executive Officer - Atlantic City Electric Company

Filed pursuant to Board of Public Utilities of the State of New Jersey directives associated with the BPU Docket No. ER18080925

BPU NJ No. 11 Electric Service - Section IV Sixtieth-Revised Sheet Replaces Fifty-Ninth-Revised Sheet No. 19

RATE SCHEDULE AGS-PRIMARY (Annual General Service)

AVAILABILITY

Available at any point within the Company's system where facilities of adequate character and capacity exist for the entire electric service requirements of any customer contracting for annual service delivered at one point and metered at or compensated to the voltage of delivery.

MONTHLY RATE

Delivery Service Charges:

Customer Charge	\$ 744.15 <u>842.34</u>
Distribution Demand Charge (\$/kW)	\$ 9.86 11.65
Reactive Demand (for each kvar over one-third of kW demand)	\$0. 74 <u>87</u>

Non-Utility Generation Charge (NGC) (\$/kWH) See Rider NGC

Societal Benefits Charge (\$/kWh)

Clean Energy Program See Rider SBC Universal Service Fund See Rider SBC Lifeline See Rider SBC **Uncollectible Accounts** See Rider SBC Transition Bond Charge (TBC) (\$/kWh) See Rider SEC Market Transition Charge Tax (MTC-Tax) (\$/kWh) See Rider SEC CIEP Standby Fee (\$/kWh) See Rider BGS Transmission Demand Charge (\$/kW) \$5.78 Reliability Must Run Transmission Surcharge (\$/kWh) \$0.000000 Transmission Enhancement Charge (\$/kWh) See Rider BGS **Basic Generation Service Charge (\$/kWh)** See Rider BGS Regional Greenhouse Gas Initiative Recovery Charge (\$/kWh) See Rider RGGI **Infrastructure Investment Program Charge** See Rider IIP **Conservation Incentive Program Recovery Charge** See Rider CIP

CORPORATE BUSINESS TAX (CBT)

Charges under this rate schedule include a component for Corporate Business Taxes as set forth in Rider CBT.

NEW JERSEY SALES AND USE TAX (SUT)

Charges under this rate schedule include a component for New Jersey Sales and Use Tax as set forth in Rider SUT.

VETERANS' ORGANIZATION SERVICE

Pursuant to N.J.S.A 48:2-21.41, when electric service is delivered to a customer that is a veterans' organization, and where the primary use of the service is dedicated to serving the needs of veterans of the armed forces, and the customer applies for and is eligible for such service.

Each customer shall be eligible for billing under this Special Provision upon submitting an Application for Veterans' Organization Service under this rate schedule 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, who will determine eligibility.

Date of Issue: September 29, 2022

Effective Date: October 1, 2022 Issued by: Issued by: J. Tyler Anthony, President and Chief Executive Officer - Atlantic City Electric Company

Filed pursuant to Board of Public Utilities of the State of New Jersey directives associated with the BPU Docket No. ER22050323

BPU NJ No. 11 Electric Service - Section IV Seventh Revised Sheet Replaces Sixth Revised Sheet No. 20

RATE SCHEDULE AGS-PRIMARY (Continued) (Annual General Service)

VETERANS' ORGANIZATION SERVICE (Cont'd)

If a customer's application is approved by the Company, the customer shall be eligible under this Special Provision beginning with the billing cycle that commences after receipt of the Application.

The customer will continue to be billed on this rate schedule. Each month, during the billing process, a comparison will be made to the RS rate schedule, and if the RS rate schedule is lower for the distribution portion of the bill, a credit will be placed on the customer's account. If the RS rate is not lower, the customer will be billed under this rate schedule and no corresponding credit will be placed on the customer's account.

DEMAND DETERMINATION FOR BILLING

Demand shall be as shown or computed from the readings of Company's demand meter during the fifteen minute period of customer's greatest use during the month, but not less than 80% of the highest such demand in the preceding months of June, July, August or September, nor in any event less than 25 kW.

Where demand is expected to exceed 100 kilowatts, the Company may measure reactive demand as the greatest rate of reactive volt-ampere hour use during a fifteen (15) minute interval during the month.

TERM OF CONTRACT

Contracts hereunder will be for not less than one (1) year with self-renewal provisions for successive periods of one (1) year each, and shall remain in effect until either party gives at least 60 days' written notice to the other of the intention to discontinue at the end of any yearly period.

STANDBY SERVICE

See Rider STB

TERMS AND CONDITIONS

See Section II inclusive for Terms and Conditions of Service.

INTERRUPTIBLE SERVICE

See Rider IS.

"In accordance with P.L. 1997, c. 162, the charges in this Rate Schedule includes provision for the New Jersey Corporation Business Tax and the New Jersey Sales and Use Tax. When billed to customers exempt from one or more of these taxes, as set forth in Riders CBT and SUT, such charges will be reduced by the relevant amount of such taxes included therein."

PRICE TO COMPARE

A customer may choose to receive electric supply from a third party supplier as defined in Section 11 of the Standard Terms and Conditions of this Tariff. A customer who receives electric supply from a third party supplier will not be billed the Basic Generation Service Charges or the Transmission Service Charges. Customers eligible for BGS CIEP who receive supply from a third party supplier will continue to be billed the CIEP Standby Fee.

Date of Issue: March 27, 2019 Effective Date: April 1, 2019

Issued by: David M. Velazquez, President and Chief Executive Officer - Atlantic City Electric Company

Filed pursuant to Board of Public Utilities of the State of New Jersey directives associated with the BPU Docket No. ER18080925

BPU NJ No. 11 Electric Service - Section IV Eighth-Revised Sheet Replaces Seventh-Revised Sheet No. 21

RATE SCHEDULE AGS-TOU - SECONDARY

(Annual General Service - Time of Use)

AVAILABILITY

Rate Schedule AGS-TOU-Secondary eliminated effective August 1, 2003.

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Date of Issue: March 27, 2019 Effective Date: April 1, 2019

Issued by: David M. Velazquez, President and Chief Executive Officer – Atlantic City Electric Company Filed pursuant to Board of Public Utilities of the State of New Jersey directives associated with the BPU Docket No. ER18080925

Exhibit A Redlined Page 81 of 150

ATLANTIC CITY ELECTRIC COMPANY

BPU NJ No. 11 Electric Service - Section IV—Second Revised Sheet Replaces First Revised Sheet No. 22

RATE SCHEDULE AGS-TOU - SECONDARY (Continued)
(Annual General Service - Time of Use)

Rate Schedule AGS-TOU-Secondary eliminated effective August 1, 2003.					

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Date of Issue: March 27, 2019 Effective Date: April 1, 2019

Issued by: David M. Velazquez, President and Chief Executive Officer – Atlantic City Electric Company Filed pursuant to Board of Public Utilities of the State of New Jersey directives associated with the BPU Docket No. ER18080925

Exhibit A Redlined Page 82 of 150

ATLANTIC CITY ELECTRIC COMPANY

BPU NJ No. 11 Electric Service - Section IV-Eighth-Revised Sheet Replaces Seventh-Revised Sheet No. 23

RATE SCHEDULE AGS-TOU - PRIMARY (Annual General Service - Time of Use)

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Rate Schedule AGS-TOU Primary eliminated effective August 1, 2003.

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Date of Issue: March 27, 2019 Effective Date: April 1, 2019

Issued by: David M. Velazquez, President and Chief Executive Officer – Atlantic City Electric Company Filed pursuant to Board of Public Utilities of the State of New Jersey directives associated with the BPU Docket No. ER18080925

Exhibit A Redlined Page 83 of 150

ATLANTIC CITY ELECTRIC COMPANY

BPU NJ No. 11 Electric Service - Section IV Second Revised Sheet Replaces First Revised Sheet No. 24

RATE SCHEDULE AGS-TOU – PRIMARY (Continued)
(Annual General Service - Time of Use)

Rate Schedule AGS-TOU Primary eliminated effective August 1, 2003.					
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Date of Issue: March 27, 2019 Effective Date: April 1, 2019

Issued by: David M. Velazquez, President and Chief Executive Officer – Atlantic City Electric Company Filed pursuant to Board of Public Utilities of the State of New Jersey directives associated with the BPU Docket No. ER18080925

ATLANTIC CITY ELECTRIC COMPANY

BPU NJ No. 11 Electric Service - Section IV-Eighth-Revised Sheet Replaces Seventh-Revised Sheet No. 25

RATE SCHEDULE AGS-TOU - SUB - TRANSMISSION (Annual General Service - Time of Use)

AVAILABILITY

Rate Schedule AGS-TOU Sub Transmission eliminated effective August 1, 2003.

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Date of Issue: March 27, 2019 Effective Date: April 1, 2019

Issued by:

David M. Velazquez, President and Chief Executive Officer – Atlantic City Electric Company
Filed pursuant to Board of Public Utilities of the State of New Jersey directives associated with the
BPU Docket No. ER18080925

Exhibit A Redlined Page 85 of 150

ATLANTIC CITY ELECTRIC COMPANY

BPU NJ No. 11 Electric Service - Section IV Second Revised Sheet Replaces First Revised Sheet No. 26

RATE SCHEDULE AGS-TOU - SUB - TRANSMISSION (Continued)
(Annual General Service - Time of Use)

Rate Schedule AGS-TOU Sub Transmission eliminated effective August 1, 2003.

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Date of Issue: March 27, 2019 Effective Date: April 1, 2019

Exhibit A Redlined Page 86 of 150

ATLANTIC CITY ELECTRIC COMPANY

BPU NJ No. 11 Electric Service - Section IVEighth-Revised Sheet Replaces Seventh-Revised Sheet No. 27

RATE SCHEDULE AGS-TOU - TRANSMISSION (Annual General Service - Time of Use)

AVAILABILITY

Rate Schedule AGS-TOU Transmission eliminated effective August 1, 2003.

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Date of Issue: March 27, 2019

Issued by: David M. Velazquez, President and Chief Executive Officer – Atlantic City Electric Company
Filed pursuant to Board of Public Utilities of the State of New Jersey directives associated with the
BPU Docket No. ER18080925

ATLANTIC CITY ELECTRIC COMPANY Page 87 o BPU NJ No. 11 Electric Service - Section IV Second-Revised Sheet Replaces First-Revised Sheet No. 28

RATE SCHEDULE AGS-TOU – TRANSMISSION (Continued)
(Annual General Service - Time of Use)

Rate Schedule AGS-TOU Transmission eliminated effective August 1, 2003.

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Date of Issue: March 27, 2019 Effective Date: April 1, 2019

BPU NJ No. 11 Electric Service - Section IV Fifty-Seventh Revised Sheet Replaces Fifty-Sixth Revised Sheet No. 29

RATE SCHEDULE TGS (Transmission General Service) (Sub Transmission Service Taken at 23kV and 34.5 kV)

AVAILABILITY

Available at any point within the Company's system where facilities of adequate character and capacity exist for the entire electric service requirements of any customer contracting for annual service delivered at one point and metered at or compensated to the voltage subtransmission level (23 or 34.5 kV).

MONTHLY RATE

Delivery Service Charges:

Customer Charge

Maximum billed demand within the most recent 12 billing months.

Less than 5,000 kW	\$131.75
5,000 – 9,000 kW	\$4,363.57
Greater than 9,000 kW	\$7,921.01

Distribution Demand Charge (\$/kW)

Maximum billed demand within the most recent 12 billing months.

Less than 5,000 kW	\$ <u>3.844.01</u>
5,000 – 9,000 kW	\$ 2.96 <u>3.09</u>
Greater than 9,000 kW	\$1. 50 57

Reactive Demand (for each kvar over one-third of kW

Conservation Incentive Program Recovery Charge

demand) \$0.5254 Non-Utility Generation Charge (NGC) (\$/kWH) See Rider NGC

Societal Benefits Charge (\$/kWh)

Clean Energy Program	See Rider SBC
Universal Service Fund	See Rider SBC
Lifeline	See Rider SBC
Uncollectible Accounts	See Rider SBC
Transition Bond Charge (TBC) (\$/kWh)	See Rider SEC
Market Transition Charge Tax (MTC-Tax) (\$/kWh)	See Rider SEC
CIEP Standby Fee (\$/kWh)	See Rider BGS
Transmission Demand Charge (\$/kW)	\$6.85
Reliability Must Run Transmission Surcharge (\$/kWh)	\$0.00000
Transmission Enhancement Charge (\$/kWh)	See Rider BGS
Basic Generation Service Charge (\$/kWh)	See Rider BGS
Regional Greenhouse Gas Initiative Recovery Charge	
(\$/kWh)	See Rider RGGI
Infrastructure Investment Program Charge	See Rider IIP

Date of Issue: September 29, 2022 Effective Date: October 1, 2022

See Rider CIP

Issued by: J. Tyler Anthony, President and Chief Executive Officer – Atlantic City Electric Company Filed pursuant to Board of Public Utilities of the State of New Jersey directives associated with the BPU Docket No. ER22050323

RATE SCHEDULE TGS (Transmission General Service) (Transmission Service Taken at or above 69kV)

AVAILABILITY

Available at any point within the Company's system where facilities of adequate character and capacity exist for the entire electric service requirements of any customer contracting for annual service delivered at one point and metered at or compensated to the voltage at transmission level (69 kV or higher).

MONTHLY RATE

Delivery Service Charges:

Customer Charge

Maximum billed demand within the most recent 12 billing months.

Less than 5,000 kW	\$128.21
5,000 – 9,000 kW	\$4,246.42
Greater than 9,000 kW	\$19,316.15

Distribution Demand Charge (\$/kW)

Maximum billed demand within the most recent 12 billing months.

Less than 5,000 kW	\$2. 98 <u>79</u>
5,000 – 9,000 kW	\$2. 31 <u>17</u>
Greater than 9,000 kW	\$0. 18 <u>17</u>

Reactive Demand (for each kvar over one-third of kW

demand) \$0.50

Non-Utility Generation Charge (NGC) (\$/kWH) \$extra See Rider NGC

Societal Benefits Charge (\$/kWh)

5 (. ,	
Clean Energy Program	See Rider SBC
Universal Service Fund	See Rider SBC
Lifeline	See Rider SBC
Uncollectible Accounts	See Rider SBC
Transition Bond Charge (TBC) (\$/kWh)	See Rider SEC
Market Transition Charge Tax (MTC-Tax) (\$/kWh)	See Rider SEC
CIEP Standby Fee (\$/kWh)	See Rider BGS
Transmission Demand Charge (\$/kW)	\$3.42
Reliability Must Run Transmission Surcharge (\$/kWh)	\$0.00000
Transmission Enhancement Charge (\$/kWh)	See Rider BGS
Basic Generation Service Charge (\$/kWh)	See Rider BGS
Regional Greenhouse Gas Initiative Recovery Charge (\$/kWh)	See Rider RGGI
Infrastructure Investment Program Charge	See Rider IIP
Conservation Incentive Program Recovery Charge	See Rider CIP

Date of Issue: September 29, 2022 Effective Date: October 1, 2022

RATE SCHEDULE TGS (Continued) (Transmission General Service)

CORPORATE BUSINESS TAX (CBT)

Charges under this rate schedule include a component for Corporate Business Taxes as set forth in Rider CBT.

NEW JERSEY SALES AND USE TAX (SUT)

Charges under this rate schedule include a component for New Jersey Sales and Use Tax as set forth in Rider SUT.

DEMAND DETERMINATION FOR BILLING

Demand shall be as shown or computed from the readings of Company's demand meter during the fifteen minute period of customer's greatest use during the month, but not less than 80% of the highest such demand in the preceding months of June, July, August or September, nor in any event less than 25 kW.

Where demand is expected to exceed 100 kilowatts, the Company may measure reactive demand as the greatest rate of reactive volt-ampere hour use during a fifteen (15) minute interval during the month.

TERM OF CONTRACT

Contracts hereunder will be for not less than one (1) year with self-renewal provisions for successive periods of one (1) year each, and shall remain in effect until either party gives at least 60 days' written notice to the other of the intention to discontinue at the end of any yearly period.

STANDBY SERVICE

See Rider STB

TERMS AND CONDITIONS

See Section II inclusive for Terms and Conditions of Service.

INTERRUPTIBLE SERVICE

See Rider IS.

"In accordance with P.L. 1997, c. 162, the charges in this Rate Schedule includes provision for the New Jersey Corporation Business Tax and the New Jersey Sales and Use Tax. When billed to customers exempt from one or more of these taxes, as set forth in Riders CBT and SUT, such charges will be reduced by the relevant amount of such taxes included therein."

PRICE TO COMPARE

A customer may choose to receive electric supply from a third party supplier as defined in Section 11 of the Standard Terms and Conditions of this Tariff. A customer who receives electric supply from a third party supplier will not be billed the Basic Generation Service Charges or the Transmission Service Charges. Customers eligible for BGS CIEP who receive supply from a third party supplier will continue to be billed the CIEP Standby Fee.

Date of Issue: March 27, 2019 Effective Date: April 1, 2019

Issued by: David M. Velazquez, President and Chief Executive Officer — Atlantic City Electric Company Filed pursuant to Board of Public Utilities of the State of New Jersey directives associated with the BPU Docket No. ER18080925

ATLANTIC CITY ELECTRIC COMPANY

BPU NJ No. 11 Electric Service – Section IV Eighty-First Revised Sheet Replaces Eightieth Revised Sheet No. 31

RATE SCHEDULE DDC (Direct Distribution Connection)

AVAILABILITY

Available at any point within the Company's existing distribution system where facilities of adequate character exist for the connection of fixed, constant and predictable non-residential loads not to exceed one kilowatt

MONTHLY RATES

Distribution:

Service and Demand (per day per connection)	\$0.163982
Energy (per day for each kW of effective load)	\$0.789839

Non-Utility Generation Charge (NGC) (\$/kWH) See Rider NGC

Societal Benefits Charge (\$/kWh)

Clean Energy Program See Rider SBC Universal Service Fund See Rider SBC

Lifeline See Rider SBC

Uncollectible Accounts See Rider SBC Transition Bond Charge (TBC) (\$/kWh) See Rider SEC Market Transition Charge Tax (MTC-Tax) (\$/kWh) See Rider SEC Transmission Rate (\$/kWh) \$0.009564 Reliability Must Run Transmission Surcharge (\$/kWh) \$0.000000 Transmission Enhancement Charge (\$/kWh) See Rider BGS **Basic Generation Service Charge (\$/kWh)** See Rider BGS Regional Greenhouse Gas Initiative Recovery Charge (\$/kWh) See Rider RGGI **Infrastructure Investment Program Charge** See Rider IIP

CORPORATE BUSINESS TAX (CBT)

Charges under this rate schedule include a component for Corporate Business Taxes as set forth in Rider CBT.

NEW JERSEY SALES AND USE TAX (SUT)

Charges under this rate schedule include a component for New Jersey Sales and Use Tax as set forth in Rider SUT.

LOAD CONSUMPTION

Effective load shall be determined by the Company and be specified in the contract. Effective load is defined as the sum of the products of the connected load in kilowatts times the percent load on at one time. No changes in attached load may be made by the customer without the permission of the Company and customer shall allow the Company access to his premises to assure conformance with this provision.

Date of Issue: September 29, 2022
Issued by: J. Tyler Anthony, President and Chief Executive Officer – Atlantic City Electric Company
Filed pursuant to Board of Public Utilities of the State of New Jersey directives associated with the
BPU Docket No. ER22050323

RATE SCHEDULE DDC (Continued) (Direct Distribution Connection)

TERM OF CONTRACT

Contracts hereunder will be for not less than one (1) year with self-renewal provisions for successive periods of one (1) year each, and shall remain in effect until either party gives at least 60 days' written notice to the other of the intention to discontinue at the end of any yearly period.

TERMS AND CONDITIONS

See Section II inclusive for Terms and Conditions of Service.

"In accordance with P.L. 1997, c. 162, the charges in this Rate Schedule includes provision for the New Jersey Corporation Business Tax and the New Jersey Sales and Use Tax. When billed to customers exempt from one or more of these taxes, as set forth in Riders CBT and SUT, such charges will be reduced by the relevant amount of such taxes included therein."

PRICE TO COMPARE

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Date of Issue: March 27, 2019 Effective Date: April 1, 2019

Issued by:

-David M. Velazquez, President and Chief Executive Officer – Atlantic City Electric Company
Filed pursuant to Board of Public Utilities of the State of New Jersey directives associated with the
BPU Docket No. ER18080925

RATE SCHEDULE TS (Traction Service)

AVAILABILITY OF SERVICE

Available for power service to Street Railway and/or Traction Companies or Authorities. Customers shall contract for a definite amount of electrical capacity in kilowatts which shall be sufficient to meet normal maximum requirements, but in no case shall the capacity contracted for be less than 1,000 kW. The Company may not be required to supply capacity in excess of that contracted for except by mutual agreement. Contracts shall be made in multiples of 100 kW.

T&D MONTHLY RATE

Primary Portion:

\$11,233.72 for the first 1,000 kW of monthly billing demand plus \$9.004473 per kW for monthly billing demand in excess of 1,000 kW. The customer shall be allowed 100 kWhs for each kW of monthly billing demand so billed.

Secondary Portion:

Energy in excess of 100 kWhs per kW of monthly billing demand \$0.069553 per kWh.

Reactive Demand:

\$0.53 per kvar of reactive billing demand in excess of 33% of monthly kW billing demand.

CORPORATE BUSINESS TAX (CBT)

Charges under this rate schedule include a component for Corporate Business Taxes as set forth in Rider CBT.

NEW JERSEY SALES AND USE TAX (SUT)

Charges under this rate schedule include a component for New Jersey Sales and Use Tax as set forth in Rider SUT.

MONTHLY BILLING DEMAND

The billing demand in kW shall be taken each month as the highest 15 minute integrated peak in kW, as registered during the month by a demand meter or indicator corrected to the nearest kW, but the monthly billing demand so established shall in no event be less than 75% of the contract capacity of the customer, nor shall it be less than 1,000 kW. If at the end of any contract year the average of the monthly billing demands for said year is in excess of the contract capacity, then the contract capacity shall be adjusted automatically to the average of the billing demand for the previous twelve months.

DETERMINATION OF REACTIVE DEMAND

Reactive billing demand shall be taken each month as the highest 15-minute integrated peak in kvar, as registered during the month by a reactive demand meter or indicator.

DELIVERY VOLTAGE

The rate set forth in this schedule is based upon the delivery and measurement of energy at primary voltage from lines designated by the Company which are operated at approximately 23,000 volts or over, the customer supplying the complete substation equipment necessary to take service at the said primary voltage.

Date of Issue: March 27, 2019 Effective Date: April 1, 2019

Issued by:

David M. Velazquez, President and Chief Executive Officer – Atlantic City Electric Company
Filed pursuant to Board of Public Utilities of the State of New Jersey directives associated with the
BPU Docket No. ER18080925

Exhibit A Redlined

RATE SCHEDULE TS (Continued) (Traction Service)

METERING

All energy delivered hereunder shall be measured at the delivery voltage, or at the Company's option, on the low voltage side of the customer's main service transformer bank but corrected by suitable means for measurement of capacity and energy at the delivery point and delivery voltage.

Customer shall mount and/or house the metering equipment, instrument transformers and associated appurtenances which shall be provided by Company.

TERMS OF CONTRACT

Contracts under this schedule will be made for periods of one (1) to five (5) years and either party shall give at least one (1) year's written notice to the other of its intention to discontinue the contract at the end of any contract period.

BREAKDOWN SERVICE

Where the service supplied by the Company under this rate schedule is used to supplement the failure of any other source of electric service or motive power, said service shall constitute Breakdown Service. Said service shall be limited to 96 hours duration for each failure.

Where Breakdown Service is supplied under the provisions of this tariff, the Company will supply a maximum total kW to be mutually agreed upon initially and subsequently revised as required and the customer will pay a fixed monthly amount equal to one-twelfth of \$9.64 per kW as contracted. All energy consumed during this period shall be included in the Energy Component of Monthly Rate. Any excess kW over the agreed upon amount shall be billed at the rates indicated under the Primary Portion of the Monthly Rate.

SPECIAL TERMS AND CONDITIONS

See Section II inclusive for Terms and Conditions of Service.

"In accordance with P.L. 1997, C. 162, the charges in this Rate Schedule include provision for the New Jersey Corporation Business Tax and the New Jersey Sales and Use Tax. When billed to customers exempt from one or more of these taxes, as set forth in Riders CBT and SUT, such charges will be reduced by the relevant amount of such taxes included therein."

PRICE TO COMPARE

A customer may choose to receive electric supply from a third party supplier as defined in Section 11 of the Standard Terms and Conditions of this Tariff. A customer who receives electric supply from a third party supplier will not be billed the Basic Generation Service Charges or the Transmission Service Charges. Customers eligible for BGS CIEP who receive supply from a third party supplier will continue to be billed the CIEP Standby Fee.

Date of Issue: March 27, 2019 Effective Date: April 1, 2019

Issued by: David M. Velazquez, President and Chief Executive Officer – Atlantic City Electric Company Filed pursuant to Board of Public Utilities of the State of New Jersey directives associated with the BPU Docket No. ER18080925

BPU NJ No. 11 Electric Service - Section IV Thirty-Second Revised Sheet Replaces Thirty-First-Revised Sheet No. 35

RATE SCHEDULE SPL (Street and Private Lighting)

AVAILABILITY OF SERVICE

Available for general lighting service in the service by December 14, 1982, new lights requested for installation before January 1, 1983 or high pressure sodium fixtures in the area served byof the Company-

The Company will provide and maintain a lighting system and provide fixture and electric energy sufficient to operate said fixture continuously, automatically controlled, from approximately one-half hour after sunset until approximately one-half-hour before sunrise, every night and all night, approximately forty-two hundred (4200) hours per annum during the term of years hereinafter set forth.

See Rider NGC

The following rates shall be applied to the kWh Usage for the particular light type and size to determine the monthly charge per light.

Distribution charges are billed on a monthly per light basis in accordance with the rates specified on the Tables on Sheets 36, 36a and 37.

Societal Benefits Charge (\$/kWh)	
Clean Energy Program	See Rider SBC
Universal Service Fund	See Rider SBC
Lifeline	See Rider SBC
the Head of the American	0 0:1 000

Uncollectible Accounts See Rider SBC See Rider RARC Regulatory Assets Recovery Charge (\$/kWh) Transition Bond Charge (TBC) (\$/kWh) See Rider SEC Market Transition Charge Tax (MTC-Tax) (\$/kWh) See Rider SEC Transmission Rate (\$/kWh) \$0.000000 Reliability Must Run Transmission Surcharge (\$/kWh) \$0.000000 **Transmission Enhancement Charge (\$/kWh)** See Rider BGS **Basic Generation Service Charge (\$/kWh)** See Rider BGS Regional Greenhouse Gas Initiative

Recovery Charge (\$/kWh) See Rider RGGI **Infrastructure Investment Program Charge** See Rider IIP

CORPORATE BUSINESS TAX (CBT)

Charges under this rate schedule include a component for Corporate Business Taxes as set forth in Rider CBT.

NEW JERSEY SALES AND USE TAX (SUT)

Non-Utility Generation Charge (NGC) (\$/kWH)

Charges under this rate schedule include a component for New Jersey Sales and Use Tax as set forth in Rider SUT.

PRICE TO COMPARE

A customer may choose to receive electric supply from a third party supplier as defined in Section 11 of the Standard Terms and Conditions of this Tariff. A customer who receives electric supply from a third party supplier will not be billed the Basic Generation Service Charges or the Transmission Service Charges. Customers eligible for BGS CIEP who receive supply from a third party supplier will continue to be billed the CIEP Standby Fee.

Date of Issue: September 29, 2020

Effective Date: October 1, 2019 Issued by: David M. Velazquez, President and Chief Executive Officer - Atlantic City Electric Company Filed pursuant to Board of Public Utilities of the State of New Jersey directives associated with the BPU Docket No. ER20050336

RATE SCHEDULE SPL (Continued) (Street and Private Lighting) RATE (Mounted on Existing Pole)

KATE (Mounted on Existing Fole)				
	WATTS	<u>LUMENS</u>	MONTHLY DISTRIBUTION CHARGE	<u>STATUS</u>
INCANDESCENT				
Standard	103	1,000	\$ <u>8.33<u>1</u>0.39</u>	Closed
Standard	202	2,500	\$ 14.35 <u>17.90</u>	Closed
Standard	327	4,000	\$ 19.89 <u>24.81</u>	Closed
Standard	448	6,000	\$ 26.57 33.15	Closed
MERCURY VAPOR				
Standard	100	3,500	\$ 13.89 17.33	Closed
Standard	175	6,800	\$ 18.49 23.06	Closed
Standard	250	11,000	\$ 23.40 29.19	Closed
Standard	400	20,000	\$ 33.64 41.97	Closed
Standard	700	35,000	\$ 53.61 <u>66.88</u>	Closed
Standard	1,000	55,000	\$ 92.48 115.37	Closed
<u>HIGH</u> <u>PRESSURE</u> <u>SODIUM</u>				
Retrofit	150	11,000	\$ 16.95 <u>21.14</u>	Closed
Retrofit	360	30,000	\$ 31.47 39.26	Closed
		RATE (Overhead/RUE)		
	<u>WATTS</u>	<u>LUMENS</u>	MONTHLY DISTRIBUTION CHARGE	<u>STATUS</u>

	<u>WATTS</u>	<u>LUMENS</u>	DISTRIBUTION CHARGE	STATUS
<u>HIGH</u> <u>PRESSURE</u> <u>SODIUM</u>				
Cobra Head	50	3,600	\$ 15.13 18.87	Closed
Cobra Head	70	5,500	\$ 15.68 19.55	Closed
Cobra Head	100	8,500	\$ 16.50 20.58	Closed
Cobra Head	150	14,000	\$ 17.9422.38	Closed
Cobra Head	250	24,750	\$	Closed
Cobra Head	400	45,000	25.38 <u>31.66</u> \$	Closed
Shoe Box	150	14,000	29.35 <u>36.61</u> \$	Open Closed
Shoe Box	250	24,750	21.83 27.23 \$	Open Closed
		•	28 <u>35</u> .30 \$	Open Closed
Shoe Box	400	45,000	32.68 <u>40.77</u>	
Post Top	50	3,600	\$ 16.79 20.94	Open Closed
Post Top	100	8,500	\$ 18.29 22.81	Open Closed
Post Top	150	14,000	\$ 21.49 26.81	Open Closed
Flood/Profile	150	14,000	\$	Open Closed
Flood/Profile	250	24,750	17.58 21.93 \$ 22.17 27.65	Open Closed
			<u>oo</u>	

					Exhibit A Redlined
Flood/Profile	400	45,000	\$ 28 35.31	Open Closed	Page 97 of 150
Decorative	50		\$ 20.57 25.66	Open Closed	
Decorative	70		\$ 20.57 25.66	Open Closed	
Decorative	100		\$ 23.16 28.89	Open Closed	
Decorative	150		\$ 25.52 31.83	Open Closed	
METAL HALIDE					
Flood/Profile	400	31,000	\$ 34.78 43.38	Open Closed	
Flood/Profile	1,000	96,000	\$ 59.22 73.87	Open Closed	

Date of Issue: September 29, 2022 Effective Date: October 1, 2022

Issued by: J. Tyler Anthony, President and Chief Executive Officer — Atlantic City Electric Company Filed pursuant to Board of Public Utilities of the State of New Jersey directives associated with the BPU Docket No. ER22050323

RATE SCHEDULE SPL (Continued) (Street and Private Lighting) Rate (Underground)

	WATTS	<u>LUMENS</u>	MONTHLY DISTRIBUTION CHARGE	<u>STATUS</u>
HIGH PRESSURE SODIUM				
Cobra Head	50	3,600	\$ 23.21 28.95	Open Closed
Cobra Head	70	5,500	\$ 23.72 29.59	Open Closed
Cobra Head	100	8,500	\$ 24.48 <u>30.53</u>	Open Closed
Cobra Head	150	14,000	\$ 26.01 <u>32.44</u>	Open Closed
Cobra Head	250	24,750	\$ 31.44 <u>39.22</u>	Open Closed
Cobra Head	400	45,000	\$ <u>35.40</u> 44.16	Open Closed
Shoe Box	150	14,000	\$ 29.92 <u>37.33</u>	Open Closed
Shoe Box	250	24,750	\$ <u>36.33</u> 45.32	Open Closed
Shoe Box	400	45,000	\$ 4 0.74 <u>50.82</u>	Open Closed
Post Top	50	3,600	\$ 20.55 <u>25.64</u>	Open Closed
Post Top	100	8,500	\$ 22.02 27.47	Open Closed
Post Top	150	14,000	\$ 30.01 <u>3</u> 7.43	Open Closed
Flood/Profile	150	14,000	\$ 27.41 <u>34.19</u>	Open Closed
Flood/Profile	250	24,750	\$ 31.99 <u>39.90</u>	Open Closed
Flood/Profile	400	45,000	\$ 36.40<u>45.41</u>	Open Closed
Flood/Profile	400	31,000	\$ 4 <u>3.03</u> 53.67	Open Closed
Flood/Profile	1000	96,000	\$ 67.44 <u>8</u> 4.13	Open Closed
Decorative	50		\$ 27.37 <u>34.14</u>	Open Closed
Decorative	70		\$ 27.37 <u>34.14</u>	Open Closed
Decorative	100		\$ 29.92 <u>37.33</u>	Open Closed
Decorative	150		\$ 39.10 48.77	Open Closed

Date of Issue: September 29, 2022 Effective Date: October 1, 2022

Issued by: J. Tyler Anthony, President and Chief Executive Officer – Atlantic City Electric Company Filed pursuant to Board of Public Utilities of the State of New Jersey directives associated with the BPU Docket No. ER22050323

ATLANTIC CITY ELECTRIC COMPANY

BPU NJ No. 11 Electric Service - Section IV Twenty-Third-Revised Sheet Replaces Twenty-Second-Revised Sheet No. 37a

RATE SCHEDULE SPL (Continued) (Street and Private Lighting) Experimental

LIGHT EMITTING DIODE (LED)

LIGHT EMITTING DIODE (LED)						
	WATTS	<u>LUMENS</u>	MONTHLY DISTRIBUTION CHARGE	STATUS		
<u>Overhead</u>						
Cobra Head	50	3,000	\$ 8.90 11.11	Open		
Cobra Head	70	4,000	\$ 9.20 11.48	Open		
Cobra Head	100	7,000	\$9.43 \$11.76	Open		
Cobra Head	150	10,000	\$ 9.97 12.44	Open		
Cobra Head	250	17,000	\$ 11.35 14.16	Open		
Cobra Head	400	28,000	\$ 15.40 19.21	Open		
Decorative	150	10,000	\$ 20.65 25.76	Open		
Mongoose	250	15,000	\$18.97 <u>23.67</u>	Open		
Mongoose	400	17,000	\$ <u>26.</u> 21 .01	Open		
Acorn (Granville)	70	7,000	\$ 23.68 29.54	Open		
Acorn (Granville)	100	8,000	\$ 23.68 29.54	Open		
Acorn (Granville)	150	10,000	\$ 23.68 29.54	Open		
Acorn (Granville) w/ ribs and bands	<u>100</u>	8,000	<u>\$34.63</u>	Open		
Acorn (Granville) w/ ribs and bands	<u>150</u>	10,000	<u>\$34.63</u>	Open		
Post Top	70	4,000	\$ 11.61 14.48	Open		
Post Top	100	7,000	\$ 12 15.15	Open		
Shoe Box	100	7,000	\$ 10.34 <u>12.90</u>	Open		
Shoe Box	150	10,000	\$ 11.24 14.02	Open		
Shoe Box	250	17,000	\$ 11.73 14.63	Open		
Tear Drop	100	7,000	\$ 19.10 23.82	Open		
Tear Drop	150	10,000	\$ 19.10 23.82	Open		
Flood	150	6,200	\$ 17.03 21.25	Open		
Flood	250	12,100	\$ 17.73 22.12	Open		
Flood	400	<u>19,700</u>	\$ 20.38 <u>25.42</u>	Open		
Flood	1000	32,900	\$ 21.21 26.45	Open		
<u>Underground</u>	50	0.000	A 40.0700.70			
Cobra Head	50	3,000	\$16.67 <u>20.79</u>	Open		
Cobra Head	70	4,000	\$16.97 <u>21.17</u>	Open		
Cobra Head	100	7,000	\$ 17.20 <u>21.46</u>	Open		
Cobra Head	150	10,000	\$ 17.74 <u>22.13</u>	Open		
Cobra Head	250	17,000	\$19.12 <u>23.85</u>	Open		
Cobra Head	400	28,000	\$ 20.02 24.98	Open		
Decorative	150	10,000	\$ <u>28.43</u> 35.46	Open		
Mongoose	250	15,000	\$ 23.61 <u>29.45</u>	Open		
Mongoose	400	17,000	\$ 25.63 31.97	Open		
Acorn (Granville)	70	7,000	\$ 28 35.30	Open		
Acorn (Granville)	100	8,000	\$ 28 35.30	Open		
Acorn (Granville)	150	10,000	\$ 28 <u>35</u> .30	Open		
Acorn (Granville) w/ ribs and bands	<u>100</u>	<u>8,000</u>	\$39.83 ************************************	Open		
Acorn (Granville) w/ ribs and bands	<u>150</u>	10,000	\$39.83	Open		
Post Top	70	4,000	\$ 19.38 <u>24.17</u>	Open		
Post Top	100	7,000	\$19.92 <u>24.85</u>	Open		
Shoe Box	100	7,000	\$18.11 <u>22.60</u>	Open		
Shoe Box	150	10,000	\$19.01 <u>23.72</u>	Open		
Shoe Box	250	17,000	\$19.50 <u>24.33</u>	Open		
Tear Drop	100	7,000	\$ 26.85 <u>33.50</u>	Open		
Tear Drop	150	10,000	\$ 26.85 <u>33.50</u>	Open		
Flood	150	<u>6,200</u>	\$24.79 <u>30.92</u>	Open		
Flood	250	<u>12,100</u>	\$ 25.49 <u>31.80</u>	Open		
Flood	400	<u>19,700</u>	\$ 28.16 <u>35.12</u>	Open		
Flood	1000	32,900	\$ 28.98 <u>36.15</u>	Open		

Date of Issue: September 29, 2022
Issued by: J. Tyler Anthony, President and Chief Executive Officer – Atlantic City Electric Company
Filed pursuant to Board of Public Utilities of the State of New Jersey directives associated with the
BPU Docket No. ER22050323

ATLANTIC CITY ELECTRIC COMPANY

BPU NJ No. 11 Electric Service - Section IV Sixth Revised Sheet Replaces Fifth-Revised Sheet No. 38

RATE SCHEDULE SPL (Continued) (Street and Private Lighting)

Bill will be rendered monthly and be prorated based on the billing cycle

Lamp sizes listed are standard ratings. Actual output shall be within commercial tolerances. The mercury vapor post standard (no longer available) will be supplied at an annual cost of \$23.09 in addition to the appropriate rate for the facility mounted on an existing pole. For installations on or before January 17, 1986, or lamp sizes 3500 Lumen or greater, an ornamental standard will be supplied at an annual cost of \$76.71 in addition to the appropriate rate for the fixture mounted on an existing pole. For standards installed after January 17, 1986, non-ornamental standards are available at an annual cost of \$112.13 in addition to the appropriate rate for the fixture mounted on an existing pole. Installation charges may be required for new construction. Ornamental standards are available under the CLE rate schedule.

UPGRADES TO EXISTING FIXTURES

Customers may upgrade existing lighting fixtures to fixtures of higher wattage subject to payment of the following charges which provide for labor to replace the light fixture and the differential cost of the light fixture:

Lamp Size up to 150W or equivalent: \$339.80 plus applicable income tax gross up
Lamp Size greater than 150W or equivalent: \$430.74 plus applicable income tax gross up

TERM OF CONTRACT

Contracts under this schedule will be made for a period of not less than one (1) year or more than five (5) years and for specified numbers and sizes of fixtures. In all cases where the customer shall authorize additional fixtures within the contract period, the number of lamps shall be increased through the remainder of the contract period.

In no case shall the Company be obliged to furnish additional lighting under any contract for a period of two (2) years or less, or during the last two (2) years of any contract for a longer period unless the customer shall reimburse the Company for all expenses incurred in the running of additional lines for such fixtures, the cost of such fixtures and the cost of the installation.

Removal of fixtures and related facilities shall be at the direction of the customer and the customer shall reimburse the Company for all actual removal costs.

CREDITS

The annual charge per unit reflects an outage allowance based on normal and abnormal operating conditions.

TERMS AND CONDITIONS OF SERVICE

See Section II inclusive for Terms and Conditions of Service.

Customers requiring service under unusual conditions, or whose service requirements are different from those provided for herein may obtain such service under mutually acceptable contractual arrangements.

Service to all incandescent, mercury vapor, and retrofit high pressure sodium, metal halide and mercury vapor lamps of all sizes is in the process of elimination and is limited to those lamps being served prior to January 1, 1983 lamp replacement

Upon removal of incandescent and mercury vapor fixtures a fixture before the expiration of theirits service liveslife, the customer will be responsible to reimburse the Company the average undepreciated value per fixture. Refer to Rate Schedule CLE.

Conversion to Rate Schedule CSL

Non-residential Governmental Agency customers taking service under Rate Schedule SPL who are eligible to take service under Rate Schedule CSL may convert at any time. The customer will be required to pay a rate schedule conversion charge, assessed on a per fixture basis, based on the following conditions:

Lighting Installations less than or equal to five years

Full Installation costs per Rate Schedule CLE

of age:

Light Installations Greater than five years of age

Labor Costs associated with street light replacement. (\$271.15, plus applicable federal income tax gross up.)

"In accordance with P.L. 1997, c. 162, the charges in this Rate Schedule include provision for the New Jersey Corporation Business Tax and the New Jersey Sales and Use Tax. When billed to customers exempt from one or more of these taxes, as set forth in Riders CBT and SUT, such charges will be reduced by the relevant amount of such taxes included therein."

Date of Issue: March 27, 2019

Issued by: David M. Velazquez, President and Chief Executive Officer – Atlantic City Electric Company
Filed pursuant to Board of Public Utilities of the State of New Jersey directives associated with the

BPU Docket No. ER18080925

Revised Sheet Replaces Thirty-Third

Revised Sheet No. 39

RATE SCHEDULE CSL (Contributed Street Lighting)

AVAILABILITY OF SERVICE

Available for general lighting service to Governmental Agencies in the service area of the Company

The Company will install and maintain a lighting system and provide electric energy sufficient to operate fixtures continuously, automatically controlled, for approximately one-half-hour after sunset until approximately one-half-hour before sunrise, every night and all night, approximately forty-two hundred (4200) hours per annum during the term of years hereinafter set forth. The installed cost of the fixtures, standards, and other installed equipment (if necessary) shall be paid by the customer upon installation. All equipment shall be the property of the Company (see Rate Schedule CLE). The rates below provide for ordinary maintenance and replacement of lamps and automatic controls. The rates below do not provide for replacement due to expiration of the service life of installed fixtures, standards or other equipment which may be billed to customer at the time of replacement.

The following rates shall be applied to the kWh Usage for the particular light type and size to determine the monthly charge per light.

Delivery charges are billed on a monthly per light basis in accordance with the rates specified on the Tables on Sheets 40 and 40a.

Non-Utility Generation Charge (NGC) (\$/kWH)	See Rider NGC
Societal Benefits Charge (\$/kWh)	
Clean Energy Program	See Rider SBC
Universal Service Fund	See Rider SBC
Lifeline	See Rider SBC
Uncollectible Accounts	See Rider SBC
Transition Bond Charge (TBC) (\$/kWh)	See Rider SEC
Market Transition Charge Tax (MTC-Tax) (\$/kWh)	See Rider SEC
Transmission Rate (\$/kWh)	\$0.000000
Reliability Must Run Transmission Surcharge (\$/kWh)	\$0.000000
Transmission Enhancement Charge (\$/kWh)	See Rider BGS
Basic Generation Service Charge (\$/kWh)	See Rider BGS
Regional Greenhouse Gas Initiative	
Recovery Charge (\$/kWh)	See Rider RGGI
Infrastructure Investment Program Charge	See Rider IIP

CORPORATE BUSINESS TAX (CBT)

Charges under this rate schedule include a component for Corporate Business Taxes as set forth in Rider CBT.

NEW JERSEY SALES AND USE TAX (SUT)

Charges under this rate schedule include a component for New Jersey Sales and Use Tax as set forth in Rider SUT.

PRICE TO COMPARE

A customer may choose to receive electric supply from a third party supplier as defined in Section 11 of the Standard Terms and Conditions of this Tariff. A customer who receives electric supply from a third party supplier will not be billed the Basic Generation Service Charges or the Transmission Service Charges. Customers eligible for BGS CIEP who receive supply from a third party supplier will continue to be billed the CIEP Standby Fee.

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BPU Docket No. ER20050336

RATE SCHEDULE CSL (continued) (Contributed Street Lighting)

·	(Continuati	ou ou cou Lig	illing)	
	WATTS	<u>LUMENS</u>	MONTHLY DISTRIBUTION CHARGE	<u>STATUS</u>
HIGH PRESSURE SODIUM				
All	50	3,600	\$ 6.67 <u>8.32</u>	Open Close d
All	70	5,500	\$ 7.23 <u>9.02</u>	Open Close d
All	100	8,500	\$8 <u>10</u> .09	Open Close d
All	150	14,000	\$ 9.59 11.96	Open Close d
All	250	24,750	\$ 13.02 16.24	OpenClose d
All	400	45,000	\$ 17.17 <u>21.42</u>	OpenClose d
METAL HALIDE				_
Flood	1000		\$ 13.02 16.24	Open Close <u>d</u>
Flood	175		\$ 12.30 <u>15.35</u>	OpenClose d
Decorative - Two Lights	175		\$41.25 <u>51.46</u>	OpenClose d
Decorative	175		\$ 29.17 36.38	Open Close <u>d</u>
	<u>WATTS</u>	<u>LUMENS</u>	MONTHLY DISTRIBUTION CHARGE	STATUS
Experimental				
LIGHT EMITTING DIODE (LED)				
Cobra Head	50	3,000	\$ 3.51 <u>4.38</u>	Open
Cobra Head	70	4,000	\$ 3.51 4.38	Open
Cobra Head	100	7,000	\$ 3.51 4.38	Open
Cobra Head	150	10,000	\$ 3.51 4.38	Open
Cobra Head	250	17,000	\$ 3.51 <u>4.38</u>	Open
Cobra Head	400	28,000	\$ 3.51 4.38	Open
Post Top	150	10,000	\$ 3.51 4.38	Open
Colonial Post Top	70	4,000	\$ 3.51 4.38	Open
Colonial Post Top	100	7,000	\$ 3.51 4.38	Open
Mongoose	250	15,000	\$ 3.51 4.38	Open
Mongoose	400	17,000	\$ 3.51 4.38	Open
Acorn (Granville)	70	7,000	\$3.51 <u>4.38</u>	Open
Acorn (Granville)	100	8,000	\$3.51 <u>4.38</u>	Open
Acorn (Granville)	150	10,000	\$ 3.51 4.38	Open
Acorn (Granville) w/ ribs and bands	<u>100</u>	<u>8,000</u>	\$4.38	Open
Acorn (Granville) w/ ribs and bands	<u>150</u>	<u>10,000</u>	\$4.38	Open
Shoe Box	100	7,000	\$3.51 <u>4.38</u>	Open
Shoe Box	150	10,000	\$ 3.51 4.38	Open
Shoe Box	250	17,000	\$3.51 <u>4.38</u>	Open
Tear Drop	100	7,000	\$3.51 <u>4.38</u>	Open
Tear Drop	150	10,000	\$3.51 <u>4.38</u>	Open
Flood	150	<u>6,200</u>	\$3.51 <u>4.38</u>	Open
Flood	250	<u>12,100</u>	\$3.51 <u>4.38</u>	Open
Flood	400	<u>19,700</u>	\$ 3.51 4.38	Open

Bill will be rendered monthly and be prorated based on the billing cycle

Flood

32,900

\$3.514.38

Open

Exhibit A Redlined Page 103 of 150

Date of Issue: September 29, 2022
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Exhibit A Redlined

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First Revised Sheet Replaces Original Sheet No. 40a

RATE SCHEDULE CSL (continued) (Contributed Street Lighting)

UPGRADES TO EXISTING FIXTURES

Customers may upgrade existing lighting fixtures to fixtures of higher wattage subject to payment of the following charges which provide for labor to replace the light fixture and the differential cost of the light fixture:

Lamp Size up to 150W: or equivalent: \$339.80 plus applicable income tax gross up Lamp Size greater than 150W or equivalent: \$430.74 plus applicable income tax gross up

TERMS OF CONTRACT

Contracts under this schedule will be made for a period of not less than one (1) year or more than five (5) years and for specified numbers and sizes of fixtures. In all cases where the customer shall authorize additional fixtures within the contract period, the number of lamps shall be increased throughout through the remainder of the contract period.

In no case shall the Company be obliged to furnish lighting unless the customer reimburses the Company for all actual expenses incurred to install additional lines for such fixtures, the cost of such fixtures and accessories and the cost of the installation of the fixtures, lines and accessories.

Removal of fixtures and related facilities shall be at the direction of the customer and the customer shall reimburse the Company for all actual removal costs.

CREDITS

The annual charge per unit reflects an outage allowance based on normal and abnormal operating conditions.

TERMS AND CONDITIONS OF SERVICE

See Section II inclusive for Terms and Conditions of Service.

Customers requiring service under unusual conditions, or whose service requirements are different from those provided for herein may obtain such service under mutually acceptable contractual arrangements.

Service to all incandescent, high pressure sodium, metal halide and mercury vapor lamps of all sizes is limited to lamp replacement.

Upon removal of any fixture before the expiration of its service life, the customer will be responsible to reimburse the Company the average undepreciated value per fixture. Refer to Rate Schedule CLE.

"In accordance with P.L. 1997, c. 162, the charges in this Rate Schedule include provision for the New Jersey Corporation Business Tax and the New Jersey Sales and Use Tax. When billed to customers exempt from one or more of these taxes, as set forth in Riders CBT and SUT, such charges will be reduced by the relevant amount of such taxes included therein."

Date of Issue: March 27, 2019 Effective Date: April 1, 2019

Issued by:

David M. Velazquez, President and Chief Executive Officer - Atlantic City Electric Company Filed pursuant to Board of Public Utilities of the State of New Jersey directives associated with the BPU Docket No. ER18080925

Exhibit A Redlined

Page 105 of 150

RATE SCHEDULE TP (Temporary Power)

AVAILABILITY OF SERVICE

Available for temporary power service.

MONTHLY RATE

Temporary power service will be supplied under any published rate schedule applicable to the class of business of the customer, when the Company has available unsold capacity of lines, transformers and generating equipment, with an additional charge of the total cost of connection and disconnection on discontinuance of service on an individually determined basis, in addition to the charges under Rate Schedule CHG.

MINIMUM CHARGE

The same minimum charge as set forth in any rate schedule under which temporary service is supplied, shall be applicable to such temporary power service, and in no case less than full monthly minimum.

TERM OF CONTRACT

As determined and set forth in a written agreement between the Company and the customer.

SPECIAL TERMS AND CONDITIONS

"In accordance with P.L. 1997, C. 162, the charges in this Rate Schedule include provision for the New Jersey Corporation Business Tax and the New Jersey Sales and Use Tax. When billed to customers exempt from one or more of these taxes, as set forth in Riders CBT and SUT, such charges will be reduced by the relevant amount of such taxes included therein."

Date of Issue: March 27, 2019 Effective Date: April 1, 2019

BPU NJ No. 11 Electric Service - Section IV __Fifth Revised Sheet Replaces Fourth Revised Sheet No. 42

RATE SCHEDULE SPP (Small Power Purchase)

AVAILABILITY OF SERVICE

Available to a "Qualifying Facility" (QF) as defined in Section 210 of the Public Utility Regulatory Policies Act of 1978 who also receives service under regular Company Rate Schedules Rate Schedules RS, MGS-Secondary, MGS-SEVC, MGS-Primary, AGS Secondary, AGS Primary, TGS Sub-Transmission, and TGS Transmission. The generation capacity of such facility must be less than 1000 kW.

Qualifying facilities with capacity greater than 1000 kW must negotiate customer specific contracts. These facilities are entitled to a contract at full avoided energy costs and, if eligible, capacity costs. Customer specific contracts are subject to approval by the New Jersey Board of Public Utilities.

MONTHLY RATE

Service Charge:

This amount is deducted prior to payment for delivered energy.

\$36.37

Energy Payment:

The customer will be paid based on the actual load weighted PJM Residual Metered Load Aggregate Locational Marginal Prices (LMPs) in effect during the month energy is received.

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 100kW 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.

TERMS OF PAYMENT

In any month, credit/charge to the Qualifying Facility shall be the Energy Credit plus the Capacity Credit (if eligible) less the Service Charge. Credit/charge shall be made within 60 days of the last customer meter reading date, in each calendar quarter. If the net monthly credit exceeds \$53.67, a credit shall be made on a monthly basis.

Date of Issue: February 26, 2021 Effective Date: March 1, 2021

Issued by:

David M. Velazquez, President and Chief Executive Officer – Atlantic City Electric Company
Filed pursuant to Board of Public Utilities of the State of New Jersey directives associated with the
BPU Docket No. E018020190

RATE SCHEDULE SPP (Continued) (Small Power Purchase)

SPECIAL PROVISIONS

- 1. The customer must pay all interconnection charges before the Company will purchase electric power.
- 2. A customer's installation must conform to Company specifications for Qualifying Facility interconnection as outlined in the Company's Technical Guidelines for Cogeneration and Small Power Producers.
- 3. Qualifying Facilities with 10 kW or less generating capacity must sign an Electric Interconnection/Small Power Purchase Agreement.
- 4. Purchases from a QF will receive a capacity credit when the capacity exceeds 100 kilowatts and that capacity meets the Company's reliability criteria. The Company will make capacity payments to the QF to the extent that the capacity of the QF reduces any capacity deficiency payments by the Company to PJM or increases any capacity payments to the Company from PJM. Capacity credits, if applicable, will be based on the average on-peak capacity in any billing month, such capacity to be defined as the on-peak kilowatt-hours divided by the on-peak hours in that month. The seller may be eligible for an additional credit where the presence of the QF allows the deferral of local transmission or distribution capacity cost.
- 5. The Service Charge will be waived for QF's with 10 kW or less generating capacity.
- 6. Due to simplified metering, QF's with 10 kW or less generating capacity will be credited based on the average non-load weighted PJM billing rate for the month the energy is received.

STANDBY SERVICE

See Rider STB.

"In accordance with P.L. 1997, c. 162, the charges in this Rate Schedule include provision for the New Jersey Corporation Business Tax and the New Jersey Sales and Use Tax. When billed to customers exempt from one or more of these taxes, as set forth in Riders CBT and SUT, such charges will be reduced by the relevant amount of such taxes included therein."

Date of Issue: March 27, 2019 Effective Date: April 1, 2019

ATLANTIC CITY ELECTRIC COMPANY

BPU NJ No. 11 Electric Service - Section IV Thirty-Ninth_Revised Sheet Replaces Thirty-Eighth-Revised Sheet No. 44

RIDER STB-STANDBY SERVICE (Applicable to MGS, AGS, TGS and SPP Rate Schedules)

AVAILABILITY

This rider is available to customers having other sources of electrical energy supply, but who desire to purchase have Standby Service from the Company. The terms of this rider shall not be available in any month when the customer's Generation Availability for the current and preceding five (5) months does not exceed 50%.

DEFINITIONS

Standby Service:

Standby Service is defined as the additional electrical capacity available to a customer in the event of a forced outage and during a mutually agreed upon customer's scheduled maintenance shutdown of the customer owned electrical energy source.

Standby Service Capacity:

The Standby Service Capacity shall be the maximum electrical capacity in kW supplied by the customer owned electrical energy source during the current and preceding five (5) months. Such Standby Service Capacity may be revised with the Company's approval as changes in the customer's load conditions warrant.

Generation Availability:

Generation Availability is defined as the availability of the customer owned electrical energy source during the current and preceding five (5) months and shall be determined by dividing the Kwhrs produced during this period by the product of the Standby Service Capacity times 4380 hours.

MODIFICATION OF DEMAND DETERMINATION

The monthly billing demand shall be as defined under the "Demand Determination" section of the applicable rate schedule.

The Standby Service Demand shall be the "Standby Service Capacity" as defined above.

During the billing months in which a forced outage or mutually agreed upon customer's scheduled maintenance shutdown occurs, the billing demand will be determined by subtracting the Standby Service Capacity from the total demand and waives the minimum charge provision of the applicable rate schedule. Electric service is provided under the terms of the applicable rate schedule. Total demand is defined as the sum of the Company's demand meter plus demand supplied by the other sources of electrical energy, all computed to the nearest whole kilowatt during a fifteen minute period.

STANDBY SERVICE CHARGE

This rider imposes a Standby Service Charge at the following voltage levels:

<u>Tariff</u>	Transmission Stand By Rate	Distribution Stand By Rate				
	<u>(\$/kW)</u>	<u>(\$/kW)</u>				
MGS-Secondary and	\$0.66	\$0. 18 <u>53</u>				
MGS-SEVC						
MGS Primary	\$0.37	\$0. 16 <u>24</u>				
AGS Secondary	\$0.57	\$ 1.26 2.25				
AGS Primary	\$0.59	\$1. 00 <u>75</u>				
TGS Sub Transmission	\$0.35	\$0.00				
TGS Transmission	\$0.35	\$0.00				

Date of Issue: September 29, 2022
Issued by: J. Tyler Anthony, President and Chief Executive Officer – Atlantic City Electric Company
Filed pursuant to Board of Public Utilities of the State of New Jersey directives associated with the
BPU Docket No. ER22050323

Page 109 of 150 **Second Revised Sheet Replaces First Sheet No. 45**

Exhibit A Redlined

RIDER STB-STANDBY SERVICE (Continued) (Applicable to MGS, AGS, TGS and SPP Rate Schedules)

TERMS AND CONDITIONS

- 1. A customer shall allow installation, at its sole expense, of suitable metering equipment or other provisions to determine the amount of generation supplied by customer's source of electrical energy on a period by period basis.
- During the initial five-(5) months application of this rider, all calculations based upon data of the current and preceding five-(5) months, shall be based upon data of the current month and the number of months of experience since its initial application.
- 3. These standby provisions may also be modified by mutual written consent between the Company and the potential standby customer.
- 4. If a customer on this rider has multiple generators, then each individual generator must meet the 50% availability requirement.

"In accordance with P.L. 1997, c. 162, the charges in this Rate Schedule include provision for the New Jersey Corporation Business Tax and the New Jersey Sales and Use Tax. When billed to customers exempt from one or more of these taxes, as set forth in Riders CBT and SUT, such charges will be reduced by the relevant amount of such taxes included therein."

Date of Issue: March 27, 2019 Effective Date: April 1, 2019

ATLANTIC CITY ELECTRIC COMPANY **BPU NJ No. 11 Electric Service - Section IV**

Redlined Page 110 of 150 First Revised Sheet Replaces Original Sheet No. 46

Exhibit A

DIDED IS INTEDDIDTIBLE SEDVICE

	(Applicable	e to AGS and	TGS Rate Sch	e dules)	
VAILABILITY					
The Interruptible Ser	vice Rider was d	liscontinued as	of December (31 , 1999.	
		Taranda salla I	Late Disast		
		Intentionally	<u>Leπ Blank</u>		

Date of Issue: March 27, 2019 Effective Date: April 1, 2019

Issued by: David M. Velazquez, President and Chief Executive Officer - Atlantic City Electric Company Filed pursuant to Board of Public Utilities of the State of New Jersey directives associated with the BPU Docket No. ER18080925

ATLANTIC CITY ELECTRIC COMPANY BPU NJ No. 11 Electric Service - Section IV

Page 111 of 150
First-Revised Sheet Replaces Original Sheet No. 47

Exhibit A Redlined

RIDER IS - INTERRUPTIBLE SERVICE (Continued)
(Applicable to AGS and TGS Rate Schedules)



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Date of Issue: March 27, 2019 Effective Date: April 1, 2019

Exhibit A Redlined Page 112 of 150

ATLANTIC CITY ELECTRIC COMPANY BPU NJ No. 11 Electric Service - Section IV

First-Revised Sheet Replaces Original Sheet No. 48

RIDER IS - INTERRUPTIBLE SERVICE (Continued) (Applicable to AGS and TGS Rate Schedules)					
AVAILABILITY (Continued)					
This Interruptible Service Rider was discontinued as of December 31, 1999.					
Intentionally Left Blank					

Date of Issue: March 27, 2019
Issued by: David M. Velazquez, President and Chief Executive Officer – Atlantic City Electric Company
Filed pursuant to Board of Public Utilities of the State of New Jersey directives associated with the

BPU Docket No. ER18080925

Exhibit A Redlined Page 113 of 150

ATLANTIC CITY ELECTRIC COMPANY BPU NJ No. 11 Electric Service - Section IV

Sixth Revised Sheet Replaces Fifth Revised Sheet No. 49

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Date of Issue: March 27, 2019 Effective Date: April 1, 2019

Second Revised Sheet replaces First Sheet No. 50

RIDER RP REDEVELOPMENT PROGRAM SERVICE

APPLICABLE TO:

Customers receiving service under Electric Rate Schedules AGS Secondary, AGS Primary, TGS

CHARACTER OF SERVICE:

Commitments for service under this rider will be made available to qualifying customers on a pilot basis effective August 24, 2016. Customers must commence service hereunder within 24 months of the date of commitment.

CREDIT:

A credit equal to 20% of the customer's distribution charge(s) as described below for the newly constructed, leased or purchased space, as determined by the Company, will be applied to the customer's monthly electric bills for a term of five years, as follows:

New Customer

A new customer for purposes of this Rider RP shall be defined as a customer contract account whose existing, newly constructed, leased or purchased space is separately metered.

The credit shall apply to the customer charge and the distribution demand charge associated with all kilowatts, as billed by the Company.

Existing Customer

An existing customer for purposes of this Rider RP shall be defined as a customer contract account whose existing, newly constructed, leased or purchased space is not separately metered from the existing service.

For existing customers, the credit shall apply only to those kilowatts, as measured by the Company, which are in excess of comparable demands in the same month established in a base year period, which period shall be defined as the 12 calendar months immediately preceding the first month service is provided under the Redevelopment Program. The credit will not be applicable to the customer charge for an existing customer.

ELIGIBILITY:

Each customer will be required to sign an Application for Redevelopment Program Service, which application shall include, an estimate of additional demand. The customer must remain on the same rate schedule as in the base year period throughout the five year term of the program. Upon verification of eligibility, the Company will provide the customer with a written commitment for Redevelopment Program Service.

To be eligible, a customer must construct, lease or purchase, new or vacant space for commercial or industrial services or build, or have added to or expanded to a building on existing property. The effective date of the lease or purchase must have been on or after August 24, 2016, the initial Effective Date of this rate schedule. The total additional leased or purchased building space must equal or exceed 8,000 square feet.

Qualifying building space must be vacant, as determined by the Company, prior to receiving a commitment for the Redevelopment Program.

A customer must add at least two permanent full-time employees to the customer's payroll at the site receiving the benefit of the Redevelopment Program Service Rider. Relocation or consolidation of employees based in the Company's service territory without employment growth will not qualify. Employment growth will be confirmed by the Company in conjunction with the New Jersey Department of Labor and/or affidavit from the customer. The Company reserves the right, in its discretion, to periodically verify employment increases and sustained level of employment. If after verification the required employment level has not been sustained, Rider RP will no longer be applicable.

A customer must qualify for, receive, and provide the Company with suitable documentation substantiating the receipt of a package of economic incentives pursuant to the Economic Opportunity Act of 2013 (P.L. 2013, c.161) conferred by the state or any other applicable economic incentive conferred by the county or local municipality, including financial assistance or a tax incentive program designed to maintain or increase employment levels in the service area.

LIMITATIONS OF SERVICE:

This service is not available to federal, state, county or local governments or governmental entities.

Date of Issue: March 27, 2019

Issued by: David M. Velazquez, President and Chief Executive Officer – Atlantic City Electric Company
Filed pursuant to Board of Public Utilities of the State of New Jersey directives associated with the
BPU Docket No. ER18080925

Exhibit A Redlined

Page 115 of 150

RIDER - SCD SMALL COMMERCIAL DEVELOPMENT

APPLICABLE TO:

Customers receiving service under Electric Rate Schedules MGS Secondary, MGS Primary

CHARACTER OF SERVICE:

Commitments for service under this rider will be made available to qualifying customers on a pilot basis effective August 24, 2016. Customers must commence service hereunder within 24 months of the date of commitment.

CREDIT:

A credit equal to 20% of the customer's distribution charge(s) as described below for the newly constructed, leased or purchased space, as determined by the Company, will be applied to the customer's monthly electric bills for the term of five years, as follows:

New Customer

A new customer for purposes of this Rider SCD shall be defined as a customer contract account whose existing, newly leased, constructed or purchased space is separately metered.

The credit shall apply to the customer charge and the distribution demand charge associated with all kilowatts, as billed by the Company.

Existing Customer

An existing customer for purposes of this Rider SCD service shall be defined as a customer contract account whose existing, newly constructed, leased or purchased space is not separately metered from the existing service.

For existing customers, the credit shall apply only to those kilowatts, as measured by the Company, which are in excess of comparable demands in the same month established in a base year period, which period shall be defined as the 12 calendar months immediately preceding the first month service is provided under the Redevelopment Program. The credit will not be applicable to the customer charge for an existing customer.

ELIGIBILITY:

Each customer will be required to sign an Application for Small Commercial Development Program Service, which application shall include an estimate of additional demand. The customer must remain on the same rate schedule as in the base year period throughout the five year term of the program. Upon verification of eligibility, the Company will provide the customer with a written commitment for Small Commercial Development Program Service.

To be eligible, a customer must construct, lease or purchase new or vacant space for Commercial services or build, have added to or expanded to a building on existing property. The effective date of the lease or purchase must have been on or after August 24, 2016, the initial Effective Date of this rate schedule. The total additional leased or purchased building space must equal or exceed 2,500 square feet.

Qualifying building space must be vacant, as determined by the Company, prior to receiving a commitment for the Small Commercial Development Rider.

Customer must be adding at least one permanent full-time year round employee to the customer's payroll at the site receiving the benefit of the Small Commercial Development Rider. Relocation or consolidation of employees based in the Company's service territory without employment growth will not qualify. Employment growth will be confirmed by the Company in conjunction with the New Jersey Department of Labor and/or affidavit from the customer on a quarterly basis. The Company reserves the right, in its discretion, to periodically verify employment increases and sustained level of employment. If, after verification, the required employment level has not been sustained, Rider SCD will no longer be applicable.

LIMITATIONS OF SERVICE:

This service is not available to federal, state, county or local governments or governmental entities.

Date of Issue: March 27, 2019

Issued by: David M. Velazquez, President and Chief Executive Officer — Atlantic City Electric Company
Filed pursuant to Board of Public Utilities of the State of New Jersey directives associated with the
BPU Docket No. ER18080925

Exhibit A Redlined Page 116 of 150 Original Sheet No. 52

CBT – RIDER (CORPORATE BUSINESS TAX)

In accordance with P.L. 1997, C. 162 (the "energy tax reform statute"), provision for the New Jersey Corporation Business Tax has been included in all charges applicable Riders [tariff designation for LEACs/LGACs] (the "Base Tariff Rates) by multiplying the Base Tariff Rates in effect immediately prior to January 1, 1998 by the factor 1.3518% [1 plus the "a" factor carried out to decimals]. The energy tax reform statute exempts the following customers from the CBT provision, and when billed to such customers, the Base Tariff 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. Operating co-generators, or those 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 Board of Utilities prior to January 1, 1998.

Date of Issue: March 27, 2019 Effective Date: April 1, 2019

Issued by: Issued by: David M. Velazquez, President and Chief Executive Officer - Atlantic City Electric

Filed pursuant to Board of Public Utilities of the State of New Jersey directives associated with the BPU Docket No. ER18080925

RIDER - SUT (SALES AND USE TAX)

- A. In accordance with P.L. 1997, C. 162 (the "energy tax reform statute"), provision for the New Jersey Sales and Use Tax ("SUT") has been included in all charges applicable under Atlantic's tariff by multiplying the charges that would apply before application of the SUT by the factor 1.06875. Pursuant to P.L. 2016, c.57, this factor is changed to 1.06625 effective January 1, 2018. The energy tax reform statute exempts the following customers from the SUT provision:
 - 1. Franchised providers of utility services (gas, electricity, water, wastewater and telecommunications services provided by local exchange carriers) within the State of New Jersey.
 - Operating co-generators, or those which have filed an application for an operating permit or 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:
 - 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.

There are, however, other tariff charges provided in the Company's current tariff which are not subject, or are excluded from the SUT calculations in the compliance filing, as follows:

2. Other Tariff Charges

Installation of Service at Original Location \$65.00 - Exempt Connect \$15.00 - Exempt Reconnect \$15.00 - Exempt Succession \$15.00 - Exempt Disconnect \$15.00 - Exempt Disconnect \$15.00 - Exempt Special Reading of Meters \$15.00 - Exempt Late Payment Charge - Exempt Uncollectible Check \$7.64 - Exempt

Date of Issue: March 27, 2019 Effective Date: April 1, 2019

Issued by: David M. Velazquez, President and Chief Executive Officer – Atlantic City Electric Company Filed pursuant to Board of Public Utilities of the State of New Jersey directives associated with the BPU Docket No. ER18080925

ATLANTIC CITY ELECTRIC COMPANY BPU NJ No. 11 Electric Service - Section IV

BPU NJ No. 11 Electric Service - Section IV Second-Revised Sheet Replaces First-Revised Sheet No. 54



Rider MTC was replaced by Rider NGC, effective June 1, 2005.

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Date of Issue: March 27, 2019 Effective Date: April 1, 2019

Issued by:

David M. Velazquez, President and Chief Executive Officer – Atlantic City Electric Company
Filed pursuant to Board of Public Utilities of the State of New Jersey directives associated with the
BPU Docket No. ER18080925

Exhibit A Redlined Page 119 of 150

ATLANTIC CITY ELECTRIC COMPANY BPU NJ No. 11 Electric Service - Section IV

BPU NJ No. 11 Electric Service - Section IV Second-Revised Sheet Replaces First-Revised Sheet No. 55



Rider NNC was replaced by Rider NGC effective June 1, 2005.

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Date of Issue: March 27, 2019 Effective Date: April 1, 2019

Issued by:

David M. Velazquez, President and Chief Executive Officer – Atlantic City Electric Company
Filed pursuant to Board of Public Utilities of the State of New Jersey directives associated with the
BPU Docket No. ER18080925

Exhibit A Redlined Page 120 of 150

ATLANTIC CITY ELECTRIC COMPANY

BPU NJ No. 11 Electric Service - Section IV Twenty-Fourth Revised Sheet Replaces Twenty-Third Revised Sheet No. 56

RIDER (SEC) Securitization

This Rider provides the two charges associated with the securitization of stranded costs. The charges included in this Rider are:

Transition Bond Charge

The Transition Bond Charge (TBC) is designed to insure full and timely recovery of all Bondable Stranded Costs including financing charges and related costs.

MTC-Tax

The Market Transition Charge Tax (MTC-Tax) is designed to recover all income taxes associated with the TBC and MTC-Tax revenues.

These charges are applicable to all kWhs delivered to customers receiving service under all Electric Rate Schedules and any customer taking service under special contractual arrangements.

The Company's TBC and MTC-Tax Charges to be effective on and after the date indicated below are as follows:

Transition Bond Charge: \$(0.001496) per kWh MTC-Tax \$0.000000 per kWh

NEW JERSEY SALES AND USE TAX (SUT)

Charges under this Rider include a component for New Jersey Sales and Use Tax as set forth in Rider SUT.

Date of Issue: August 31, 2022 Effective Date: October 1, 2022

Issued by:

J. Tyler Anthony, President and Chief Executive Officer — Atlantic City Electric Company
Filed pursuant to Board of Public Utilities of the State of New Jersey directives associated with the
BPU Docket Nos. EF01060394 and EF03020121

BPU NJ No. 11 Electric Service - Section IV Twenty-Eighth Revised Sheet Replaces Twenty-Seventh Revised Sheet No. 57

Rider (NGC) Non-Utility Generation Charge (NGC)

Applicable to customers receiving service under Electric Rate Schedules RS, MGS, AGS, TS, TGS, DDC, SPL, CSL, STB, SPP are subject to a non-bypassable Non-Utility Generation Charge (NGC).

This charge provided for the full and timely recovery of the following costs:

- 1. Costs associated with the Company's purchase power contracts with non-utility generators, which are intended recover the stranded costs associated with such commitments. The costs recovered via the NGC are based on the difference between the average estimated cost of energy and capacity in the regional market and the associated costs provided in existing power purchase contracts with non-utility generators. Differences between actual and estimated costs occurring under previously approved rates shall be added or subtracted as appropriate to the estimated costs.
- 2. Costs associated with the transition to a competitive electric market and the restructuring of the electric utility industry in the State of New Jersey.
- 3. Costs associated with the Company's generation facilities, net of any revenue received from the sale of energy, capacity and ancillary services associated with these units.

The following table provides the component rates of the NGC charge for each rate schedule based on the cost categories listed above in \$ per kWh.

Total NGC
\$ 0.009827
\$ 0.009827
\$ 0.009569
\$ 0.009827
\$ 0.009569
\$ 0.009368
\$ 0.009827
\$ 0.009827

Date of Issue: May 26, 2022 Effective Date: June 1, 2022

Issued by:

J. Tyler Anthony, President and Chief Executive Officer – Atlantic City Electric Company
Filed pursuant to Board of Public Utilities of the State of New Jersey directives associated with the
BPU Docket No. ER22020038

Exhibit A Redlined Page 122 of 150

ATLANTIC CITY ELECTRIC COMPANY	
BPU NJ No. 11 Electric Service - Section IV	Second Revised Sheet Replaces First Sheet No. 57a

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Date of Issue: March 27, 2019 Effective Date: April 1, 2019

Issued by: David M. Velazquez, President and Chief Executive Officer - Atlantic City Electric Company Filed pursuant to Board of Public Utilities of the State of New Jersey directives associated with the BPU Docket No. ER18080925

Exhibit A Redlined Page 123 of 150

ATLANTIC CITY ELECTRIC COMPANY

BPU NJ No. 11 Electric Service - Section IV Forty-Fourth Revised Sheet Replaces Forty-Third Revised Sheet No. 58

RIDER (SBC) Societal Benefits Charge (SBC)

Applicable to customers receiving service under Electric Rate Schedules RS, MGS, AGS, TS, TGS, DDC, SPL, and CSL and any customer taking service under special contractual arrangements.

In accordance with the New Jersey Electric Discount and Energy Competition Act, Societal Benefits Charges include:

- Clean Energy Program Costs
- Uncollectible Accounts
- Universal Service Fund
- Lifeline

The Company's Societal Benefits Charges to be effective on and after the date indicated below are as follows:

Clean Energy Program \$0.003251 per kWh
Uncollectible Accounts \$0.001712 per kWh
Universal Service Fund \$0.003417 per kWh
Lifeline \$0.000784 per kWh

Date of Issue: September 29, 2022 Effective Date: October 1, 2022

Issued by:

Exhibit A Redlined Page 124 of 150

ATLANTIC CITY ELECTRIC COMPANY
BPU NJ No. 11 Electric Service - Section IV

Eighth Revised Replaces Seventh Revised Sheet No. 59

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Date of Issue: March 27, 2019 Effective Date: April 1, 2019

BPU NJ No. 11 Electric Service - Section IV Twenty-Seventh Revised Sheet Replaces Twenty-Sixth Revised Sheet No. 60

RIDER (BGS) Basic Generation Service (BGS)

Basic Generation Service (BGS) will be arranged for any customer taking service under Electric Rate Schedules RS, MGS Secondary, MGS-SEVC, MGS Primary, AGS Secondary, AGS Primary, TGS, DDC, SPL, and CSL who has not notified the Company of an Alternative Electric Supplier choice. BGS is also available to customers whose arrangements with Alternative Electric Suppliers have terminated for any reason, including nonpayment.

BGS is offered under two different terms of service; Basic Generation Service-Residential Small Commercial Pricing (BGS-RSCP) and Basic Generation Service -Commercial and Industrial Energy Pricing (BGS-CIEP). BGS-RSCP is offered to customers on Rate Schedules RS, DDC, SPL and CSL. BGS-RSCP is also offered to customers on Rate Schedules MGS Secondary, MGS-SEVC, MGS Primary, AGS Secondary, AGS Primary with an annual peak load share ("PLS") for generation capacity of less than 500 kW as of November 1 or each year. Additionally, BGS customers on Rate Schedule RS have the option of taking BGS-RSCP on a time of use basis.

BGS customers on Rate Schedule TGS and BGS customers on Rate Schedules MGS Secondary, MGS-SEVC, MGS Primary, AGS Secondary or AGS Primary with a PLS for generation capacity equal to or greater than 500 kW as of November 1 of each year are required to take service under BGS-CIEP.

Customers on Rate Schedules MGS Secondary, MGS-SEVC, MGS Primary, AGS Secondary or AGS Primary with a PLS of less than 500 kW, have the option of taking either BGS-RSCP or BGS-CIEP service. Customers who elect BGS-CIEP must notify the Company of their selection no later than the second working day of January of the year they wish to begin BGS-CIEP service. Such election will be effective on June 1 of that year and remain as the customer's default supply for the following twelve months. Customers electing BGS-CIEP as their default supply in a prior procurement period and who are otherwise eligible to return to BGS-RSCP may return to BGS RSCP by notifying the Company no later than the second working day of January of the year that they wish to return to BGS-RSCP service. Such election shall be effective on June 1 of that year.

BGS-RSCP Supply Charges (\$/kWh):	SUMMER		W	INTER
Rate Schedule RS	June Thr	ough September	October \$	Through May 0.074368
<=750 kwhs summer	\$	0.069150		
> 750 kwh summer	\$	0.079173		
RS TOU BGS Option				
On Peak (See Note 1)	\$	0.094446	\$	0.100414
Off Peak (See Note 1)	\$	0.054075	\$	0.055403
MGS-Secondary and MGS-SEVC	\$	0.072372	\$	0.070277
MGS-Primary	\$	0.065779	\$	0.063717
AGS-Secondary	\$	0.069409	\$	0.067159
AGS-Primary	\$	0.065038	\$	0.062937
DDC	\$	0.065335	\$	0.063197
SPL/CSL	\$	0.055779	\$	0.056637

Note 1: On Peak hours are considered to be 8:00 AM to 8:00 PM, Monday through Friday.

The above Basic Generation Service Energy Charges reflect costs for Energy, Generation Capacity, Ancillary Services and Administrative Charges pursuant to N.J.S.A. 48:2-60 plus New Jersey Sales and Use Tax as set forth in Rider SUT.

Date of Issue: March 25, 2022 Effective Date: June 1, 2022

Issued by: J. Tyler Anthony, President and Chief Executive Officer – Atlantic City Electric Company Filed pursuant to Board of Public Utilities of the State of New Jersey directives associated with the BPU Docket No. ER21030631

ATLANTIC CITY ELECTRIC COMPANY

BPU NJ No. 11 Electric Service - Section IV Forty-Second Revised Sheet Replaces Forty-First Revised Sheet No. 60a

RIDER (BGS) continued Basic Generation Service (BGS)

BGS Reconciliation Charge (\$/kWh):

The above charge shall recover the difference between the monthly amount paid to Basic Generation Service (BGS) suppliers and the total revenue from customers for BGS for the preceding months for the applicable BGS supply. These charges include New Jersey Sales and Use Tax as set forth in Rider SUT and are changed on June 1 and October 1 of each year.

Rate Schedule Charge (\$ per kWh)
RS \$ (0.000262)
MGS Secondary, MGS-SEVC, AGS Secondary, SPL/CSL, DDC \$ (0.000262)
MGS Primary, AGS Primary \$ (0.000255)

BGS-CIEP

Energy Charges

BGS Energy Charges for Rate Schedule TGS, AGS and MGS customers with a Peak Load Share (PLS) of 500 kW or more, and AGS and MGS customers with a PLS of less than 500 kW who have elected BGS-CIEP are hourly and are provided at the real time PJM Load Weighted Average Residual Metered Load Aggregate Locational Marginal Prices for the Atlantic Electric Transmission Zone, adjusted for losses, plus administrative charges pursuant to N.J.S.A. 48:2-60 and New Jersey Sales and Use Tax as set forth in Rider SUT.

Generation Capacity Obligation Charge

Summer Winter \$0.304540 \$0.304540

This charge is equal to the winning bid price from the BGS-CIEP default service auction plus administrative charges pursuant to N.J.S.A. 48:2-60 and New Jersey Sales and Use Tax as set forth in Rider SUT. The above charge shall be applied to each customer's annual peak load share ("PLS") for generation capacity, adjusted for the applicable PJM-determined Zonal Scaling Factor and the applicable PJM-determined capacity reserve margin factor, on a daily basis for each day in each customer's respective billing cycle.

Ancillary Service Charge

	Charge
	(\$ per kWh)
Service taken at Secondary Voltage	\$ 0.006750
Service taken at Primary Voltage	\$ 0.006574
Service taken at Sub-Transmission Voltage	\$ 0.006499
Service taken at Transmission Voltage	\$ 0.006436

Charge per kilowatt of Generation Obligation (\$ per kW per day)

This charge represents the average annual cost of Ancillary Services in the Atlantic Electric Transmission zone adjusted for losses, plus administrative charges pursuant to N.J.S.A. 48:2-60 and New Jersey Sales and Use Tax as set forth in Rider SUT.

BGS Reconciliation Charge:

	Charge
	(\$ per kWh)
Service taken at Secondary Voltage	\$ 0.018407
Service taken at Primary Voltage	\$ 0.017925
Service taken at Sub-Transmission Voltage	\$ 0.017722
Service taken at Transmission Voltage	\$ 0.017548

The above charge shall recover the difference between the monthly amount paid to Basic Generation Service (BGS) suppliers and the total revenue from customers for BGS for the preceding months for the applicable BGS supply. These charges include administrative charges pursuant to N.J.S.A. 48:2-60 and New Jersey Sales and Use Tax as set forth in Rider SUT and are changed on June 1 and October 1 of each year.

Date of Issue: August 31, 2022 Effective Date: October 1, 2022

Issued by: J. Tyler Anthony, President and Chief Executive Officer – Atlantic City Electric Company Filed pursuant to Board of Public Utilities of the State of New Jersey directives associated with the BPU Docket Nos. ER20030190 and ER21030631

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Fifty-Eight Revised Sheet Replaces Fifty-Seventh

Exhibit A

RIDER (BGS) continued Basic Generation Service (BGS)

CIEP Standby Fee

\$0.000160 per kWh

This charge recovers the costs associated with the winning BGS-CIEP bidders maintaining the availability of the hourly priced default electric supply service plus administrative charges pursuant to N.J.S.A. 48:2-60 and New Jersey Sales and Use Tax as set forth in Rider SUT. This charge is assessed on all kWhs delivered to all CIEP- eligible customers on Rate Schedules MGS Secondary, MGS-SEVC, MGS Primary, AGS Secondary, AGS Primary or TGS.

Transmission Enhancement Charge

MCC

This charge reflects Transmission Enhancement Charges ("TECs"), implemented to compensate transmission owners for the annual transmission revenue requirements for "Required Transmission Enhancements" (as defined in Schedule 12 of the PJM OATT) that are requested by PJM for reliability or economic purposes and approved by the Federal Energy Regulatory Commission (FERC). The TEC charge (in \$ per kWh by Rate Schedule), including administrative charges pursuant to N.J.S.A. 48:2-60 and New Jersey Sales and Use Tax as set forth in Rider SUT, is delineated in the following table.

Ra	te	CI	ass

		MGS Secondary						
	<u>RS</u>	And MGS- SEVC	MGS Primary	AGS Secondary	AGS Primary	<u>TGS</u>	SPL/ CSL	DDC
VEPCo	0.000367	0.000278	0.000256	0.000179	0.000156	0.000133	_	0.000114
TrAILCo	0.000275	0.000192	0.000131	0.000138	0.000113	0.000104	-	0.000082
PSE&G	0.003256	0.002478	0.002276	0.001591	0.001385	0.001184	-	0.001018
PATH	0.000010	0.000007	0.000006	0.000004	0.000004	0.000003	-	0.000003
PPL	0.000095	0.000066	0.000046	0.000048	0.000039	0.000036	-	0.000029
PECO	0.000216	0.000150	0.000103	0.000109	0.000088	0.000083	-	0.000065
Pepco	0.000022	0.000016	0.000011	0.000012	0.000010	0.000009	-	0.000006
MAIT	0.000042	0.000032	0.000029	0.000020	0.000018	0.000015	-	0.000013
JCP&L	0.000003	0.000002	0.000002	0.000001	0.000001	0.000001	-	0.000001
EL05-121	0.000019	0.000015	0.000013	0.000010	0.000009	0.000006	-	0.000006
Delmarva	0.000010	0.000006	0.000004	0.000004	0.000004	0.000003	-	0.000003
BG&E	0.000041	0.000028	0.000019	0.000020	0.000017	0.000015	-	0.000012
AEP-East	0.000081	0.000062	0.000057	0.000039	0.000034	0.000030	-	0.000026
Silver Run	0.000325	0.000247	0.000227	0.000159	0.000139	0.000118	-	0.000101
NIPSCO	0.000003	0.000002	0.000002	0.000002	0.000001	0.000001	-	0.000001
CW Edison	-	-	-	-	-	-	-	-
ER18-680 & Form 715	-	-	-	-	-	-	-	-
SFC Duquesne Total	0.000004 0.000002 0.004771	0.000003 0.000001 0.003585	0.000003 0.000001 0.003186	0.000002 0.000001 0.002339	0.000002 0.000001 0.002021	0.000002 0.000001 0.001744	- -	0.000001 0.000001 0.001482
Total	0.004771	0.003585	0.003186	0.002339	0.002021	0.001744	-	0.001482

Date of Issue: December 30, 2022

Effective Date: February 1, 2023

Issued by: Issued by: J. Tyler Anthony, President and Chief Executive Officer – Atlantic City Electric

Company

Filed pursuant to Board of Public Utilities of the State of New Jersey directives associated with the BPU Docket No. ER21121246

RIDER NEM Net Energy Metering

AVAILABILITY

This Rider is available to any customer served under the Company's Rate Schedules RS, MGS-Secondary, MGS-SEVC, MGS-Primary, AGS Secondary, AGS Primary, TGS Subtransmission, and TGS Transmission who owns and operates a customer-generator facility that:

- Uses a New Jersey defined Class I renewable resource, including solar technologies, photovoltaic technologies, wind energy, fuel cells powered by renewable fuels, geothermal technologies, wave or tidal action, and/or methane gas from landfills or a biomass facility, provided that the biomass is cultivated and harvested in a sustainable manner, as more specifically defined in Board of Public Utilities Regulations at N.J.A.C. 14:8; and
- 2. Is located on the customer's premises or contiguous property; and
- 3. Is interconnected and operated in parallel with the Company's transmission or distribution facilities; and
- 4. Is intended primarily to offset all or part of the customer's own electricity requirements; and
- 5. Is not a Qualifying Facility (QF) served under the Company's Rate Schedule SPP, Small Power Purchase.

CONNECTION TO THE COMPANY'S SYSTEM

Any customer who elects this Rider must submit a New Jersey Interconnection Application Form with the Company, at least 30 days prior to activating the customer-generator facility. The customer should not install a customer-generator facility without prior approval from the Company and the customer shall not operate a customer-generator facility without final written approval from the Company.

The customer-generator facility shall not be connected to the Company's system unless it meets all applicable safety and performance standards established by the National Electric Code, The Institute of Electrical and Electronics Engineers (IEEE), Underwriters Laboratories, and as currently detailed in the Company's Technical Interconnection Requirements, Technical Considerations Covering Parallel Operations of customer owned generation and interconnected with the Company's Power Delivery System in the State of New Jersey and the applicable codes of the local public authorities. Special attention should be given to IEEE Standard 929-2000 Recommended Practice for Utility Interface of Photovoltaic Systems. 1547-2018 (or latest amended revision) for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces. The customer must obtain, at the customer's sole expense, all necessary inspections and approvals required by the local public authorities before the customer-generator facility is connected to the Company's electric system.

INTERCONNECTION AND PARALLEL OPERATION

Interconnection with the Company's system requires the installation of protective equipment which provides safety for personnel, affords adequate protection against damage to the Company's system or to the customer's property, and prevents any interference with the Company's supply of service to other customers. Such protective equipment shall be installed, owned and maintained by the customer at the Customer's expense. Generation systems and equipment that comply with the standards established in the previous Section of this Rider shall be deemed by the Company to have generally complied with the requirements of this Section.

CESSATION OF PARALLEL OPERATION

The customer's equipment must be installed and configured so that parallel operation must cease immediately and automatically during system outages or loss of the Company's primary electric source. The customer must also cease parallel operation upon notification by the Company of a system emergency, abnormal condition, or in cases where such operation is determined to be unsafe, interferes with the supply of service to other customers, or interferes with the Company's system maintenance or operation.

DELIVERY VOLTAGE

The delivery voltage of the customer-generator facility shall be at the same voltage level and at the same delivery point as if the Customer were purchasing all of its electricity from the Company.

Date of Issue: February 26, 2021 Effective Date: March 1, 2021

Issued by: David M. Velazquez, President and Chief Executive Officer – Atlantic City Electric Company Filed pursuant to Board of Public Utilities of the State of New Jersey directives associated with the BPU Docket No. E018020190

RIDER NEM (Continued) Net Energy Metering

TERM OF CONTRACT

The contract term shall be same as that under the customer's applicable Rate Schedule.

MONTHLY RATES, RATE COMPONENTS AND BILLING UNIT PROVISIONS

The monthly rates, rate components and billing unit provisions shall be those as stated under the customer's applicable Rate Schedule. Under this Rider, only the per kilowatt-hour charge components of the customer's bill are affected. The monthly charges shall be based on one of the following conditions:

- a) When the monthly energy meter reading registers that the customer has consumed more energy than the customer delivered to the Company's delivery system by the end of the monthly billing period, the customer shall be charged for the net amount of electricity consumed based on the rates and charges under the customer's applicable Rate Schedule for either Delivery Service when the customer has a third party supplier as its electric supplier, or the combined Delivery, Transmission and Basic Generation Service when the customer has the Company as its electric supplier; or
- b) If the customer is receiving combined Delivery, Transmission and Basic Generation Service, and the monthly energy meter reading registers that the customer has delivered more energy to the Company's delivery system than the customer has consumed by the end of the monthly billing period, the customer shall be charged the Customer Charge and any appropriate demand charges based on the customer's applicable Rate Schedule. In addition, the Company shall receive and take ownership of the delivered energy from the customer and the Company shall credit the customer for that delivered energy. At the end of twelve consecutive monthly billing periods beginning with the first month in which net metering becomes applicable (annualized period), the customer will be compensated for any remaining credits at the average Residual Metered Load Aggregate locational marginal price for energy, for the annualized period, in the Pennsylvania, New Jersey and Maryland Interconnection (PJM) Control Area Transmission Zone for the Company. In the event that a customer leaves Basic Generation Service prior to the end of the annualized period, the end of the service period will be treated as if it were the end of the annualized period; or
- c) If the customer has a third party supplier and the monthly energy meter reading registers that the customer has delivered more energy to the Company's delivery system than the customer has consumed by the end of the monthly billing period, the customer shall be charged the Customer Charge and any appropriate demand charges based on the customer's applicable Rate Schedule. Monthly meter data will be forwarded to the customer's third party supplier in accordance with existing Electronic Data Interchange (EDI) Standards. In the event that a customer changes electric supplier prior to the end of the annualized period, the end of the service period will be treated as if it were the end of the annualized period.

The customer has one opportunity to select an annualized billing period in accordance with the provisions of N.J.A.C. 14:8-4.3.

RENEWABLE ENERGY CERTIFICATES

The Renewable Energy Certificates generated by the customer-generator facility are owned entirely by the customer or the eligible customer's assignee.

METERING

The watt-hour energy meter at the customer's location shall measure the net energy consumed by the customer or the net energy delivered by the customer-generator facility for the monthly billing period. The Company shall furnish, install, maintain and own all the metering equipment needed for measurement of the service supplied.

Date of Issue: March 27, 2019 Effective Date: April 1, 2019

Issued by: David M. Velazquez, President and Chief Executive Officer – Atlantic City Electric Company Filed pursuant to Board of Public Utilities of the State of New Jersey directives associated with the BPU Docket No. ER18080925

First Revised Sheet Replaces Original Sheet No. 63

Exhibit A Redlined

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RIDER NEM (Continued) Net Energy Metering

MODIFICATION OF THE COMPANY'S SYSTEM

If it is necessary for the Company to extend or modify portions of its systems to accommodate the delivery of electricity from the customer-generator facility, the Company at the customer's expense shall perform such extension or modification.

LIABILITY

The Company accepts no responsibility whatsoever for damage or injury to any person or property caused by failure of the customer to operate in compliance with Company's requirements. The Company shall not be liable for any loss, cost, damage or expense to any party resulting from the use or presence of electric current or potential which originates from the customer-generator facility. Connection by the Company under this Rider does not imply that the Company has inspected or certified that the customer-generator facility has complied with any necessary local codes or applicable safety or performance standards. All inspections, certifications and compliance with applicable local codes and safety requirements are the sole responsibility of the customer-generator.

FAILURE TO COMPLY

If the customer fails to comply with any of the requirements set forth in this Rider, the Company may disconnect the customer's service from the Company's electric system until the requirements are met, or the customer-generator facility is disconnected from the customer's electric system.

TERMS AND CONDITIONS

The Terms and Conditions set forth in this tariff shall govern the provision of service under this Rider.

Date of Issue: March 27, 2019 Effective Date: April 1, 2019

Issued by: David M. Velazquez, President and Chief Executive Officer – Atlantic City Electric Company Filed pursuant to Board of Public Utilities of the State of New Jersey directives associated with the BPU Docket No. ER18080925

First Revised Sheet Replaces Original Sheet No. 63a

Exhibit A Redlined

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RIDER ANEM Aggregated Net Energy Metering

AVAILABILITY

This Rider is available to any customer served under the Company's Rate Schedules RS, MGS-Secondary, MGS-SEVC, MGS-Primary, AGS Secondary, AGS Primary, TGS Sub-Transmission, and TGS Transmission who owns and operates a customer-generator facility that:

- 1) Is a solar electric power generation system; and
- 2) Is not an on-site generation system; and
- 3) Is located on the customer's premises; and
- 4) Is interconnected and operated in parallel with the Company's transmission or distribution facilities; and
- 5) Is intended primarily to offset all or part of the customer's own aggregated electricity requirements; and
- 6) Is not a Qualifying Facility (QF) served under the Company's Rate Schedule SPP, Small Power Purchase; and
- 7) The customer Is a State entity, school district, county, county agency, county authority, municipality, municipal agency, or municipal authority; and have multiple metered accounts including the host account that:
 - a) Must be located within the customer's territorial jurisdiction or, for a State entity, be located within 5 miles of one another: and
 - b) Are served by Basic Generation Service (BGS) under the same eligible rate schedule or be supplied by the same (third-party) energy supplier; and
 - c) None of the accounts to be aggregated have been included in a previous aggregation for another qualified customer facility; and
 - d) is not located on land that has been actively devoted to agricultural or horticultural use and that is valued, assessed, and taxed pursuant to the Farmland Assessment Act of 1964 at any time within the 10 years prior to July 23, 2012. (The municipal planning board of a municipality where the customer-generator facility is to be located may waive this requirement.)

The customer may aggregate the meters for the purpose of net metering regardless of which individual meter receives energy from a customer-generator facility provided that:

1) Before a customer can participate under this rider and activate the customer-generator facility, the customer shall file an application with the Company available at:

http://www.atlanticcityelectric.com/greenpowerconnection/ and include the following information:

- a) For the metered account behind which a customer-generator is net metered ("the host account"), a description of the customer-generator facility including its location, capacity, and description of its generating technology:
- b) A list of the individual metered accounts that the customer seeks to aggregate, identified by name, address, rate schedule, and account number;
- 2) The customer may provide written notice of a change to its list of aggregated metered accounts no more than once annually and should allow for up to 30 days for the change to go into effect; and
- 3) In order to continue under this rider, the customer must notify the Company of any change in ownership of the accounts by providing the Company 30 days written notice.

Customer-generators applying under this rider may be subject to FERC jurisdiction with respect to net sales of excess generation and interconnection requirements.

eligible customer participating aggregated net metering under this Rider can be charged by the Company for incremental costs providing this service.

Date of Issue: February 26, 2021 Effective Date: March 1, 2021

Issued by: David M. Velazquez, President and Chief Executive Officer - Atlantic City Electric Company Filed pursuant to Board of Public Utilities of the State of New Jersey directives associated with the BPU Docket No. EO18020190

Exhibit A Redlined Page 132 of 150 Original-Sheet No. 63b

Original Silect No. 03

RIDER ANEM (Continued) Aggregated Net Energy Metering

CONNECTION TO THE COMPANY'S SYSTEM

Any customer who elects this Rider must submit a New Jersey Interconnection Application Form with the Company, at least 30 days prior to activating the customer-generator facility. The customer should not install a customer-generator facility without prior approval from the Company and the customer shall not operate a customer-generator facility without final written approval from the Company.

The customer-generator facility shall not be connected to the Company's system unless it meets all applicable safety and performance standards established by the National Electric Code, The Institute of Electrical and Electronics Engineers (IEEE), Underwriters Laboratories, and as currently detailed in the Company's Technical Interconnection Requirements, Technical Considerations Covering Parallel Operations of Customer Owned Generation and Interconnected with the Company's Power Delivery System in the State of New Jersey and the applicable codes of the local public authorities. Special attention should be given to IEEE Standard 929-2000 Recommended Practice for Utility Interface of Photovoltaic Systems. 1547-2018 (or latest amended revision) for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces. The customer must obtain, at the customer's sole expense, all necessary inspections and approvals required by the local public authorities before the customer-generator facility is connected to the Company's electric system.

INTERCONNECTION AND PARALLEL OPERATION

Interconnection with the Company's system requires the installation of protective equipment which provides safety for personnel, affords adequate protection against damage to the Company's system or to the Customer's property, and prevents any interference with the Company's supply of service to other customers. Such protective equipment shall be installed, owned and maintained by the customer at the customer's sole expense. Generation systems and equipment that comply with the standards established in the previous Section of this Rider shall be deemed by the Company to have generally complied with the requirements of this Section.

CESSATION OF PARALLEL OPERATION

The customer's equipment must be installed and configured so that parallel operation must cease immediately and automatically during system outages or loss of the Company's primary electric source. The customer must also cease parallel operation upon notification by the Company of a system emergency, abnormal condition, or in cases where such operation is determined to be unsafe, interferes with the supply of service to other customers, or interferes with the Company's system maintenance or operation.

DELIVERY VOLTAGE

The delivery voltage of the customer-generator facility shall be at the same voltage level and at the same delivery point as if the customer were purchasing all of its electricity from the Company.

TERM OF CONTRACT

The contract term shall be same as that under the customer's applicable Rate Schedule.

MONTHLY RATES, RATE COMPONENTS AND BILLING UNIT PROVISIONS

The monthly rates, rate components and billing unit provisions shall be those as stated under the customer's applicable Rate Schedule. Under this Rider, only the per kilowatt-hour charge components of the customer's bill for the host account are affected. The monthly charges shall be based on one of the following conditions:

a) When the monthly energy meter reading registers on the host account that the customer has consumed more energy than the customer delivered to the Company's delivery system by the end of the monthly billing period, the customer shall be charged for the net amount of electricity consumed based on the rates and charges under the customer's applicable Rate Schedule for either Delivery Service when the customer has a third party supplier as its electric supplier, or the combined Delivery, Transmission and Basic Generation Service when the customer has the Company as its electric supplier; or

Date of Issue: March 27, 2019
Issued by: David M. Velazquez, President and Chief Executive Officer — Atlantic City Electric Company
Filed pursuant to Board of Public Utilities of the State of New Jersey directives associated with the
BPU Docket No. ER18080925

Exhibit A Redlined Page 133 of 150 Original No. 63c

RIDER ANEM (Continued) Aggregated Net Energy Metering

- b) If the customer is receiving combined Delivery, Transmission and Basic Generation Service, and the monthly energy meter reading on the host account registers that the customer has delivered more energy to the Company's delivery system than the customer has consumed by the end of the monthly billing period, the customer shall be charged the Customer Charge and any appropriate demand charges based on the customer's applicable Rate Schedule. In addition, the Company shall receive and take ownership of the delivered energy from the customer and the Company shall credit the customer for that delivered energy on the next monthly billing period. At the end of twelve consecutive monthly billing periods beginning with the first month in which net metering becomes applicable (annualized period), the customer will be compensated for any remaining credits at the average locational marginal price for energy, for the annualized period, in the Pennsylvania, New Jersey and Maryland Interconnection (PJM) Control Area Transmission Zone for the Company. In the event that a customer leaves Basic Generation Service prior to the end of the annualized period, the end of the service period will be treated as if it were the end of the annualized period; or
- c) If the customer has a third party supplier and the monthly energy meter reading on the host account registers that the customer has delivered more energy to the Company's delivery system than the customer has consumed by the end of the monthly billing period, the customer shall be charged the Customer Charge and any appropriate demand charges based on the customer's applicable Rate Schedule. Monthly meter data will be forwarded to the customer's third party supplier in accordance with existing Electronic Data Interchange (EDI) Standards. In the event that a customer changes electric supplier prior to the end of the annualized period, the end of the service period will be treated as if it were the end of the annualized period.

The customer has one opportunity to select an annualized billing period in accordance with the provisions of N.J.A.C. 14:8-4.3.

RENEWABLE ENERGY CREDITS

The Renewable Energy Credits generated by the customer-generator facility are owned entirely by the customer or the eligible customer's assignee.

METERING

The watt-hour energy meter at the customer's location shall measure the net energy consumed by the customer or the net energy delivered by the customer-generator facility for the monthly billing period. The Company shall furnish, install, maintain and own all the metering equipment needed for measurement of the service supplied.

MODIFICATION OF THE COMPANY'S SYSTEM

If it is necessary for the Company to extend or modify portions of its systems to accommodate the delivery of electricity from the customer-generator facility, the Company, at the customer's sole expense, shall perform such extension or modification.

LIABILITY

The Company accepts no responsibility whatsoever for damage or injury to any person or property caused by failure of the customer to operate in compliance with Company's requirements. The Company shall not be liable for any loss, cost, damage or expense to any party resulting from the use or presence of electric current or potential which originates from the customer-generator facility. Connection by the Company under this Rider does not imply that the Company has inspected or certified that the customer-generator facility has complied with any necessary local codes or applicable safety or performance standards. All inspections, certifications and compliance with applicable local codes and safety requirements are the sole responsibility of the customer-generator.

Date of Issue: March 27, 2019 Effective Date: April 1, 2019

Issued by: David M. Velazquez, President and Chief Executive Officer – Atlantic City Electric Company Filed pursuant to Board of Public Utilities of the State of New Jersey directives associated with the BPU Docket No. ER18080925

ATLANTIC CITY ELECTRIC COMPANY
BPU NJ No. 11 Electric Service - Section IV

Exhibit A Redlined Page 134 of 150 Original Sheet No. 63d

RIDER ANEM (Continued) Aggregated Net Energy Metering

FAILURE TO COMPLY

If the customer fails to comply with any of the requirements set forth in this Rider, the Company may disconnect the customer's service from the Company's electric system until the requirements are met, or the customer-generator facility is disconnected from the customer's electric system.

TERMS AND CONDITIONS

The Terms and Conditions set forth in this tariff shall govern the provision of service under this Rider.

Date of Issue: March 27, 2019 Effective Date: April 1, 2019

Issued by: David M. Velazquez, President and Chief Executive Officer – Atlantic City Electric Company Filed pursuant to Board of Public Utilities of the State of New Jersey directives associated with the BPU Docket No. ER18080925

ATLANTIC CITY ELECTRIC COMPANY

BPU NJ No. 11 Electric Service - Section IV Twenty-Sixth Revised Sheet Replaces Twenty-Fifth Revised Sheet No. 64

RIDER RGGI

Regional Greenhouse Gas Initiative Recovery Charge

A. Applicability

This Rider is applicable to Rate Schedules RS, MGS Secondary, MGS-SEVC, MGS Primary, AGS Secondary, AGS Primary, TGS, DDC, SPL and CSL. Amounts billed to customers shall include a charge to reflect regional greenhouse gas initiative program costs. Except where indicated otherwise, Rider "RGGI" will be determined annually based on projections of program costs (including an adjustment for variances between budgeted and actual prior year expenditures) and forecasts of kilowatt hour sales. The charge (in dollars per kilowatt hour) will be computed by dividing the total annual amount to be recovered for by forecasted retail sales (in kilowatt hours).

RGGI Programs

Solar Renewable Energy Certificate (SREC) (\$/kWh)

\$0.000189

This charge component is intended to recover net costs associated with the Solar Renewable Energy Certificate Program.

Solar Renewable Energy Certificate (SREC II) (\$/kWh)

\$0.000000

This charge component is intended to recover net costs associated with the Solar Renewable Energy Certificate II Program.

Transition Renewable Energy Certificate (TREC) (\$/kWh)

\$0.000988

This charge component is intended to recover net costs associated with the Solar Transition Incentive Program.

Energy Efficiency Surcharge (EE) (\$/kWh)

\$0,000840

This charge component is intended to recover the costs associated with the Energy Efficiency Program.

Successor Solar Incentive Program (SuSI) (\$/kWh)

\$0.000379

This charge component is intended to recover the costs associated with the Successor Solar Incentive Program.

Community Solar Energy Program (CSEP) (\$/kWh)

\$0.000000

This charge component is intended to recover the net costs associated with the Community Solar Energy Program.

Total Rider RGGI Surcharge (\$/kWh)

\$0.002396

Date of Issue: August 26, 2022 Effective Date: September 1, 2022

Issued by: J. Tyler Anthony, President and Chief Executive Officer – Atlantic City Electric Company Filed pursuant to Board of Public Utilities of the State of New Jersey directives associated with the BPU Docket Nos. ER22020114 and ER21060871

Exhibit A
Redlined
ATLANTIC CITY ELECTRIC COMPANY
Page 136 of 150
BPU NJ No. 11 Electric Service - Section IV
Fourth Revised Sheet Replaces Third Revised Sheet No. 65

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Date of Issue: March 27, 2019 Effective Date: April 1, 2019

Issued by: David M. Velazquez, President and Chief Executive Officer – Atlantic City Electric Company Filed pursuant to Board of Public Utilities of the State of New Jersey directives associated with the BPU Docket No. ER18080925

RIDER EDIT

Excess Deferred Income Tax Credit

AVAILABILITY

This rider is applicable to Rate Schedules RS, MGS Secondary, MGS Primary, AGS Secondary, AGS Primary, TGS, DDC, SPL and CSL.

Rider "EDIT" is to ensure the full amount of the Tax Cut and Jobs Act (TCJA) tax benefits associated with the non-protected assets are returned to customers over a five (5) year period.

The charge for each Rate Schedule is as follows:

Rate Class	EDIT (Credit (w/ SUT)	
RS	\$	(0.004884)	\$ per kWh
MGS Secondary	\$	(0.000000)	\$ per kWh
MGS Primary	\$	(0.000000)	\$ per kWh
AGS Secondary	\$	(0.002785)	\$ per kWh
AGS Primary	\$	(0.001621)	\$ per kWh
TGS Subtransmission	\$	(0.000605)	\$ per kWh
TGS Transmission	\$	(0.000630)	\$ per kWh
SPL/CSL	\$	(0.019798)	\$ per kWh
DDC	\$	(0.000000)	\$ per kWh

Date of Issue: September 26, 2022 Effective Date: December 1, 2022

Issued by: J. Tyler Anthony, President and Chief Executive Officer – Atlantic City Electric Company Filed pursuant to Board of Public Utilities of the State of New Jersey directives associated with the BPU Docket No. ER20120746

ZERO EMISSION CERTIFICATE ("ZEC") RECOVERY CHARGE

APPLICABILITY: The Zero Emission Certificate Recovery Charge ("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.

Rate Component (\$ per kWh)

	Excluding SUT	Including SUT
ZEC Charge	\$0.004000	\$0.004265
ZEC Reconciliation Charge	\$0.000000	\$0.000000
Total ZEC Charge	\$0.004000	\$0.004265

Pursuant to the BPU's Zero Emission Certificate Charge Order dated November 19, 2018 in BPU Docket No. EO18091003, 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 <u>L.</u> 2018, <u>c.</u> 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, interest-bearing account 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.

The ZEC Charge will become effective upon the issuance of the April 2019 Board Order in BPU Docket No. EO18080899.

Date of Issue: January 30, 2023 Effective Date: February 1, 2023

RIDER IIP Infrastructure Investment Program

APPLICABILITY:

This rider is applicable to Rate Schedules RS, MGS Secondary, MGS Primary, AGS Secondary, AGS Primary, TGS, DDC, SPL and CSL, and Rider STB.

This charge provides for the full and timely recovery of revenue requirements associated with the Infrastructure Investment Program ("IIP") projects subject to the IIP recovery rules, codified at N.J.A.C. 14:3-2A.1 et seq., as approved by the New Jersey Board of Public Utilities.

The following table provides the rates for the IIP, including ("SUT"). For billing presentation purposes these rates are to be added to the base distribution rates for each Rate Schedule. This applies to the distribution charges for the Rate Schedules on the following Tariff Sheets: 5, 11, 14, 17, 19, 29, 29a, 31, 36, 37,37a, 40, and 44. These rates are subject to all other applicable charges and taxes in accordance with the underlying rate schedule's distribution rates.

RATE SCHEDULE	IIP <u>Rate</u>	Billing Units
RS	\$ 0.001282	Per kWh
MGS Secondary	\$ 0.04 \$ 0.001095	Per kW Per kWh
MGS Primary	\$ 0.03 \$ 0.000758	Per kW Per kWh
AGS Secondary	\$ 0.24	Per kW
AGS Primary	\$ 0.17	Per kW
TGS Sub Transmission	\$ 0.06	Per kW
TGS Transmission	\$ 0.04	Per kW
SPL/CSL	\$ 0.27 Per la	mp per month
DDC Service and Demand (per day per connection) Energy (per day for each kW of effective load)	\$ 0.002775 \$ 0.013367	
RIDER STB MGS Secondary MGS Primary AGS Secondary AGS Primary TGS – Sub Transmission TGS – Transmission	\$ 0.00 \$ 0.00 \$ 0.02 \$ 0.02 \$ 0.00	Per kW Per kW Per kW Per kW Per kW

Date of Issue: March 31, 2022 Effective Date: April 1, 2022

Issued by: J. Tyler Anthony, President and Chief Executive Officer – Atlantic City Electric Company Filed pursuant to Board of Public Utilities of the State of New Jersey directives associated with the BPU Docket No. ER21111206

RIDER CIP CONSERVATION INCENTIVE PROGRAM RECOVERY CHARGE

APPLICABILITY:

This rider is applicable to Rate Schedules RS, MGS Secondary, MGS Primary, AGS Secondary, AGS Primary, and TGS and TGS Sub Transmission. The Company's CIP shall be based on the differences between actual and allowedrevenue per customer during the preceding annual period. This adjustment will be effectuated through a credit or surcharge applied to customers' bills during the adjustment period. The credit or surcharge will also be adjusted to reflect prior year under or over recoveries pursuant to Rider "CIP". The Company at its discretion will make annual filings.

The Company's CIP Recovery Charge including sales and use tax to be effective on and after the date indicated below is as follows:

Rate Schedule	Rate	
Residential	\$(0.000354)	per kWh
MGS Secondary	\$(0.008526)	per kWh
MGS Primary	\$(0.032302)	per kWh
AGS Secondary	\$0.04	per kW
AGS Primary	\$(0.13)	per kW
TGS Sub Transmission	\$(0.17)	per kW
TGS Transmission	\$0.05	per kW

I. DEFINITION OF TERMS AS USED HEREIN:

1. Actual Number of Customers

- The Actual Number of Customers ("ANC") shall be determined on a monthly basis for each Rate Schedule, to which the CIP applies. The ANC shall equal the aggregate actual monthly customer charge revenue for each classof customers subject to the CIP as recorded on the Company's books, divided by the customer charge rate applicable to such class of customers in each Rate Schedule.

2. Actual Revenue Per Customer

The Actual Revenue per Customer ("ARC") shall be determined in dollars per customer on a monthly basis for each Rate Schedule, to which the CIP applies. The ARC shall equal the aggregate actual booked variable margin revenue per applicable rate schedule for the month as recorded on the Company's books divided by the Actual Number of Customers for the corresponding month. Actual revenues shall include Distribution Kilowatt-hour and Distribution Kilowatt demand charges, as well as any PowerAhead and Infrastructure Investment Program revenues, and shall not include the customer charge and any non-base rate charges such as the Societal Benefits, Non-Utility Generation, Regional Greenhouse Gas Initiative Recovery ("RGGI"), Securitization, or the Zero EmissionCertificate ("ZEC") Charges.

3. Adjustment Period

- Shall be the year beginning immediately following the conclusion of the Annual Period.

4. Annual Period

 Shall be the twelve consecutive months from July 1st of one calendar year through June 30th of the followingcalendar year.

5. Average 13 Month Common Equity Balance

Shall be the average of the beginning and ending common equity balances based on the latest publicly available financials available before the end of the Annual Period. The Company shall provide the most recently available actual months plus forecasted data at the time of each Initial Filing. The forecasted data will be updated with actuals once the financial statements for the months have been disclosed.

Date of Issue: December 19, 2022
Issued by: J. Tyler Anthony, President and Chief Executive Officer – Atlantic City Electric Company Filed pursuant to Board of Public Utilities of the State of New Jersey directives associated with the BPU Docket No. ER22070463

Revised Sheet	Replaces	Third Revised
	Revised Sheet	Revised Sheet Replaces

RIDER CIP (continued) CONSERVATION INCENTIVE PROGRAM RECOVERY CHARGE

6. Baseline Revenue per Customer

The Baseline Revenue per Customer shall be stated in dollars per customer on a monthly basis for each of the Rate Schedules, to which the CIP applies. The Baseline Revenue per Customer shall be calculated as the current variable margin revenue per rate schedule, including any revenue from PowerAhead and Infrastructure Investment Program rate adjustments, divided by the number of customers from the most recent approved base rate case for the rate schedule.

Baseline revenues shall include Distribution Kilowatt-hour and Distribution Kilowatt charges and shall not include the customer charge and any non-base rate charges such as the Societal Benefits, Non-Utility Generation Charge, RGGI, Securitization, or the ZEC Charges.

The table below summaries the Board approved monthly Baseline Revenue per customer:

	<u>RS</u>	MGSS	MGSP	<u>AGSS</u>	<u>AGSP</u>	<u>TGSS</u>	<u>TGS</u>
Jan	\$	\$	\$	\$		\$	\$
	46.56 57.	127. 67 1	1, 321.70 468	1,693.56 2,	\$10, 202.91 08	7,067.00 8,48	6,053.22 4,32
	52	8	.61	020.52	9.63	3.11	2.24
Feb	\$	\$	\$	\$	\$	\$	- \$
	37.60 51.	108.77 1	885.59 1,4	1, 491.22 9	7,154.149,3	7,162.546,83	6, 182.00 888.5
	71	24.25	51.55	10.07	78.29	3.58	6
Mar	\$	\$	\$	\$	\$	\$	\$
	34.20 45.	105.79 1	1, 515.35 4	1, 458.77 <u>8</u>	8,534.63 9,8	6, 674.35 935.	6,790.34 <u>5,87</u>
	<u>05</u>	21.00	<u>53.05</u>	62.34	<u>63.95</u>	<u>47</u>	2.60
Apr	\$	\$	\$	\$	\$	\$	\$ 5,436.86 <u>\$</u>
-	33.27 39.	97.21 122.	1, 395.76 4	1, 688.45 9	9,241.27 <u>10,</u>	7,236.19 9,92	3,260.78
	<u>13</u>	<u>78</u>	<u>10.43</u>	<u>11.53</u>	<u>266.06</u>	<u>9.68</u>	
May	\$	\$	\$	\$	\$	\$	\$ 4,867.35 <u>\$</u>
	28.88 <u>32.</u>	82.30 12	893.95 1,3	1,4 <u>40.98</u> 8	7,845.17 9,7	6,347.33 9,89	<u>3,649.66</u>
	<u>33</u>	<u>0.94</u>	<u>64.69</u>	<u>53.69</u>	<u>15.06</u>	<u>6.55</u>	
June	\$	\$	\$	\$	\$	\$	\$ 5,263.43 \$
	4 0.60 54.	105.37 1	512.13 1,6	1, 374.18 <u>8</u>	7,384.28 <u>10,</u>		<u>4,373.90</u>
	<u>27</u>	<u>60.24</u>	<u>71.81</u>	<u>56.93</u>	<u>711.67</u>	<u>81.30</u>	
July	\$	\$	\$	\$	\$	\$	\$ 3,282.03 \$
	76.19 86.	160.92 1	1, 483.91 <u>3</u>	1, 810.38 9	9,968.55 <u>10,</u>		<u>7,608.31</u>
	<u>42</u>	<u>93.80</u>	<u>88.05</u>	<u>60.94</u>	080.24	<u>3.50</u>	
Aug	\$	\$	\$	\$	\$ 10,101.50	\$	-\$
	85.64 <u>97.</u>	175.07 2	1, 637.30 9	1, 616.51 9	<u>11,297.01</u>	7,447.82 <u>8,10</u>	6, 705.79 246.
	<u>51</u>	<u>08.58</u>	<u>69.53</u>	<u>69.28</u>		<u>6.62</u>	<u>29</u>
Sept	\$	\$	\$	\$	\$	\$	\$ 6,212.86 \$
	68.96 <u>86.</u>	163.13 2	1, 350.12 9	1, 664.97 9	8 ,994.03 <u>11,</u>	8, 399.49 <u>993.</u>	<u>5,400.11</u>
	<u>43</u>	<u>05.86</u>	80.04	<u>56.72</u>	441.59	<u>31</u>	
Oct	\$	\$	\$	\$	\$	\$	\$5,197.65 <u>\$</u>
	38.18 <u>45.</u>	124.82 1	962.18 1,6	1, 323.06 <u>8</u>	7,217.56 <u>10,</u>		11,075.30
	<u>65</u>	38.64	14.70	86.04	988.78	9.40	
Nov	\$	\$	\$	\$	\$	\$	-\$
	30.77 <u>34.</u>	102.39 1	1, 816.55 <u>5</u>	1, 612.46 <u>7</u>	8,203.84 <u>9,7</u>		6, 269.77 829.
_	<u>29</u>	<u>18.43</u>	<u>76.18</u>	<u>61.76</u>	<u>14.65</u>	4.54	<u>31</u>
Dec	\$ 20 7E 4 4	\$ 106.02 1	\$	\$ 1.400.370	0 100 9410	\$	-\$ 5, 746.35
	38.75 44. 61	27.89	1, 256.10 1	1,492.37 <u>2,</u> 003.63	9,190.84 <u>12,</u> 716.64	0, . 0 0 0 <u>0, . 0</u>	<u>156.31</u>
	01	21.03	<u>00.41</u>	003.03	110.04	<u>8.92</u>	

7. Forecast Annual Usage

The Forecast Annual Usage shall be the projected total annual Kilowatt-hour sales or Kilowatt demand for all customers within the applicable Rate Schedules. The Forecasted Annual Usage shall be estimated based on normal weather.

8. Cooling and Heating Degree Days ("CDD" & "HDD")

- CDD are the difference between 65°F and the mean daily temperature. The mean daily temperature is the simple average of the 24-hourly temperature observations for a day. HDD are used to measure the difference between 35°F and the mean daily temperature during winter weather.

9. Actual Calendar Month CDD and HDD

- The accumulation of the actual CDD and HDD for each day of a calendar month.

10. Normal Calendar Month CDD and HDD

- The level of calendar month CDD and HDD, to which the weather portion of this CIP applies. The normal calendar month CDD and HDD will be based on the twenty-year average of the National Oceanic and Atmospheric Administration (NOAA) First Order Weather Observation Station hourly observations at the Atlantic City Airport and will be updated annually. The base level of normal CDD and HDD for the defined winter and summer period months for the 2021 Periods are set forth in the table below:

Date of Issue: December 19, 2022 Effective Date: January 1, 2023

Issued by: _J. Tyler Anthony, President and Chief Executive Officer – Atlantic City Electric Company Filed pursuant to Board of Public Utilities of the State of New Jersey directives associated with the BPU Docket No. ER22070463

RIDER CIP (continued) CONSERVATION INCENTIVE PROGRAM RECOVERY CHARGE

	Normal	Normal
Month	Heating	Cooling
	Degree Days	Degree Days
January	877	0
February	929	0
March	742	0
April	541	0
May	256	35
June	0	138
July	0	306
August	0	369
September	0	248
October	123	83
November	396	0
December	662	0

11. Winter Period

- Shall be the eight consecutive calendar months from October of one calendar year through May of the following calendar year.

12. Summer Period

- Shall be the three consecutive calendar months from July through September of the calendar year and starting June of the following calendar year.

II. DETERMINATION OF THE CONSERVATION INCENTIVE PROGRAM

- 1. At the end of the Annual Period, a calculation shall be made that determines for each Rate Schedule the deficiency or excess to be surcharged or credited to customers pursuant to the CIP mechanism. The deficiency or excess shall be calculated each month by multiplying the result obtained from subtracting the Baseline Revenue per Customer from the Actual Revenue per Customer by the Actual Number of Customers, and then multiplying the resulting usage by the Margin Revenue Factor.
- 2. The weather-related change in customer usage shall be calculated as the difference between actual CDD and HDD and the above CDD and HDD multiplied by the weather normalization factors and multiplying the result by the margin revenue factors of this Rate Schedule to determine the weather-related deficiency or excess. The weather-related amount will be subtracted from the total deficiency or excess to determine the non-weather-related deficiency or excess.
- 3. Recovery of margin deficiency associated with non-weather-related changes in customer usage will be subject to a Basic General Service ("BGS") savings test and a Variable Margin Revenue recovery limitation ("recovery tests"). Recovery of non-weather-related margin deficiency will be limited to the smaller of (1) the level of BGS savings achieved when such savings are less than 75 percent of the non-weather-related margin deficiency, i.e. BGS savings test, and (2) 6.5 percent of variable margins for the CIP Annual Period, i.e., Variable Margin Revenue recovery limitation. Any amount that exceeds the above limitations may be deferred for future recovery and is subject to either or both recovery tests in a future year consistent with the amount by which either or both non-weather-related margin deficiency exceeded the recovery tests. For the purposes of this calculation, the value of the weather-related portion shall be calculated as set forth in Section II.2 of this Rate Schedule.

Date of Issue: December 19, 2022 Effective Date: January 1, 2023

RIDER CIP (continued) CONSERVATION INCENTIVE PROGRAM RECOVERY CHARGE

- 4. In addition, if the calculated Return on Equity ("ROE") exceeds the allowed ROE from the utility's last base rate case by 50 basis points or more, recovery of lost revenues through the CIP shall not be allowed for the applicable filing period. For purposes of this section, the Company's rate of return on common equity shall be calculated by dividing the Company's net income for the applicable period as defined in the Average 13-Month Common Equity Balance by the Company's average common equity balance for the same period. The Company's Average 13-Month Common EquityBalance shall be the ratio of Electric Distribution Net Plant (including the Electric Distribution allocation of Common Plant) to the total Company Net Plant for the Average 13 Month Common Equity Balance period multiplied by the Company's total common equity for the same period.
- 5. The amount to be surcharged or credited shall equal the eligible aggregate deficiency or excess for all months during the Annual Period determined in accordance with the provisions herein, divided by the Forecast Annual Usage for the Rate Schedule.

III. TRACKING THE OPERATION OF THE CONSERVATION INCENTIVE PROGRAM

The revenues billed, or credits applied, net of taxes and assessments, through the application of the Conservation Incentive Program Rate shall be accumulated for each month of the Adjustment Period and applied against the CIP excess or deficiency from the Annual Period and any cumulative balancesremaining from prior periods.

NEW JERSEY SALES AND USE TAX (SUT)

Charges under this Rider include a component for New Jersey Sales and Use Tax as set forth in Rider SUT.

CORPORATE BUSINESS TAX (CBT)

Charges under this rate schedule include a component for Corporate Business Taxes as set forth in Rider CBT.

Date of Issue: December 19, 2022 Effective Date: January 1, 2023

Exhibit A Redlined Page 145 of 150 Original Sheet No. 70

RIDER RNEM Remote Net Energy Metering

Limitations and Qualifications for Remote Net Metering (BPU Docket No. QO18070697, Orders dated September 17, 2018 and August 18, 2021)

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. On September 17, 2018, the Board established the application and approval process and defined public entity for Remote Net Metering, in Docket No. QO18070697; this process was further clarified by Order dated August 18, 2021.

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, county community college, 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 in the Atlantic City Electric Co. ("ACE" or the "Company") service territory. The entities designated to receive credits are considered to be receiving customers. Receiving customers must be public entities also located in the ACE service territory. Both the host customer and the receiving customer must be a customer of record of ACE. Receiving customers must maintain positive bill payment practices on their ACE account to remain eligible for credits. There may be no more than 10 receiving customer accounts per host customer. Host customer and receiving customers must be served by Basic Generation Service ("BGS") or be supplied by the same (third-party) energy supplier. None of the accounts can be included in a previous aggregation for another qualified customer facility or be a NEM customer.

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 ACE and the BPU, 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 business 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 Board with a recommendation for approval or denial. The Company, contingent on the cooperation of the Public Entity Applicant(s), will continue to perform any additional technical processing of the eligible public entities' interconnection application, subject to the Board's final approval or denial. ACE is not responsible for resolving disputes which may arise between host customer and receiving customers.

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 applicable host customer's electric account(s) 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 must 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 the number of accounts, if more than one account is used, and 1,200 annual kWh per kilowatt ("kWdc") to arrive at the maximum capacity for the solar electric generation facility in kWs ("kWdc" and "kWac").

Date of Issue: July 29, 2022
Issued by: J. Tyler Anthony, President and Chief Executive Officer – Atlantic City Electric Company
Filed pursuant to Board of Public Utilities of the State of New Jersey directives associated with the
BPU Docket No. ET21101152

Original Sheet No. 70a

RIDER RNEM (Continued) Remote Net Energy Metering

Billing and Credits for Remote Net Metering: No more than 10 receiving accounts may be party to a Public Entity Certification Agreement and no less than 10% of the solar electric generating facility output may be allocated to a receiving customer account and intended primarily to offset all or part of the receiving customer's own electricity requirements except to the extent that 10% of the solar electric generating facility output is greater. Receiving customers must maintain positive payment practices on their ACE accounts to remain eligible to receive credits. 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'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 that is specified, owned, and installed by the Company. This revenue grade production meter will 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 approved 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, 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 approved 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 host customers and receiving customers. 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.

Date of Issue: July 29, 2022 Effective Date: August 1, 2022

Issued by:

RIDER CSEP Community Solar Energy Pilot Program

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 9.6 MW based upon the Company's 12.8% 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 5 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.

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.

Date of Issue: August 26, 2022 Effective Date: September 1, 2022

Issued by:

J. Tyler Anthony, President and Chief Executive Officer – Atlantic City Electric Company
Filed pursuant to Board of Public Utilities of the State of New Jersey directives associated with the
BPU Docket No. ER21060871

Original Sheet No. 71a

RIDER CSEP (Continued) Community Solar Energy Pilot Program

Interconnection Application & Requirements

Community solar pilot projects shall comply with all current and future applicable interconnection requirements, as set forth in N.J.A.C. 14:8-9.9(a) and N.J.A.C. 14:8-5 and shall be processed by the Company following normal interconnection procedures.

Although projects are not required to have submitted an interconnection agreement or have an executed interconnection agreement prior to applying to the Pilot Program with the BPU, projects may file an interconnection application with the Company prior to being selected by the BPU at their own risk and cost. Additionally, only projects that have been approved by the BPU to participate in the Pilot Program are eligible to allocate community solar bill credits.

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.

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Original Sheet No. 71b

RIDER CSEP (Continued) Community Solar Energy Pilot Program

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-bypassable 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, the TBC charge, the MTC-Tax charge and the ZEC charge. The value of the bill credit shall be set at the retail rate for their respective service classification. The BGS bill credit for CIEP eligible customers will be set at the average prior calendar year hourly Locational Marginal Price (LMP) of energy in the ACE PJM zone. 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 section on the subscribers' utility bills.

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 prior calendar year hourly Locational Marginal Price (LMP) of energy in the ACE PJM 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 prior calendar year hourly Locational Marginal Price (LMP) of energy in the ACE PJM 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.

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Original Sheet No. 71c

RIDER CSEP (Continued) Community Solar Energy Pilot Program

Subscription Enrollments & Management

The subscriber organization must provide subscriber information for a project to the Company using the Company's online portal for subscription management, known as the Community Solar Portal ("CSP"). The CSP and informational material can be accessed at

https://www.atlanticcityelectric.com/SmartEnergy/MyGreenPowerConnection/Pages/CommunitySolarResources.as px.

Subscriber organizations shall indicate in CSP the subscribers that qualify as LMI in accordance with N.J.S.A. 14:8-9.8, and by doing so the subscriber organization confirms that all LMI information entered in CSP has been verified as accurate. Additionally, the subscriber organization shall have obtained authorization from each subscriber for the utility to release that subscriber's account information to the subscriber organization as necessary. Once a project is operational, subscriber organizations shall update their subscriber information for each community solar facility every month unless there is no change from the previous month. Updates to subscriber information must be submitted electronically through CSP. Depending on timing of notification from the subscriber organization of the subscriber's subscription amount, it may take up to two billing cycles before a bill credit is applied to the subscriber's bill. Updates received by the Company on or before the 10th of each month will be effective the following month. Subscriptions may not take effect retroactively.

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Issued by:

J. Tyler Anthony, President and Chief Executive Officer – Atlantic City Electric Company
Filed pursuant to Board of Public Utilities of the State of New Jersey directives associated with the
BPU Docket No. ER21060871

Exhibit B

Proposed Public Notice

NOTICE OF ATLANTIC CITY ELECTRIC COMPANY'S PUBLIC HEARINGS AND OPPORTUNITY FOR PUBLIC COMMENTS

In the Matter of the Petition of Atlantic City Electric Company for Approval of Amendments to its Tariff to Provide for an Increase in Rates and Charges for Electric Service Pursuant to N.J.S.A. 48:2-21 and N.J.S.A. 48:2-21.1, and for Other Appropriate Relief (2/2023)

BPU Docket No.	
OAL Docket No.	

PLEASE TAKE NOTICE that, on February 15, 2023, Atlantic City Electric Company ("ACE" or "Company"), filed a petition with the New Jersey Board of Public Utilities ("Board" or "BPU") seeking approval of, among other things, (i) proposed changes to certain elements of the Company's tariff, (ii) recovery and/or regulatory asset treatment of certain costs related to the deployment of the Company's Smart Energy Network ("SEN") advanced metering initiative and electric vehicle charging infrastructure program known as EVsmart, (iii) a final prudency review of the execution of the PowerAhead program, and (iv) a refund to customers of a gross receipts tax reserve liability via one-time credit ("Petition"). If approved, the request would increase the net annual revenues of the Company by \$111.7 million, including Sales and Use Tax. The Company is requesting the rate increase due to increases in operating expenses and investments in plant and equipment made since the Company's last base rate case. In order to maintain and enhance the reliability of service to all ACE customers and improve the resiliency of the distribution system in severe weather events, the Company has continued to invest in its distribution system. The costs of these investments, along with other cost increases incurred since ACE's last base rate case, are not reflected in the Company's current distribution rates. The proposed filing requests recognition and recovery of these costs in distribution rates.

The Company requested that the rates shown below become effective for service rendered on and after November 17, 2023 [that is, following the anticipated expiration of two (2) statutory, BPU-adopted suspension periods]. If this filing is not resolved within the nine (9) month time period set forth under applicable law, ACE, consistent with N.J.A.C. 14:1-5.12, intends to implement the rate changes set out in the Petition on an interim basis, subject to refund with interest once the case is finally resolved by the Board.

If the Board approves the request, as proposed, the estimated total monthly bill for a typical residential customer, using approximately 669 kWh per month, will increase by \$12.22 or approximately 8.8%. The exact amount that your bill will increase depends upon the amount of electricity you use. A chart is included with this notice to help residential customers assess the impact of the new rates on their monthly bills based on February 1, 2023 rates.

The Company has filed the following changes to its existing rates with the BPU, inclusive of Sales and Use Tax. Any final rate adjustments found by the Board to be just and reasonable may be modified and/or allocated by the Board in accordance with the provisions of N.J.S.A. 48:3-4, and for other good and legally sufficient reasons, to any class or classes of customers of the Company. Therefore, the above-described changes may increase or decrease based upon the Board's decision.

	Residential Service (RS)	
Customer Charge:	\$7.60	
Distribution Charges (\$/kWh):		
0 – 750 Summer	\$0.090162	
0 – 500 Winter	\$0.082054	
Over 750 Summer	\$0.105853	
Over 500 Winter	\$0.082054	

Residential customers can compare their monthly usage with the chart below to see how these rate changes, as proposed based on February 1, 2023 rates, will affect their bills:

Charges Under		
Previous Rates		
Monthly kWh Use	Winter	Summer
100	\$26.02	\$26.16
300	\$65.56	\$65.97
500	\$105.10	\$105.78
669	\$138.52	\$139.41
750	\$154.53	\$155.53
1000	\$203.96	\$210.97
1500	\$302.81	\$321.84
2000	\$401.67	\$432.72
3000	\$599.36	\$654.46
Charges Under		
Proposed Rates		
Monthly kWh Use	Winter	Summer
100	\$28.95	\$29.24
300	\$71.63	\$72.50
500	\$114.31	\$115.77
669	\$150.39	\$152.33
750	\$167.68	\$169.85
1000	\$221.04	\$230.36
1500	\$327.75	\$351.37
2000	\$434.48	\$472.40
3000	\$647.90	\$714.43

The above assumes that customers purchase their electric supply from the Company and not from a third-party supplier. Customers who receive service pursuant to other classes of service may consult the Company's complete filing which is available for public review on the Company's website at www.atlanticcityelectric.com/PublicPostings.

The chart below provides information as to the estimated average percentage rate change per customer by class as of _______, 2023:

PERCENT INCREASE BY CUSTOMER CLASS

Rate Schedule	Percent Increase by Customer Class*
Residential	8.99%
Monthly General Service Secondary	3.47%
Monthly General Service Primary	(18.52%)
Annual General Service Secondary	0.03%
Annual General Service Primary	3.64%
Transmission General Service – Subtransmission	0.25%
Transmission General Service	(0.17%)
Street and Private Lighting/ Contributed Street Lighting	0.51%
Direct Distribution Connection	0.00%

^{*} The above table includes impacts associated with the Company's Conservation Incentive Program ("CIP").

A copy of this Notice of Public Hearings is being served upon the clerk, executive or administrator of each municipality and county within the Company's service territory. The Petition and this Notice have also been sent to the New Jersey Division of Rate Counsel ("Rate Counsel"), who will represent the interests of all ACE customers in this proceeding. Copies of ACE's Petition and this Public Notice are posted on ACE's website at www.atlanticcityelectric.com/PublicPostings.

PLEASE TAKE FURTHER NOTICE that the Board has transmitted the Company's Petition to the Office of Administrative Law ("OAL") for the purpose of conducting public and evidentiary hearings thereon. The Petition has been docketed as OAL Docket No. ______.

PLEASE TAKE FURTHER NOTICE that, due to the COVID-19 pandemic, the OAL has scheduled virtual public comment hearings before an Administrative Law Judge on the following date and times:

[day of the week], [date], 2023, at 4:30 P.M. and 5:30 P.M.

Members of the public may participate in the public hearings by following the dial-in instructions

set out below:
Call in numbers (callers can use either phone number):
Upon calling in, the caller will be prompted to enter the meeting ID of and press the pound or hashtag button (#).
Press the pound or hashtag button (#) a second time (in response to the second electronic prompt)
The caller will then be prompted to enter the passcode for the public meeting of and press the pound or hashtag button (#).

The caller will then be entered into the waiting room where the Office of Administrative Law Information Technology ("OAL IT") staff will admit the caller into the public hearing. The caller should mute their phone to prevent background noise. Failure to mute your own line may cause

Members of the increase. Such of	public are invited to part comments will be made a pate in the virtual public hea	OAL will preside over the virtual public hearings. icipate and express their views on the proposed rate part of the final record in the proceeding. Whether or aring, written comments may be submitted to the Hon. ve Law, P. O. Box 049, Trenton, New Jersey 08625-
0049 Please inc		C in your comment letter.
requests for spec		his opportunity for public comment, please submit any ding interpreters, at least 48 hours prior to this hearing (609) 909-7034.
Dated:	, 2023	Atlantic City Electric Company

OAL IT staff to mute the caller and the caller would have to disconnect and call back in to

participate in the public discussion portion.

Exhibit C

Comparative Balance Sheet

Atlantic City Electric Company Comparative Balance Sheet

	December 31,		September 30,	
	2020	2021	2022	
HCPG Blood				
Utility Plant	<u>ቀ</u>	Ф 4 000 C04 0E7	¢ 5440,000,007	
Utility Plant	\$ 4,583,362,091	\$ 4,896,631,857	\$ 5,148,000,337	
Construction Work In Progress TOTAL Utility Plant	<u>182,570,016</u> 4,765,932,107	242,568,840 5,139,200,697	223,725,167 5,371,725,504	
Less: Accumulated Depreciation	952,429,371	1,049,501,323	1,145,310,631	
Net Utility Plant	3,813,502,736	4,089,699,374	4,226,414,873	
THOSE STATES	0,010,002,100	1,000,000,01	1,220,111,010	
Other Property and Investments				
Nonutility Property	13,613,379	13,614,426	13,614,426	
Less: Accumulated Depreciation	11,741,291	11,784,972	11,817,732	
Net Nonutility Plant	1,872,088	1,829,454	1,796,694	
Investment in Subsidiary Companies	2,200,001	_	-	
Other Investments	33,668	31,384	62,556	
Other Special Funds	-	-	-	
Total Other Property and Investments	4,105,757	1,860,838	1,859,250	
Current and Asserted Assets				
Current and Accrued Assets Cash	17,433,223	29,154,251	111,493,379	
Working Funds	4,000	4,000	4,000	
Temporary Cash Investments	4,000	9,948	530,217	
Customer Accounts Receivable	129,591,108	152,566,276	179,783,705	
Other Accounts Receivable	70,761,566	74,042,249	67,265,095	
Less: Provision for Uncollectible Accounts	43,325,320	63,970,515	60,462,666	
Accounts Receivable from Associated Companies	5,220,292	1,361,240	1,125,776	
Plant Materials and Operating Supplies	36,425,041	36,171,580	41,607,323	
Allowances	381,434	332,011	1,119,034	
Stores Expense Undistributed	-	-	262,206	
Prepayments	869,977	999,911	13,053,607	
Interest and Dividends Receivable	524	203	1,279	
Miscellaneous Current and Accrued Assets	1,323,269	1,675,279	1,579,742	
Rents Receivable	1,281,919	1,282,013	3,205,031	
Accrued Utility Revenues	29,409,805	39,730,660	42,303,992	
Total Current and Accrued Assets	249,376,838	273,359,106	402,871,720	
Deferred Debits				
Unamortized Debt Expenses	7,600,472	9,746,727	10,512,455	
Other Regulatory Assets	138,508,230	141,761,261	305,698,483	
•	136,306,230	141,701,201	(190,139)	
Clearing Accounts Miscellaneous Deferred Debits	- 60 114 085	47 624 054	, ,	
	60,114,085	47,634,954	40,873,304	
Unamortized Loss on Reacquired Debt Accumulated Deferred Income Taxes	3,498,083 155,469,504	2,934,103	2,543,926	
Total Deferred Debits	<u>155,469,504</u> 365,190,374	145,329,393 347,406,438	<u>134,880,980</u> 494,319,009	
TOTAL ASSETS	\$ 4,432,175,705	\$ 4,712,325,756	\$ 5,125,464,852	

Atlantic City Electric Company Comparative Balance Sheet

	December 31,		September
	2020	2021	2022
Proprietary Capital			
Common Stock	\$ 25,638,051	\$ 25,638,051	\$ 25,638,051
Premium on Capital Stock	107,755,439	107,755,439	107,755,439
Other Paid-In Capital	1,138,219,188	1,456,619,188	1,631,689,473
Less: Capital Stock Expense	532,682	532,682	532,682
Retained Earnings	127,177,217	(14,348,852)	(12,490,095)
Total Proprietary Capital	1,398,257,213	1,575,131,144	1,752,060,186
Long-Term Debt			
Bonds	1,387,015,000	1,573,150,000	1,748,150,000
Advances from Associated Companies	9,733,977	-	13,750
Less: Unamortized Discount on Long-Term Debt	477,643	592,001	566,882
Total Long-Term Debt	1,396,271,334	1,572,557,999	1,747,596,868
Other Non-Current Liabilities			
Obligations Under Capital Leases	11,330,850	16,147,195	16,838,911
Accumulated Provision for Injuries and Damages	11,964,265	12,328,722	11,402,116
Accumulated Provision for Pensions and Benefits	17,178,768	12,146,787	9,281,138
Accumulated Miscellaneous Operating Provisions	297,809	258,624	152,500
Asset Retirement Obligations	5,670,537	8,805,982	6,965,899
Total Other Noncurrent Liablities	46,442,229	49,687,310	44,640,564
Current and Accrued Liabilities			
Notes Payable	187,462,678	144,471,395	-
Accounts Payable	150,569,528	135,702,128	133,672,935
Notes Payable to Associated Companies	-	-	-
Accounts Payable to Associated Companies	31,545,906	30,467,638	20,223,053
Customer Deposits	22,554,507	17,793,687	18,982,828
Taxes Accrued	11,580,147	11,006,605	4,725,121
Interest Accrued	11,929,521	11,491,263	16,294,087
Miscellaneous Current and Accrued Liabilities	52,018,502	56,953,769	195,641,476
Tax Collections Payable	, , , -	4,491	3,927
Obligations Under Capital Leases	1,555,409	2,652,160	2,897,621
Total Current and Accrued Liabilities	469,216,198	410,543,136	392,441,048
Deferred Credits			
Customer Advances for Construction	1,811,757	5,035,005	9,971,368
Accumulated Deferred Investment Tax Credits	2,708,204	2,391,980	2,129,834
Other Deferred Credits	18,751,692	15,328,134	85,666,337
Other Regulatory Liabilities	317,700,604	255,045,853	223,672,245
Accumulated Deferred Income Taxes-Other Property	725,791,908	778,702,740	821,204,481
Accumulated Deferred Income Taxes-Other	55,224,566	47,902,455	46,081,921
Total Deferred Credits	1,121,988,731	1,104,406,167	1,188,726,186
TOTAL LIABILITIES AND STOCKHOLDERS EQUITY	\$ 4,432,175,705	\$ 4,712,325,756	\$ 5,125,464,852

Atlantic City Electric Company Balance Sheet as of September 30, 2022

Utility Plant		Proprietary Capital	
Utility Plant	\$ 5,148,000,337	Common Stock	\$ 25,638,051
Construction Work In Progress	223,725,167	Premium on Capital Stock	107,755,439
TOTAL Utility Plant	5,371,725,504	Other Paid-In Capital	1,631,689,473
Less: Accumulated Depreciation	1,145,310,631	Less: Capital Stock Expense	532,682
Net Utility Plant	4,226,414,873	Retained Earnings	(12,490,095)
•	, , ,	Total Proprietary Capital	1,752,060,186
		, , ,	, , ,
Other Property and Investments	40.044.400	Lawa Tama Daki	
Nonutility Property	13,614,426	Long-Term Debt	4 740 450 000
Less: Accumulated Depreciation	11,817,732	Bonds	1,748,150,000
Net Nonutility Plant	1,796,694	Advances from Associated Companies	13,750
Investment in Subsidiary Companies	-	Less: Unamortized Discount on Long-Term Debt	566,882
Other Investments	62,556	Total Long-Term Debt	1,747,596,868
Total Other Property and Investments	1,859,250		
		Other Non-Current Liabilities	
		Obligations Under Capital Leases	16,838,911
Current and Accrued Assets		Accumulated Provision for Injuries and Damages	11,402,116
Cash	111,493,379	Accumulated Provision for Pensions and Benefits	9,281,138
Working Funds	4,000	Accumulated Miscellaneous Operating Provisions	152,500
Temporary Cash Investments	530,217	Asset Retirement Obligations	6,965,899
Customer Accounts Receivable	179,783,705	Total Other Noncurrent Liabilities	44,640,564
Other Accounts Receivable	67,265,095		,,
Less: Provision for Uncollectible Accounts	60,462,666		
Accounts Receivable from Associated Companies	1,125,776	Current and Accrued Liabilities	
Plant Materials and Operating Supplies	41,607,323	Notes Payable	-
Allowances	1,119,034	Accounts Payable	133,672,935
Stores Expense Undistributed	262,206	Notes Payable to Associated Companies	-
Prepayments	13,053,607	Accounts Payable to Associated Companies	20,223,053
Interest and Dividends Receivable	1,279	Customer Deposits	18,982,828
Miscellaneous Current and Accrued Assets	1,579,742	Taxes Accrued	4,725,121
Rents Receivable	3,205,031	Interest Accrued	16,294,087
Accrued Utility Revenues	42,303,992	Miscellaneous Current and Accrued Liabilities	195,641,476
Total Current and Accrued Assets	402,871,720	Tax Collections Payable	3,927
	10=,0: 1,: =0	Obligations Under Capital Leases	2,897,621
		Total Current and Accrued Liabilities	392,441,048
			, ,
Deferred Debits		Deferred Credits	
Unamortized Debt Expenses	10,512,455	Customer Advances for Construction	9,971,368
Other Regulatory Assets	305,698,483	Accumulated Deferred Investment Tax Credits	2,129,834
Clearing Accounts	(190,139)	Other Deferred Credits	85,666,337
Miscellaneous Deferred Debits	40,873,304	Other Regulatory Liabilities	223,672,245
Unamortized Loss on Reacquired Debt	2,543,926	Accumulated Deferred Income Taxes-Other Property	821,204,481
Accumulated Deferred Income Taxes	134,880,980	Accumulated Deferred Income Taxes-Other Accumulated Deferred Income Taxes-Other	46,081,921
Total Deferred Debits	494,319,009	Total Deferred Credits	1,188,726,186
Total Detelled Debits	+3+,3 l 3,003	Total Deletied Orealts	1,100,120,100
TOTAL ASSETS	\$ 5,125,464,852	TOTAL LIABILITIES AND STOCKHOLDERS EQUITY	\$ 5,125,464,852
I O I / LE MODE I O	Ψ 0,120,404,002	101/16 EIRDIEITIEG AIRD GTOOMTOEDENG EGGITT	Ψ 5,125,767,032

Exhibit D

Comparative Income Statement

Atlantic City Electric Company Comparative Income Statement

	Twelve Months Ended December 31,	Twelve Months Ended December 31,	Twelve Months Ended September 30,		
	2020	2021	2022		
OPERATING RESULTS					
Operating Revenue	\$ 1,243,517,151	\$ 1,424,227,562	\$ 1,441,119,520		
Operating Expenses:					
Purchased Power & Interchange	610,522,892	663,835,636	625,623,864		
Deferred Fuel/Other Operations	(21,317,967)	43,579,741	41,423,219		
Other Operation Total Production	589,204,925	707,415,377	667,047,083		
Operation Maintenance	5,832,346 16,301,659	9,064,932 19,104,378	9,686,091 18,885,433		
Total Transmission	22,134,005	28,169,310	28,571,524		
Regional Market Expense	47,125	59,869	38,618		
Regional Market Expense	47,125	39,009	30,010		
Operation	35,876,789	32,761,620	35,895,512		
Maintenance	73,600,574	69,556,345	76,065,926		
Total Distribution	109,477,363	102,317,965	111,961,438		
Customer Accounts Expenses	84,171,512	75,517,315	79,286,501		
Customer Service Expenses	31,789,850	31,748,768	33,152,801		
Sales Expense	-	-	-		
Operation	95,549,189	91,297,419	90,764,439		
Operation Maintenance	1,763	136,840	493,954		
Total Administrative & General	95,550,952	91,434,259	91,258,394		
Total Operations & Maintenance	932,375,732	1,036,662,863	1,011,316,359		
Depreciation	132,816,208	143,297,760	151,400,242		
Amortization & Depletion of Utility Plant	7,420,351	11,797,795	15,977,906		
Amortization of Regulatory Debits	31,787,073	33,209,786	54,249,681		
Amortization of Regulatory Credits	(365,202)	207,479	(1,536,273)		
Total Depreciation & Amortization Expense	171,658,430	188,512,820	220,091,556		
Federal - Current	(3,863,409)	1,198,701	(4,903,652)		
Federal - Deferred	(42,486,663)	(25,919,815)	(4,514,269)		
State - Current	2,000	497,085	138,952		
State - Deferred ITC - Amortized	6,677,733	12,199,177	12,625,274		
Total Income Taxes	(325,763) (39,996,102)	(316,224) (12,341,076)	(275,197) 3,071,108		
rotal moone raxes	(00,000,102)	(12,041,070)	0,071,100		
Other Taxes	7,623,436	8,074,012	8,465,746		
Total Taxes	(32,372,666)	(4,267,064)	11,536,854		
Accretion Expense	85,552	88,307	88,195		
Total Operating Expenses	1,071,747,048	1,220,996,926	1,243,032,963		
Operating Income	171,770,103	203,230,636	198,086,557		
Other Income and Deductions:					
AFUDC	4,295,091	3,094,477	6,259,147		
Other Income and Deductions	(5,827,792)	(2,822,513)	(7,431,765)		
Income Taxes on Other Income	1,417,191	476,271	1,809,137		
Net Other Income & Deductions	(115,510)	748,235	636,519		
Net Income before Interest	171,654,593	203,978,871	198,723,076		
Interest Charges					
Interest - Long-Term Debt and Debt to Assoc. Companies	58,889,899	56,738,744	59,523,791		
Amort - Prem, Disc & Exp	1,946,885	1,876,272	1,760,387		
Other Interest Charges	1,239,483	604,113	4,086,853		
AFUDC - Credit	(2,558,790)	(1,614,189)	(2,514,907)		
Total Other Interest	59,517,477	57,604,940	62,856,123		
Net Income (FERC)	\$ 112,137,116	\$ 146,373,931	\$ 135,866,953		
Hot moonio (i Eito)	Ψ 112,137,110	Ψ 170,070,301	Ψ 100,000,900		

Exhibit E

Statement of Revenue Derived

ATLANTIC CITY ELECTRIC COMPANY

BILLED REVENUE DERIVED FOR 12 MONTHS ENDING DECEMBER 31, 2022

	Distibution*	
RESIDENTIAL SERVICE - RS	\$	285,043,747
MONTHLY GENERAL SERVICE - MGS SECONDARY	\$	92,118,782
MONTHLY GENERAL SERVICE - MGS PRIMARY	\$	5,561,418
ANNUAL GENERAL SERVICE - AGS SECONDARY	\$	55,980,212
ANNUAL GENERAL SERVICE - AGS PRIMARY	\$	12,569,231
TRANSMISSION GENERAL SERVICE	\$	3,301,293
DIRECT DISTRIBUTION SERVICE - DDC	\$	2,124,344
STREET & PRIVATE LIGHTING - SPL	\$	18,972,981
CONTRIBUTED STREET LIGHTING - CSL	\$	583,089
TOTAL:	\$	476,255,096

^{*}Distribution Revenues include: Customer Charge, Sales, Demands, Lamp Charges, Reactive Demand, DDC Fixed Charges, and EDIT credits. Distribution revenues exclude the impacts of CIP.

Exhibit F

Pro Forma Rate Base/Income Statement

Atlantic City Electric Company

Exhibit F Page 1 of 48

Average Net Investment

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Return on Average Net Investment for Proposed Distribution Rates	2
Determination of Average Net Investment for 5+7 June 30, 2023	3
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ACE Pro Forma Capital Structure	44-47
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Average Net Investment

(1)	(2)	(3)
Line <u>No.</u>	<u>ltem</u>	Distribution
1	Present Distribution Rates	System
2 3	Operating Income (Exhibit F, Page 5 of 48)	\$ 84,302,594
4	Average Net Investment	\$ 2,032,480,532
5	Return - %	4.15%
6	Proposed Distribution Rates	
7 8	Operating Income (Exhibit F, Page 5 of 48)	\$ 159,408,955
9	Average Net Investment	\$ 2,032,480,532
10	Return - %	7.84%

Average Net Investment

(1)	(2)	(3)	(4)	(5)
			5+7	
Line		June 30	June 30	
No.	<u>ltem</u>	2022	2023	Average
				_
1	Electric Plant In-Service	\$ 3,220,084,526	\$ 3,486,545,538	\$ 3,353,315,032
2	Held for Future Use	\$ 6,382,499	\$ 6,477,249	\$ 6,429,874
3	Total Distribution Plant	\$ 3,226,467,025	\$ 3,493,022,788	\$ 3,359,744,906
4				
5				
6	<u>Additions</u>			
7				
8	Materials & Supplies	\$ 30,817,250	\$ 35,736,589	\$ 33,276,919
9	Cash Working Capital	\$ 112,633,727	\$ 121,558,345	\$ 117,096,036
10				
11	Total Additions	\$ 143,450,977	\$ 157,294,935	\$ 150,372,956
12				
13	<u>Deductions</u>			
14				
15	Accumulated Provision for			
16	Depreciation	\$ (821,799,794)	\$ (929,929,623)	\$ (875,864,708)
17	Customer Advances	\$ (7,008,599)	\$ (6,319,096)	\$ (6,663,847)
18	Customer Deposits	\$ (18,072,674)	\$ (18,259,444)	\$ (18,166,059)
19	Accum Deferred Income Taxes	\$ (573,271,613)	\$ (580,613,818)	\$ (576,942,715)
20				
21	Total Deductions	\$ (1,420,152,679)	\$ (1,535,121,980)	\$ (1,477,637,330)
22				
23	Net Investment	\$ 1,949,765,322	\$ 2,115,195,742	\$ 2,032,480,532

Atlantic City Electric Company 5+7 Months Ending June 2023 Rate of Return Analysis

(1) (2) (3) (4) <u>5+7 M/E June 2023</u>

Line				
No.	<u>ltem</u>	S	ystem Electric	Distribution
1	Rate Base			
2	Electric Plant in Service	\$	5,632,236,528	\$ 3,486,545,538
3	Less: Depreciation Reserve	\$	1,336,339,832	\$ 929,929,623
4	Net Plant in Service	\$	4,295,896,696	\$ 2,556,615,916
5				
6	Plant Held For Future Use	\$	12,298,643	\$ 6,477,249
7	Materials & Supplies	\$ \$ \$	41,290,109	\$ 35,736,589
8	Cash Working Capital	\$	160,961,428	\$ 121,558,345
9	Customer Advances	\$	(6,319,096)	\$ (6,319,096)
10	Customer Deposits	\$	(18,259,444)	\$ (18,259,444)
11	Def Federal and State Tax Bal ⁽¹⁾	\$	(924,200,865)	\$ (580,613,818)
12	Total Rate Base	\$	3,561,667,470	\$ 2,115,195,742
13				
14	Total Rate Base	\$	3,561,667,470	\$ 2,115,195,742
15				
16	<u>Earnings</u>			
17	Operating Revenues	\$	1,387,681,860	\$ 486,246,812
18				
19	O & M Expense	\$	973,618,472	\$ 254,937,371
20	Deprec and Amort Expense		245,308,516	\$ 122,951,000
21	Taxes Other than Income Taxes	\$	8,618,509	\$ 5,663,172
22	Net ITC Adjustment	\$	(288,671)	\$ (170,035)
23	IOCD	\$	11,532	\$ 11,532
24	State Income Tax	\$ \$ \$ \$ \$ \$ \$	-	\$ -
25	Federal Income Tax	\$	(10,781,010)	\$ (2,168,627)
26	Deferred SIT Expense	\$	7,813,928	\$ 5,845,029
27	Deferred FIT Expense	\$	(1,283,060)	\$ 145,975
28				
29	Total Operating Expenses	\$	1,223,018,216	\$ 387,215,417
30				
31	Operating Income	\$	164,663,644	\$ 99,031,395
32				
33	Rate of Return		4.62%	4.68%

⁽¹⁾ Includes Excess Deferred Income Taxes

Atlantic City Electric Company 5+7 Months Ending June 2023 Determination of Revenue Requirements

(1)	(2)	(3)
Line <u>No.</u>	<u>ltem</u>	\$
1 2	Adjusted Net Rate Base	\$ 2,235,749,719
3	Required Rate of Return	7.13%
4 5 6	Required Operating Income	\$ 159,408,955
7	Pro Forma Operating Income	\$ 84,302,594
8 9 10	Operating Income Deficiency	\$ 75,106,361
11	Revenue Conversion Factor	 1.3952
12 13 14	Revenue Requirement	\$ 104,788,395
15	Sales & Use Tax Factor	 1.06625
16 17	Revenue Requirement (Adjusted for Sales & Use Tax)	\$ 111,730,626

Atlantic City Electric Company 5+7 Months Ending June 2023 <u>Distribution Adjustments</u>

(1) Line			(2)	(3)		(4)	(5) Rate	(6)	(7)	(8) Rev. Req. Def. (Exc.)
No.			<u>ltem</u>	<u>Witness</u>		<u>Earnings</u>	Base	ROR	ROE	Exclude Sales & Use Tax
1	Per Boo	ks - 5+7	7 Months Ending June 2023	Ziminsky	\$	99,031,395 \$	2,115,195,742	4.68%	5.62%	\$ 72,246,333
2										
3	Adjustm		Defined the Device Association Associated with Community Devices	Ob a re/Norman and	•	745 454				Φ (007.770)
4	Adj	1	Reflect the Revenue Annualization Associated with Conservation Incentive Program	Chen/Normand	\$ \$	715,151				\$ (997,779)
5	Adj	2	Reflect Revenue Associated with Customer Counts as of December, 2023	Chen/Normand	ф	934,044				\$ (1,303,179)
ь 7	Adj	3	Annualize Wage and FICA changes through March 2024	Chen	ф	(2,241,425)				\$ 3,127,236
/	Adj	4	Proforma Wage Rate Changes for Rate Effective Period	Chen	Э	(71,744)				\$ 100,098
8	Adj	5	Regulatory Commission Expense Adjustment Pension and Other Post-Employment Benefits ("OPEB") Expense Adjustment	Chen Ziminskv	\$	26,507 (1,021,822)				\$ (36,983) \$ 1.425.646
40	Adj	7		- ,	Φ	. , , ,				\$ 1,425,646
10 11	Adj	8	Reflection of 5-year Average Inflation on Non-Labor O&M Expense Remove Executive Incentive Expense	Ziminsky	\$	(3,327,145) 912,841				\$ 4,642,033 \$ (1,273,596)
	Adj	9	2021 Storm Ida Adjustment	Ziminsky Chen	φ	(1,665,956) \$	4 464 990			\$ (1,273,596) \$ 2,738,655
12 13	Adj	10	Normalize Injuries & Damages Expense	Chen	φ	1,042,783	4,164,889			
14	Adj Adj	11	Adjust Mays Landing Complex Rent	Chen	φ	1,042,763				\$ (1,454,891)
15	Adj	12	Annualize Depreciation Expense @ June 23 Plant	Chen	\$	(4,388,670) \$	(4,388,670)			\$ 5.686.498
16	Adj	13	Servo Assets @ ACE Approved Depreciation Rates	Chen	\$	94.789	(4,300,070)			\$ (132,250)
17	Adj Adj	14	Reflect Plant Additions from July 2023 - December 2023	Ziminsky	Ф	(\$3,172,131)	\$113,265,374			\$ (132,250) \$ 15,693,142
			Reflect Plant Additions from January 2024 - June 2024	•			\$69,777,613			\$ 15,693,142
18 19	Adj Adj	15 16	Credit Facilities Fee	Ziminsky	\$	(\$1,554,552) (525,482) \$	578,298			\$ 9,110,232
20	Adj Adj	17	Restate Interest on Customer Deposit Expense	Ziminsky Chen	э \$	(239,083)	3/0,290			\$ 790,000
20	Adj Adj	18	Remove Annual IIP Revenue Requirement	Chen/Normand	Ф	\$2,229,103	(\$91,518,054)			\$ 333,566 \$ (12,214,055)
22	Adj Adj	19	Adjust Cash Working Capital	Chen		\$2,229,103	2,788,756			\$ (12,214,055) \$ 277.419
23		20	Adjust Interest Synchronization	Chen	\$	715,069	2,700,730			\$ (997,664)
23 24	Adj Adj	21	Corporate Alternative Minimum Tax ("CAMT") Adjustment	Ziminsky	Ф	7 15,069	12,119,271			\$ (997,664) \$ 1,205,598
25	Adj	22	Excess Deferred Income Taxes ("EDIT") – Expiring Riders Regulatory Asset	Ziminsky/Normand		φ	186,703			\$ 1,205,596
26	Adj	23	Reflection of Electric Vehicle Regulatory Asset	Ziminsky	\$	(374,245) \$	932,794			\$ 614.939
27	Adj	23	AMI SEN Investment Deferral Regulatory Asset	Ziminsky	\$	(815,747) \$	3,670,860			\$ 1,503,299
28	Adj	25	AMI SEN Incremental O&M Expenses/Savings Regulatory Asset	Ziminsky	\$	(1,824,585) \$	8,210,632			\$ 3,362,436
29	Adj	26	Reflection of Benchmarking Requirement Cost Recovery	Ziminsky	\$	(176,502) \$	765,513			\$ 3,302,430
30	Auj	20	Nenection of Benchmarking Requirement Cost Recovery	ZIIIIIIISKY	φ	(170,502) \$	100,013			Ψ 322,407
31										.
32			Adjusted Total		\$	84,302,594 \$	2,235,749,719	3.77%	3.80%	\$ 104,788,395

Atlantic City Electric Company 5+7 Months Ending June 2023 Rate of Return Analysis

(1)	(2)		(3)	(4)	(5)	(6)
Line No.	<u>ltem</u>	S	ystem Electric	<u>Distribution</u>	Proforma <u>Adjustments</u>	Fully <u>Adjusted</u>
1	Rate Base					
2	Electric Plant in Service	\$	5,632,236,528	\$ 3,486,545,538	\$ 77,426,787	\$ 3,563,972,326
3	Less: Depreciation Reserve	\$	1,336,339,832	\$ 929,929,623	\$ (9,032,315)	\$ 920,897,308
4 5	Net Plant in Service	\$	4,295,896,696	\$ 2,556,615,916	\$ 86,459,103	\$ 2,643,075,018
6	Plant Held For Future Use	\$	12,298,643	\$ 6,477,249	\$ -	\$ 6,477,249
7	Materials & Supplies	\$	41,290,109	\$ 35,736,589	\$ -	\$ 35,736,589
8	Cash Working Capital	\$	160,961,428	\$ 121,558,345	\$ 28,014,466	\$ 149,572,811
9	Customer Advances	\$	(6,319,096)	\$ (6,319,096)	\$ -	\$ (6,319,096)
10	Customer Deposits	\$	(18,259,444)	\$ (18,259,444)	\$ -	\$ (18,259,444)
11	Def Federal and State Tax Bal ⁽¹⁾	\$	(924,200,865)	\$ (580,613,818)	\$ 6,080,409	\$ (574,533,409)
12	Total Rate Base	\$	3,561,667,470	\$ 2,115,195,742	\$ 120,553,977	\$ 2,235,749,719
13						
14	Total Rate Base	\$	3,561,667,470	\$ 2,115,195,742	\$ 120,553,977	\$ 2,235,749,719
15						
16	<u>Earnings</u>					
17	Operating Revenues	\$	1,387,681,860	\$ 486,246,812	\$ 2,300,989	\$ 488,547,801
18						
19	O & M Expense	\$	973,618,472	\$ 254,937,371	\$ 12,067,387	\$ 267,004,758
20	Deprec and Amort Expense	\$	245,308,516	\$ 122,951,000	\$ 10,409,689	\$ 133,360,689
21	Taxes Other than Income Taxes	\$	8,618,509	\$ 5,663,172	\$ 176,198	\$ 5,839,369
22	Net ITC Adjustment	\$	(288,671)	\$ (170,035)	\$ -	\$ (170,035)
23	IOCD	\$	11,532	\$ 11,532	\$ 332,567	\$ 344,100
24	State Income Tax	\$	-	\$ -	\$ (1,906,953)	\$ (1,906,953)
25	Federal Income Tax	\$	(10,781,010)	\$ (2,168,627)	\$ (4,049,098)	\$ (6,217,725)
26	Deferred SIT Expense	\$	7,813,928	\$ 5,845,029	\$ -	\$ 5,845,029
27	Deferred FIT Expense	\$	(1,283,060)	\$ 145,975	\$ -	\$ 145,975
28						
29	Total Operating Expenses	\$	1,223,018,216	\$ 387,215,417	\$ 17,029,790	\$ 404,245,207
30						
31	Operating Income	\$	164,663,644	\$ 99,031,395	\$ (14,728,801)	\$ 84,302,594
32						
33	Rate of Return		4.62%	4.68%		3.77%

⁽¹⁾ Includes Excess Deferred Income Taxes

Atlantic City Electric Company 5+7 Months Ending June 2023 Proforma Earnings Adjustments

(1)	(2)	(3)	(4)	(5)	(6)	(7)	8))	(9)	(10)		(11)
No.	<u>Adjustment</u>	Revenue	<u>0&M</u>	Deprec <u>Amort</u>	Other <u>Taxes</u>	<u>SIT</u>	<u>FI</u>	<u>FIT</u>		Total Expense	Ea	arnings
1	Reflect the Revenue Annualization Associated with Conservation Incentive Program ("CIP")	\$ 997,792			\$ 3,007	\$ 89,531	\$ 19	0,103		\$ 282,641 \$	è	715,151
2	Reflect Revenue Associated with Customer Counts as of December, 2023	\$ 1,303,197			\$ 3,928	\$ 116,934	\$ 24	8,290		\$ 369,152 \$	ذ	934,044
3	Annualize Wage and FICA changes through March 2024		\$ 2,953,226		\$ 164,627	\$ (280,607)	\$ (59	5,822)		\$ 2,241,425 \$	2) د	2,241,425)
4	Proforma Wage Rate Changes for Rate Effective Period		\$ 95,162		\$ 4,635	\$ (8,982)	\$ (9,071)		\$ 71,744 \$	ڼ	(71,744)
5	Regulatory Commission Expense Adjustment		\$ (36,872)			\$ 3,318	\$	7,046		\$ (26,507) \$	į د	26,507
6	Pension and Other Post-Employment Benefits ("OPEB") Expense Adjustment		\$ 1,421,368			\$ (127,923)	\$ (27	1,624)		\$ 1,021,822 \$	′) ذ	1,021,822)
7	Reflection of 5-year Average Inflation on Non-Labor O&M Expense		\$ 4,628,106			\$ (416,530)	\$ (88	34,431)		\$ 3,327,145 \$	i (:	3,327,145)
8	Remove Executive Incentive Expense		\$ (1,269,775)			\$ 114,280	\$ 24	2,654		\$ (912,841) \$	ô	912,841
9	2021 Storm Ida Adjustment		\$ 2,317,368			\$ (208,563)	\$ (44	2,849)		\$ 1,665,956 \$	i (*	1,665,956)
10	Normalize Injuries & Damages Expense		\$ (1,450,526)			\$ 130,547	\$ 27	7,195		\$ (1,042,783) \$	å í	1,042,783
11	Adjust Mays Landing Complex Rent		\$ -			\$ -	\$	-		\$ - \$	ô	-
12	Annualize Depreciation Expense @ June 23 Plant			\$ 6,104,702		\$ (549,423)	\$ (1,16	6,609)		\$ 4,388,670 \$	i (1	4,388,670)
13	Servco Assets @ ACE Approved Depreciation Rates			\$ (131,853)		\$ 11,867	\$ 2	5,197		\$ (94,789) \$	į د	94,789
14	Reflect Plant Additions from July 2023 - December 2023			\$ 4,412,478		\$ (397,123)	\$ (84	3,225)		\$ 3,172,131 \$	i (:	3,172,131)
15	Reflect Plant Additions from January 2024 - June 2024			\$ 2,162,404		\$ (194,616)	\$ (4	3,235)		\$ 1,554,552 \$	′) ذ	1,554,552)
16	Credit Facilities Fee		\$ 730,952			\$ (65,786)	\$ (13	9,685)		\$ 525,482 \$	ۮ	(525,482)
17	Restate Interest on Customer Deposit Expense					\$ (29,931)	\$ (6	3,554)	\$ 332,567	\$ 239,083 \$	ۮ	(239,083)
18	Remove Annual IIP Revenue Requirement			\$ (3,898,500)		\$534,492	\$1,13	34,905		\$ (2,229,103) \$	\$ 7	2,229,103
19	Adjust Interest Synchronization					\$ (228,944)	\$ (48	6,125)		\$ (715,069) \$	ô	715,069
20	Corporate Alternative Minimum Tax ("CAMT") Adjustment					\$ -	\$	-		\$ - \$	i	-
21	Excess Deferred Income Taxes ("EDIT") – Expiring Riders Regulatory Asset					\$ -	\$	-		\$ - \$	i	-
22	Reflection of Electric Vehicle Regulatory Asset			\$ 520,580		\$ (46,852)	\$ (9	9,483)		\$ 374,245 \$	i	(374,245)
23	AMI SEN Investment Deferral Regulatory Asset			\$ 1,134,715		\$ (102,124)	\$ (2	6,844)		\$ 815,747 \$	i	(815,747)
24	AMI SEN Incremental O&M Expenses/Savings Regulatory Asset		\$ 2,538,023			\$ (228,422)	\$ (48	35,016)		\$ 1,824,585 \$	j (*	1,824,585)
25	Reflection of Benchmarking Requirement Cost Recovery		\$ 140,355	\$ 105,162		\$ (22,097)	\$ (4	6,918)		\$ 176,502 \$	ۮ	(176,502)
26												
27	Total	\$ 2,300,989	\$ 12,067,387	\$ 10,409,689	\$ 176,198	\$ (1,906,953)	\$ (4,04	19,098)	\$ 332,567	\$ 17,029,790 \$	5 (14	4,728,801)

Atlantic City Electric Company 5+7 Months Ending June 2023 Proforma Rate Base Adjustments

(1) Line	(2)	(3) Plant In	D.	(4)		(5)	(6) Cash Working		(7)		(8)		(9)
No.	<u>Adjustment</u>	•		Reserve Net Plant		<u>Capital</u>		eferred SIT	Deferred FIT		Rate Base		
1	Reflect the Revenue Annualization Associated with Conservation Incentive Program ("CIP")	\$ -	\$	-	\$	- :	-	\$	-	\$	- 9	\$	-
2	Reflect Revenue Associated with Customer Counts as of December, 2023	\$ -	\$	-	\$	- :	-	\$	-	\$	- 9	\$	-
3	Annualize Wage and FICA changes through March 2024	\$ -	\$	-	\$	- :	-	\$	-	\$	- \$	\$	-
4	Proforma Wage Rate Changes for Rate Effective Period	\$ -	\$	-	\$	- :	-	\$	-	\$	- \$	\$	-
5	Regulatory Commission Expense Adjustment	\$ -	\$	-	\$	- :	-	\$	-	\$	- \$	\$	-
6	Pension and Other Post-Employment Benefits ("OPEB") Expense Adjustment	\$ -	\$	-	\$	- :	-	\$	-	\$	- \$	\$	-
7	Reflection of 5-year Average Inflation on Non-Labor O&M Expense	\$ -	\$	-	\$	- :	-	\$	-	\$	- \$	\$	-
8	Remove Executive Incentive Expense	\$ -	\$	-	\$	- :	-	\$	-	\$	- \$	\$	-
9	2021 Storm Ida Adjustment	\$ -	\$	-	\$	- :	5,793,419	\$	(521,408)	\$	(1,107,122)	\$	4,164,889
10	Normalize Injuries & Damages Expense	\$ -	\$	-	\$	- :	-	\$	-	\$	- 9	\$	-
11	Adjust Mays Landing Complex Rent	\$ -	\$	-	\$	- :	-	\$	-	\$	- 9	\$	-
12	Annualize Depreciation Expense @ June 23 Plant	\$ -	\$	6,104,702	\$	(6,104,702)	-	\$	549,423	\$	1,166,609	\$	(4,388,670)
13	Servco Assets @ ACE Approved Depreciation Rates	\$ -	\$	-	\$	- :	-	\$	-	\$	- 9	\$	-
14	Reflect Plant Additions from July 2023 - December 2023	\$ 108,413,107	\$	(5,542,072)	\$	113,955,179	-	\$	(220,855)	\$	(468,949)	\$ 1	113,265,374
15	Reflect Plant Additions from January 2024 - June 2024	\$ 62,266,897	\$	(7,792,146)	\$	70,059,043	-	\$	(90,106)	\$	(191,324)	\$	69,777,613
16	Credit Facilities Fee	\$ -	\$	-	\$	- :	578,298	\$	-	\$	- 9	\$	578,298
17	Restate Interest on Customer Deposit Expense	\$ -	\$	-	\$	- :	-	\$	-	\$	- \$	\$	-
18	Remove Annual IIP Revenue Requirement	\$ (93,253,216)	\$	(1,802,799)	\$	(91,450,417)	-	\$	(21,656)	\$	(45,982)	\$	(91,518,054)
19	Adjust Cash Working Capital	\$ -	\$	-	\$	- :	2,788,756	\$	-	\$	- 9	\$	2,788,756
20	Adjust Interest Synchronization	\$ -	\$	-	\$	- :	-	\$	-	\$	- 9	\$	-
21	Corporate Alternative Minimum Tax ("CAMT") Adjustment	\$ -	\$	-	\$	- :	-	\$	-	\$	12,119,271	\$	12,119,271
22	Excess Deferred Income Taxes ("EDIT") – Expiring Riders Regulatory Asset	\$ -	\$	-	\$	- :	259,707	\$	(23,374)	\$	(49,630)	\$	186,703
23	Reflection of Electric Vehicle Regulatory Asset	\$ -	\$	-	\$	- :	1,301,451	\$	(118,033)	\$	(250,624)	\$	932,794
24	AMI SEN Investment Deferral Regulatory Asset	\$ -	\$	-	\$	- :	5,106,217	\$	(459,560)	\$	(975,798)	\$	3,670,860
25	AMI SEN Incremental O&M Expenses/Savings Regulatory Asset	\$ -	\$	-	\$	- :	11,421,104	\$	(1,027,899)	\$	(2,182,573)	\$	8,210,632
26	Reflection of Benchmarking Requirement Cost Recovery	\$ -	\$	-	\$	- :	765,513	\$	-	\$	- 9	\$	765,513
27	·												
28	Total	\$ 77,426,787	\$	(9,032,315)	\$	86,459,103	28,014,466	\$	(1,933,467)	\$	8,013,876	\$ '	120,553,977

Atlantic City Electric Company 5+7 Months Ending June 2023 Reflect the Revenue Annualization Associated with Conservation Incentive Program ("CIP") Adjustment No. 1

(1) Line	(2)		(3)
No.	<u>ltem</u>		<u>\$</u>
1 2 3	Total CIP Deferral Balance CIP Revenue Annualization - excludes IIP Net change in revenue	\$ \$	11,865,106 (10,867,314) 997,792
4	Revenue tax	\$	3,007
5	State Income Tax	\$	89,531
6	Federal Income Tax	\$	190,103
7	Total Expense	\$	282,641
8	Earnings	\$	715,151

Atlantic City Electric Company 5+7 Months Ending June 2023 Reflect Revenue Associated with Customer Counts as of December, 2023 Adjustment No. 2

(1) Line	(2)	(3)
No.	<u>Item</u>	<u>\$</u>
1	Revenues from Customers as of June 30, 2023	\$ 1,092,382
2	Revenue from Customers as of December 31, 2023	\$ 210,814
3	Revenue	\$ 1,303,197
4	Revenue Tax	\$ 3,928
5	State Income Tax	\$ 116,934
6	Federal Income Tax	\$ 248,290
7	Total Expense	\$ 369,152
8	Earnings	\$ 934,044

Atlantic City Electric Company 5+7 Months Ending June 2023 Wage and FICA Adjustment

Proforma Wage Rate Changes effective within Nine Months of End of Test Year (for changes effective by March 31, 2024) Adjustment No. 3

(1) Line	(2)	(3)
<u>No</u>	<u>ltem</u>	<u>Total</u>
1	Salary and Wage Adjustment	
2	Change in Expense due to labor rate change	\$ 3,412,162
3	Distribution Allocation	86.55%
4	Change in Expense due to labor rate change-Distribution	\$ 2,953,226
5		
6	State Income Tax	\$ (265,790)
7	Federal Income Tax	\$ (564,361)
8	Total Expense	\$ 2,123,074
9		
10	Earnings	\$ (2,123,074)
11		
12	FICA Adjustment	
13	Change in FICA Expense due to labor rate change	\$ 190,211
14	Distribution Allocation	 86.55%
15	Change in FICA Expense due to labor rate change-Distribution	\$ 164,627
16		
17	State Income Tax	\$ (14,816)
18	Federal Income Tax	\$ (31,460)
19	Total Expense	\$ 118,351
20		
21	Earnings	\$ (118,351)
22		
23	Total Earnings Adjustment	\$ (2,241,425)

Atlantic City Electric Company 5+7 Months Ending June 2023 Wage and FICA Adjustment Proform Wage Rate Changes effective for Rate Effective Period Adjustment No. 4

(1)	(2)		(3)
Line			
<u>No</u>	<u>ltem</u>		<u>Distribution</u>
1	Salary and Wage Adjustment		
2	Change in Expense due to labor rate change	\$	109,950
3	Distribution Allocation		86.55%
4	Change in Expense due to labor rate change-Distribution	\$	95,162
5			
6	State Income Tax	\$	(8,565)
7	Federal Income Tax	<u>\$</u> \$	(18,185)
8	Total Expense	\$	68,412
9			
10	Earnings	\$	(68,412)
11			
12	FICA Adjustment		
13	Change in FICA Expense due to labor rate change	\$	5,355
14	Distribution Allocation		86.55%
15	Change in FICA Expense due to labor rate change-Distribution	\$	4,635
16			
17	State Income Tax	\$	(417)
18	Federal Income Tax	\$ <u>\$</u> \$	(886)
19	Total Expense	\$	3,332
20			
21	Earnings	\$	(3,332)
22			
23	Total Earnings Adjustment	\$	(71,744)

Atlantic City Electric Company 5+7 Months Ending June 2023 Normalize Regulatory Commission Expense Adjustment No. 5

(1) Line	(2)		(3)			
No.	<u>ltem</u>		<u>\$</u>			
1 2 3 4	Normalized Regulatory Expense Adjustment to Test Period Current Case Amortization Total Regulatory Expense	\$ \$ \$	535,007 102,382 637,388	(1) (2)		
5	Test Year Regulatory Expenses	\$	674,260			
6	Adjustment to O & M Expense	\$	(36,872)			
7	Distribution Allocation		100%			
8	Distribution Allocation Amount	\$	(36,872)			
9	State Income Tax	\$	3,318			
10	Federal Income Tax	\$	7,046			
11	Total Expense	\$	(26,507)			
12	Earnings	\$	26,507			
13 14 15 16 17	(1) Account 928: 12 me June 2021 12 me June 2022 5+7 me June 2023 3 Yr Average	\$ \$ \$	FERC 928 1,350,566 778,018 1,480,678 \$1,203,087	Less BPU Assessments \$ - \$ - \$ 0	Internal Expenses \$ 802,066 \$ 395,758 \$ 806,418 \$668,081	Reg Expense to be Normalized \$ 548,499 \$ 382,260 \$ 674,260 \$ 535,007
19 20 21 22 23 24 25	(2) Cost of outside counsel Return on Equity witness Cost of depreciation witness Public notices Court reporters Miscellaneous Total incremental costs 3 Yr. Amortization - Current Base Rate Case	\$\$ \$\$ \$\$ \$\$ \$\$	150,000 103,645 15,000 30,000 8,500 307,145 102,382			

Atlantic City Electric Company 5+7 Months Ending June 2023 Pension and OPEB Expense Adjustment Adjustment No. 6

(1)			(2)	(3)	(4)	(5)	(6)
Line				Expense	ACE	ACE Dist	ACE Dist
<u>No.</u>			Total \$	<u>%</u>	<u>%</u>	<u>%</u>	<u>\$</u>
1 2	Earnings					¢	670.050
3	Pension Expense OPEB Expense					\$	679,952 741,416
4	Total					<u>\$</u>	1,421,368
5	Impact to State Income Taxes					\$	(127,923)
6	Impact to State income raxes					\$	(271,624)
7	Impact to Federal Income taxes					<u>\$</u>	(1,021,822)
8	puot to _ugo						(1,021,022)
9	Pension - 2023 Actuary Report						
10	ACE	\$	16,729,000	43.17%	100.00%	86.55% \$	6,250,232
11	Service Company	\$	29,528,000	74.53%	29.35%	86.55% \$	5,590,563
12	Exelon Business Service Company	\$	9,278,000	3.91%	100.00%	86.55% \$	314,242
13	Total	\$	55,535,000			\$	12,155,037
14							
15	Pension 5+7 M/E June 2023 Expense						
16	<u>ACE</u>	\$	16,221,491	43.17%	100.00%	86.55% \$	6,060,618
17	Service Company	\$	27,263,607	74.53%	29.35%	86.55% \$	5,161,844
18	Exelon Business Service Company	\$	7,458,696	3.91%	100.00%	86.55% \$	252,623
19	<u>Total</u>	\$	50,943,794			\$	11,475,085
20							
21	OPEB - 2023 Actuary Report						
22	ACE	\$	(1,199,000)	43.17%	100.00%	86.55% \$	(447,966)
23	Service Company	\$	1,267,000	74.53%	29.35%	86.55% \$	239,882
24	Exelon Business Service Company	\$	2,621,000	5.69%	100.00%	86.55% \$	129,110
25	<u>Total</u>	\$	2,689,000			\$	(78,974)
26 27	ODED 5.7 M/C lune 2022 Evmanas						
27 28	OPEB - 5+7 M/E June 2023 Expense ACE	ď	(2.406.927)	43.17%	100.00%	86.55% \$	(022.056)
28 29		\$ \$	(2,496,827)	43.17% 74.53%	29.35%	86.55% \$	(932,856)
30	Service Company Exelon Business Service Company	\$ \$	175,630 1,608,079	74.53% 5.69%	29.35% 100.00%	86.55% \$	33,252 79,214
31	Total	\$	(713,118)	5.0976	100.00%	\$	(820,390)
31	Total	Ψ	(113,110)			Ψ	(020,390)

Atlantic City Electric Company Reflection of 5-year Average Inflation on Non-Labor O&M Expense 5+7 Months Ending June 2023 Adjustment No. 7

(1)		(2)	(3)	(4)
Line <u>No.</u>		<u>ltem</u>	<u>Amount</u>	
1	<u>Earnings</u>			
2				
3		Non-Labor O&M Expense	141,532,289	
4				
5		5-Year Average Inflation Factor (CPI)	3.27%	
6				
7		Adjustment to O&M Expense		\$ 4,628,106
8				
9		Adjustment to State Income Taxes		\$ (416,530)
10				
11		Adjustment to Federal Income Taxes		\$ (884,431)
12				
13		Total Expense		\$ 3,327,145
14				
15		Earnings		\$ (3,327,145)

Atlantic City Electric Company 5+7 Months Ending June 2023

Remove Executive Incentive Expense Adjustment No. 8

(1) Line	(2)	(3)				
No.	Item	 Detail				
	Earnings:					
1	O & M Expense	\$ (1,269,775)				
2	State Income Tax	\$ 114,280				
3	Federal Income Tax	\$ 242,654				
4	Total Expense	\$ (912,841)				
5	Earnings	\$ 912,841				

		ACE System O&M	Α	CE Distribution O&M
CC	General Ledger	5+7 ME Jun 23		5+7 ME Jun 23
1500	710068 - Salaries - Incentive Executive	\$ 9,713	\$	8,407
9000	SC7900 and BSC - LTIP Allocation (Exec)	\$ 1,457,387	\$	1,261,368
		\$ 1,467,100	\$	1,269,775

ACE Distribution % = 86.55%

Atlantic City Electric Company 5+7 Months Ending June 2023 2021 Storms Adjustment Adjustment No. 9

(1)	(2)	(3)
Line <u>No.</u>	Item	<u>Distribution</u>
140.	<u>nom</u>	<u> Distribution</u>
1	<u>Earnings</u>	
2		
3	Storm Ida - Amortization Expense	\$ 2,317,368
4		
5	Total Operating Expense	\$ 2,317,368
6		A (000 T 00)
7	State Income Tax	\$ (208,563)
8	Federal Income Tax	\$ (442,849) \$ 1.665.956
9 10	Total Expenses	\$ 1,665,956
11	Earnings	\$ (1,665,956)
12	Lamings	Ψ (1,000,000)
13		
14	Rate Base	
15	Average Amortizable Balance -Ida 2021 Storm	\$ 5,793,419
16		
17	Deferred State Income Tax	\$ (521,408)
18	Deferred Federal Income Tax	\$ (1,107,122)
19		
20	Total Rate Base	\$ 4,164,889
21	(4) Others He COM Defended Associated Bases	Φ 0.050.400
22	(1) Storm Ida O&M Deferral - Amortizable Base	\$ 6,952,103
23 24	Amortization Period (Years) Amortization Expense	\$ 3 \$ 2,317,368
25	Amortization Expense	φ 2,317,300
26	(2) Unamortized Balance of Storm Ida - Beg. Of Period	\$ 6,952,103
27	Amortization Expense - 1st Year	\$ 2,317,368
28	Unamortized Balance - End Of Period	\$ 4,634,735
29	Average - Year 1	\$ 5,793,419

Atlantic City Electric Company 5+7 Months Ending June 2023 Normalize Injuries and Damages Expense Adjustment No. 10

(1) Line	(2)		(3)	
<u>No.</u>	<u>ltem</u>		<u>\$</u>	
1	Normalized Injuries & Damages Expense			
2	Three year average Injuries & Damages Expense	\$	1,663,116	(1)
3	Test Period Injuries & Damages Expense	\$	3,339,055	
4	Adjustment to O & M Expense	\$	(1,675,940)	
5				
6	Distribution Allocation		86.55%	
7				
8	Distribution Allocation Amount	\$	(1,450,526)	
9				
10	State Income Tax	\$	130,547	
11				
12	Federal Income Tax	\$	277,195	
13				
14	Total Expense	\$	(1,042,783)	
15		•	4 0 40 =00	
16	Earnings	\$	1,042,783	
17				
18				
19	(A) 1 1 1 2 B 5			
20	(1) Injuries & Damages Expense	•		
21	12 me June 2021	\$ \$ \$	1,213,943	
22	12 me June 2022	\$	436,349	
23	5+7 me June 2023	\$	3,339,055	
24	3 Year Average	\$	1,663,116	

Atlantic City Electric Company 5+7 Months Ending June 2023 Adjust Mays Landing Complex Rent Adjustment No. 11

(1) Line	(2)		(3)	(4)		(5)
No.	<u>ltem</u>		<u>\$</u>	<u>%</u>		<u>\$</u>
1	<u>Earnings</u>					
2	Expense	\$	-			
3						
4	State Income Tax	\$	-			
5	Federal Income Tax	\$				
6	Total Expenses	\$	-			
7						
8	Earnings	\$	-			
9						
10	Lower of Cost vs. Market Analysis					
11	Finished Space					
12	# of Square Feet - Mays Landing Complex		85,048			
13						
14	Market Cost/Square Foot	\$ \$	21.32		% \$	1,813,230
15	ACE - Actual Cost/Square Foot		3.00		% \$	255,090
16	Difference (no adjustment needed - cost < market)	\$	18.32	86	\$ \$	1,558,140
17						
18	<u>Unfinished Space</u>					
19	# of Square Feet - Mays Landing Complex		134,386			
20						
21	Market Cost Per Square Foot	_				
22	Triple Net Rate	\$	5.75			
23	Common Area Maintenance Rate	\$ \$ \$ \$	3.37			
24	Total	\$	9.12		% \$	1,225,604
25	ACE - Actual Cost/Square Foot	\$	3.00		\$	403,159
26	Difference	\$	6.12	67	% \$	822,445
27						
28						
29						
30	Finished & Unfinished Space				۵, ۵	
31	Market Cost/Square Foot				% \$	3,038,834
32	ACE - Actual Cost/Square Foot				% \$	658,249
33	Total (no adjustment needed - cost < market)			78	\$ \$	2,380,584

Atlantic City Electric Company 5+7 Months Ending June 2023 Annualization of Depreciation on Year-End June 30, 2023 Plant Adjustment No. 12

(1)	(2)	(3)	(4)		(5)	(6)	(7)
Line <u>No.</u>	Plant Category	Annualized oreciation Exp	 -7 ME Jun 2023 epreciation Exp		<u>Adjustment</u>	ACE Distribution Allocator	<u>\$</u>
1 2	Distribution	\$ 100,819,407	\$ 97,645,303	\$	3,174,104	100.00%	\$ 3,174,104
3 4	General	\$ 16,665,885	\$ 13,279,868	\$	3,386,017	86.55%	\$ 2,930,598
5 6	Total	\$ 117,485,292	\$ 110,925,171	\$	6,560,122		\$ 6,104,702
7 8 9					te Income Tax leral Income Tax		\$ (549,423)
10 11					al Expense		\$ (1,166,609) 4,388,670
12 13				Ear	nings	:	\$ (4,388,670)
14				Rat	e Base		\$ (4,388,670)

Atlantic City Electric Company 5+7 Months Ending June 2023 Depreciation on PHI Service Company Assets Using ACE Depreciation Rates Adjustment No. 13

(1) Line	(2)	(3) ACE	(4) Distribution	(5)
No.	<u>ltem</u>	<u>Total</u>	<u>%</u>	<u>\$</u>
	<u>Earnings</u>			
1	Depreciation	\$ (152,343)	86.55% \$	(131,853)
2				
3	State Income Tax		\$	11,867
4	Federal Income Tax		\$	25,197
5	Total Expense		\$	(94,789)
6				
7	Earnings		\$	94,789

Atlantic City Electric Company 5+7 Months Ending June 2023 Reflect Plant Additions from Jul 2023 -Dec 23 (does not include IIP) Adjustment No. 14

(1)	(2)			(3)						
Line <u>No.</u>	<u>Item</u>		<u>Jı</u>	ıl 23 - Dec 23 Plant Closings \$	<u>s</u>					
<u>140.</u>				₹						
1 2	Earnings Distribution									
3	Book Depreciation Expense	3.26%		\$2,819,717						
5 6	Tax Depreciation Expense - MACRS	3.75%	\$3,593,702							
7	General									
8 9	Book Depreciation Expense	7.24%		\$1,592,762						
10	Tax Depreciation Expense - MACRS	14.29%	\$3,272,723							
11	Deferred Otate Income Tax			\$200.0FF						
12 13	Deferred State Income Tax Deferred Federal Income Tax			\$220,855 \$468,949						
14	State Income Tax			(\$617,978)						
15	Federal Income Tax			(\$1,312,174)						
16 17	Total Expense			\$3,172,131						
18	Earnings			(\$3,172,131)						
19	•		•	<u> </u>						
20	Rate Base									
21 22	Plant in Service Distribution									
23	Distribution Plant Closings			95,832,054						
24	Retirements			(\$9,422,183)						
25	Adjustment to Plant in Service		•	\$86,409,871						
26 27	General									
28	General Plant Closings			26,468,635						
29	Retirements			(\$1,046,065)						
30	Adjustment to General Plant Closings			\$25,422,571						
31 32	Distribution Allocation Ratio Adjustment to General Plant Closings			86.55% \$22,003,235						
33	Adjustment to deneral Flant closings			Ψ22,003,203						
34	Depreciation Reserve									
35	Depreciation Expense			\$4,785,479						
36 37	Retirements Adjustment to Depreciation Reserve			(\$10,327,551) (\$5,542,072)						
38	Adjustment to Depressation Reserve			(\$0,0.12,0.12)						
39	Net Plant			\$113,955,179						
40 41	Deferred State Income Tax			\$220,855						
42	Deferred Federal Income Tax			\$468,949						
43	Not Data Dana Adhirotanasi			#440.005.074						
44 45	Net Rate Base Adjustment		į	\$113,265,374						
45 46	Plant Closings			Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	
47	runt Glosnigs			Jul-23	Aug-23	Sep-23	Oct-23	Nov-23	Dec-23	Total
48	Distribution				3					
49	All Other Project Types			-	(431,263)	(278)	(139)	(89,789)	(35)	(521,504)
50	Capacity Expansion			5,625,541	318,660	283,656	290,831	278,343	791,882	7,588,913
51	Corrective Maintenance			3,033,179	3,290,943	2,784,773	2,932,196	2,435,260	2,169,694	16,646,045
52	Facility Relocation			190,338	206,016	186,990	188,873	191,798	186,077	1,150,092
53	New Business Connections			2,305,686	2,294,097	2,034,709	2,060,757	2,078,515	2,657,506	13,431,270
54	Other EED			4,297,704	4,311,853	4,299,133	4,308,658	4,286,052	4,276,139	25,779,538
55	System Performance IIP 2.0 Removal			3,494,903 (779,167)	6,043,122 (779,167)	7,128,058 (779,167)	5,250,057 (779,167)	4,195,593 (779,167)	10,320,967 (779,167)	36,432,700 (4,675,000)
56	Distribution Total			18,168,184	15,254,261	15,937,874	14,252,066	12,596,606	19,623,064	95,832,054
57				-	-	-	-	-	-	
58	General				4 700					4 700
59 60	All Other Project Types Back Office Allocation			- 276,426	1,730 97,862	100,307	149,091	149,107	- 272,928	1,730 1,045,721
61	BSC Originally Contracted Work			39,780	45,203	50,469	46,689	37,932	25,249	245,322
62	Corrective Maintenance			51,911	51,107	50,816	51,611	52,100	52,950	310,494
63	New Business Connections			68	(67,997)	(891)	(62,890)	(4,672)	(88,777)	(225,158)
64 65	Other EED Proventative Maintenance			312,003	10,442,170	408,079	282,635	269,585	2,461,981	14,176,453
65 66	Preventative Maintenance Real Estate			11,944 38,902	11,780 115,286	11,789 65,420	11,974 66,973	10,738 90,561	5,669 9,789,485	63,893 10,166,628
67	System Performance			50,948	51,052	243,637	51,644	50,751	235,520	683,553
68	General Total	•	•	781,981	10,748,193	929,625	597,727	656,102	12,755,006	26,468,635
69 70	Total			18,950,165	26,002,454	16,867,499	14,849,793	13,252,708	32,378,070	122,300,690
10	TOTAL			10,930,103	20,002,434	10,007,499	14,043,133	13,232,100	32,310,010	122,300,030

Adjusment No. 14.1

Atlantic City Electric Company PLANT ADDITIONS Reflect Plant Additions from July 2023 - December 2023 (excluding IIP & PowerAhead) 5+7 Months Ending June 2023

Line No.	EPS Project ID	EPS Project Name	Forecast Jul-2023	Forecast Aug-2023	Forecast Sep-2023	Forecast Oct-2023	Forecast Nov-2023	Forecast Dec-2023	Total
1	AJ17DAB01	Removal Salvage Cap Eqp ACE	-	(55,162)	(36)	(18)	(9)	(4) \$	(55,229)
2	AJ17DAB02	Salvage Scrap Wire Cable ACE	-	(376,101)	(243)	(121)	(61)	(30) \$	(376,556)
3	AJ17DCB01	Meters ACE	150,949	150,949	150,949	150,949	150,949	150,952 \$	905,696
4	AJ17DCB02	Meter Install ACE	87,816	101,965	89,245	98,770	76,164	66,249 \$	520,209
5	AJ17DEB03	Cape May Sub Establish two ne	3,221	3,576	2,909	3,107	2,991	38,356 \$	54,160
6	AJ17DEB10	Capacity Expansion ACE	140,008	142,465	128,124	130,655	125,894	126,344 \$	793,490
7	AJ17DEB11	ACE Underbuilt Distribution	46	20	34	72	64	41 \$	277
8	AJ17DMB00	Subsurface Silo Transf Replace	66,029	67,756	100,947	102,497	57,724	31,237 \$	426,190
9	AJ17DMB01	Atlantic Region Submarine Ca	41	69	108	116	64	76 \$	475
10	AJ17DMB02	Emergency Restoration OH ACE	1,187,855	1,159,455	1,004,427	1,053,270	803,996	802,151 \$	6,011,155
11	AJ17DMB03	Emergency Restoration UG ACE	168,249	269,993	181,551	198,777	204,749	138,482 \$	1,161,801
12	AJ17DMB05	Cable ACE	155,219	160,138	387,649	506,025	546,621	309,280 \$	2,064,932
13	AJ17DMB06	Planned Pole ACE	384,744	399,047	358,632	243,840	237,211	181,951 \$	1,805,425
14	AJ17DNB02	Solar Projects Dist Line Upg	(9,844)	(9,870)	(9,864)	(9,848)	(9,855)	359,694 \$	310,414
15	AJ17DSB13	Planned Improvements ACE	111,574	101,980	131,591	135,603	132,374	99,085 \$	712,207
16	AJ17DSB14	Priority Feeder Improvemnt ACE	293,470	284,329	263,014	288,082	272,243	247,285 \$	1,648,421
17	AJ17DSB15	Reliability Improvements ACE	51,242	49,000	65,661	66,636	64,917	39,993 \$	337,449
18	AJ17DSB16	Network Xfrmr Prot Planned ACE	57,262	56,325	67,457	74,303	77,067	61,359 \$	393,773
19	AJ17DSB19	Comprehnsve Reliab Improve ACE	58,010	58,675	80,619	80,954	78,972	48,644 \$	405,874
20	AJ17DZB01	Facility Relo Agency ACE	190,511	206,016	186,990	188,873	191,798	186,077 \$	1,150,265
21	AJ17QE105	Cape May Sub Add 2nd 42 45 MV	14,177	15,685	12,913	13,783	13,285	102,030 \$	171,873
22	AJ17QEB03	Williamstown Upgrade T5 UDS	12,047	13,386	10,878	11,604	11,164	10,777 \$	69,856
23	AJ17QMB01	Atlantic Distribution Substati	124,925	136,595	100,333	199,929	72,041	37,928 \$	671,750
24	AJ17QMB02	NERC Physical Security Atlant	1,466	1,469	2	1	1	0 \$	2,939
25	AJ17QS112	Chestnut Neck Retire 69 12 k	-	-	263,906	269,958	258,596	321,416 \$	1,113,876
26	AJ17QS113	Mullica Hill Retire substati	244	473	456	441	224	243 \$	2,081
27	AJ17QSB08	Atlantic Substation Animal Pr	-	1,464	59,746	324,808	229	115 \$	386,361
28	AJ17QSB14	Penns Grove Retire 69 4 kV Su	-	-	-	174,652	167,452	169,267 \$	511,371
29	AJ17QSB25	ECA Repl Dist Batteries ACE	19,236	37	19	9	5	2 \$	19,308
30	AJ17QSB28	ECA Repl DCntrl House Roof ACE	64,338	1,637	63	32	16	8 \$	66,094
31	AJ17QSB29	SCADA RTU Capability ACE	1,911	1,929	38,761	215,586	152	76 \$	258,416
32	AJ17QSB31	ECA Dist Circuit Switch ACE	2,920	2,924	68,989	1,536	29,189	180,474 \$	286,031
33	AJ17QSB33	ECA Repl Dist Breakers ACE	113,954	115,782	290,656	262,686	216,539	134,962 \$	1,134,579
34	AJ17QSB34	ECA Repl DistSub Structure ACE	132,704	9,496	8,256	8,286	117,393	8,408 \$	284,543
35	AJ17RAB01	Tools ACE	82,669	82,669	82,669	82,669	82,669	82,678 \$	496,023
36	AJ17RFB06	Office Furniture ACE	-	12,597	15,078	16,629	20,093	517,234 \$	581,631
37	AJ17RFB07	Security Systems Equip ACE	-	24,446	50,342	50,344	70,468	75,495 \$	271,096
38	AJ17RT150	TR TX FIREWALL Repl ATCO	-	-	-	-	-	4,627 \$	4,627
39	AJ17RT151	TR TX FIREWALL Repl CARDIFF	-	-	-	-	-	51,001 \$	51,001
40	AJ17RT152	TR TX FIREWALL Repl HIGBEE	-	-	-	-	-	50,104 \$	50,104
41	AJ17RT161	TR TX FIREWALL Repl DACOSTA	-	-	-	-	-	36,607 \$	36,607
42	AJ17RT162	TR TX FIREWALL Repl FAIRTON	-	-	-	-	-	4,738 \$	4,738
43	AJ17RT177	TR TX FIREWALL Repl ROWAN	-	-	-	-	-	31,807 \$	31,807
44	AJ17RT183	TR TX FIREWALL Repl ABSECON	-	-	-	-	-	11 \$	11
45	AJ17RTB04	Fiber Work for Solar ACE	0	0	0	0	0	1 \$	1
46	AJ17TS108	Churchtown Pennsgrove 69kV Reb	-	-	-	-	-	(14) \$	(14)
47	AJ17TS139	TSOM 0722 2017 CVI P30 REPAIRS	-	-	20	-	-	- \$	20
48	AJ17TS232	TSOM 0760 2016 CVI P40 REPAIRS	-	-	23	-	-	- \$	23
49	AJ17TS258	TSOM 0784 2016 CVI P40 REPAIRS		-	17	-	-	- \$	17
50	AJ18DM999	Unbilled Capital ACE NJ - Non-	1,305	1,172	1,559	2,208	1,638	1,369 \$	9,252
51	AJ18DNB02	ACE New Business Commercial	881,899	971,318	796,078	825,838	765,206	856,552 \$	5,096,891

Adjusment No. 14.1

Atlantic City Electric Company PLANT ADDITIONS Reflect Plant Additions from July 2023 - December 2023 (excluding IIP & PowerAhead) 5+7 Months Ending June 2023

Line No.	EPS Project ID	EPS Project Name	Forecast Jul-2023	Forecast Aug-2023	Forecast Sep-2023	Forecast Oct-2023	Forecast Nov-2023	Forecast Dec-2023	Total
52	AJ18DNB03	ACE New Business Residential	1,186,207	1,138,592	1,056,480	1,079,253	1,034,892	1,175,432 \$	6,670,856
53	AJ18DNB04	ACE New Business Streetlights	218,014	165,830	182,309	199,896	281,032	282,833 \$	1,329,914
54	AJ18DRB01	SGSM LRP Pool (ACE) - Cap	31,130	31,224	31,135	31,116	31,109	31,099 \$	186,814
55	AJ18DS062	Trip Savers - Core Budget	781	794	1,125	1,155	1,111	605 \$	5,570
56	AJ18DSB01	Newport Sub: Dist Line Mod	-	-	1,125	1,155	-	592,923 \$	592,923
57	AJ18QSB05	ACE Sub Dist Fire Protection	4,752	72,202	76,117	108,396	133,167	3,889 \$	398,524
58	AJ18QSB10	ACE Dist Switch Budget	4,732	23,823	15	190,077	1,469	64 \$	215,448
59	AJ18QSB11	ACE Dist Owner Budget ACE Dist LTC Budget	3,503	3,523	238,812	137,982	167	84 \$	384,070
60	AJ18QSB12	ACE Dist ETO Budget ACE Dist LA Budget	-	10,386	33,790	113,585	2,772	45 \$	160,578
61	AJ18RT052	Chambers EHV FW-DC Sys Replace	_	10,500	-	-	2,112	37,388 \$	37,388
62	AJ19DCB02	Placeholder for ACE AMI	1,459,326	1,459,326	1,459,326	1,459,326	1,459,326	1,459,326 \$	8,755,954
63	AJ19DEB01	ACE TLM BUDGET-ONLY	17,427	17,744	15,870	16,206	15,575	15,621 \$	98,443
64	AJ19DSB03	Churchtown - Pennsgrove	-	-	15,570	10,200	-	1,765,188 \$	1,765,188
65	AJ19DSB04	Monroe to Pinehill Underbuild	_	_	3,046,700	175,818	2,152	2,085 \$	3,226,755
66	AJ19DSB09	Recloser & Battery ACE Capital	11,944	11,780	11,789	11,973	10,738	5,669 \$	63,893
67	AJ19QE001	BEACH HAVEN BATTERY PROJECT	3,762,607	6,440	5,817	6,608	5,810	4,567 \$	3,791,849
68	AJ19QEB01	BEACH HAVEN BATTERY BUDGET	1,491,640	3,145	1,858	2,311	1,702	1,357 \$	1,502,013
69	AJ19QMB04	ACE NJ CM Non-emergency D-Sub	13,529	10,803	688	1,185	1,674	3,331 \$	31,211
70	AJ19QS038	Cardiff AG Install Bus Tie	-	10,003	-	1,100	-	12,154 \$	12,154
71	AJ19QS039	Cardiff LA Upgrade Bus Tie			_	_	_	4,205 \$	4,205
72	AJ19QSB03	High Street 2nd 69/12kV Xfmr	57,764	271,630	180,658	201,242	195,192	175,426 \$	1,081,912
73	AJ19QSB07	ACE Distr Civil Site Assess	119,121	270,573	493,948	18,670	271,991	273,392 \$	1,447,695
74	AJ19QSB08	ACE Districtive Assess ACE Dist Drainage & Driveway	4,761	44,910	2,744	35,782	197,914	5,030 \$	291,141
75	AJ19QSB15	ACE 40MVA 69/12kV Xfmr	-,,,,,,,	(39,325)	2,7-1-1	-	107,014	- \$	(39,325)
76	AJ19QSB19	Dist-Station Transformer Repl	5,322	5,397	4,861	4,937	27,564	5,180 \$	53,262
77	AJ19QSB29	NJ (Dist) Flood Remediation	28,669	207,759	13,374	89	45	22 \$	249,959
78	AJ19RT016	FW Absecon Control House Repl	20,003	201,100	10,574	-	-	83,344 \$	83,344
79	AJ19RT017	FW Cardiff MW Cntl House #1	_		_	_	_	31,487 \$	31,487
80	AJ19RT165	FW Tabernacle FW&DC Install	_	_	_	_	_	89,474 \$	89,474
81	AJ19RT177	SG Fairton Control Bld Router	_		_	_	_	22,392 \$	22,392
82	AJ20DCB01	Budget - Region 1 ACE AMI	2,337,961	2,337,961	2,337,961	2,337,961	2,337,961	2,337,961 \$	14,027,768
83	AJ20DCB02	Budget - Region 2 ACE AMI	258,657	258,657	258,657	258,657	258,657	258,657 \$	1,551,941
84	AJ20DCB03	Budget - Region 3 ACE AMI	3,038	3,038	3,038	3,038	3,038	3,038 \$	18,225
85	AJ20DDB01	ACE NJ Dist Smart Fault Sensor	61,350	63,289	63,278	65,562	60,001	57,301 \$	370,780
86	AJ20DMB02	CrossArm Repl Program ACE	19,658	20,081	28,108	28,827	28,240	16,156 \$	141,070
87	AJ20DNB02	ACE Solar LRP place holder	10,318	9,095	(935)	(1,621)	(2,042)	6,005 \$	20,820
88	AJ20DNB03	LRP for ACE non-PJM customer	7,045	5,748	(238)	(943)	(1,882)	2,949 \$	12,679
89	AJ20DS011	Monroe to Pine Hill Underbuild	23,744	-	(200)	-	(.,552)	- \$	23,744
90	AJ20DS024	Monroe-PHill Undrbuild Winslow	37,335	_	_	_	_	- \$	37,335
91	AJ20DS032	Paulsboro Underbuild	-	-	_	_	_	86,744 \$	86,744
92	AJ20DS085	MDO By Sunoco in Pennsville	_	_	_	_	_	22,014 \$	22,014
93	AJ20DSB02	Paulsboro Underbuild	_	_	_	_	_	784,654 \$	784,654
94	AJ20DSB05	Unfused Lateral Program ACE	34,328	184,056	26,103	171,628	31,046	14,080 \$	461,242
95	AJ20DSB13	Cumberland-Union Dist Underbld	-	-	20,100		-	170,644 \$	170,644
96	AJ20QD008	Second St - Upgrade Fdr Relays	1,443,037	812,947	-	312,658	119,512	118,999 \$	2,807,153
97	AJ20QS041	Salem Land Purchase	-		_	-	-	172,006 \$	172,006
98	AJ20QS071	Glassboro T-3 Bushings	-	_	-	3,867	-	- \$	3,867
99	AJ20QS096	River 34kV DSW D Upgrade	-	_	-	-	-	81,947 \$	81,947
100	AJ20QSB14	Budget 74128 - Williamstown	6,993	7,756	639,956	652,440	135,818	102,902 \$	1,545,865
101	AJ20RF012	Mays Landing Ctrl Cntr Rebuild	-	10,121,394	90,423	-	-	- \$	10,211,817
102	AJ20RNB01	LRP Ace telecom	927	(859)	(834)	(1,030)	(2,437)	(1,971) \$	(6,203)
		** *********	321	(555)	(55.)	(.,000)	(=,)	(.,σ, ψ	(0,200)

Adjusment No. 14.1

Atlantic City Electric Company PLANT ADDITIONS Reflect Plant Additions from July 2023 - December 2023 (excluding IIP & PowerAhead) 5+7 Months Ending June 2023

Line No.	EPS Project ID	EPS Project Name	Forecast Jul-2023	Forecast Aug-2023	Forecast Sep-2023	Forecast Oct-2023	Forecast Nov-2023	Forecast Dec-2023	Total
103	AJ20RNB02	LRP for ace non-pim telecom	898	(774)	(57)	(585)	(2,236)	(1,940) \$	(4,694)
104	AJ20RT027	SG Highee CntlHS PDDN Refresh	-	-	-	(000)	(2,200)	17,827 \$	17,827
105	AJ20RTB06	Sub FO Entr ACE Non-AIIP	219,896	220,231	203,303	166,014	149,052	98,362 \$	1,056,859
106	AJ20RTB07	Router Upg Cores ACE Non-AllP	92,107	100,545	114,353	116,621	120,532	116,665 \$	660,823
107	AJ20XB002	OT Cyber Security ACE Capex	39,780	45,203	50,469	46,689	37,932	25,249 \$	245,322
108	AJ21DDB01	Budget Dist Auto Placeholder	132,297	154,291	197,173	227,232	220,319	425,675 \$	1,356,987
109	AJ21DE006	NJBPU - Solar Hosting Capacity	-	-	-	-	-	5,326 \$	5,326
110	AJ21DMB02	ACE UG Plan Cap P30/P40	161,800	174,206	164,588	169,065	162,330	144,071 \$	976,060
111	AJ21DMB04	ACE OH PLAN CAP P30/P40	353,829	332,563	268,426	275,949	329,836	343,627 \$	1,904,230
112	AJ21DMB05	ACE NJ DIST Porcelain Cutout	57,283	58,240	53,406	54,705	53,616	54,075 \$	331,325
113	AJ21DN007	Solar - PJM AE1-218 Glassboro	-	(2)	-	-	-	- \$	(2)
114	AJ21DN022	Game Creek Warehouse 3 PH Srv	-	-	_	_	_	110,736 \$	110,736
115	AJ21DN051	2121 Eden Rd Solar Dist Reimb	-	_	_	_	_	(40,587) \$	(40,587)
116	AJ21DNB02	BUDGET PROJ-Quinton-Al Distrib	_	_	_	-	_	(106,887) \$	(106,887)
117	AJ21DS001	Church-Pennsgrove Dist Under	-	_	_	_	_	438,530 \$	438,530
118	AJ21DS040	Beach Haven West 5&6 Cab Repl	_	2,922	_	-	_	- \$	2,922
119	AJ21DS055	Winslow South Reliability Work	_	-,022	_	-	_	170,267 \$	170,267
120	AJ21DS061	Rio Villas East Zone Work	_	_	_	_	_	38,822 \$	38,822
121	AJ21DS062	Rio Villas West Zone Work	_	_	_	_	_	57,336 \$	57,336
122	AJ21DSB06	Recloser Saturation ACE Budget	187,042	189,638	224,642	230,301	226,837	158,722 \$	1,217,182
123	AJ21QS010	High St.12k Circuit Breaker	-	-	224,042	200,001	-	265,433 \$	265,433
124	AJ21QS010	Union - Upgrade Fdr Relays	8,694	3,309	577	574	577	596 \$	14,326
125	AJ21QS014 AJ21QS015	Cardiff - Upgrade Fdr Relays	-	5,505	-	-	-	16,875 \$	16,875
126	AJ21QS013	Silver Lake-Upgrade Fdr Relays	_	_	_	_	_	14,261 \$	14,261
127	AJ21QS017	Corson - T4 Relay Replacement	_	_	_	_	_	88,158 \$	88,158
128	AJ21QS020	Williamstown T5	_	_	_	_	_	628,476 \$	628,476
129	AJ21RDB01	Budget Recloser Radio/Control	19,818	19,828	19,121	20,528	19,642	168,136 \$	267,073
130	AJ21RDB01	Budget Radio/Telecom Cor Maint	51,911	51,107	50,816	51,611	52,100	52,950 \$	310,494
131	AJ21RF003	Cape May EV Charging Station	-	-	-	-	-	179,801 \$	179,801
132	AJ21RF004	Pleasantville EV charging Stat	_	_	_	_	_	357,043 \$	357,043
133	AJ21RF005	West Creek EV Charging Station	_	_	_	_	_	181,545 \$	181,545
134	AJ21RN004	Solar Proj AE1-218 100% Reim	_	(65,872)	_	_	_	- \$	(65,872)
135	AJ21RN004	1403 Wheaton Ave-Telecom Reim	_	(03,072)	_	(19,924)	_	- \$	(19,924)
136	AJ21RN009	2121 Eden Rd- Telecom 100%Reim				(13,324)		(84,867) \$	(84,867)
137	AJ21RT019	Rio Grande to Green Creek	_	_	_	_	_	93,303 \$	93,303
138	AJ21RT019	Middle Township ADSS						87,795 \$	87,795
139	AJ21RT150	Harbor Beach UCOMM Equip	_	_	_	_	_	32,189 \$	32,189
140	AJ21RTB03	Deepwater Relocation - Fiber	(1,756)	(492)	_	_	_	- \$	(2,248)
141	AJ22DD001	DA Reconductoring - NJ1400	(1,730)	(432)	_	_	_	26,737 \$	26,737
142	AJ22DD001 AJ22DD004	DA Reconductoring - No 1400 DA Recond-NJ1403/NJ1407/NJ1409	_	_	_	_	_	2,388 \$	2,388
143	AJ22DD007	DA Reconductor - NJ1408/NJ1410						19,019 \$	19,019
144	AJ22DD007 AJ22DD015	YFA Device Licenses - ACE	_	_				547,167 \$	547,167
145	AJ22DEB26	NJ2062 CONDUCTOR UPGRADE	_		_	_	_	508,920 \$	508,920
146	AJ22DEB20 AJ22DGB01	Glassboro Conn Community CAP					432,929	53,443 \$	486,372
140	AJ22DGB01 AJ22DMB01	Replace Dist OH Equip Emergent	- 513,831	681,399	540,027	620,767	500,826	434,324 \$	3,291,175
147	AJ22DMB01 AJ22DMB02	Replace Dist UG Equip Emergent	37,383	37,803	35,320	35,764	34,930	434,324 \$ 34,990 \$	3,291,175 216,190
148	AJ22DMB02 AJ22DN025	1 Technology Dr Dist-100%Reimb	31,383	37,003	35,320	(43,422)	34,930	34,990 \$ - \$	(43,422)
150	AJ22DN025 AJ22DN042	312 UNIT APARTMENT COMPLEX	-	-	-	(43,422)		- \$ - \$	(89,719)
			-	-	-	-	(89,719)		
151 152	AJ22DS012 AJ22DS039	2022 NJ0926 Priority Feeder	-	-	-	-	-	76,657 \$ 4,750 \$	76,657
152	AJ22DS039 AJ22DS042	NJ1983 Cutout R/P Program	-	-	-	-	-		4,750
103	MJZZD304Z	NJ1191 Cutout R/P Program	-	-	-	-	-	176,194 \$	176,194

Adjusment No. 14.1

Atlantic City Electric Company PLANT ADDITIONS Reflect Plant Additions from July 2023 - December 2023 (excluding IIP & PowerAhead) 5+7 Months Ending June 2023

Line No.	EPS Project ID	EPS Project Name	Forecast Jul-2023	Forecast Aug-2023	Forecast Sep-2023	Forecast Oct-2023	Forecast Nov-2023	Forecast Dec-2023	Total
154	AJ22DS062	NJ1983 C/O Replacement Program	-	-	-	-	-	305 \$	305
155	AJ22DSB01	Deepwater Distribution Budget	(173)	-	-	-	-	- \$	(173)
156	AJ22DSB08	Budget ACE NJ - DA Reg Install	27,232	27,452	27,014	55,179	41,031	34,098 \$	212,007
157	AJ22DSB09	Budget ACE NJ - DA Cap Install	62,082	62,415	60,977	61,477	61,343	61,631 \$	369,925
158	AJ22QE001	Clayton Land Purchse	213,814	-	-	-	-	- \$	213,814
159	AJ22QEB01	Logan Land Purchase	-	148,846	131,953	134,979	129,298	129,706 \$	674,782
160	AJ22QN004	1236 Haddonfield Berlin D/SRei	-	-	-	-	-	2 \$	2
161	AJ22QS009	Atco 12KV Brk Replacements	-	-	-	-	-	39,241 \$	39,241
162	AJ22QS018	Huron- AG and LG Installs	-	-	-	-	-	12,690 \$	12,690
163	AJ22QS026	Churchtown Dsub Bus Improve	-	-	-	-	-	4,530 \$	4,530
164	AJ22QS042	Pine Hill Sta Svc ATS Install	-	-	-	-	647	- \$	647
165	AJ22QS059	Rep 12KV breakers "J" Williams	-	-	-	85	-	- \$	85
166	AJ22QSB03	NJ DIST SUB OIL CONTAINMENT	28,034	-	-	-	-	- \$	28,034
167	AJ22QSB04	NJ DIST SUB LIGHTING	79,833	128,348	-	-	-	- \$	208,181
168	AJ22QSB05	ACE NJ Cardiff Sub DA Upgrade	-	-	-	-	-	349,470 \$	349,470
169	AJ22QSB06	ACE NJ Silver Lake Sub DA Upgr	-	-	-	-	-	346,823 \$	346,823
170	AJ22QSB12	Motts Farm Sub Parent	-	2,611,867	122	129	109	120 \$	2,612,346
171	AJ22RB001	Mays Landing Dist Lrng Room	-	-	-	-	-	122,544 \$	122,544
172	AJ22RF020	Cape May Court House Yard Pave	-	78,243	-	-	-	- \$	78,243
173	AJ22RF021	ACE NJ: Pleasantville: Yard Pa	38,902	-	-	-	-	- \$	38,902
174	AJ22RN009	1 Technology Dr- TC 100%Reim	-	-	-	(41,351)	-	- \$	(41,351)
175	AJ22RT001	Tuckahoe Diverse Path ADSS	-	-	-	-	-	393,490 \$	393,490
176	AJ22RT003	Berlin to Silver Lake ADSS	-	-	-	-	-	246,346 \$	246,346
177	AJ22RT005	Seal Isle Sub Diverse Path	-	-	-	-	-	154,274 \$	154,274
178	AJ22RT006	Churchtown to Bridgeton Ph 1	-	-	-	-	-	4,085 \$	4,085
179	AJ22RT008	Cedar to Ship Bottom Rebuild	-	-	-	-	-	18,215 \$	18,215
180	AJ22RT012	Core Upg Carneys Point 1830 7	-	-	-	-	-	153,763 \$	153,763
181	AJ22RT013	Core Upg Mays Landing 1830 775	-	-	-	-	-	153,180 \$	153,180
182	AJ22RTB01	Budget for 79873 Monroe- PH	-	-	193,381	-	-	- \$	193,381
183	AJ22RVB01	Bridgeton Fuel Island Replace	-	-	-	-	-	27,276 \$	27,276
184	AJ22RVB03	Pleasantville Fleet Pole Barn	-	-	-	100,608	100,659	100,663 \$	301,929
185	AJ22RVB04	Glassboro Fleet Pole Barn	226,805	50,896	50,580	160	80	40 \$	328,560
186	AJ22TF006	Kennett Data Center (ACE) Cap	-	-	-	-	-	5,314,826 \$	5,314,826
187	AJ23RF001	Winslow Polebarn / Vehicle Sto	-	-	-	-	-	415,250 \$	415,250
188	AJ23RF003	Winslow Window Replacement	-	-	-	-	-	328,442 \$	328,442
189	AJ23RF004	Pleasantville Roof Replacement	-	-	-	-	-	1,377,344 \$	1,377,344
190	AJ23RF005	Pleasantville Window Replaceme	-	-	-	-	-	352,660 \$	352,660
191	AJ23RF006	Bridgeton Entrance & Sidewalk	-	-	-	-	-	83,318 \$	83,318
192	AJ23RF007	West Creek Gate & Opener Repla	-	-	-	-	-	51,665 \$	51,665
193	AJ23RF008	Cape May Paving Project	-	-	-	-	-	554,863 \$	554,863
194	AJCBAMTLC	AMI Elec Mtr Labor Commercial	(10)	(10)	(10)	(10)	(10)	(10) \$	(60)
195	AJCBAMTLR	AMI Elec Mtr Labor Residential	(32)	(32)	(32)	(32)	(32)	(32) \$	(195)

Adjusment No. 14.1

Atlantic City Electric Company PLANT ADDITIONS Reflect Plant Additions from July 2023 - December 2023 (excluding IIP & PowerAhead) 5+7 Months Ending June 2023

			Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	
Line No.	EPS Project ID	EPS Project Name	 Jul-2023	Aug-2023	Sep-2023	Oct-2023	Nov-2023	Dec-2023	Total
196	AJCBAMTRR	AMI Elec Meter Precap Resident	(0)	(0)	(0)	(0)	(0)	(0) \$	(1)
197	CAPOHACE	A&G Pool - ACE	(33,048)	(35,704)	(32,942)	(34,345)	(34,300)	(32,996) \$	(203,336)
198	ITACE229A	PHI LLO - ACE Q4 2021 HW	-	-	-	-	-	454,420 \$	454,420
199	SPIT110A	Fission - IT Apps Target DD	-	1,730	-	-	-	- \$	1,730
200		IIP 2.0 Unfused Laterals	(18,333)	(18,333)	(18,333)	(18,333)	(18,333)	(18,333) \$	(110,000)
201		IIP 2.0 Capacitor Bank Upgrade Project	(45,833)	(45,833)	(45,833)	(45,833)	(45,833)	(45,833) \$	(275,000)
202		IIP 2.0 Capacitor Controller Upgrade Project	(45,833)	(45,833)	(45,833)	(45,833)	(45,833)	(45,833) \$	(275,000)
203		IIP 2.0 ACE NJ Recloser Installation	(320,833)	(320,833)	(320,833)	(320,833)	(320,833)	(320,833) \$	(1,925,000)
204		IIP 2.0 Regulator Controller Upgrade Project	(55,000)	(55,000)	(55,000)	(55,000)	(55,000)	(55,000) \$	(330,000)
205		IIP 2.0 Replace Deteriorated URD Cable	(36,667)	(36,667)	(36,667)	(36,667)	(36,667)	(36,667) \$	(220,000)
206		IIP 2.0 DA Feeder Improvement Project	(45,833)	(45,833)	(45,833)	(45,833)	(45,833)	(45,833) \$	(275,000)
207		IIP 2.0 Strengthen DA Feeder Ties	(137,500)	(137,500)	(137,500)	(137,500)	(137,500)	(137,500) \$	(825,000)
208		IIP 2.0 ACE NJ Distribution Smart Fault Sensors	(73,333)	(73,333)	(73,333)	(73,333)	(73,333)	(73,333) \$	(440,000)
			\$ 18,950,165 \$	26,002,454 \$	16,867,499 \$	14,849,793 \$	13,252,708 \$	32,378,070 \$	122,300,690

Atlantic City Electric Company 5+7 Months Ending June 2023 Reflect Plant Additions from Jan 2024 - Jun 2024 (does not include IIP) Adjustment No. 15

(1) Line <u>No.</u>	(2) Item		<u>Jan 24</u>	(3) - Jun 24 Plant Closin	g <u>s</u>					
1	Earnings Distribution									
2	Book Depreciation Expense	3.26%		\$1,924,755						
3 4	Tou Depresiation Funence MACRS	3.75% \$	2 565 220							
5	Tax Depreciation Expense - MACRS	3.75% 3	2,565,228							
	General									
	Book Depreciation Expense	7.24% \$	303,186	\$237,649						
	Tax Depreciation Expense - MACRS	14.29% \$	598,351							
6 7	Deferred State Income Tax Deferred Federal Income Tax			\$90,106 \$191,324						
8	State Income Tax			(\$284,722)						
9	Federal Income Tax			(\$604,560)						
10	Total Expense			\$1,554,552						
11 12	Earnings			(\$1,554,552)						
13	Lannigo		•	(ψ1,001,002)						
14	Rate Base									
15	Plant in Service									
16 17	Distribution Plant Closings Retirements			68,406,073 (\$9,422,183)						
18	Adjustment to Plant in Service		-	\$58.983.891						
19	,			***,***,***						
20	General									
21 22	General Plant Closings			4,839,254						
23	Retirements Adjustment to General Plant Closings			(\$1,046,065) \$3,793,190						
24	Distribution Allocation Ratio			86.55%						
25	Adjustment to General Plant Closings			\$3,283,006						
26										
27 28	Depreciation Reserve Depreciation Expense			\$2,535,405						
29	Retirements			(\$10,327,551)						
30	Adjustment to Depreciation Reserve		-	(\$7,792,146)						
31	N . B		-							
32 33	Net Plant			\$70,059,043						
34	Deferred State Income Tax			\$90.106						
35	Deferred Federal Income Tax		_	\$191,324						
36	Not Data Dana Adicatasan			600 777 040						
37 38	Net Rate Base Adjustment			\$69,777,613						
39	Distribution Plant Closings			Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	
40	Distribution Flam Gloomigo			Jan-24	Feb-24	Mar-24	Apr-24	May-24	Jun-24	Total
41	Distribution									
42 43	All Other Project Types Capacity Expansion			186.292	181.564	- 177.157	- 174.748	2.388.419	461.223	3,569,404
43 44	Corrective Maintenance			2.851.665	2,697,582	3,188,404	3,424,762	3,461,287	3.074.128	18.697.829
45	Facility Relocation			203,832	192,283	195,977	200,664	211,473	190,022	1,194,251
	New Business Connections			2,859,321	2,527,366	2,078,702	2,002,124	2,175,214	2,115,051	13,757,778
	Other EED			4,305,294	4,288,209	4,282,333	4,295,848	4,293,096	4,282,881	25,747,660
	System Performance IIP 2.0 Removal			2,018,114 (2,124,702)	2,509,192 (2,124,702)	2,854,627 (2,124,702)	3,479,612 (2,124,702)	3,604,443 (2,124,702)	3,721,379 (2,124,702)	18,187,366 (12,748,215)
	Distribution Total			10,299,816	10,271,494	10,652,498	11,453,056	14,009,229	11,719,981	68,406,073
				-	-	-	-	-	-	
	General All Other Project Types									
	Back Office Allocation			148,505	152,855	277,487	276,303	274,529	279,150	1,408,829
	BSC Originally Contracted Work			18,762	18,183	20,714	24,488	26,382	33,979	142,508
	Corrective Maintenance			54,073	54,277	54,205	54,255	54,302	54,700	325,812
	New Business Connections Other EED			(4,878)	8,205	9,062	(4,424)	(336)	(4,603)	3,025
	Other EED Preventative Maintenance			257,095 9,221	265,315 11,217	261,419 12,366	464,650 13,133	567,453 13,525	515,940 13,810	2,331,873 73,271
	Real Estate			15,394	35,851	35,839	15,375	-	-	102,459
	System Performance			70,743	84,395	73,762	121,181	50,473	50,925	451,478
	General Total			568,915	630,297	744,853	964,961	986,327	943,901	4,839,254
	Total			10,868,731	10,901,791	11,397,351	12,418,016	14,995,556	12,663,882	73,245,328

Adjusment No. 15.1

Atlantic City Electric Company PLANT ADDITIONS Reflect Plant Additions from January 2024 - July 2024 (excluding IIP & PowerAhead) 5+7 Months Ending June 2023

Line No.	EPS Project ID	EPS Project Name	Forecast Jan-2024	Forecast Feb-2024	Forecast Mar-2024	Forecast Apr-2024	Forecast May-2024	Forecast Jun-2024	1	Γotal
1	AJ17DCB01	Meters ACE	133,010	133,010	133,010	133,010	133,010	133,010	\$	798.061
2	AJ17DCB02	Meter Install ACE	113,345	96,260	90,384	103,899	101,147	90,932		595,967
3	AJ17DEB10	Capacity Expansion ACE	186,243	181,477	177,107	174,678	181,000	178,182		1,078,688
4	AJ17DEB11	ACE Underbuilt Distribution	48	87	50	70	25	20		300
5	AJ17DMB00	Subsurface Silo Transf Replace	70,135	68,018	98,842	98,041	67,767	66,247		469,050
6	AJ17DMB01	Atlantic Region Submarine Ca	61	142	54	90	68	60		476
7	AJ17DMB02	Emergency Restoration OH ACE	1,155,488	1,175,782	1,234,447	1,319,262	1,158,670	1,262,717		7,306,366
8	AJ17DMB03	Emergency Restoration UG ACE	173,779	151,820	149,464	154,841	170,923	139,889	\$	940,716
9	AJ17DMB05	Cable ACE	260,338	180,298	157,171	261,453	507,197	553,772		1,920,229
10	AJ17DMB06	Planned Pole ACE	62,311	86,898	99,327	342,731	353,937	346,431		1,291,633
11	AJ17DNB02	Solar Projects Dist Line Upg	(29,969)	(29,960)	(30,026)	(29,999)	(30,036)	(30,057)		(180,047)
12	AJ17DSB13	Planned Improvements ACE	90,349	101,496	192,246	189,311	195,792	155,137		924,330
13	AJ17DSB14	Priority Feeder Improvemnt ACE	332,177	319,623	380,920	348,791	393,031	326,130		2,100,674
14	AJ17DSB15	Reliability Improvements ACE	78,414	89,994	158,888	158,422	161,074	122,252		769,044
15	AJ17DSB16	Network Xfrmr Prot Planned ACE	47,784	46,224	75,999	90,210	99,611	87,555		447,382
16	AJ17DSB19	Comprehnsve Reliab Improve ACE	103,826	127,226	286,897	292,214	298,217	190,894		1,299,274
17	AJ17DZB01	Facility Relo Agency ACE	203,832	192,283	195,977	200,664	211,473	190,022		1,194,251
18	AJ17QE105	Cape May Sub Add 2nd 42 45 MV	10,672	9,464	10,528	11,772	10,107	8,740		61,282
19	AJ17QMB01	Atlantic Distribution Substati	143,412	1,033	156,832	1,287	93,080	44,104		439,748
20	AJ17QMB02	NERC Physical Security Atlant	140,412	1,000	100,002	1,207	-	171,692		171,692
21	AJ17QSB08	Atlantic Substation Animal Pr			3,626	94,478	16,649	37		114,791
22	AJ17QSB25	ECA Repl Dist Batteries ACE	9,117	14,047	15,123	3,602	95,824	148,770		286,483
23	AJ17QSB25 AJ17QSB26	ECA Repl Dist Bushings ACE	1,222	1,194	1,172	1,151	1,193	1,183		7,115
24	AJ17QSB28	ECA Repl DCntrl House Roof ACE	-	1,134	- 1,172	9,853	105,091	71,244		186,188
25	AJ17QSB29	SCADA RTU Capability ACE	1,932	16,261	15,877	15,639	16,244	2,547		68,500
26	AJ17QSB29 AJ17QSB31	ECA Dist Circuit Switch ACE	2,673	3,236	23,915	23,553	17,189	2,648		73,214
27	AJ17QSB31 AJ17QSB33	ECA Repl Dist Breakers ACE	119,750	390,940	334,653	253,902	120,018	114,707		1,333,970
28	AJ17QSB33 AJ17QSB34	ECA Repl DistSub Structure ACE	3,172	39,430	37,621	8,451	12,714	7,846		109,233
29	AJ17RAB01	Tools ACE	84,738	84,738	84,738	84,738	84,738	84,738		508,428
30	AJ17RAB01 AJ17RTB04	Fiber Work for Solar ACE	04,738	04,736	04,730	04,736	04,736	04,730		1
31	AJ18DM999			2,264				1,213		10,195
32	AJ18DNB02	Unbilled Capital ACE NJ - Non-	1,618 1,052,897	2,26 4 985,116	1,883	1,723 865,859	1,494 809,092	902,064		5,499,049
32 33	AJ18DNB02 AJ18DNB03	ACE New Business Commercial			884,020			966,902		6,771,156
33 34	AJ18DNB03	ACE New Business Residential	1,564,452	1,345,176	946,059	988,518	960,050	,		
34 35		ACE New Business Streetlights	200,078	164,144	225,133	178,371	199,447	283,028 57,269		1,250,201
	AJ18QSB05	ACE Sub Dist Fire Protection	-	5,636	5,122	12,904	74,430			155,362
36	AJ18QSB10	ACE Dist Switch Budget	-	- 0.400	- 4 575	- 4 400	56,256	32		56,288
37	AJ18QSB11	ACE Dist LTC Budget	3,513	3,423	4,575	4,469	3,440	3,423		22,844
38	AJ18QSB12	ACE Dist LA Budget	-	-	12,932	24,340	134,292	86		171,650
39	AJ19DCB02	Placeholder for ACE AMI	1,459,326	1,459,326	1,459,326	1,459,326	1,459,326	1,459,326		8,755,954
40	AJ19DSB09	Recloser & Battery ACE Capital	9,221	11,217	12,366	13,133	13,525	13,810		73,271
41	AJ19QE001	BEACH HAVEN BATTERY PROJECT	1	-	-	-	-		\$	1
42	AJ19QMB04	ACE NJ CM Non-emergency D-Sub	25,890	125	1,432	17,660	43,654	102,631		191,392
43	AJ19QSB07	ACE Distr Civil Site Assess	-	-	-	-	50,518	49,176		99,694
44	AJ19QSB08	ACE Dist Drainage & Driveway	-	-	-	-	-	5,200		5,200
45	AJ19QSB19	Dist-Station Transformer Repl	-					17,606		17,606
46	AJ19QSB29	NJ (Dist) Flood Remediation	-	5,109	5,011	124,885	2,995	14,302		152,301
47	AJ20DCB01	Budget - Region 1 ACE AMI	2,337,961	2,337,961	2,337,961	2,337,961	2,337,961	2,337,961		14,027,768
48	AJ20DCB02	Budget - Region 2 ACE AMI	258,657	258,657	258,657	258,657	258,657	258,657		1,551,941
49	AJ20DCB03	Budget - Region 3 ACE AMI	3,038	3,038	3,038	3,038	3,038	3,038		18,225
50	AJ20DDB01	ACE NJ Dist Smart Fault Sensor	54,656	53,286	52,593	52,224	52,445	62,591		327,795
51	AJ20DMB02	CrossArm Repl Program ACE	8,849	11,083	27,358	26,924	27,907	17,982	\$	120,103

Adjusment No. 15.1

Atlantic City Electric Company PLANT ADDITIONS Reflect Plant Additions from January 2024 - July 2024 (excluding IIP & PowerAhead) 5+7 Months Ending June 2023

			Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	
Line No.	EPS Project ID	EPS Project Name	Jan-2024	Feb-2024	Mar-2024	Apr-2024	May-2024	Jun-2024	 Total
52	AJ20DN043	Repauno Sub Distribution	-	-	-	-	5,879		\$ 5,879
53	AJ20DNB02	ACE Solar LRP place holder	11,292	8,798	6,081	(115)	2,994	4,560	33,609
54	AJ20DNB03	LRP for ACE non-PJM customer	6,892	5,454	3,425	(458)	1,644	2,496	19,454
55	AJ20DSB05	Unfused Lateral Program ACE	75,264	23,039	22,615	22,375	72,862	38,451	\$ 254,606
56	AJ20QN001	Repauno Sub Dist	-	-	-	-	225,066	-	\$ 225,066
57	AJ20QNB01	Repauno Sub - Dist Sub	-	-	-	-	-	(15,026)	\$ (15,026)
58	AJ20QSB14	Budget 74128 - Williamstown	358,233	348,024	232,235	-	-	-	\$ 938,492
59	AJ20RNB01	LRP Ace telecom	(1,975)	(1,999)	(1,994)	(2,016)	(2,043)	(1,889)	\$ (11,916)
60	AJ20RNB02	LRP for ace non-pjm telecom	(2,904)	(2,935)	(2,082)	(2,408)	(2,615)	(2,714)	\$ (15,658)
61	AJ20RT020	Repauno Sub Fiber	-	-	-	-	4,322	-	\$ 4,322
62	AJ20RTB03	Repauno Substation - Fiber	-	13,139	13,139	-	-	-	\$ 26,278
63	AJ20RTB06	Sub FO Entr ACE Non-AIIP	77,784	93,512	84,638	116,294	185,401	179,479	\$ 737,109
64	AJ20RTB07	Router Upg Cores ACE Non-AIIP	88,899	81,391	86,394	99,684	133,076	146,128	\$ 635,573
65	AJ20XB002	OT Cyber Security ACE Capex	18,762	18,183	20,714	24,488	26,382	33,979	\$ 142,508
66	AJ21DDB01	Budget Dist Auto Placeholder	158,849	156,689	281,570	278,967	204,653	202,449	\$ 1,283,178
67	AJ21DMB02	ACE UG Plan Cap P30/P40	191,172	189,524	182,750	201,512	200,310	174,254	\$ 1,139,522
68	AJ21DMB04	ACE OH PLAN CAP P30/P40	356,688	330,016	302,728	330,409	375,623	292,751	\$ 1,988,216
69	AJ21DMB05	ACE NJ DIST Porcelain Cutout	58,447	57,254	56,209	55,257	57,309	56,236	\$ 340,712
70	AJ21DN054	Quinton-Al Distr 100% REIMB	-	-	-	(41,353)	-	-	\$ (41,353)
71	AJ21DNB02	BUDGET PROJ-Quinton-Al Distrib	53,678	48,637	44,010	41,301	1,079	1,084	\$ 189,789
72	AJ21DSB06	Recloser Saturation ACE Budget	133,735	155,983	252,144	238,210	246,306	187,455	\$ 1,213,832
73	AJ21QS013	Woodstown - Upgrade Fdr Relay	-	-	-	-	6,743	-	\$ 6,743
74	AJ21QS015	Cardiff - Upgrade Fdr Relays	683	683	694	692	-	-	\$ 2,751
75	AJ21QS017	Silver Lake-Upgrade Fdr Relays	683	683	694	692	-	-	\$ 2,751
76	AJ21QS025	WINSLOW T2 XFMR UPGRADE	-	-	-	384,911	-	-	\$ 384,911
77	AJ21QS029	Huron - CAP Fdn Replacement	-	-	-	-	-	24,011	\$ 24,011
78	AJ21QS032	Newport-Cap Fdn Replacement	-	-	-	-	-	33,968	\$ 33,968
79	AJ21QS033	Paulsboro-Cap Fdn Replacement	-	-	-	-	-	27,615	\$ 27,615
80	AJ21RDB01	Budget Recloser Radio/Control	70,742	84,395	73,762	121,181	50,473	50,925	\$ 451,477
81	AJ21RDB02	Budget Radio/Telecom Cor Maint	54,073	54,277	54,205	54,255	54,302	54,700	\$ 325,812
82	AJ22DEB06	Nortonville 2nd Transformer	-	-	-	-	2,207,393	283,021	\$ 2,490,414
83	AJ22DGB01	Glassboro Conn Community CAP	5,563	5,563	13,903	13,909	13,925	41,818	\$ 94,681
84	AJ22DMB01	Replace Dist OH Equip Emergent	628,649	647,891	900,883	893,193	929,939	588,298	\$ 4,588,853
85	AJ22DMB02	Replace Dist UG Equip Emergent	33,614	32,987	32,405	37,088	37,915	37,551	\$ 211,560
86	AJ22DSB03	Winslow Dis Line Budget	-	-	-	-	52,252	-	\$ 52,252
87	AJ22DSB08	Budget ACE NJ - DA Reg Install	31,426	29,989	29,137	28,654	28,588	28,530	\$ 176,323
88	AJ22DSB09	Budget ACE NJ - DA Cap Install	56,995	56,659	56,388	56,095	56,702	56,395	\$ 339,234
89	AJ22QS023	Cardiff DA Fdr Relay Upgrade	-	-	-	2,909	-	-	\$ 2,909
90	AJ22QS024	Silver Lake DA Fdr Relay Upgra	-	-	507	-	-	-	\$ 507
91	AJ22QS025	Cardiff Dsub Bus Improvements	-	-	-	356	-	-	\$ 356
92	AJ22QS027	Silver Lake Dsub Bus Improve	-	-	176	-	-	-	\$ 176
93	AJ22QS040	ATL Mobile Unit A12 Purchase	-	-	-	-	-	770,077	\$ 770,077

Adjusment No. 15.1

Atlantic City Electric Company PLANT ADDITIONS Reflect Plant Additions from January 2024 - July 2024 (excluding IIP & PowerAhead) 5+7 Months Ending June 2023

			Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	
Line No.	EPS Project ID	EPS Project Name	Jan-2024	Feb-2024	Mar-2024	Apr-2024	May-2024	Jun-2024	Total
94	AJ22QSB03	NJ DIST SUB OIL CONTAINMENT	7,852	7,636	39,222	2,471	2,555	2,568	\$ 62,303
95	AJ22QSB04	NJ DIST SUB LIGHTING	7,511	32,918	32,837	33,896	17,698	75,926	\$ 200,786
96	AJ22QSB05	ACE NJ Cardiff Sub DA Upgrade	820	113,593	2,470	301,505	311,099	1,041	\$ 730,528
97	AJ22QSB06	ACE NJ Silver Lake Sub DA Upgr	2,458	113,593	58,955	77,090	1,049	-	\$ 253,145
98	AJ22QSB08	ACE NJ Woodstown Sub DA Upgrad	-	-	-	-	108,377	-	\$ 108,377
99	AJ22RVB01	Bridgeton Fuel Island Replace	90,411	90,411	90,387	248,672	248,976	190,333	\$ 959,190
100	AJ22RVB03	Pleasantville Fleet Pole Barn	100,573	100,747	226,374	226,529	226,835	227,096	\$ 1,108,155
101	AJ22TF006	Kennett Data Center (ACE) Cap	15,394	35,851	35,839	15,375	-	-	\$ 102,459
102	AJCBAMTLC	AMI Elec Mtr Labor Commercial	(10)	(10)	(10)	(10)	(10)	(10)	\$ (60)
103	AJCBAMTLR	AMI Elec Mtr Labor Residential	(32)	(32)	(32)	(32)	(32)	(32)	\$ (195)
104	AJCBAMTRR	AMI Elec Meter Precap Resident	(0)	(0)	(0)	(0)	(0)	(0)	\$ (1)
105	CAPOHACE	A&G Pool - ACE	(36,806)	(32,630)	(33,626)	(34,964)	(37,044)	(32,684)	\$ (207,754)
106		IIP 2.0 Priority Feeders	(551,001)	(551,001)	(551,001)	(551,001)	(551,001)	(551,001)	\$ (3,306,004)
107		IIP 2.0 Unfused Laterals	(138,935)	(138,935)	(138,935)	(138,935)	(138,935)	(138,935)	\$ (833,611)
108		IIP 2.0 Capacitor Bank Upgrade Project	(36,667)	(36,667)	(36,667)	(36,667)	(36,667)	(36,667)	\$ (220,000)
109		IIP 2.0 Capacitor Controller Upgrade Project	(24,933)	(24,933)	(24,933)	(24,933)	(24,933)	(24,933)	\$ (149,600)
110		IIP 2.0 ACE NJ Recloser Installation	(399,667)	(399,667)	(399,667)	(399,667)	(399,667)	(399,667)	\$ (2,398,000)
111		IIP 2.0 Regulator Controller Upgrade Project	(36,667)	(36,667)	(36,667)	(36,667)	(36,667)	(36,667)	\$ (220,000)
112		IIP 2.0 Replace Deteriorated URD Cable	(403,333)	(403,333)	(403,333)	(403,333)	(403,333)	(403,333)	\$ (2,420,000)
113		IIP 2.0 Network Transformer and Protector Replacement	(47,667)	(47,667)	(47,667)	(47,667)	(47,667)	(47,667)	\$ (286,000)
114		IIP 2.0 Substation Reverse Power Protection Project (8 Projects)	(183,333)	(183,333)	(183,333)	(183,333)	(183,333)	(183,333)	\$ (1,100,000)
115		IIP 2.0 DA Feeder Improvement Project	(110,000)	(110,000)	(110,000)	(110,000)	(110,000)	(110,000)	\$ (660,000)
116		IIP 2.0 Strengthen DA Feeder Ties	(128,333)	(128,333)	(128,333)	(128,333)	(128,333)	(128,333)	\$ (770,000)
117		IIP 2.0 ACE NJ Distribution Smart Fault Sensors	(64,167)	(64,167)	(64,167)	(64,167)	(64,167)	(64,167)	\$ (385,000)
			10,868,731 \$	10,901,791 \$	11,397,351 \$	12,418,016 \$	14,995,556 \$	12,663,882	\$ 73,245,328

Atlantic City Electric Company 5+7 Months Ending June 2023 Reflect Credit Facilities Cost Adjustment No. 16

(1)	(2)	(3)					
Line <u>No.</u>	<u>Item</u>	<u>D</u>	<u>istribution</u>				
1	Earnings_						
2	Expense	\$	730,952 (1)				
3							
4	State Income Tax	\$	(65,786)				
5	Federal Income Tax	\$	(139,685)				
6	Total Expenses	\$	525,482				
7							
8	Earnings	\$	(525,482)				
9							
10	Rate Base	_					
11	Amortizable Balance	\$	578,298 (2)				
12							
13							
14		•	0.40.07.4				
15	(1) Annual amortization of start-up costs	\$ \$ \$	249,874				
16	Annual cost of maintaining credit facility	\$	594,669				
17	Total ACE expense	\$	844,543				
18	1050	•	0.4.4.5.40				
19	ACE System	\$	844,543				
20	Allocation to Distribution	_	86.55%				
21	ACE Distribution	\$	730,952				
22							
23							
24	(2) Luna 22 Amartizable Delance	æ	000 407				
25	(2) June 23 Amortizable Balance	\$	668,167				
26	ACE Customs	φ	000 407				
27	ACE System	\$	668,167				
28	Allocation to Distribution	Φ.	86.55%				
29	ACE Distribution	\$	578,298				

Atlantic City Electric Company 0 Restate Interest on Customer Deposit Expense Adjustment No. 17

(1)	(2)		(3)			
Line <u>No.</u>	<u>Item</u>	<u>\$</u>				
1 2	Customer Deposit Balance @ 5+7 ending June 23	\$	24,578,540			
3	2023 Interest Rate		1.40%			
5 6	Annual Interest Expense	\$	344,100			
7 8	Interest Expense @ 5+7 ending June 23	\$	11,532			
9 10	IOCD Expense	\$	332,567			
11 12	Distribution Allocation		100%			
13 14	Distribution Allocation Amount	\$	332,567			
15 16	State Income Tax	\$	(29,931)			
17 18	Federal Income Tax	\$	(63,554)			
19 20	Total Expense	\$	239,083			
21	Earnings	\$	(239,083)			

Atlantic City Electric Company 5+7 Months Ending June 2023 Remove Annual IIP Revenue Requirement Adjustment No. 18

(1) Line	(2)	(3)
No.	<u>ltem</u>	<u>\$</u>
1	<u>Earnings</u>	
2		
3		
4	Depreciation	\$ (3,898,500)
5	Deferred State Income Tax	\$21,656
6	Deferred Federal Income Tax	\$45,982
7	State Income Tax	\$512,837
8	Federal Income Tax	 \$1,088,923
9	Total Expense	\$ (2,229,103)
10		
11	Earnings	\$ 2,229,103
12		
13	Rate Base	
14	Gross Plant	(93,253,216)
15	Accumulated Depreciation	(\$1,802,799)
16	Deferred State Income Tax	\$21,656
17	Deferred Federal Income Tax	 \$45,982
18		
19	Net Rate Base Adjustment	 (91,518,054)

Atlantic City Electric Company 5+7 Months Ending June 2023 <u>Cash Working Capital on Proforma Adjustments</u> Adjustment No. 19

(1)	(2)	(3)		(4)		(5)		(6)		(7)	(8)		(9)	(10)	(11)	(12)	(13)		(14)
Line No.	<u>Adjustment</u>	Revenue		O&M	Dep	rec/Amort		ther axes	9	SIT	DSIT		<u>FIT</u>	DFIT	IOCD	Total Expense	Interest		Earnings
	Reflect the Revenue Annualization Associated with Conservation Incentive Program ("CIF \$	997.792					•	3.007 \$		89.531		•	190.103			\$ 282,641		•	715.151
2	Reflect Revenue Associated with Customer Counts as of December, 2023		\$				\$	3.928 \$		116.934		¢.	248,290			\$ 369.152		\$	934.044
3	Annualize Wage and FICA changes through March 2024	1,000,107	Š	2.953.226			\$ 1	64.627 \$		(280,607)		\$	(595,822)			\$ 2.241.425		\$	(2,241,425)
4	Proform Wage Rate Changes for Rate Effective Period		\$	95.162			\$	4.635 \$,	(8,982)		ŝ	(19,071)			\$ 71.744		\$	(71,744)
5	Regulatory Commission Expense Adjustment		\$	(36,872)			-	\$		3.318		\$	7.046			\$ (26,507)		Š	26.507
6	Pension and Other Post-Employment Benefits ("OPEB") Expense Adjustment		Š	1.421.369				Š	((127,923)		Š	(271,624)			\$ 1,021,822		\$	(1,021,822)
7	Reflection of 5-year Average Inflation on Non-Labor O&M Expense		\$	4,628,106				\$		(416,530)		\$	(884,431)			\$ 3,327,145		\$	(3,327,145)
8	Remove Executive Incentive Expense		\$	(1,269,775)				\$		114,280		\$	242,654			\$ (912,841)		\$	912,841
9	Storms		\$	2,317,368				\$	((208,563)		\$	(442,849)			\$ 1,665,956		\$	(1,665,956)
10	Normalize Injury & Damage Expense		\$	(1,450,526)				\$		130,547		\$	277,195			\$ (1,042,783)		\$	1,042,783
11	Adjust Mays Landing Complex Rent \$	-						\$		-		\$	-			\$ -		\$	-
12	Annualize Depreciation Expense @ June 23 Plant				\$	6,104,702		\$	((549,423)		\$	(1,166,609)			\$ 4,388,670		\$	(4,388,670)
13	Servco Assets @ ACE Approved Depreciation Rates				\$	(131,853)		\$		11,867		\$	25,197			\$ (94,789)		\$	94,789
14	Reflect Plant Additions from Jul 2023 - Dec 2023				\$	4,412,478		\$		(617,978) \$	220,855		(1,312,174) \$	468,949		\$ 3,172,131		\$	(3,172,131)
15	Reflect Plant Additions from Jan 2024 - Jun 2024				\$	2,162,404		\$		(284,722) \$	90,106	\$	(604,560) \$	191,324		\$ 1,554,552		\$	(1,554,552)
16	Credit Facilities Fee		\$	730,952				\$		(65,786)		\$	(139,685)			\$ 525,482		\$	(525,482)
17	Interest on Customer Deposit							\$		(29,931)		\$	(63,554)		\$ 332,567	\$ 239,083		\$	(239,083)
18	Remove Annual IIP Revenue Requirement				\$	(3,898,500)		\$		512,837 \$	21,656	\$	1,088,923 \$	45,982		\$ (2,229,103)		\$	2,229,103
19	Interest Synchronization							\$	((228,944)		\$	(486,125)			\$ (715,069)		\$	715,069
20	Corporate Alternative Minimum Tax ("CAMT") Adjustment							\$		-		\$	-			\$ -		\$	-
21	Excess Deferred Income Taxes ("EDIT") – Expiring Riders Regulatory Asset							\$		-		\$	-			\$ -		\$	-
22	Reflection of Electric Vehicle Regulatory Asset				\$	520,580		\$		(46,852)		\$	(99,483)			\$ 374,245		\$	(374,245)
23	SEN Investment Deferral Regulatory Asset				\$	1,134,715		\$	((102,124)		\$	(216,844)			\$ 815,747		\$	(815,747)
24	AMI SEN Incremental O&M Expenses		\$	2,538,023				\$	((228,422)		\$	(485,016)			\$ 1,824,585		\$	(1,824,585)
25	Benchmarking Requirement		\$	140.355	\$	105,162		\$,	(22,097)		\$	(46,918)			\$ 176,502		\$	(176,502)
26	3 1, 1 1									(, ,			(-//						, -, ,
27																			
28	Total \$	2.300.989	\$	12.067.387	\$	10,409,689	\$ 1	76.198 \$	(2.	,239,570) \$	332,617	\$	(4,755,354) \$	706,256	\$ 332.567	\$ 17.029.790	\$	- \$	(14.728.801)
29	Cash Working Capital Ratio	_,,	7	8.710%	-	16.397%		7.487%	ζ-,	4.815%	4.815%	, •	4.815%	4.815%		÷,520,700	Ŧ	Ψ.	(, 5,00)
30	Cash Working Capital Requirement		\$	1.051.027	\$		\$	30.811									\$	- \$	2.788.756
31	Table 1 and		~	.,,021	-	.,,	*	,									•	Ψ	_, 5,, 00
01																			

Atlantic City Electric Company 5+7 Months Ending June 2023 Adjust Interest Synchronization Adjustment No. 20

(1) Line	(2	2)	(3)
No.	<u>lte</u>	<u>em</u>	<u>\$</u>
1 2	Adjusted Rate Base	\$	2,235,749,719
3 4 5	Weighted Cost Rate Long Term Debt		1.86%
6 7	Proforma Interest Expense	\$	41,584,945
8 9	Test Year Interest Expense	\$	39,041,122
10 11	Change in Interest Expense	\$	2,543,823
12 13	Taxable Income	\$	(2,543,823)
14	Operating Expense		
15	State Income Tax	\$	(228,944)
16	Federal Income Tax	_ \$	(486,125)
17 18	Total Expense	\$	(715,069)
19	Earnings		715,069

Atlantic City Electric Company Corporate Alternative Minimum Tax ("CAMT") Adjustment 5+7 Months Ending June 2023 Adjustment No. 21

(1)	(2)		(3)
Line No.	Item		Amount
	Rate Base		
1	Rate Effective Period		
2	CMT Deferred Tax Asset	\$	14,002,624
3	Distribution Allocated		12,119,271
4			
5			
6	Adjustment to Rate Base		12,119,271
7			
8	Adjustment to Federal Deferred Income Tax Expense		12,119,271
9			_
10	Total Rate Base	\$	12,119,271

Atlantic City Electric Company Excess Deferred Income Tax (EDIT) Adjustment 5+7 Months Ending June 2023 Adjustment No. 22

(1)	(2)	(3)
Line No.	ltem	Amount
1	<u>EDIT</u>	
2 3 4	EDIT Regulatory Asset	259,707
5 6 7	DSIT DFIT	(23,374)
8 9	Adjustment to Rate Base	(49,630) 186,703
10	Rate Base	\$ 186,703

Atlantic City Electric Company Electric Vehicle Reg Asset 5+7 Months Ending June 2023 Adjustment No. 23

(1) Line	(2)		(3)
No.	Adjustment 23 - Reflection of Electric Vehicle Regulatory Asset		Amount
	Earnings		
1 2	Electric Vehicle Costs Deferred Balance	\$	1,561,741
3 4	Adjustment to Amortization Expense (3 year amortization period)		520,580
5 6	Adjustment to state income tax expense		(46,852)
7 8	Adjustment to federal income tax expense	-	(99,483)
9 10	Total Expense		374,245
11	Earnings	\$	(374,245)
12 13			
14 15	Rate Base		
16 17	Electric Vehicle Costs Deferred Balance	\$	1,561,741
18 19	Decline in Balance after year 1		(260,290)
20 21	Total average unamortized rate base balances		1,301,451
22 23	Adjustment to accumulated deferred income taxes		(368,658)
24	Adjustment to rate base, net of accumulated deferred taxes		932,794
25 26	Rate Base	\$	932,794

Atlantic City Electric Company 5+7 Months Ending June 2023 SEN Investment Deferral Regulatory Asset Adjustment No. 24

(1)	(2)		(3)
Line <u>No.</u>	<u>Item</u>	<u>Di</u>	stribution
1 2	<u>Earnings</u>		
3	SEN Investment Deferral Regulatory Asset - June 30th, 2023	\$	5,673,575
4	Proposed Amortization period	*	5
5	·		
6	Amortization of SEN Investment Deferral	\$	1,134,715
7			
8		•	
9	State Income Tax	\$	(102,124)
10	Federal Income Tax	<u>\$</u> \$	(216,844)
11 12	Total Expenses	Ф	815,747
13	Earnings	\$	(815,747)
14		<u> </u>	(818,117
15			
16	Rate Base		
17	Average Amortizable Balance -SEN Investment Deferral Regulatory Asset	\$	5,106,217
18			
19	Deferred State Income Tax	\$	(459,560)
20	Deferred Federal Income Tax	\$	(975,798)
21	Total Data Dasa		0.070.000
22	Total Rate Base	\$	3,670,860
23 24	(1) SEN Investment Deferral - Amortizable Base	¢	E 672 E7E
2 4 25	Amortization Period (Years)	\$ \$	5,673,575 5
26	Amortization Expense	φ \$	1,134,715
27	Amonization Expense	Ψ	1,104,710
28	(2) Unamortized Balance of SEN Investment Deferral - Beg. Of Period	\$	5,673,575
29	Amortization Expense - 1st Year	\$	1,134,715
30	Unamortized Balance - End Of Period	\$ \$ \$	4,538,860
31	Average - Year 1	\$	5,106,217

Atlantic City Electric Company 5+7 Months Ending June 2023 AMI SEN Incremental O&M Expenses Adjustment No. 25

(1) Line	(2)		(3)
No.	<u>ltem</u>	<u>D</u>	<u>istribution</u>
1	<u>Earnings</u>		
2			
3	Incremental SEN O&M Regulatory Asset - June 30th, 2023	\$	12,690,116
4	Proposed Amortization period		5
5	Amendication of CEN COM Devolution, Accord		0.500.000
6 7	Amortization of SEN O&M Regulatory Asset	\$	2,538,023
8			
9	State Income Tax	\$	(228,422)
10	Federal Income Tax	\$ \$ \$	(485,016)
11	Total Expenses	\$	1,824,585
12 13	Earnings	¢	(4 924 595)
14	Earnings	\$	(1,824,585)
15			
16	Rate Base		
17	Average Amortizable Balance -Incremental SEN O&M Regulatory Asset	\$	11,421,104
18			
19	Deferred State Income Tax	\$	(1,027,899)
20 21	Deferred Federal Income Tax	\$	(2,182,573)
22	Total Rate Base	\$	8,210,632
23	Total Nato Bass	<u> </u>	0,210,002
24	(1) SEN O&M Defferal - Amortizable Base	\$	12,690,116
25	Amortization Period (Years)	\$ \$	5
26	Amortization Expense	\$	2,538,023
27	(0) II	•	10.000.110
28	(2) Unamortized Balance of SEN O&M - Beg. Of Period	\$	12,690,116
29 30	Amortization Expense - 1st Year Unamortized Balance - End Of Period	\$ \$	2,538,023 10,152,093
31	Average - Year 1	<u>\$</u> \$	11,421,104
		*	, ,

Atlantic City Electric Company Benchmark Requirement 5+7 Months Ending June 2023 Adjustment No. 26

(1) Line No.	(2) Item	(3) Amount
1	Earnings	
2		
3		
4	Benchmarking Requirement - O&M Related Regulatory Asset	315,485
5	Adii ataa aat ta Aasaatiistiisa Furaasaa (Ouraan aasaatiisatiisa saaisal)	405.400
6 7	Adjustment to Amortization Expense (3 year amortization period)	105,162
8	Ongoing O&M Maintenance Expense - PHI	552,360
9	ongoing Cain maintenance Expense 1711	332,333
10	ACE Allocation	25.41%
11		
12	Ongoing O&M Maintenance Expense - ACE	140,355
13	A divertise and the extent in a constant and a constant	(00.007)
14 15	Adjustment to state income tax expense	(22,097)
16	Adjustment to federal income tax expense	(46,918)
17	Adjustment to rederal moonie tax expense	(40,010)
18	Total Expense	176,502
19	·	
20	Earnings	(176,502)
21		
22		
23	Rate Base	
24 25	Panahmarking Paguirament Conital	805,154
26 26	Benchmarking Requirement - Capital	005,154
27	Benchmarking Requirement - O&M related	315,485
28		5 7 5, 7 5 5
29	Decline in Balance after year 1	(52,581)
30		
31	Total average unamortized rate base balances	262,904
32	Total Data Daga	4.000.050
33 34	Total Rate Base	1,068,058
3 4 35	Adjustment to accumulated deferred income taxes	(302,545)
36	. Isjania to accumulated action of modific taxoc	(002,010)
37	Adjustment to Rate Base	765,513

Atlantic City Electric Company Overall Rate of Return Pro Forma as of September 30, 2022

Type of Capital	Ratios	Cost Rate	Weighted Cost Rate
Long-Term Debt	49.80%	3.73%	1.86%
Common Equity	50.20%	10.50%	5.27%
Total	100.00%		7.13%

Atlantic City Electric Company Cost of Debt Pro Forma as of September 30, 2022

	Pro Forma 6/3	30/23
Type of Capital	Amount	Ratios
	(\$)	
Long-Term Debt	1,823,150,000	
Unamortized Net Discount	(566,882)	
Unamortized Debt Issuance Costs	(10,454,439)	
Unamortized Debt Reacquisition Costs	(2,543,927)	
Total Long-Term Debt	1,809,584,752	49.80%
Common Equity	1,824,119,569	50.20%
Total	3,633,704,321	100.00%

Atlantic City Electric Company Cost of Debt Long-Term Debt Pro Forma as of September 30, 2022

					Cur	rent			
			•	Principal	Unamortized	Unamortized		Effective	Annual
	Coupon			Amount	Debt Issuance	(Premium)/	Net Amount	Cost	Net
Issue	Rate	Maturity	Offering Date	Outstanding	Expense	Discount	Outstanding	Rate	Cost
First Mortgage Bonds									
First Mortgage Bollus	4.00%	10/15/28	10/16/18	\$350,000,000	\$1,841,087	\$222,992	\$347,935,921	4.11%	\$14,305,601
	3.38%	09/01/24	08/25/14	\$150,000,000	\$302,748	\$222,992 \$14,176	\$149,683,075	3.49%	\$5,223,115
	3.500%	12/01/25	12/08/15	\$150,000,000	\$400,987	\$14,176	\$149,599,014	3.60%	\$5,385,945
	3.500%	05/21/29	05/21/19	\$100,000,000	\$540,140	\$0 \$0	\$99,459,860	3.59%	\$3,572,635
	4.14%	05/21/29	05/21/19	\$50,000,000	\$357,999	\$0 \$0	\$49,642,001	4.18%	\$2,077,450
	3.24%	06/09/50	06/09/20	\$100,000,000	\$337,999 \$707,990	\$0 \$0	\$99,292,010	3.28%	\$3,255,919
	2.30%	03/15/31	03/10/21	\$350,000,000	\$2,427,079	\$162,179	\$347,410,742	2.39%	\$8,307,309
	2.27%	03/15/31	11/16/21	\$75.000,000	\$471.306	\$102,179	\$74,528,694	2.35%	\$1,748,033
	3.06%	02/15/52	02/15/22	\$150,000,000	\$1,003,246	\$0 \$0	\$148,996,754	3.09%	\$4,611,203
	2.27%	02/15/32	02/15/22	\$25,000,000	\$184,490	\$0 \$0	\$24,815,510	2.35%	\$582,490
	5.55%	02/15/52	03/15/23	\$75,000,000	\$750,000	\$0 \$0	\$74,250,000	5.62%	\$4,172,364
Total First Mortgage Bonds	5.55%	03/13/33	03/15/23	\$1,575,000,000	\$8,987,071	\$399,348	\$1,565,613,581	5.02%	\$53,242,062
Total First Mortgage Bollus			•	\$1,373,000,000	φο,θοτ,θτι	φ399,346	\$1,505,015,561		φ33,242,002
Senior Notes									
	5.80%	5/15/2034	4/8/2004	\$120,000,000	\$759,673	\$167,534	\$119,072,792	5.91%	\$7,042,351
	5.80%	3/1/2036	3/15/2006	\$105,000,000	\$365,652	\$0	\$104,634,348	5.85%	\$6,120,358
Total Senior Notes				\$225,000,000	\$1,125,326	\$167,534	\$223,707,140		\$13,162,709
Tax Exempt Fixed Rate Bonds									
Tax Exempt Fixed Rate Bolius	2.25%	6/1/2029	6/2/2020	\$23,150,000	\$342,043	\$0	\$22,807,957	2.49%	\$568,486
Total Tax Exempt Fixed Rate Bond	ls			\$23,150,000	\$342,043	\$0	\$22,807,957		\$568,486
·			•	· · · ·	• •	·	· · · · · ·		
Unamortized Debt Reacquisition C	ost						(\$2,543,927)		\$520,235
Total I am Tama Baht Balanca				£4,000,450,000	£40.454.400	\$500,000	<u> </u>	0.700/	
Total Long-Term Debt Balance			:	\$1,823,150,000	\$10,454,439	\$566,882	\$1,809,584,752	3.73%	\$67,493,492

Atlantic City Electric Company Calculation of the Effective Cost Rate of Long-Term Debt Pro Forma as of September 30, 2022

					0	riginal		Net	Effective
	Coupon		•	Principal	Debt Issuance	(Premium)/	Net Amount	Amount	Cost
Issue	Rate	Maturity	Offering Date	Amount Issued	Expense	Discount	to Company	Per Unit	Rate
First Mortgage	Bonds								
	4.00%	10/15/2028	10/16/2018	\$350,000,000	\$2,831,904	\$343,000	\$346,825,096	\$99.09	4.11%
	3.38%	9/1/2024	8/25/2014	\$150,000,000	\$1,376,973	\$64,500	\$148,558,527	\$99.04	3.49%
	3.50%	12/1/2025	12/8/2015	\$150,000,000	\$1,252,365	\$0	\$148,747,635	\$99.17	3.60%
	3.50%	5/21/2029	5/21/2019	\$100,000,000	\$767,495	\$0	\$99,232,505	\$99.23	3.59%
	4.14%	5/21/2049	5/21/2019	\$50,000,000	\$381,289	\$0	\$49,618,711	\$99.24	4.18%
	3.24%	6/9/2050	6/9/2020	\$100,000,000	\$743,629	\$0	\$99,256,371	\$99.26	3.28%
	2.30%	3/15/2031	3/10/2021	\$350,000,000	\$2,828,459	\$0	\$347,171,541	\$99.19	2.39%
	2.27%	2/15/2032	11/16/2021	\$75,000,000	\$514,030	\$0	\$74,485,970	\$99.31	2.35%
	3.06%	2/15/2052	2/15/2022	\$150,000,000	\$1,016,406	\$0	\$148,983,594	\$99.32	3.09%
	2.27%	2/15/2032	2/15/2022	\$25,000,000	\$171,312	\$0	\$24,828,688	\$99.31	2.35%
Pro Forma	5.55%	3/15/2053	3/15/2023	\$75,000,000	\$750,000	\$0	\$74,250,000	\$99.00	5.62%
Senior Notes									
	5.80%	5/15/2034	4/8/2004	\$120,000,000	\$1,558,257	\$368,400	\$118,073,343	\$98.39	5.91%
	5.80%	3/1/2036	3/15/2006	\$105,000,000	\$730,537	\$0	\$104,269,463	\$99.30	5.85%
Tau 5 5:	us d Data D								
Tax Exempt Fi			0/0/0000	#00.450.000	£440.050	C O	#00 700 040	#00.00	0.400/
	2.25%	6/1/2029	6/2/2020	\$23,150,000	\$449,958	\$0	\$22,700,043	\$98.06	2.49%

Pepco Holdings Inc. (Consolidated) Capitalization and Related Capital Structure Ratios Actual at September 30, 2022

	Actual at September 3 Amount	<u>0, 2022</u>
	Outstanding (\$ millions)	Ratios
Long-Term Debt	8,039 (1)	41.65%
Common Equity	11,263	58.35%
Total Permanent Capital	19,302	100.00%

Notes: (1) Excludes unamortized debt issuance costs, discount, premium, reacquired debt costs, and Pepco lease obligations.

Exhibit G

Schedule of Payments or Accruals to Affiliated Companies

ATLANTIC CTY ELECTRIC COMPANY NINE MONTHS ENDED SEPTEMBER 30, 2022 PAYMENTS OR ACCRUALS TO AFFILIATES FOR SERVICES AND GOODS (\$000)

DELMARVA POWER & LIGHT COMPANY	
Materials	1,109
Extra-High Voltage (EHV) Transmission Agreement charges	59
Facility Services Mutual Assistance	14 9
Total Delmarva Power & Light Company	1,191
POTOMAC ELECTRIC POWER COMPANY	
Materials	134
Adjustment of mutual assistance recorded in prior periods	(96
Total Potomac Electric Power Company	38
COMMONWEALTH EDISON COMPANY	
Materials	197
Fransmission System Operations Services nformation Technology Services	112 29
Total Commonwealth Edison Company	338
BALTIMORE GAS & ELECTRIC COMPANY	
nformation Technology Services	37
Fransmission System Operations Services	-
Drone Training Services	1
True-up of BGE CAM Overhead	
Total Baltimore Gas & Electric Company	32
PECO ENERGY COMPANY	~-
Extra-High Voltage (EHV) Transmission Agreement charges nformation Technology Services	22
Jtility Charges at Transmission Operations Center in Kennett Square	
Total PECO Energy Company	23
CONSTELLATION ENERGY COMMODITIES GROUP	
Purchased Power	1,655
Total Constellation Energy Commodities Group (a)	1,655
EXELON CLEARSIGHT, LLC	
nspection Services	83
CONSTELLATION POWER SOURCE GENERATION	
	5
MILLENNIUM ACCOUNT SERVICES LLC	
Mechanical and Electrical Industrial Services Total Constellation Power Source Generation (a) MILLENNIUM ACCOUNT SERVICES LLC	4,389
Mechanical and Electrical Industrial Services Total Constellation Power Source Generation (a) MILLENNIUM ACCOUNT SERVICES LLC Meter Reading Services Total Millennium Account Services LLC	4,389
Mechanical and Electrical Industrial Services Total Constellation Power Source Generation (a) MILLENNIUM ACCOUNT SERVICES LLC Meter Reading Services Total Millennium Account Services LLC ATLANTIC SOUTHERN PROPERTIES, INC.	4,389
Mechanical and Electrical Industrial Services Total Constellation Power Source Generation (a) MILLENNIUM ACCOUNT SERVICES LLC Meter Reading Services Total Millennium Account Services LLC	4,389
Mechanical and Electrical Industrial Services Total Constellation Power Source Generation (a) MILLENNIUM ACCOUNT SERVICES LLC Meter Reading Services Total Millennium Account Services LLC ATLANTIC SOUTHERN PROPERTIES, INC. Facility Services Total Atlantic Southern Properties, Inc.	4,389
Mechanical and Electrical Industrial Services Total Constellation Power Source Generation (a) MILLENNIUM ACCOUNT SERVICES LLC Meter Reading Services Total Millennium Account Services LLC ATLANTIC SOUTHERN PROPERTIES, INC. Facility Services Total Atlantic Southern Properties, Inc. EXELON BUSINESS SERVICES COMPANY	4,389 4,389 429 429
Mechanical and Electrical Industrial Services Total Constellation Power Source Generation (a) MILLENNIUM ACCOUNT SERVICES LLC Meter Reading Services Total Millennium Account Services LLC ATLANTIC SOUTHERN PROPERTIES, INC. Facility Services Total Atlantic Southern Properties, Inc. EXELON BUSINESS SERVICES COMPANY Information Technology Services	4,389 4,389 425 425 57,042
Mechanical and Electrical Industrial Services Total Constellation Power Source Generation (a) MILLENNIUM ACCOUNT SERVICES LLC Meter Reading Services Total Millennium Account Services LLC ATLANTIC SOUTHERN PROPERTIES, INC. Facility Services Total Atlantic Southern Properties, Inc. EXELON BUSINESS SERVICES COMPANY Information Technology Services Financial Services	4,389 4,389 429 429 57,049 5,940
Mechanical and Electrical Industrial Services Total Constellation Power Source Generation (a) MILLENNIUM ACCOUNT SERVICES LLC Meter Reading Services Total Millennium Account Services LLC ATLANTIC SOUTHERN PROPERTIES, INC. Facility Services Total Atlantic Southern Properties, Inc. EXELON BUSINESS SERVICES COMPANY Information Technology Services Financial Services Utility Strategy, Policy, and Oversight Services	4,389 4,389 429 429 57,042 5,940 4,163
Mechanical and Electrical Industrial Services Total Constellation Power Source Generation (a) MILLENNIUM ACCOUNT SERVICES LLC Meter Reading Services Total Millennium Account Services LLC ATLANTIC SOUTHERN PROPERTIES, INC. Facility Services Total Atlantic Southern Properties, Inc. EXELON BUSINESS SERVICES COMPANY Information Technology Services Financial Services Utility Strategy, Policy, and Oversight Services Legal Services	4,389 4,389 429 429 57,049 5,940 4,169 3,114
Mechanical and Electrical Industrial Services Total Constellation Power Source Generation (a) MILLENNIUM ACCOUNT SERVICES LLC Meter Reading Services Total Millennium Account Services LLC ATLANTIC SOUTHERN PROPERTIES, INC. Facility Services Total Atlantic Southern Properties, Inc. EXELON BUSINESS SERVICES COMPANY Information Technology Services Financial Services Utility Strategy, Policy, and Oversight Services Legal Services Security Services	4,389 4,389 4,389 429 429 57,040 5,940 4,160 3,114 2,274
Mechanical and Electrical Industrial Services Total Constellation Power Source Generation (a) MILLENNIUM ACCOUNT SERVICES LLC Meter Reading Services Total Millennium Account Services LLC ATLANTIC SOUTHERN PROPERTIES, INC. Facility Services Total Atlantic Southern Properties, Inc. EXELON BUSINESS SERVICES COMPANY Information Technology Services Financial Services Utility Strategy, Policy, and Oversight Services Legal Services Becurity Services Human Resources Services Executive Management Services	4,389 4,389 4,389 429 429 57,049 5,940 4,169 3,114 2,274 1,520 1,449
Mechanical and Electrical Industrial Services Total Constellation Power Source Generation (a) MILLENNIUM ACCOUNT SERVICES LLC Meter Reading Services Total Millennium Account Services LLC ATLANTIC SOUTHERN PROPERTIES, INC. Facility Services Total Atlantic Southern Properties, Inc. EXELON BUSINESS SERVICES COMPANY Information Technology Services Financial Services Utility Strategy, Policy, and Oversight Services Legal Services Becurity Services Human Resources Services Executive Management Services Executive Management Services Executive Services	4,389 4,389 4,389 429 429 57,049 5,940 4,169 3,114 2,274 1,520 1,449 1,189
Mechanical and Electrical Industrial Services Total Constellation Power Source Generation (a) MILLENNIUM ACCOUNT SERVICES LLC Meter Reading Services Total Millennium Account Services LLC ATLANTIC SOUTHERN PROPERTIES, INC. Facility Services Total Atlantic Southern Properties, Inc. EXELON BUSINESS SERVICES COMPANY Information Technology Services Financial Services Utility Strategy, Policy, and Oversight Services Legal Services Human Resources Services Executive Management Services Executive Management Services Other Services Other Services	4,389 4,389 4,389 429 429 57,049 5,940 4,169 3,114 2,274 1,529 1,449 1,189 1,169
Mechanical and Electrical Industrial Services Total Constellation Power Source Generation (a) MILLENNIUM ACCOUNT SERVICES LLC Meter Reading Services Total Millennium Account Services LLC ATLANTIC SOUTHERN PROPERTIES, INC. Facility Services Total Atlantic Southern Properties, Inc. EXELON BUSINESS SERVICES COMPANY Information Technology Services Financial Services Jtility Strategy, Policy, and Oversight Services Legal Services Security Services Human Resources Services Executive Management Services Executive Management Services Other Services Communication Services	4,389 4,389 4,389 429 429 57,042 5,940 4,163 3,114 2,274 1,522 1,449 1,183 1,162 469
Mechanical and Electrical Industrial Services Total Constellation Power Source Generation (a) MILLENNIUM ACCOUNT SERVICES LLC Meter Reading Services Total Millennium Account Services LLC ATLANTIC SOUTHERN PROPERTIES, INC. Facility Services Total Atlantic Southern Properties, Inc. EXELON BUSINESS SERVICES COMPANY Information Technology Services Financial Services Utility Strategy, Policy, and Oversight Services Legal Services Security Services Human Resources Services Executive Management Services Communication Services Communication Services Real Estate Services	4,389 4,389 4,389 4,389 4,389 4,29 4,29 4,163 3,114 2,274 1,522 1,449 1,183 1,162 469 329
Mechanical and Electrical Industrial Services Total Constellation Power Source Generation (a) MILLENNIUM ACCOUNT SERVICES LLC Meter Reading Services Total Millennium Account Services LLC ATLANTIC SOUTHERN PROPERTIES, INC. Facility Services Total Atlantic Southern Properties, Inc. EXELON BUSINESS SERVICES COMPANY Information Technology Services Financial Services Utility Strategy, Policy, and Oversight Services Legal Services Security Services Human Resources Services Executive Management Services Communication Services Communication Services Real Estate Services	4,389 4,389 4,389 429 429 57,042 5,940 4,163 3,114 2,274 1,522 1,449 1,187 1,162 469 329 147
Mechanical and Electrical Industrial Services Total Constellation Power Source Generation (a) MILLENNIUM ACCOUNT SERVICES LLC Meter Reading Services Total Millennium Account Services LLC ATLANTIC SOUTHERN PROPERTIES, INC. Facility Services Total Atlantic Southern Properties, Inc. EXELON BUSINESS SERVICES COMPANY Information Technology Services Financial Services Jtility Strategy, Policy, and Oversight Services Legal Services Security Services Human Resources Services Executive Management Services Executive Management Services Communication Services Communication Services Regulatory and Government Affairs Services Total Exelon Business Services Company	4,389 4,389 4,389 429 429 57,042 5,940 4,163 3,114 2,274 1,522 1,449 1,187 1,162 469 329 147
Mechanical and Electrical Industrial Services Total Constellation Power Source Generation (a) MILLENNIUM ACCOUNT SERVICES LLC Meter Reading Services Total Millennium Account Services LLC ATLANTIC SOUTHERN PROPERTIES, INC. Facility Services Total Atlantic Southern Properties, Inc. EXELON BUSINESS SERVICES COMPANY Information Technology Services Financial Services Jtility Strategy, Policy, and Oversight Services Legal Services Security Services Human Resources Services Executive Management Services Executive Management Services Communication Services Real Estate Services Regulatory and Government Affairs Services Total Exelon Business Services Company	4,389 4,389 4,389 4,389 4,389 4,389 57,042 5,940 4,163 3,114 2,274 1,522 1,449 1,187 1,162 469 329 147 78,789
Mechanical and Electrical Industrial Services Total Constellation Power Source Generation (a) MILLENNIUM ACCOUNT SERVICES LLC Meter Reading Services Total Millennium Account Services LLC ATLANTIC SOUTHERN PROPERTIES, INC. Facility Services Total Atlantic Southern Properties, Inc. EXELON BUSINESS SERVICES COMPANY Information Technology Services Financial Services Utility Strategy, Policy, and Oversight Services Legal Services Executive Management Services Executive Management Services Executive Management Services Communication Services Real Estate Services Regulatory and Government Affairs Services Total Exelon Business Services Company PHI SERVICE COMPANY Customer Services	4,389 4,389 4,389 4,389 4,389 57,042 5,940 4,163 3,114 2,274 1,522 1,449 1,187 1,162 469 329 147 78,789
Mechanical and Electrical Industrial Services Total Constellation Power Source Generation (a) MILLENNIUM ACCOUNT SERVICES LLC Meter Reading Services Total Millennium Account Services LLC ATLANTIC SOUTHERN PROPERTIES, INC. Facility Services Total Atlantic Southern Properties, Inc. EXELON BUSINESS SERVICES COMPANY Information Technology Services Financial Services Jtility Strategy, Policy, and Oversight Services Legal Services Security Services Human Resources Services Executive Management Services Supply Services Communication Services Real Estate Services Regulatory and Government Affairs Services Total Exelon Business Services Company PHI SERVICE COMPANY Customer Services Regulated Electric Operations Services Information Technology Services	4,389 4,389 4,389 4,389 4,389 4,389 4,389 57,042 5,940 4,163 3,114 2,274 1,522 1,449 1,187 1,162 469 329 147 78,789
Mechanical and Electrical Industrial Services Total Constellation Power Source Generation (a) MILLENNIUM ACCOUNT SERVICES LLC Meter Reading Services Total Millennium Account Services LLC ATLANTIC SOUTHERN PROPERTIES, INC. Facility Services Total Atlantic Southern Properties, Inc. EXELON BUSINESS SERVICES COMPANY Information Technology Services Financial Services Julitity Strategy, Policy, and Oversight Services Legal Services Gecurity Services Human Resources Services Executive Management Services Supply Services Other Services Communication Services Regulatory and Government Affairs Services Total Exelon Business Services Company PHI SERVICE COMPANY Customer Services Regulated Electric Operations Services Regulatory Services Regulatory Services Regulatory Services Regulatory Services Regulatory Services	4,389 4,389 4,389 4,389 4,389 4,389 57,043 5,940 4,163 3,114 2,,274 1,522 1,449 1,187 1,162 469 329 147 78,789 25,819 21,299 8,859 5,268
Mechanical and Electrical Industrial Services Total Constellation Power Source Generation (a) MILLENNIUM ACCOUNT SERVICES LLC Meter Reading Services Total Millennium Account Services LLC ATLANTIC SOUTHERN PROPERTIES, INC. Facility Services Total Atlantic Southern Properties, Inc. EXELON BUSINESS SERVICES COMPANY Information Technology Services Financial Services Utility Strategy, Policy, and Oversight Services Legal Services Security Services Human Resources Services Executive Management Services Executive Management Services Communication Services Regulatory and Government Affairs Services Total Exelon Business Services Company PHI SERVICE COMPANY Customer Services Regulated Electric Operations Services Regulatory Services	4,389 4,389 4,389 4,389 4,389 4,389 57,041 5,940 4,163 3,114 2,274 1,522 1,449 1,187 1,162 465 329 147 78,789 25,819 21,299 8,859 5,268 5,033
Mechanical and Electrical Industrial Services Total Constellation Power Source Generation (a) MILLENNIUM ACCOUNT SERVICES LLC Meter Reading Services Total Millennium Account Services LLC ATLANTIC SOUTHERN PROPERTIES, INC. Facility Services Total Atlantic Southern Properties, Inc. EXELON BUSINESS SERVICES COMPANY Information Technology Services Financial Services Utility Strategy, Policy, and Oversight Services Legal Services Human Resources Services Executive Management Services Executive Management Services Communication Services Regulatory and Government Affairs Services Total Exelon Business Services Company PHI SERVICE COMPANY Customer Services Regulated Electric Operations Services Regulatory Services	4,389 4,389 4,389 4,389 4,389 4,389 4,389 57,041 5,940 4,163 3,114 2,274 1,522 1,449 1,187 1,162 469 329 147 78,789 25,819 21,299 8,859 5,268 5,033 4,388
Mechanical and Electrical Industrial Services Total Constellation Power Source Generation (a) MILLENNIUM ACCOUNT SERVICES LLC Meter Reading Services Total Millennium Account Services LLC ATLANTIC SOUTHERN PROPERTIES, INC. Facility Services Total Atlantic Southern Properties, Inc. EXELON BUSINESS SERVICES COMPANY Information Technology Services Financial Services Utility Strategy, Policy, and Oversight Services Legal Services Becurity Services Human Resources Services Executive Management Services Communication Services Regulatory and Government Affairs Services Total Exelon Business Services Company PHI SERVICE COMPANY Customer Services Regulated Electric Operations Services Regulatory Services	4,389 4,389 4,389 4,389 4,389 57,041 5,940 4,163 3,114 2,274 1,522 1,445 1,187 1,162 465 325 147 78,785 25,815 21,299 8,859 5,268 5,033 4,388 2,511
Mechanical and Electrical Industrial Services Total Constellation Power Source Generation (a) MILLENNIUM ACCOUNT SERVICES LLC Meter Reading Services Total Millennium Account Services LLC ATLANTIC SOUTHERN PROPERTIES, INC. Facility Services Total Atlantic Southern Properties, Inc. EXELON BUSINESS SERVICES COMPANY Information Technology Services Financial Services Juliity Strategy, Policy, and Oversight Services Legal Services Security Services Human Resources Services Executive Management Services Communication Services Real Estate Services Regulatory and Government Affairs Services Total Exelon Business Services Company PHI SERVICE COMPANY Customer Services Regulated Electric Operations Services Regulatory Services Support Services Support Services Support Services Executive Management Services Executive Management Services Executive Management Services Support Services Executive Management Services	4,389 4,389 4,389 4,389 4,389 4,389 57,041 5,940 4,163 3,114 2,274 1,522 1,449 1,187 1,162 469 329 147 78,789 25,819 21,299 8,859 5,268 5,033 4,388 2,511 2,371
Mechanical and Electrical Industrial Services Total Constellation Power Source Generation (a) MILLENNIUM ACCOUNT SERVICES LLC Meter Reading Services Total Millennium Account Services LLC ATLANTIC SOUTHERN PROPERTIES, INC. Facility Services Total Atlantic Southern Properties, Inc. EXELON BUSINESS SERVICES COMPANY Information Technology Services Financial Services Julility Strategy, Policy, and Oversight Services Legal Services Legal Services Leward Management Services Executive Management Services Executive Management Services Communication Services Regulatory and Government Affairs Services Total Exelon Business Services Company PHI SERVICE COMPANY Customer Services Regulated Electric Operations Services Regulatory Services Support Services Executive Management Services Support Services Su	4,389 4,389 4,389 4,389 4,389 57,041 5,940 4,163 3,114 2,274 1,522 1,445 1,187 1,162 469 329 147 78,785 25,819 21,298 8,859 5,268 5,033 4,388 2,511 2,371 1,368
Total Constellation Power Source Generation (a) MILLENNIUM ACCOUNT SERVICES LLC Meter Reading Services Total Millennium Account Services LLC ATLANTIC SOUTHERN PROPERTIES, INC. Facility Services Total Atlantic Southern Properties, Inc. EXELON BUSINESS SERVICES COMPANY Information Technology Services Financial Services Julility Strategy, Policy, and Oversight Services Legal Services Human Resources Services Executive Management Services Communication Services Communication Services Regulatory and Government Affairs Services Regulatory and Government Affairs Services Regulated Electric Operations Services Regulated Electric Operations Services Regulatory Services Support Services Regulatory Services Support Services Regulated Electric Operations Services Regulated Electric Operations Services Regulatory Services Support Services Support Services Enancial Services Executive Management Services Executive Management Services Executive Management Services Executive Management Services Communication Services Executive Management Services Communications Services Communications Services Communications Services	4,389 4,389 4,389 4,389 4,389 57,040 5,940 4,160 3,114 2,274 1,522 1,449 1,180 1,162 469 329 149 78,789 25,819 21,299 8,859 5,268 5,030 4,388 2,510 2,370 1,368 1,059
Mechanical and Electrical Industrial Services Total Constellation Power Source Generation (a) MILLENNIUM ACCOUNT SERVICES LLC Meter Reading Services Total Millennium Account Services LLC ATLANTIC SOUTHERN PROPERTIES, INC. Facility Services Total Atlantic Southern Properties, Inc. EXELON BUSINESS SERVICES COMPANY Information Technology Services Financial Services Julility Strategy, Policy, and Oversight Services Legal Services Becurity Services Human Resources Services Executive Management Services Communication Services Regulatory and Government Affairs Services Total Exelon Business Services Company PHI SERVICE COMPANY Customer Services Regulated Electric Operations Services Regulatory Services Regulatory Services Regulatory Services Regulatory Services Regulated Electric Operations Services Regulatory Services	4,389 4,389 4,389 4,389 4,389 57,043 5,940 4,163 3,114 2,274 1,522 1,449 1,187 1,162 469 329 147 78,789 25,819 21,299 8,859 5,268 5,033 4,388 2,513 2,373

⁽a) This amount represents one month of charges to ACE for these affiliates as a result of the separation that occurred on February 1, 2022 between Exelon's Utility entities and Generation (ExGen), one of Exelon's principal subsdiaries, into two publicly traded companies - Exelon and Constellation.

Exhibit H

Voluntary Data Requests

Atlantic City Electric Company February 2023 Base Rate Case

Preliminary Data Requests

- **P-AREV-1** Re: Format Provide full explanation and justification of all claims that differ from the unadjusted test period operating revenues and expenses that were not fully explained and justified in the filing.
- **P-AREV-2** Re: Format Provide a list identifying all estimates and forecasts in the filing that are not clearly marked as estimates. Update this response with each set of updated workpapers you provide.
- **P-AREV-3** Re: Format Supply actuals to replace forecasted data on a quarterly basis unless otherwise agreed upon by the parties.
- **P-AREV-4** Re: Format Submit workpapers supporting and clearly quantifying the derivation of all proposed adjustments to test year operating income and rate base. Workpapers should be clearly labeled as to the witness supplying the data or information and identification of the witnesses relying upon this data or information in their testimony, if applicable.
- **P-AREV-5** Re: Detail Submit budgeted and actual data along with an explanation of any major variances between budgeted and actual data, for each month of the two years ended at test year end. If actual data is not available through the end of the period, provide monthly updates as the data becomes available.
- **P-AREV-6** Re: Detail Submit an explanation of past and anticipated changes in major accounting procedures since the 2020 base rate case along with an explanation of its effect on revenues and expenses in the current rate proceeding.
- **P-AREV-7** Re: Detail Explain how any of the items contained in the Company's test year and how any of the proposed adjustments differ from the regulatory treatment afforded the item(s) by the Board in Petitioner's prior litigated base rate proceeding. Also, provide the revenue requirement impact of these changes.
- **P-AREV-8** Re: Reports Submit Securities and Exchange Commission Forms 10-K and 10Q corporate annual reports and proxy statements for the most recent three-year period. Update this response as the reports become available.
- **P-AREV-9** Re: Reports Submit a copy of the most recent utility and/or parent company annual report to shareholders. Update this response as the reports become available.
- **P-AREV-10 Re: Reports** Submit a copy of the most recent FERC Forms 1 and/or annual report to the BPU. Update this response as the reports become available.

- **P-AREV-11** Re: Reports Provide the most recent interim financial/operating reports (monthly and/or quarterly) covering the test year requested. Update this response as the reports become available.
- **P-AREV-12 Re: Reports** Provide the latest financial profile of Petitioner by the following rating agencies:
 - (a) Moody's
 - **(b)** Standard and Poor's
 - (c) Duff & Phelps
 - (d) Fitch

- **P-AREV-13** Re: Reports Provide the Petitioner's detailed trial balance report for each month in the two years ended at test year-end.
- **P-AREV-14 Re: Reports** Provide all statements of the mission, goals, objectives and longrange plans for the Company issued for the most recent three-year period.
- **P-AREV-15 Re:** Compliance Provide a list of all studies, methodologies or information of any kind previously ordered by the Board to be filed in the company's base rate case, and indicate where it is included in the filing.
- **P-AREV-16 Re: Revenues** Provide detailed calculations for all revenue requirement related allocation factors, between the utility and affiliates, between jurisdictional and non-jurisdictional related revenues and expenses, between on-system and off-system related revenues and expenses utilized in the filing.
- **P-AREV-17 Re: Revenues** Submit workpapers supporting all adjustments to elements of operating income. Update this response with each set of updated workpapers you provide.
- **P-AREV-18** Re: Revenues On a monthly basis, submit a detailed listing, including associated dollar amounts, of all "other revenues" for the two years ended at test year-end. Update this response with each set of updated workpapers you provide.
- **P-AREV-19 Re: Gains/Losses** With regard to gains and/or losses on sales of property, submit the following information:
 - (a) Listing of properties sold during each year for the five years ended at test year end and projected for the following 12-month period. In addition, indicate the dates of these property sales.

- **(b)** Indication of whether these properties were previously included in rate base for ratemaking purposes.
- (c) The pre-tax profits or losses associated with the sales to be provided in (a); also identify the account number(s) in which these profits/losses are recorded.
- (d) A description of the proposed ratemaking treatment.

P-AREV-20 Re: Affiliate Transactions - Provide the corporate structure of the utility and any of its affiliates, providing the names and titles of utility employees and any job titles they may hold with any of the affiliates.

P-AREV-21 Re: Affiliate Transactions –

(a) If Petitioner is part of a holding Company or a multi-state utility company, provide balance sheets and income statements with a breakdown by major subsidiary and/or division for consolidated, regulated and unregulated operations. Utility statements shall include supporting detail for all intersegment and Company eliminations and adjustments. Update this response with each set of updated workpapers you provide.

For the test year period and the prior year, submit a complete schedule of all expense /revenue allocations, charges and credits between Petitioner, its parent corporation, other divisions, and other affiliated companies. Also submit a copy of all related contract(s) currently in effect. As part of the schedule also submit the following:

- 1. Month and year that the service or item was supplied including a description of the service or item.
- 2. Month and year that the allocation, charge or credit was actually made for the service or item.
- 3. Month and year that payment was made.
- 4. Basis for the allocation, charge or credit.
- 5. Copy of invoice or other written documentation.

- **P-AREV-22** Re: Operation & Maintenance (O&M) Expenses Submit a detailed breakdown (including associated dollar amounts) of the components included in account 920.2 "Miscellaneous General Expense" for the test year. Update this response with each set of updated workpapers you provide.
- **P-AREV-23** Re: Operation & Maintenance (O&M) Expenses For each O&M expense account, provide a comparison of the level of expense reflected in the test year of the filed case versus the level of expense during the test year of the utility's 2020 base rate case.
- **P-AREV-24** Re: Recurring/Non-recurring (a) Provide the details of any expenses included in the pro forma ratemaking results that can be considered to be of an abnormal, non-recurring nature and/or which do not occur annually but occur over an extended time period (b) provide the details of any extraordinary test year expenses. Update this response with each set of updated workpapers you provide.
- **P-AREV-25 Re: Recurring/Non-recurring** Itemize the outside consulting/professional fees included in the test year's income statement and provide the following:
 - (a) The identity of the professional service/ consulting firm, the purpose of their services, and the amount of their fee for each item listed.
 - **(b)** Of those items and amounts listed, explain which are of a recurring nature and why.
 - (c) For those items that are recurring, state the anticipated amount of recurring expense and the basis for that amount.
 - (d) Submit the written contract or document that specifies the services provided for each item and the amount of payment.
 - (e) Submit actual expenses booked, by item for the three years ended at test year end and show the account numbers that they were booked to.

- **P-AREV-26 Re: Recurring/Non-recurring** If any major "study costs" are included in the test year results, provide the reasons for such studies, the associated dollar amounts and the account numbers that they were booked to. In addition, explain whether such studies are performed on an annual recurring basis or not. Update this response with each set of updated workpapers you provide.
- **P-AREV-27** Re: Out of Period Bookings Submit all test year revenue, expense and tax bookings relating to periods prior to the test year, including an explanation for these "out-of-period" bookings.

- **P-AREV-28 Re: Capitalized Leases** With regard to any capitalized leases carried by Petitioner, submit the following information:
 - (a) What capitalized leases does Petitioner carry, and what is the underlying cost rate (return on capital rate) associated with these capitalized leases?
 - (b) How are such leases treated for book purposes as well as for ratemaking purposes in this case? Show where this is reflected in the schedules in this rate case filing.
 - (c) Are any of such leases included in Petitioner's rate base or capital structure and, if so, what are the dollar amounts?

- **P-AREV-29** Re: Uncollectible Accounts Submit a copy of Petitioner's current policy on provision of bad debts, write-offs and recoveries, and a description of any changes made to this policy since Petitioner's last base rate case.
- **P-AREV-30 Re: Uncollectible Accounts** Submit a schedule showing each of the five years ending at test year end with the following information:
 - (a) Uncollectible starting balance
 - **(b)** Net write-offs
 - (c) Uncollectible accrual
 - (d) Uncollectible ending balance
 - (e) Firm revenues
 - (f) % Net write-offs of firm revenues
 - (g) % Uncollectible accruals of firm revenues

- **P-AREV-31** Re: Insurance Expense Explain whether Petitioner receives refunds or retroactive invoice adjustments from its group insurance companies for the difference between actual claims and the number of claims upon which the premiums were based or for any other reasons. If so, submit the following additional information:
 - (a) Annual amount of refunds or retroactive premium adjustments received during each of the five years ended at test year end. In addition, explain the reasons and for which insurance these refunds or adjustments were received.

- **(b)** Amount of refunds or retroactive premium adjustments received or to be received during the test year and to which type of insurance these refunds applied.
- (c) Explanation of how such refunds or retroactive premium adjustments are treated for book purposes by the Company and how they were reflected in the test year ratemaking results.

P-AREV-32 Re: Rate Case Expenses –

- (a) Provide a list stating the amount of rate case expense included in the test year period along with a detailed list of rate case expense items and associated costs incurred for the current rate case at the time of filing and estimated through the close of the case. Update this response with each set of updated workpapers you provide.
- **(b)** Provide agreements, contracts and/or invoices to support any requested rate case expenses. Update this response with each set of updated workpapers you provide.
- P-AREV-33 Re: Rate Case Expenses For each ACE rate case decided by the Board in the past ten years identifiable by case name, year, and BPU docket number, submit a detailed breakdown on each rate case of all rate case expenses actually incurred versus all rate case expenditures requested for cost recovery. The breakdown of all rate case expenditures for each historic rate case should be presented in the same manner as was in the workpapers supplied in the case at the time (i.e., legal expenses, Ratepayer Advocate's fees, etc.).
- P-AREV-34 Re: Contributions Provide a breakdown of each charitable and civic contribution, by recipient and amount, for the test period and the prior twelve month period. State which recipients are located in New Jersey and provide the location of those recipients which are not located in New Jersey and for which the Company is requesting recovery in rates. Update this response with each set of updated workpapers you provide.
- **P-AREV-35** Re: Advertising Provide a breakdown of all advertising costs of \$5,000 or more per advertisement stating the type and purpose of such advertising. Update this response with each set of updated workpapers you provide.
- P-AREV-36 Re: Advertising Submit a listing (description, dollar amounts, account numbers) of all expenses in the test year results related to institutional advertising and public relations as defined in the Board's Order In the Matter of the Board's Investigation of Advertising Practices of the Telephone, Electric and Gas Distribution Companies of New Jersey Order of Modification, BPU Docket No. 7512-1254 (Apr. 11, 1980) regarding the ratemaking of utility advertising

practices. Submit samples of advertisements in each classification. Update this response with each set of updated workpapers you provide.

- **P-AREV-37 Re: Public Relations** With regard to any "community affairs" and/or "public relations" expenses, please submit the following information:
 - (a) What are the expense levels for these expense types included in the test year results.
 - **(b)** In which account(s) are these expenses recorded?
 - (c) Submit a detailed description of the scope and purpose of these expense types.

- **P-AREV-38** Re: Association/Club Dues Submit the following information for Edison Electric Institute ("EEI") dues and separately for Electric Power Research Institute ("EPRI") dues on a test year basis:
 - (a) The total amount of dues included in test year expenses, including the account number(s) in which these expenses have been booked.
 - **(b)** The portion of the dues to be submitted in (a) associated with "media communications" (advertising) and associated with lobbying and/or "government relations".
 - (c) With regard to the "media communications" (advertising) portion to be identified in P-AREV-39(b), please submit the following additional information:
 - 1 A detailed description of the type of advertising covered, including the purpose and objectives of such advertising.
 - 2 Samples of the type of advertising.
 - 3 Is AGA/NJUA advertising geared towards the specific New Jersey service territory of ACE or is it nationwide advertising? Please explain.
- P-AREV-39 Re: Association/Club Dues Provide a breakdown of any club dues or membership fees incurred in excess of \$750.00, in the test year and for the prior twelve month period. The breakdown should include the identity of the organization, the amount paid to each organization, the associated account numbers where the amounts are recorded, and the titles of individuals for whom the dues are paid. Also, specify whether or not the dues are included in pro forma test year level of expenses requested for cost recovery in this rate case.

- **P-AREV-40** Re: Federal Income Taxes Submit a detailed reconciliation of book and taxable income in Petitioner's test year filing results. Update this response with each set of updated workpapers you provide.
- **P-AREV-41** Re: Federal Income Taxes Submit a computation supporting the unadjusted and adjusted federal income tax expense reflected in the filing. Update this response with each set of updated workpapers you provide.

P-AREV-42 Re: Federal Income Taxes -

- (a) Submit a copy of Petitioner's most recent federal income tax returns and any consolidated income tax returns in which Petitioner is a participant. Update this response as the reports become available.
- (b) If Petitioner is a participant in a consolidated federal income tax filing, provide the following sections of the consolidated federal income tax returns (Form 1120) for the 10 most recent tax years: page 1; page 3 (Schedule J); and supporting statements depicting holding company and subsidiaries' individual income and expense summary for lines 1-30 of Form 1120.
- (c) Submit the same information as provided in the schedules submitted as part of (b) above, but on an estimated basis for the current tax year. Update this response with each set of updated workpapers you provide.
- **P-AREV-43** Re: Federal Income Taxes Explain the methodology used to allocate the tax liability to the member companies. Identify the time frame utilized in calculating any consolidated tax adjustment in the utility's most recently decided base rate case.
- **P-AREV-44** Re: Deferred Income Tax Expense Provide a reconciliation between the actual accumulated deferred income tax balance and the deferred income tax balance reflected as rate base deduction. Update this response with each set of updated workpapers you provide.
- **P-AREV-45** Re: Employee Compensation Submit a schedule showing, on a monthly basis and broken out by major employee category, all of Petitioner's actual employees for the two years prior to the test year and the test year, including the most recent actuals at the time of the filing. Update actual monthly employee levels through the close of the record.
- **P-AREV-46** Re: Employee Compensation Submit a detailed description for each classification of Company employee.
- **P-AREV-47** Re: Employee Compensation Submit a copy of all current union employment contracts negotiated by the Company.

- **P-AREV-48 Re: Employee Compensation** Specify when the employees in each of the payroll classifications receive their annual wage/salary merit increase.
- P-AREV-49 Re: Employee Compensation Submit, for each year of the five-year period beginning January 1, 2017 and ending on December 31, 2021, the payroll expense, the capitalized payroll, and the percent capitalized of payroll (capitalized payroll/payroll expense). Provide this data as of the end of the test year. Also, show the two, three, four and five year weighted average percent capitalized of payroll.
- P-AREV-50 Re: Employee Compensation Submit the number of seasonal employees and the associated O&M payroll for each of the five years ended at test year end. Also, submit an explanation for any variance of 10% or more in the expense amount between consecutive years. Update this response with each set of updated workpapers you provide.
- P-AREV-51 Re: Employee Compensation Submit a schedule showing for the five-year period ended at test year end, including the straight time dollars, the overtime dollars, and the overtime percentage (e.g., overtime dollars/straight time dollars). Also, show the two, three, four, and five year weighted average overtime percentages. Update this response with each set of updated workpapers you provide.
- **P-AREV-52 Re: Employee Compensation** What amounts if any are included in test year operating expense for the officer and non-officer incentives and in what accounts are they recorded?
- **P-AREV-53** Re: Employee Compensation Provide all current outside consultants' written advice and surveys which the Company utilized in developing its current employee compensation and benefits package.
- **P-AREV-54** Re: Employee Compensation Describe, in extensive detail, all changes to employee compensation packages since the 2018 rate case. Include changes to health benefit packages offered, post-retirement benefits, stock option changes, bonus programs, etc.
- **P-AREV-55** Re: Employee Compensation/Pension Submit a copy of all pension plan reports issued by the Company's pension plan consultants for the last two years, including the test year, for the respective employee classifications. Include reports covering both the appropriate expense and funding levels. Update this response as the reports become available.
- **P-AREV-56** Re: Employee Compensation/Pension Submit an analysis for each of the five years ended at test year end showing the amounts actually paid by Petitioner into the pension accounts (funded) versus what was expensed each year. Submit the underlying workpapers to support the amounts expensed and the amounts funded each year.

- **P-AREV-57 Re: Employee Compensation/Pension** What is the length of service requirement for each employee classification to become vested in the pension plan?
- **P-AREV-58** Re: Employee Compensation/Health Insurance Submit the total health/life insurance expense for each of the five years ended at test year end and also itemize any related credits or refunds by carrier that were issued each year.
- **P-AREV-59 Re: Employee Compensation/OPEB** Submit a detailed description for each employee classification of the benefits associated with the OPEB costs.
- **P-AREV-60 Re: Employee Compensation/OPEB** Submit a description of any changes made to the OPEB program over the past five years.
- **P-AREV-61** Re: Employee Compensation/OPEB Submit a copy of all plans, trust agreements, contracts, etc. which the Company uses for the funding of OPEB costs.
- **P-AREV-62** Re: Employee Compensation/OPEB Submit the annual reports for the latest five years reflecting the financial status from each of the Company's OPEB funding arrangements. Update this response as the reports become available.
- **P-AREV-63** Re: Employee Compensation/OPEB Submit a copy of the actuarial reports for the last two years including the test period covering the Company's OPEB costs. Update this response as the reports become available.
- **P-AREV-64** Re: Rate Base Reconciliation Submit a detailed reconciliation between the rate base and capital structure claimed in Petitioner's filing results. Update this response with each set of updated workpapers you provide. If capital structure exceeds rate base, explain why. If rate base exceeds actual test year end capitalization, explain why.
- **P-AREV-65** Re: CWIP/AFUDC Submit the following information regarding Petitioner's Construction Work in Progress (CWIP) and Allowance for Funds Used During Construction (AFUDC):
 - (a) Management summary of current accounting and rate-making treatment for CWIP and associated AFUDC.
 - **(b)** CWIP elements that do not accrue AFUDC.
 - (c) Method of AFUDC compounding, if any.
 - (d) AFUDC rates in effect during the year prior to the test year, in the test year and as anticipated for the year after the test year. In addition, explain the basis of formula used for the determination of the AFUDC rate.

- **P-AREV-66** Re: Materials and Supplies Submit a supporting schedule showing by month for the three years ended at test year end, the beginning balance, purchases, usage or consumption, ending balance, average balance for the month, and 12-month average balance. Update this response with each set of updated workpapers you provide.
- **P-AREV-67** Re: Cash Working Capital Provide a schedule of sources and uses of funds for the most recent 12-month period. Update this response with each set of updated workpapers you provide.
- P-AREV-68 Re: Cash Working Capital Provide a lead-lag study, completed no more than six months prior to the rate increase filing using the most recent information available. Provide all data and calculations supporting the revenue collection lag and payment leads/lags reflected in the current study. State all known changes that will affect the leads/lags contained in the current study.
- P-AREV-69 Re: Cash Working Capital If the proposed Cash Working Capital Allowance does not include a specific offset for net asset and liability balance amounts, representing the uses and sources of cash funds by those assets and liabilities that have not already been accounted for in the lead/lag study or as separate rate base items, explain why not. Provide a Net Assets and Liabilities analysis showing the individual balances for assets and liabilities that have not already been accounted for in the lead/lag study or as separate rate base items.
- **P-AREV-70** Re: Reconciliation Submit a detailed reconciliation of book and taxable income in Petitioner's test year filing results.

P-AREV-71 Re: Consolidated Tax Savings –

- (a) If Petitioner and its affiliates were to file separate tax returns, rather than a consolidated return, describe how, if at all, each of these companies could use their taxable losses on a stand-alone basis.
- (b) Include a full description of the Internal Revenue Service carry back and carry forward provisions for Net Operating Losses ("NOL") and how many years NOLs can be carried forward and carried back. Also, indicate if the number of years for carry backs and carry forwards is different for NOLs in each of the tax years, 1991 through the present.
- **P-AREV-72** Re: Consolidated Tax Savings What was the name of the parent company that filed the consolidated tax return that included Petitioner in each year since 1991?
- **P-AREV-73** Re: Consolidated Tax Savings What was Petitioner's stand-alone tax liability for each of the tax years, 1991 through the present?

P-AREV-74 Re: Consolidated Tax Savings –

- 1. For each of the years 1991 through the present, provide the taxable income/(loss) for Petitioner and each its affiliates included in the consolidated tax return (broken down by company), the total consolidated taxable income, any alternative minimum tax payments, the federal income tax rate, and the federal tax liability. Also, indicate which of these companies are regulated.
- **2.** If actual data is not available for the current year, provide estimated data for the current year in the same format.
- **3.** Provide actual data for the current year in the same format as soon as it becomes available.
- **P-AREV-75** Re: Consolidated Tax Savings What were Petitioner's payments to its parent company for Federal Income Taxes for each of the years 1991 through the present?

P-AP-1 Re: Plant Studies –

- (a) Provide a list of each plant addition or modification in excess of \$250,000 included in rate base since the Company's 2020 base case.
- **(b)** For each plant addition or modification since the Company's 2020 base case in excess of \$1,000,000, provide a narrative description of the project and any studies conducted by or for the Company supporting the need for these projects.
- P-AP-2 Re: Plant Held for Future Use (PHFU) Provide a description and the cost of each plant or land site, the date each item was constructed or purchased and placed in the PHFU Account, the associated projected in-service date of each item, changes in projected in-service date since original property acquisition, prior regulatory treatment and the purpose for each item's proposed inclusion in rate base. Also, provide support showing that the item's in-service date and proposed usage are consistent with the Company's current load forecast.
- **P-AP-3** Re: Plant Additions Quantify the total dollar amount of plant additions to rate base reflected in the present filing from the end of the test year of the utility's 2020 base rate case, with subtotals for distribution, customer and other major account categories. Provide internal project authorization requests for each capital distribution project in excess of \$1,000,000.
- **P-AP-4** Re: Plant Construction Submit a copy of the Company's latest construction budget and forecasts vs. actual expenditures for the most recent three year period.
- **P-AP-5** Re: Plant Construction Provide a description of the Company's new construction approval process to include a sample project whose budget cost exceeds \$100,000.

- **P-AP-6** Re: Plant Construction (Bidding) Does the company utilize bidding to carry out its construction projects? If yes, please describe in detail. If no, please explain why not.
- **P-AP-7** Re: Plant Construction (Project Awarding) Please describe, in detail, the procedure the Company employs to award construction projects. Does the Company perform construction using in-house personnel, outside contractors, bidding, etc.
- **P-AP-8** Re: Plant Construction (Construction Budget) Concerning the Company's latest construction budget in the categories of distribution main, distribution services and other major construction work over \$100,000, provide in dollars and % the amount, historical and projected, that is performed by: company personnel; outside contractors; contractors chosen as a result of bidding.
- **P-AP-9** Re: Plant Retirements Submit a listing and associated dollar amounts of all plant retirements over \$30,000 reflected in the test year results and the journal entries used to book these plant retirements. In addition, submit all test year expenses associated with retired plant.
- **P-AP-10** Re: Construction Budgets Explain the processes and procedures used by the Company to prioritize authorize, budget, and control major construction expenditures.
- **P-AP-11** Re: Bidding Procedures Please describe when, and the manner in which the Company solicits bids for materials or contract work. Who evaluates the bids and what is the basis for determining the successful bidder?
- **P-AP-12** Re: Plant Construction Submit a copy of the most recent five years construction expenditure forecast for distribution.
- **P-AP-13** Re: Plant Construction Provide a description of the Company's current construction approval process to include a sample project whose budget costs exceeds \$500,000.
- **P-AROR-1** Re: Rate of Return Provide equity analysts' and fixed income analysts' reports on the Company published in the prior 12-month period.
- **P-AROR-2** Re: Rate of Return Provide an analysis of the potential for debt refunding operations for the next three years and the method used by the Company to determine the net economic benefit of the refunding operations.
- **P-AROR-3** Re: Rate of Return Provide a history for the most recent five years of monthly stock market price, book value and market to book ratio for Petitioner's parent.

- P-AROR-4

 Re: Rate of Return Provide a table showing the allowed versus earned returns on average common equity for the most recent five years and bond interest coverage ratios computed in accordance with the formulas prescribed by the Securities Exchange Commission, Standard and Poor's and the Company's mortgage indenture. Show the effect of purchased power adjustments, if applicable. Update this response with each set of updated workpapers you provide.
- **P-AROR-5** Re: Rate of Return Provide a complete derivation of embedded costs including all calculations for both long-term debt and preferred stock.
- **P-AROR-6** Re: Rate of Return If the filing relies upon a comparable group of companies:
 - (a) Provide the allowed returns on common equity and the date granted for each of the sample companies used in the analysis:
 - **(b)** Provide the Moody's and Standard and Poor's bond ratings for each of the sample group;
 - (c) Provide the capital structure for each company in the sample group.
 - (d) Update this response with each set of updated workpapers you provide.
- **P-AROR-7** Re: Rate of Return Submit a schedule for the test year showing internally generated funds as a percentage of capital expenditures, showing all calculations.
- **P-AROR-8** Re: Rate of Return Provide an explanation of Petitioner's dividend policy, as well as that of its parent company. Include a history of actual dividend payouts for the most recent three years as compared to existing policy.

Exhibit I

EDGE Rider and Veteran's Rate Law Analysis

ATLANTIC CITY ELECTRIC COMPANY EDGE RIDER AND VETERANS RATE LAW ANALYSIS

EDGE	Forecast January 2023	Forecast February 2023	Forecast March 2023	Forecast April 2023	Forecast May 2023	Forecast June 2023	Actual July 2022	Actual August 2022	Actual September 2022	Actual October 2022	Actual November 2022	Forecast December 2022	5+7me June 2023 Total
Billed Revenues (before credits) Annual General Service - AGS Secondary	12,665	12,665	12,665	12,665	12,665	12,665	14,746	13,196	12,878	11,221	11,286	12,665	151,985
Monthly General Service - MGS Secondary	826 13,492	826 13,492	826 13,492	826 13,492	826 13,492	826 13,492	1,165 15,911	1,147 14,343	958 13,836	419 11,640	444 11,730	826 13,492	9,917 161,903
<u>Credits</u> Annual General Service - AGS Secondary Monthly General Service - MGS Secondary	(1,466)	(1,466) (14)	(1,466) (14)	(1,466) (14)	(1,466) (14)	(1,466) (14)	(1,184) (18)	(1,161) (19)	(1,843) (16)	(1,612) (8)	(1,528) (8)	(1,466) (14)	(17,589) (165)
<u>Customers</u> Annual General Service - AGS Secondary	(1,479)	(1,479)	(1,479)	(1,479)	(1,479)	(1,479)	(1,202)	(1,180)	(1,859)	(1,620)	(1,536)	(1,479)	(17,754)
Monthly General Service - MGS Secondary VETERANS LAW Credits	1	1	1	1	1	1	1	1	1	1	1	1	
Monthly General Service - MGS Secondary	(392.03)	(392.03)	(392.03)	(392.03)	(392.03)	(392.03)	(390.60)	(406.31)	(373.57)	(357.13)	(432.56)	(392.03)	(4,704)

ATLANTIC CITY ELECTRIC COMPANY

BEFORE THE NEW JERSEY BOARD OF PUBLIC UTILITIES DIRECT TESTIMONY OF JAY C. ZIMINSKY BPU DOCKET NO. ER23020091

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ATLANTIC CITY ELECTRIC COMPANY

BEFORE THE NEW JERSEY BOARD OF PUBLIC UTILITIES DIRECT TESTIMONY OF JAY C. ZIMINSKY BPU DOCKET NO. <u>ER230200091</u>

1		I. <u>INTRODUCTION AND QUALIFICATIONS</u>
2	Q1.	Please state your name and position.
3	A1.	My name is Jay C. Ziminsky. I am the Director, Regulatory Strategy & Revenue
4		Policy, in the Regulatory Affairs Department of Pepco Holdings ("PHI"). I am testifying
5		on behalf of Atlantic City Electric Company ("ACE" or the "Company").
6	Q2.	What are your responsibilities in your role as Director of Regulatory Strategy &
7		Revenue Policy?
8	A2.	I am responsible for the coordination of revenue requirement, cost allocation, and
9		rate determinations in New Jersey, Delaware, Maryland, and the District of Columbia as
10		well as PHI utilities' transmission filings with the Federal Energy Regulatory Commission
11		("FERC"). In addition, I am responsible for coordinating and supporting regulatory
12		strategy, revenue policy, and various other regulatory compliance matters.
13	Q3.	Please state your educational background and professional experience.
14	A3.	I received a Bachelor of Science Degree in Business Administration with a
15		concentration in Accounting from Drexel University in 1988 and a Master's in Business
16		Administration, with a concentration in Finance, from the University of Delaware in 1996.
17		I earned my Certified Public Accountant certification in the State of Pennsylvania in 1988.
18		In 1988, I joined Price Waterhouse as a Tax Associate. In 1991, I joined Atlantic
19		City Electric Company ("ACE") as a Staff Accountant in the General Accounting section

Witness Ziminsky

1		of the Controller's Department, and over the next several years worked in positions of
2		increasing responsibility in the accounting and finance areas. In 2006, I joined the PHI
3		Regulatory Department and was later promoted to Manager of Revenue Requirements in
4		October 2008, where my responsibilities included the coordination of revenue requirement
5		determinations in New Jersey, Delaware and Maryland as well as coordinating various
6		other regulatory compliance matters. With the consummation of the merger between Pepco
7		Holdings, Inc. and Exelon, I was promoted to my current position in April 2016. I am also
8		the Co-Chairperson of the New Jersey Utilities Association's Finance & Regulations
9		Committee.
10	Q4.	Have you previously submitted testimony before the New Jersey Board of Public
11		Utilities ("BPU" or the "Board") or other regulatory agencies?
12	A4.	Yes. I was a witness for ACE before the Board in Docket Nos. ER11080469,
13		ER12121071, ER14030245, ER16030252, ER17030308, ER18060638 and ER20120746.
14		I have also been a witness in filings before the Delaware Public Service Commission, the
15		Maryland Public Service Commission, the District of Columbia Public Service
1516		Maryland Public Service Commission, the District of Columbia Public Service Commission, and FERC.
	Q5.	
16	Q5.	Commission, and FERC.

proceeding. Specifically, ACE is seeking an increase in its rates for electric service of

\$104,788,395 (excluding Sales and Use Tax).¹ The net monthly bill impact of this request on a residential customer taking Basic Generation Service and using 669 kWhs per month is approximately \$12.22 or approximately 8.8% of a total monthly bill. My Direct Testimony in support of this request is organized in the following four sections:

- SECTION II: Application Overview and Benefits provides an overview of the Company and its important role in the southern New Jersey economy and summarizes the prudency of ACE's investments which have resulted in continued safe and reliable service and improved customer experience. Importantly, this filing includes the Company's initial investments in key programs that support New Jersey's leading clean energy and climate goals, including ACE's Advanced Metering Infrastructure ("AMI") program ("Smart Energy Network" or "SEN"), and Electric Vehicle ("EV") make-ready program ("EVsmart"). The filing also includes a prudency review of the Company's PowerAhead program, which entailed important storm hardening improvements over a five-year period, beginning in 2017.
- **SECTION III: Development of the Revenue Requirement** presents and explains the basis for the development of the \$104,788,395 Distribution-Related Revenue Requirement, which is based on a test period comprised of the 12-month period ending June 30, 2023 (including five months of actual data and seven months of forecasted data).

The \$104.788.395 revenue requirement stated throughout this testimony excludes Sales and

¹ The \$104,788,395 revenue requirement stated throughout this testimony excludes Sales and Use Tax ("SUT"). The revenue requirement including SUT is \$111,730,626.

1		• SECTION IV: Pro Forma Capital Structure and Rate of Return summarizes
2		ACE's proposed capital structure and proposed rate of return and explains how
3		customers benefit from the Company's financial health and its ability to access
4		capital on reasonable terms.
5		• SECTION V: Other Topics includes ACE's Consolidated Tax Adjustment
6		("CTA") calculation, as required by N.J.A.C. 14:1-5.12. I also present a proposed
7		one-time credit to customers related to Pepco Holdings Service Company
8		("PHISCO") Gross Receipts Tax and discuss ACE's COVID-19 Regulatory Asset.
9		I am sponsoring Schedules (JCZ)-1 through (JCZ)-19, which cover the areas
10		detailed in this testimony. This Direct Testimony and the attached Schedules were prepared
11		by me or under my direct supervision and control. The sources for my testimony are
12		Company records, public documents, and my personal knowledge and experience.
13		II. APPLICATION OVERVIEW AND BENEFITS
14		A. Atlantic City Electric Company ("ACE") Overview
15	Q6.	Please provide an overview of the Company.
16	A6.	Incorporated in 1924, ACE has played a vital role in the economy of southern New
17		Jersey for nearly a century. The Company currently provides reliable electric service to
18		approximately 568,000 residential, commercial, and industrial customers. ² The Company
19		is committed to powering a cleaner and brighter future for its customers and communities.

² ACE serves its customers through a complex distribution system that includes approximately 10,315 circuit miles of distribution lines and 92 substations. ACE's service area is spread over 2,800 square miles located in all or parts of eight counties in the southern one-third of the State.

- 1 ACE has a foundation of principles that help guide the Company's efforts to provide safe, 2 reliable, clean and affordable energy service:
 - Enabling Climate Change Solutions;
 - Enhancing Grid Performance;
 - Improving Social Equity and Maintaining Affordability, and
 - Delivering a World-Class Customer Experience.

ACE remains focused on grid performance enhancements that support excellent service and enduring reliability. These enhancements are supported through ongoing investments and targeted efforts, like the Company's recently proposed Powering the Future ("PTF") filing which will accelerate projects to meet customers' evolving expectations and prepare the system for more damaging storms driven by climate change. ACE is also doing its part to support the achievement of the State's climate goals with a commitment to achieve net-zero emissions for ACE operations by 2050. The Company is also dedicated to providing customer service that excels by investing in new tools and resources for all communities. Programs like SEN and EVsmart are meant to both propel clean energy efforts and provide modern technology and benefits that are available to all customers.

Social equity and affordability are other key tenets in the Company's planning, as discussed later in my Direct Testimony. ACE is focused on enabling customer access to new technologies, maintaining reasonable rates, and providing support to customers struggling to manage their energy bills. The Company also provides workforce

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³ In 2021, Exelon announced a new goal targeting a reduction in greenhouse gas emissions of at least 50% below 2015 levels by 2030, and net zero emissions by 2050. ACE is on track to meet this GHG reduction target and is doing so by activities such as minimizing losses of Sulfur Hexafluoride from gas-insulated electrical equipment, investing in vehicle electrification, and improving the energy efficiency of its buildings and other facilities. More information is available at atlanticcityelectric.com/Climate.

development and supplier diversity programs that drive direct and indirect economic benefits from its investments to its communities and customers.

B. Economic Development and Support of the Local Economy

Please summarize ACE's impact on southern New Jersey's economy.

O7.

A7.

The Company plays a vital role in the regional economy and its investments and workforce provided stability to South Jersey throughout the COVID pandemic. ACE, and its parent, PHI, employ a workforce of approximately 1,000 people within New Jersey in a variety of managerial and bargaining unit positions. ACE employees contribute their skills to support the Company in its mission to provide significant value to customers in the form of safe and reliable electric service. The Company has made distribution capital investments of \$953 million over the past five years, improving reliability for individuals and businesses across the region, supporting employment across the State, and contributing to the region's economy.

ACE is also committed to supporting economic development efforts in southern New Jersey by partnering with organizations and businesses to facilitate customer investment and expansion in the region. The Company has a team who are dedicated to supporting major business expansions or significant new investments in the region, providing major customers with a dedicated relationship manager to walk them through the new business process and understand the options. In addition, the Company offers the Energy Discounts for Growing Enterprises ("EDGE") to support the expansion and growth of business in the region. EDGE offers businesses, small and large, a 20 percent discount off the electric delivery distribution portion of their rate for a five-year period based on

1	certain qualifications. ACE is also actively involved with organizations such as the
2	Cumberland County Improvement Authority, NJ Alliance for Action, Southern NJ
3	Development Council, ChooseNJ and Atlantic City Metropolitan, Business & Citizens
4	Association to ensure its continued support of regional economic growth.

Q8. What efforts has ACE made to maintain reasonable rates for service for all customersin New Jersey?

A9.

A8.

The Company has pursued a variety of means to maintain reasonable rates for electric service. These efforts include both new programs that leverage technology to promote affordability, as well as funding methods that leverage investment from the Federal Government to support ACE's system investments. I will discuss more about these topics later in this section.

Q9. What efforts has ACE made to ensure its investments support equity in the communities it serves?

ACE has two well established programs that ensure the economic benefits of its investments are supporting equity across southern New Jersey communities. The Company's supplier diversity program ensures a significant portion of its contractors and suppliers are diverse and minority-owned businesses. In addition, the Company runs workforce development programs across the region, which are training the future energy workforce and providing career opportunities, with a specific focus on reaching residents of overburdened communities.

1 Q10. Please describe ACE's commitment to support local and diverse companies.

A11.

A10. ACE is committed to supplier diversity as a core business value that enhances its ability to remain competitive while contributing to a healthier and more vibrant local economy. Through November 2022, ACE purchased \$111 million in goods and services from diversity-certified suppliers, including \$22.3 million from New Jersey-based diverse suppliers. The Company continues to increase its diverse spending year-over-year, targeting a long-term goal of 40% of total spend. Through critical programs like this, the Company is working to ensure its infrastructure investments both maintain reliability and directly benefit the local economy, helping local businesses and job creation and supporting equity in New Jersey communities.

Q11. Please describe the Company's ongoing workforce development programs and their results.

ACE has several workforce development initiatives, including Science, Technology, Engineering and Mathematics ("STEM") Awareness and Education, Career Pathway Exploration, and Work-Readiness and Job Training, that support individuals seeking training and employment. These fall under the South Jersey Utilities Training Program, which is a \$6.5 million program that ACE launched in partnership with seven South Jersey Community Colleges and Workforce Development Boards to expand workforce development efforts. It is free and accessible through six community colleges across southern New Jersey, both virtually and in-person. There was a \$1.1 million investment into workforce development funding in 2022. Recent positive impacts from workforce development include the hiring of 14 candidates by the Company's meter

deployment vendor to support smart meter installations as part of SEN, with additional hiring anticipated this year.

As part of this effort, in September 2022, ACE and the City of Atlantic City announced the Atlantic City Infrastructure Program, an energy workforce training program which provides residents of Atlantic City a path to careers in the energy field, with a job opportunity for every program graduate with ACE or one of the Company's contractors of choice. The program focuses on residents from the under-resourced population in Atlantic City, enabling participants to gain utility training and work-ready skills to prepare them for promising careers in the energy field. The first cohort of 26 Atlantic City residents graduated from the 14-week program in February 2023.

In addition, ACE has other initiatives to encourage workforce development across southern New Jersey that include:

- The Company recently joined Jingoli Power to provide jobs to 16 Atlantic City young adults as part of its Atlantic City/Brigantine Community Reliability Project.
- The Company's High School Energy Career Academy is a four-year program focused on preparing students in grades nine through 12, for entering post-secondary education or moving directly to employment in the energy field.
- The Spark Internship Program provides an eight-week paid summer work experience and work-readiness education for rising South Jersey high school juniors and seniors with an interest in engineering, Information Technology ("IT"), technical services, trades, environmental studies, and other energy industry relevant subject areas.
- Through the Company's \$75,000 annual grant to its Community Scholars Program, hundreds of South Jersey community college students have

1 2		received support of up to \$5,000 to pursue degrees in various disciplines, including STEM and business-related fields.
3	Q12.	Please describe the various charitable activities in which ACE is engaged within
4		southern New Jersey?
5	A12.	ACE supports the surrounding region through corporate philanthropy and many
6		programs that advance public policy and support those individuals in the community that
7		are low-to-moderate income or in under-resourced communities. ACE works with dozens
8		of organizations throughout the year, consistently providing South Jersey non-profit
9		organizations with over \$1 million of charitable contributions annually. It is important to
10		note that the costs of these initiatives are not borne by customers but instead are funded by
11		shareholder contributions. The Company's community giving focuses on organizations
12		that help provide equal access to arts and culture, that educate customers about the energy
13		industry and science, as well as organizations supporting community vibrancy, that help
14		provide energy empowerment through sustainability, environmental and open space
15		initiatives, and that help foster the energy workforce of tomorrow.
16		Moreover, ACE employees are heavily involved in giving back to local communities
17		by making personal financial contributions and volunteering over 10,000 hours of time to
18		various philanthropic organizations in New Jersey in 2022.
19		C. Efforts to Advance Clean Energy Goals
20	Q13.	Please describe ACE's overall commitment to advancing the clean energy and
21		decarbonization goals of New Jersey.

New Jersey has a goal of 100% clean energy by 2050 and a mandate to reduce the

State's greenhouse gas emissions by 80% below 2006 levels. The Energy Master Plan

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A13.

("EMP") provides a comprehensive	set o	f strategies	and	goals	for	modernizing	New
Jersey's energy system to achieve the	se out	comes.					

ACE has been a critical and effective partner in advancing the State's clean energy and climate goals through a number of approved programs, including two bedrock programs that are included in this request: the SEN and the Company's EVsmart program. These programs are aligned with the following goals from the EMP and the Clean Energy Act ("CEA"):

- Achieving 100% clean energy and reducing emissions by 80% (below 2006 levels) by 2050;
- Registering 330,000 EVs in New Jersey by 2025, which will reduce emissions from the transportation sector that accounts for 46% of the state's net greenhouse gas emissions;
- Modernizing the grid and advanced communications to enable more Distributed Energy Resources ("DER");
- Growing New Jersey's clean energy economy;
- Ensuring reliability and affordability for all customers;
- Reducing the state's carbon footprint;
- Advancing new technologies for all residents; and
- Reducing peak electricity demand by 2%.

Further complementing the goals of the EMP and the 2021 Solar Act⁴, in its recent PTF filing⁵, the Company also proposed investments that would maintain the safe and reliable operation of the electric distribution system while further expanding the system's ability to incorporate solar, as well as other DERs. Finally, the Company so far within its first three-year triannual energy efficiency ("EE") cycle has realized 42,043 MWh

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⁴ On July 9, 2021, Governor Murphy signed the Solar Act of 2021, P.L. 2021, c. 169, *available at* https://pub.njleg.state.nj.us/Bills/2020/PL21/169_.PDF, directing BPU to double the growth of the existing solar program, incentivizing up to 3,750 megawatts ('MW') of solar generation by 2026 (750 MW annually).

⁵ Docket No. ER22100666.

1	savings ⁶ . The Company looks forward to updating its programs for the next triennium
2	review by November 2023.

D. Customer Benefits Provided Through ACE's System Advancements

Q14. Please provide a summary of the Company's recent reliability performance.

ACE customers continue to experience improvements in the reliability and resiliency of their distribution electric service. These improvements are a direct result of the Company's ongoing investments in programs to modernize the electric distribution system and are a testament to the ongoing benefits of implementing best practices across the Exelon family of companies.

Over the last five years, energy system upgrades and new innovative technologies have driven a 26% decrease in the frequency of electric outages for ACE customers. In fact, ACE's customers experienced the lowest frequency of electric outages ever in 2021 and again in 2022.⁷

Q15. Do ACE's investments help the Company meet customers' reliability expectations?

Yes. As a result of the Company's investments in its distribution system, customers have experienced fewer service disruptions and shorter outage durations. The Company's reliability and storm restoration improvements have contributed significantly to the 95% customer satisfaction score for reliability performance achieved by ACE in 2022. As part

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⁶ The Company is not seeking recovery of spending associated with energy efficiency programs in this proceeding; however, these programs are an important part of ACE's investment that advance the State's goals in alignment with the EMP. This figure is consistent with the reported quarterly savings filed in Docket EO20090621.

⁷ In 2022, reliability performance for ACE exceeded its 2022 regulatory commitment, with a SAIFI of 0.64 exceeding the commitment of 1.82 and a Customer Average Interruption Duration Index ("CAIDI") of 78 minutes, exceeding the commitment of 120 minutes.

of its commitment to deliver a high quality of service to New Jersey customers, ACE will continue to invest in its system and improve reliability and enhance the customer experience in 2023 and beyond.

Q16. What are the Company's primary objectives that supported the investments included in this rate filing?

A17.

A16.

ACE's objectives are three-fold: 1) provide safe, reliable service to its customers, 2) ready the grid to support the State's climate and clean energy goals and to be responsive to changing energy needs of customers, and 3) prepare for, respond to, and maintain reliability in the face of damaging storms. These objectives are core components that underpin the Company's recent investments and components of the request for a rate increase.

Q17. How does the Company plan to prepare for future weather emergencies?

The Company has continued to make grid resiliency a key part of its future planning, investment and management. It includes assessing previous damage and investing in mitigation efforts to lessen the impact of future weather emergencies. Recent damaging storms attributed to climate change, such as Tropical Storm Ida, had a significant financial impact, and the Company needed to repair or replace damaged storm equipment, as discussed further by Company Witnesses Brubaker and Whitman in their Direct Testimony. Investments, such as the PowerAhead Grid Resiliency Initiative, are designed to improve, modernize, and enhance energy infrastructure during severe weather events. In addition, once the SEN is operational, ACE will have near real-time visibility into its distribution system and be alerted when customers experience outages that will help enable faster and more efficient power restoration efforts.

ACE is also involved in regular maintenance and enhancement work in an effort to
prevent or significantly reduce outages. Inspections are being completed in preparation for
severe weather to ensure the grid is ready for the impact of winter storms. Additionally,
the Company regularly completes emergency response drills to test the readiness of the
system, its supporting technology, and the employees who also support the network and
customers affected by severe weather.

Q18. What system investments are included in this filing that provide customer benefits?

A19.

A18.

ACE is making investments in several key initiatives to benefit customers. In their Direct Testimony, Witnesses Brubaker and Whitman describe the Company's core reliability investments included in this rate request, which have supported better reliability and resiliency for customers. Their Direct Testimony will also describe PowerAhead and the measurable impacts this program has had in improving reliability for customers during severe weather events. In addition, this filing includes the initial cost recovery requests related to the Company's SEN and EVsmart initiatives, each of which will be discussed below.

Q19. Has the Company included changes to its Street Lighting program in this rate request?

Yes. ACE has adopted a Light Emitting Diode ("LED") Street Light Strategy to address supply chain concerns regarding existing street lighting and provide the benefits of LEDs to customers. The Company is proposing to offer only LED streetlights for customers moving forward. This strategy will improve light quality and light pollution issues, provide more innovative and energy efficient lighting, reduce environmental emissions, limit High-Pressure Sodium ("HPS") and Metal Halide ("MH") risk exposure,

and avoid future re-lamping maintenance costs. Furthermore, it addresses supply chain challenges regarding HPS and MH lightning. For municipalities and large customers, ACE's LED Streetlight Strategy will reduce monthly energy usage in addition to improving lighting quality. Company Witness Normand further discusses these changes in his Direct Testimony.

A20.

E. Features and Benefits of the SEN

Q20. Please give a brief overview of the SEN program and its customer benefits.

The SEN initiative involves upgrading current electric meters with SEN meters that are designed to automate and communicate near real-time electric usage information securely. Access to near real-time data helps the Company have greater insight into its distribution system, and also helps customers more easily manage their energy usage through digital tools with access to the meter information.

There are numerous benefits to the SEN, including:

- Enhanced reliability;
- Improved bill management;
- Better customer experience through improved technology; and
- Better integration with other clean energy technologies.

ACE has completed installation of the SEN telecommunications network and began installing SEN meters in the spring of 2022. In their Direct Testimony, Company Witnesses Brubaker and Whitman provide additional information regarding the benefits

⁸ For a discussion of Street Lighting prepared by the American Council for an Energy-Efficient Economy, see Reducing Energy Use in Public Outdoor Lighting | ACEEE.

1	and deployment of SEN, and I discuss the recovery of the SEN spend in Section III of my
2	testimony.

A22.

A21.

Q21. Has the Company leveraged investments related to SEN to support South Jersey communities?

Yes. As discussed above, ACE has constructed a workforce development program to attract and train local talent in the community, with a specific emphasis on creating career opportunities for residents in overburdened or underserved communities. The Company's Atlantic City Infrastructure Program and the South Jersey Utility Training Program both provide work-readiness and job training. These programs have led to the hiring of 14 candidates to support the deployment of meter installations in 2022. As deployment continues to ramp up, the Company expects to hire more than 50 candidates in total from local communities and through its workforce development programs, which Company Witnesses Brubaker and Whitman discuss further in their Direct Testimony.

Q22. What steps has the Company taken to reduce barriers to adoption for low-and-moderate-income customers during the SEN deployment?

As the Board is aware, SEN deployment may identify needed electrical work on the meter pan on the customer's side of the meter which must be completed at the customer's expense. For some low to moderate income ("LMI") customers, the need to complete that work could act as a barrier to SEN participation. To address this issue, the Company has collaborated with NJ SHARES, a non-profit organization that provides assistance to income-eligible New Jersey households, to support equity in the SEN deployment by providing a \$1.1 million Meter Pan Grant (for which the Company is not seeking recovery in this proceeding), and that will cover the costs of repairs of customer-

owned metering equipment for LMI customers. The program provides an additional source of financial assistance to income-eligible residential customers of ACE who may not be able to cover the cost of necessary repairs on customer-owned meter equipment. This funding is available to all Owner-Occupied ACE Eligible Customers. The term "Eligible Customers" means those residential customers of ACE with household income up to 400% of the Federal Poverty Level, as defined by The United States Federal Poverty Guidelines issued by the United States Department of Health and Human Services, who require assistance in paying their ACE electric bills.

A23.

Q23. Is the Company seeking recovery of certain capital costs associated with the deployment of the SEN in this rate request?

Yes. As discussed in the Direct Testimony of Company Witnesses Brubaker and Whitman, the Company spent approximately \$67.4 million on the SEN capital as of December 2022, with an additional \$45.8 million of forecasted capital spending, for a total spend of \$113.2 million by the end of June 2023. This spending represents used and useful assets placed into service during the test year period. Smart meters are providing immediate benefits to customers upon installation and will provide further benefits to customers as mass meter activation begins. The inclusion of these SEN costs in this request will spread the costs associated with this project over a longer time period, minimizing the upfront impact to customers and reducing the potentially negative financial impact to the Company associated with the large investment needed to deploy the SEN. In their Direct Testimony, Witnesses Brubaker and Whitman detail the actual and forecasted SEN costs, and later in my testimony I discuss the recovery of two proposed SEN regulatory assets, which represent \$4.9 million of the Company's revenue requirement in this case.

F. ACE's EVsmart Program

2 Q24. Please describe the Company's EVsmart program.

A24. The Board approved ACE's multi-year EV charging infrastructure program in BPU Docket No. EO18020190. EVsmart has been developed to remove barriers surrounding electric transportation and to add charging infrastructure solutions to make EV traveling easier and better supported. The Company's EVsmart program is designed to support New Jersey's goal of putting 330,000 electric vehicles on the road by 2025. The program helps to incentivize "make-ready" electric infrastructure needs for customers looking to install electric vehicle charging stations across ACE's territory.

Q25. When did the Company begin the EVsmart program?

A25. ACE's EVsmart program formally launched in December 2021 and will run through 2026 (or until funding is exhausted). ACE began reviewing applications in January 2022 and collecting relevant required data in March 2022. The website for applicants became accessible in late 2022 and marketing efforts began around the same time. These efforts will continue throughout the length of the program and are expected to drive additional customer applications and program growth in the coming years.

⁹ See Docket No. EO18020190.

Q26. What offerings are included in the EVsmart program?

A27.

A26.

The Program provides make-ready incentives for Residential, Multi-family, Workplace, Fleet, and Public Level 2 and Direct Current ("DC") fast charging applications. The program also includes a new rate option for customers installing DC fast chargers for public use at \$0.109/kWh, while also informing the development of future time-of-use rates for ACE's residential customers, which will be discussed further by Company Witness Normand in his Direct Testimony. The DC fast charging rate will be available until December 31, 2024, or when a new rate based on a cost-of-service study prepared by ACE has been approved by the Board.

Make-ready work includes the pre-wiring of electrical infrastructure at a parking space, or set of parking spaces, to facilitate easy and cost-efficient future installation of EV charging stations, including, but not limited to, Level 2 and DC fast chargers. It includes expenses related to service panels, junction boxes, conduit, wiring, and so on, necessary to make a particular location able to accommodate EV charging equipment on a "plug and play" basis. Once make-ready work is completed, incentives can be paid to those customers who connect eligible charging stations at their site and share charging data in accordance with the program data requirements.

Q27. Since the start of EVsmart, what has been the benefit to ACE's customers?

The program currently has received approximately 500 applications which equates to over \$900,000 in incentives. To date, 72 applications have been completed; the majority of which were submitted by residential customers. When customers apply to the program, it is done through an online portal where their application can be reviewed. Once approved, customers can proceed with the installation work, and then provide their invoices for the

work that has been completed. ACE will review their invoicing along with confirming connectivity, and incentives will be paid out based on the acquired information. As of January 2023, incentives have been paid out directly to the customers with applications completed. Altogether, the amount paid is approximately \$79,000. Currently, the 72 completed applications have resulted in 87 ports.

Q28. What is the Company requesting in terms of recovery for EVsmart?

7 A28. The Company is seeking to recover \$1.6 million of current and estimated costs
8 through June 2023, as they relate to ACE's EVsmart Program. This amount does not
9 include any estimates for incentives, as project completion can vary by customer.
10 Incentives will be requested in the period in which they are realized.

G. ACE's PowerAhead Program

Q29. Please give an overview of PowerAhead.

The PowerAhead Program¹⁰ was approved in May 2017 by the Board to improve distribution system resiliency and storm hardening. PowerAhead entailed an investment level of \$79 million, to run over a five-year period, and included initiatives in six subprograms, as detailed in the Company Witnesses Brubaker and Whitman's Direct Testimony. The investments approved in the PowerAhead Stipulation were completed in June 2022. Over the course of the five-year program, ACE submitted seven rate recovery roll-in filings which resulted in provisional approval by the Board to implement the rate

A29.

¹⁰ Docket No. ER16030252

increases associated with these investments.	The investments, depreciation expenses, and
revenue related to PowerAhead are included	in the overall revenue requirement.

A30.

In its Order approving PowerAhead, the Board directed that the prudency of the program execution would be reviewed and determined in a future base rate case—which is the instant proceeding. More specific program details are provided in the Direct Testimony of Company Witnesses Brubaker and Whitman.

H. Summary of ACE's Rate Request

Q30. Please summarize the Company's rate increase request and provide the main driving factors.

The Company is requesting a \$104.8 million (excluding Sales and Use Tax) increase in base distribution-related revenue to recover the Company's capital investments and costs to maintain, operate, and improve the distribution system based on a June 30, 2023, test period consisting of five months of actual results and seven months of forecast data.

The Company is requesting recovery of its expenses, and recovery of and on its investments, through the end of the test period of June 30, 2023, and recovery of certain expenses and investments that extend beyond the test period including recovery of plant closings through June 30, 2024, which I will further explain in Section III. In addition, the Company's request reflects a Return on Equity ("ROE") of 10.50%, which represents the Cost of Equity that Company Witness D'Ascendis found reasonable and appropriate.

1 Q31. Why is the Company filing its rate request now?

A32.

2 A31. The Company is filing now to recover costs associated with several key programs,
3 such as SEN and EVsmart. In addition, there are external factors that have impacted ACE
4 over the last few years, such as substantial costs due to severe storms and the impacts of
5 rising inflation, which require the Company to adjust rates.

Q32. What external factors are affecting the Company's proposed rate increase request?

There are several external factors that are affecting not only the Company's rate increase proposal but also the New Jersey economy as a whole. Inflation and the rising costs of goods and services have similarly affected ACE's operations in this rate period, which I will discuss in greater detail later in my Testimony. Another significant factor in this rate period was several damaging storms and the costs associated with recovery from such storms. The ACE territory was hit with multiple storms, including an Enhanced Fujita ("EF") Scale 3 tornado in September 2021 during Tropical Storm Ida that caused significant damage to the distribution system. The Company has worked towards quicker recovery from the impacts of storms. In their Direct Testimony, Company Witnesses Brubaker and Whitman provide additional information regarding the Company's efforts and associated costs to recover from storms in this period.

Q33. What is the impact of the Company's rate increase request to the typical residential customer bill?

As noted above and discussed further in Company Witness Normand's Direct
Testimony, under the proposed rates in this application, a typical residential customer using
669 kWh per month will see a total monthly bill increase of \$12.22 or 8.80%.

Q34.	What is ACE doing to support customers and minimize the potential impacts of this
	rate request?

A34.

The Company recognizes the impact rate adjustments have on customers and has worked on several approaches to support reasonable and affordable service for customers. Those methods include fair rate design and gradualism, efforts to offset costs via federal funding, such as the Infrastructure Investment and Jobs Act ("IIJA"), and the provision of payment plans, budget billing, and other programs, along with supporting eligible customers in accessing energy assistance. ACE helped more than 35,000 eligible customers secure over \$88 million in energy assistance in 2022 alone, which assists customer with paying their energy bills without the requirement to pay it back. Furthermore, it is important to highlight that many of the investments being made by ACE allow customers to have better visibility into, and management of their energy usage through SEN.

Q35. What affordability measures were considered in the rate design?

14 A35. The Company leverages gradualism to each individual rate schedule. As discussed
15 by Company Witness Normand in his Direct Testimony, the application of gradualism
16 avoids large bill impacts and wide variations in all rate classes. Additionally, Witness
17 Normand discusses how fairness across customer classes is implemented to support
18 equitable rate design.

Q36. Is the Company pursuing any funding opportunities from the Federal government?

A36. Yes. On December 16, 2022, ACE submitted concept papers for the first funding opportunity announcement through the U.S. Department of Energy's ("DOE") Grid Resilience and Innovation Partnership ("GRIP") program, which seeks to enhance grid flexibility and improve the resilience of the power system against growing threats of

1		extreme weather and climate change. ACE's proposed projects include: 1) the Storm
2		Hardening New Jersey Infrastructure for Resiliency project, and 2) the implementation of
3		the SEN project. ACE has received letters of encouragement for the concept papers from
4		DOE and is moving forward with developing full applications for submission later this
5		year.
6	Q37.	Does the Company offer any programs to customers in need of bill assistance?
7	A37.	Yes, through the Company's Customer Care services, customers can access
8		assistance with their bills. Payment plans are available for customers interested in arranging
9		installment plans to manage balances. Budget billing can give customers a consistent and
10		predictable monthly payment throughout the year to minimize seasonal variation.
11		ACE also offers support by connecting customers to state assistance programs that
12		offer economic grants to New Jersey residents experiencing economic hardship, such as
13		Payment Assistance for Gas and Electric ("PAGE"), Universal Service Fund ("USF"), and
14		New Jersey SHARES ("NJ SHARES").
15		I. Overview of the Company's Application
16	Q38.	Please summarize the Company's application.
17	A38.	The filing consists of the Petition for an increase in base distribution rates, together
18		with my Direct Testimony and the Direct Testimony of six other witnesses. Those
19		witnesses and the topics they address are as follows:
20 21 22		 Mr. Gregory W. Brubaker, Sr. Manager, Strategic Planning, and Mr. Ryan P. Whitman, Manager, Project Execution, provide testimony on the maintenance of the Company's distribution system, ACE's significant electric system

investment program, and the SEN investments;

1 2 3 4 5 6 7 8 9		 Mr. Dylan W. D'Ascendis, Managing Partner, Scott Madden Inc., provides testimony and schedules in support of the Company's proposed return on common equity ("ROE"); Ms. Shengrong Chen, Principal Rate Analyst, Regulatory Policy and Strategy, provides testimony and schedules in support of the Company's revenue requirement; Mr. Joshua L. Masters, Sr. Manager, Rate Administration, provides testimony and schedules in support of the Company's Class Cost of Service Study ("CCOSS"); and Mr. Michael T. Normand, Manager, Retail Rates, provides testimony and
11 12		schedules in support of the Company's rate design.
13		III. <u>DEVELOPMENT OF THE REVENUE REQUIREMENT</u>
14	Q39.	Have you relied on any other Direct Testimony in developing the Company's
15		requested Revenue Requirement?
16	A39.	Yes. In addition to my own Direct Testimony and Schedules, the development of
17		the \$104,788,395 revenue requirement includes and relies on the Direct Testimonies and
18		recommendations of Company Witnesses D'Ascendis, Chen and Normand.
19		A. The Company's Test Period
20	Q40.	What is the test period presented in this filing?
21	A40.	As previously noted, the test period used for the revenue requirement calculation in
22		this filing is five months of actual data and seven months of forecasted data ending June
23		30, 2023. The test year used for class cost of service and supported by Company Witness
24		Masters is the 12-month period ending September 2022. The annual period during which
25		new rates would be effective is expected to be November 17, 2023, through November 16,
26		2024, which I will refer to in my Direct Testimony as the "rate effective period." The start

of the rate effective period is nine months after this filing, which is the date when New

Jersey utilities have the right to implement interim rates, subject to refund, if the Board has
not acted within the required statutory time period.¹¹

Q41. Is this test period a reasonable basis for establishing rates?

A42.

4 A41. Yes. The 12 months ending June 2023 test period is consistent with the minimum filing requirements. This test period provides a proper matching of revenues, expenses, and rate base that is largely consistent with the Board's practice in previous ACE proceedings. However, this test period does not represent the optimal approach to setting the Company's revenue requirement for the rate effective period.

Q42. Please explain why the Board's test period policy is not the best approach.

Ratemaking, by its very nature, is an estimate of conditions likely to be incurred during the first year that rates are in effect (the rate effective period). Rates should be set to reflect the cost of providing service to customers during that rate effective period. Although the Company may file a partially historical and partially forecasted test period, that test-year data is historical by the time new rates are set and become effective. The Board's policy to permit only certain types of post-test year adjustments means that other, more current, cost data (including new rate base additions) are excluded from the new rates. Taken together, this means that the new rates do not accurately reflect the cost of utility service at the time the rates become effective. Thus, this creates a timing mismatch that results in rates that do not accurately reflect the cost of providing service during the rate effective period.

¹¹ N.J.S.A. 48.2-21 (d), N.J.S.A. 48-2-21.1(c) and N.J.A.C. 14:1-5.12 (e).

- Q43. Have you made any adjustments to the Company's June 2023 test period as well as included adjustments for recovery of certain post test period investments?
- A43. In accordance with prior decisions of the Board, including the decision in Docket

 No. WR8504330 for Elizabethtown Water Company, I have included known and

 measurable pro-forma adjustments to track costs more accurately during the rate effective

 period including all post test period plant additions net of retirements from July 2023

 through December 2023.

Q44. Please describe the Schedules that you support.

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Schedule (JCZ)-1 presents a summary of the necessary financial and accounting data for the test period ending June 30, 2023. Schedule (JCZ)-2 provides the calculation of the increase in revenues necessary to earn the 7.13% rate of return reflected in Schedule (JCZ)-16. This rate of return is still not expected to be achieved in the rate effective period, given the historical nature of test period data by the time new rates go into effect in this filing. Company Witness Normand provides support for the details and additional billing comparisons in his Direct Testimony. Schedule (JCZ)-3 shows the unadjusted per-books earnings and rate base having a rate of return of 4.68% which translates to a return on equity of 5.62%. Schedule (JCZ)-3 then displays ratemaking adjustments that would be reflective of the rate-effective period. This Schedule displays a fully adjusted rate of return of 3.77% for the rate effective period, which translates to an ROE of only 3.80% and emphasizes the need for full and current rate relief given the Company's continuing investment level in its electric system. Schedule (JCZ)-3 also displays the effect of each earnings and rate base pro-forma adjustment by component and provides for fully adjusted earnings and rate base.

1	Schedules (JCZ)-4 through (JCZ)-16 provide the details of each of the operating
2	income, rate base, and pro-forma adjustments that I discuss later in my Direct Testimony.
3	Workpapers supporting my Schedules will be provided under separate cover.

B. Revenue Requirement Determination

Q45. How did you determine the \$104,788,395 revenue requirement?

A45.

I first developed the test period for the 12-month period ending June 30, 2023, based on five months of actual data and seven months of forecasted data by assembling the revenues, expenses, and rate base for that time period. I reviewed that data to determine whether any adjustments were necessary to reflect a full year of normal operating conditions. As a result of that review, I made adjustments to reflect known and measurable changes in revenues, expenses, and investments as well as to include those adjustments proposed by Company Witnesses Normand and Chen. These adjustments are discussed later in my Direct Testimony. After making all required adjustments, I determined the Company's test period operating income by subtracting test period expenses from test period revenues.

Next, by multiplying test period adjusted rate base by the overall rate of return reflected in Schedule (JCZ)-2, I determined the required operating income. Subtracting the test period operating income from the required operating income determines the operating income deficiency.

Finally, the operating income deficiency was adjusted for Federal and State income taxes, revenue taxes, and SUT to establish the total requested revenue requirement. A summary of these results is on Schedules (JCZ)-1 through (JCZ)-3.

Q46. How was rate base developed for this filing?

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2 A46. Rate base was developed using data based on the Company's actual five months 3 totals and seven months forecasted totals ending June 30, 2023. I have used the data to 4 calculate the necessary test period adjustments, including those adjustments proposed by 5 Company Witnesses Normand and Chen, to rate base and operating income as shown on 6 Schedule (JCZ)-1. Using the data, the test period levels of Electric Plant in Service, 7 Depreciation Reserve, and Accumulated Deferred Income Tax Balances (including Excess 8 Deferred Income Taxes resulting from the Tax Cuts and Jobs Act of 2017) were calculated. 9 Materials and Supplies, Customer Deposits, and Customer Advances for Construction were 10 carried forward as rate-base items and apportioned to the electric-distribution function based on allocations from the Company's Cost of Service Study. The Cash Working 11 12 Capital rate-base addition is based on the Company's lead/lag study performed on historic 2021 data and applied to the test period operations. 13

Q47. How was operating income developed?

A47. The operating income was based on five months of actual data from June 2022 through November 2022 and seven months of forecasted data from December 2022 through June 2023. The data were then allocated to ACE's distribution function. Operating income was then adjusted for known and measurable changes. These adjustments are summarized on Schedule (JCZ)-3.

C. Distribution Cost of Service

Q48. Please discuss the development of the ACE cost of service on a distribution-only basis.

The basis for ACE's distribution-only cost of service is the distribution accounts as specified in the FERC Uniform System of Accounts. In addition, I have allocated to distribution a portion of other Company cost elements functionalized as general, intangible, and miscellaneous. This method is consistent with that provided in ACE's last base case filing, BPU Docket No. ER20120746. The result of this separation, or functionalization of costs, is shown on Schedule (JCZ)-1.

Q49. Please describe the detail provided on Schedule (JCZ)-1.

A49.

A48.

Schedule (JCZ)-1 shows the items of rate base, revenue, expense, and return for ACE for the total Company in column (3), titled "System Electric," and those same cost elements for the distribution function in Column (4), titled "Distribution." Column (3) shows total Company rate base of \$3,561,667,470, total operating revenues of \$1,387,681,860, total operating expenses of \$1,223,018,216, and operating income of \$164,663,644. As I described above, I separated each cost element into its distribution component. The distribution component is shown in column (4) of this Schedule. The distribution rate base for the Company is \$2,115,195,742, distribution operating revenues are \$486,246,812, distribution operating expenses are \$387,215,417, and distribution operating income is \$99,031,395. Additionally, I provided Company Witness Masters with the comparable functionalized distribution information for the 12 months ending September 2022 to develop the Class Cost of Service Study included with his Direct Testimony. This functionalized distribution information can be found in the Minimum Filing Requirements, which are included in this filing.

1 Q50.	How are system	distribution	costs develor	ped?
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2	A50.	ACE's overall costs consist of supply, transmission, and distribution-related costs.
3		Distribution plant costs are those costs contained in FERC distribution accounts, numbers
4		360 to 373. Distribution expense costs are those costs contained in FERC distribution
5		accounts (inclusive of Customer Accounts Expense, Customer Service and Informational
6		Expenses, and Sales Expenses), numbers 580 through 916. Transmission Plant Costs are
7		from FERC's transmission accounts, numbered 350 through 359. Transmission Expense
8		costs are those costs contained in FERC transmission accounts, numbers 560 through 573.
9		Other costs, such as General Plant and Administrative and General Expenses, are contained
10		in FERC accounts that are not specific to the transmission and distribution functions and
11		thus must be functionalized to produce the distribution-related portion of these costs.

Q51. Was a lead/lag study prepared by the Company to determine the cash working capital requirement in this filing?

A51. Yes. Please refer to Company Witness Chen's Direct Testimony for details regarding the Company's lead/lag study. The total per books ACE distribution cash working capital requirement is \$121,558,345.

D. Ratemaking Adjustments

Q52. Please describe the purpose of the ratemaking adjustments detailed on Schedule (JCZ)-3.

As I explained earlier, the ratemaking adjustments reflect known and measurable changes to the test period data to provide for the revenues, expenses, and investment in plant that will be generally representative of the term for which rates will be in effect. To

1	develop the test period data in this manner, the Company has included several
2	normalization and annualization adjustments to be reflective of the rate effective period.
3	Generally, these adjustments follow the adjustments submitted in the Company's last base
4	case, BPU Docket No. ER20120746.

Q53. What general guidance do you use for adjustments in terms of the time periods theyencompass?

A53. The Board's Order in Elizabethtown Water Company, BPU Docket No. WR8504330, provides guidance used in the development of the revenue requirement in this filing in terms of adjustments for known and measurable changes to the test period data. Page 1 of the Order states:

Based upon the foregoing, the Board determines, for purposes of this proceeding, that Petitioner shall have the opportunity to make a record with regard to: (a) known and measurable changes to income and expense items for a period of nine months beyond the end of the test year; (b) changes to rate base for a period of six months beyond the end of the test year, provided there is clear likelihood that such proposed rate base additions shall be in service by the end of said six-month period, that such rate base additions are major in nature and consequence, and that such additions be substantiated with very reliable data; (c) changes to capitalization for a period of three months past the end of the test year, provided that such changes are major in nature and consequence, and that the results of said proposed financing are actual prior to the Board's determination in this case.

Q54. Please list the ratemaking adjustments detailed in your Direct Testimony.

A54. Below is a list of all the Company's proposed adjustments in this case, along with the sponsoring witness. My testimony contains details for each adjustment for which I am listed as the sponsoring witness. Company Witnesses Normand and Chen's Direct Testimonies contain details for the adjustments they are sponsoring.

Adj	Sponsoring Witness	Adjustment Description
1	Chen/Normand	Reflect the Revenue Annualization Associated with Conservation Incentive Program ("CIP")
2	Chen/Normand	Reflect Revenue Associated with Customer Counts as of December, 2023
3	Chen	Reflect Wage and Federal Insurance Contributions Act ("FICA") Expense Changes Within Nine Months After End of Test Period
4	Chen	Reflect Wage and Federal Insurance Contributions Act ("FICA") Expense Changes for Rate Effective Period
5	Chen	Normalize Regulatory Commission Expense
6	Ziminsky	Pension and Other Post-Employment Benefits ("OPEB") Expense Adjustment
7	Ziminsky	Reflection of 5-year Average Inflation on Non-Labor Operations & Maintenance ("O&M") Expense
8	Ziminsky	Remove Executive Incentive Expenses
9	Chen	2021 Storm Ida Adjustment
10	Chen	Normalize Injuries and Damages Expense
11	Chen	Adjust Mays Landing Complex Rent
12	Chen	Annualize Depreciation Expenses on Year-End June 30, 2023 Plant Using Depreciation Rates Approved in Docket No. ER18060638
13	Chen	Restate PHI Service Company assets at ACE Approved Depreciation Rates
14	Ziminsky	Reflect Plant Additions from July 2023 – December 2023
15	Ziminsky	Reflect Plant Additions from January 2024 – June 2024
16	Ziminsky	Reflect Credit Facilities Cost
17	Chen	Restate Interest on Customer Deposit ("IOCD") Expense
18	Chen	Remove Annual Infrastructure Investment Program (" IIP") Revenue Requirement
19	Chen	Adjust Cash Working Capital
20	Chen	Adjust Interest Synchronization
21	Ziminsky	Corporate Minimum Tax Adjustment
22	Ziminsky/Normand	Excess Deferred Income Taxes ("EDIT") – Expiring Riders Regulatory Asset
23	Ziminsky	Reflection of Electric Vehicle Regulatory Asset
24	Ziminsky	Reflect AMI SEN Regulatory Asset

25	Ziminsky	Reflect AMI SEN Incremental O&M Expenses Regulatory Asset
26	Ziminsky	Reflection of Benchmarking Requirement Cost Recovery

Q55. Please describe Adjustment No. 6, which reflects increases to the Company's test period pension and OPEB expenses to be reflective of the rate effective period - Schedule (JCZ)-4.

A56.

A55.

The Company proposes to adjust the recorded test period level of pension and OPEB expense to the 2023 level provided by the Company's independent actuary. This more recent actuarial-determined amount better reflects the appropriate level of pension and OPEB expense in the rate effective period.

The Company will update this adjustment to reflect the 2023 actuarial expense levels as part of its 12+0 update filing. This adjustment is detailed on Schedule (JCZ)-4, and results in a \$1,021,822 decrease to test period earnings.

Q56. Please describe Adjustment No. 7, which reflects the five-year historical average inflation on non-labor O&M expense.

The Company is proposing this adjustment so that (i) its test period expenses will appropriately reflect general inflation impacts on non-labor O&M costs to be incurred during the rate effective period, and (ii) to eliminate the regulatory lag that would otherwise exist in the mismatch of cost levels between the Company's test period and those levels actually present and impacted by general inflation during the rate effective period.

For the inflation impacts in this adjustment, the Company relied on data from the U.S. Department of Labor's Bureau of Labor Statistics and results in the Consumer Price Index ("CPI"). More specifically, CPI data related to ACE's service territory is used as

1		the basis for the Company's five-year average calculation. The use of a five-year historical
2		average is effective at measuring inflationary trends over time and better addresses
3		systemic inflation and the leveling of associated effects on non-labor O&M expense. It
4		also helps to effectively match revenue and expense during the rate effective period. The
5		calculated 5-year Average Inflation Factor that the Company has included in Adjustment
6		7 is 3.27%.
7	Q57.	Please explain the actual and published inflationary conditions that are prevalent,
8		and which have compelled the Company to introduce this adjustment in this
9		proceeding for first time.
10	A57.	Current economic conditions, including a key indicator component, inflation, have
11		been topics of major national focus and concern in the news for well over a year now.
12		Given the magnitude of the inflationary growth over this time period, there are several
13		articles informing the public of the related impacts. The Company has reviewed and
14		included the following articles as Schedule (JCZ)-19:
15 16 17 18		• February 7, 2023, Forbes Article, "What's the US' Projected Inflation Rate in 2023?" This article discusses that while inflation has come down since June 2022, it remains high, and it is unclear what level it will get to in 2023.
19 20 21		 November 12, 2022, News release from the U.S. Bureau of Labor Statistics, "Consumer Price Index Summary". This release gives CPI data from October 2022 that shows annual inflation still running at 7.7 percent.
22 23 24 25 26 27		 November 10, 2022, CNBC article headline reads "Fed officials welcome inflation news but still see tighter policy ahead" (2022). The article notes that inflation is still running at an annual rate of 7.7% that is, "still far too high and well off the Central Bank's 2% goal." October 18, 2022, Article from U.S. Bank titled, "Analysis: How persistent
28 29		might inflation be?" This article notes persistent inflation by stating, "In 2021, the cost-of-living, as measured by the Consumer Price Index (CPI), rose 7.0%

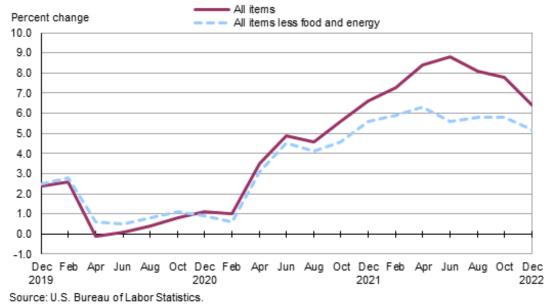
for the year. It was the highest calendar-year reading since 1981 and stood in sharp contrast to the trend over the past 40 years, when inflation averaged 2% to 3% annually."

To illustrate the impact from the national level down to the areas that are included in the Company's service territory, which are affected by the current inflationary trends, Chart 1 below provides PA-DE-NJ CPI data that represents local conditions and how the current trends are notably higher than those experienced over the past three years.

1 2

A58.

Chart 1. Over-the-year percent change in CPI-U, Philadelphia-Camden-Wilmington, PA-NJ-DE-MD, December 2019–December 2022



Q58. Please explain if there is positive precedent in the Company's other jurisdictions related to an inflation adjustment such as the one proposed in this proceeding.

The proposed adjustment is consistent with the Maryland Public Service Commission's decision in Order No. 88975, Case No. 9484, *In the Matter of the Application of Baltimore Gas and Electric Company for Adjustments to its Gas Base Rates* where the Commission found as follows:

1 2 3 4 5		The Commission finds that a more reasoned and accurate approach to assessing the impact of inflation is to use a five-year average of the CPI. This approach addresses the actual trend in inflation during the rate-effective period in a verifiable and measurable manner while accounting for variances. 12
6		The Commission reaffirmed its decision in Delmarva Power Case No. 9630, as well
7		as in Order No. 89227, Case No. 9602, In the Matter of the Application of Potomac Electric
8		Company ("PEPCO") for Adjustment to its Retail Rates for the Distribution of Electric
9		Energy, where it found:
10 11 12 13		Based on record, Pepco's adjustment is consistent with the Commission's approval of a similar BGE adjustment, and the proposed inflation rate is an appropriate proxy for the impact of inflation during the rate effective period. ¹³
14	Q59.	What has the Delaware Commission stated about a non-labor O&M inflation
15		adjustment?
		•
16	A59.	The Delaware Commission addressed Delmarva Power & Light's request for an
16 17	A59.	The Delaware Commission addressed Delmarva Power & Light's request for an adjustment for non-labor O&M inflation in its electric base rate case, Docket No. 20-0149.
	A59.	
17	A59.	adjustment for non-labor O&M inflation in its electric base rate case, Docket No. 20-0149.
17 18	A59.	adjustment for non-labor O&M inflation in its electric base rate case, Docket No. 20-0149. Although the Commission ultimately denied the adjustment, Chairman Winslow made the

¹² MD PSC Order No. 88975, p. 25.

Case No. 9602, Proposed Order of Public Utility Law Judge ("Proposed Order"), p. 72, MailLog 225999, as adopted by the MD PSC and authorized in final Order 89227, MailLog 226376.

probably approve	of. But I think,	because of	f the previous
precedent, I'm goin	g to vote and sup	port the mot	ion. ¹⁴

A60.

Thus, despite prior Delaware precedent prevailing, Chairman Winslow's remarks signal an openness to the inflationary adjustment due to the then current circumstances.

Since the time of that observation and vote in August 2021, inflationary pressures have not only persisted, but they have also continued to rise. While there has been minor slowing of the rate of increase over the recent months, a plateau has not yet occurred as of the time of this filing and easing back to recovery is not anticipated to occur for some time, including well into or beyond the rate effective period associated with this current case. In view of these current conditions, the Board should also distinguish its past precedent on inflationary adjustments.

Q60. Please summarize the Company's position regarding the importance and relevance of this inflation adjustment.

Allowing this adjustment would place the Company in a position where it is better able to absorb the effects of inflationary pressures between rate cases. The widely recognized inflation conditions and the impacts they are having, and will continue to have, on non-labor O&M over time will continue to have an adverse impact on the Company, and absent approval of an adjustment like this, will drive the Company to seek rate relief more frequently to reflect the higher costs. The prevailing trends data and indicators explained herein support a finding that the Company's proposed inflation adjustment is

¹⁴ Public Service Commission Docket No. 20-0149, Hearing Transcript Volume 12, page 1932.

1	appropriate in this case. This adjustment is detailed on Schedule (JCZ)-5, and results in a
2	\$3,327,145 decrease to earnings.

- Q61. Please describe Adjustment No. 8 Remove Executive Incentive Expense Schedule
 (JCZ)-6.
- 5 A61. This adjustment removes the test period level of executive incentive expense associated with financial-related goals of the Executive Incentive Compensation Plan 6 7 ("EICP") and the Long-Term Incentive Plan ("LTIP"). The Company disagrees with this 8 adjustment because these "compensation at risk" payments are an important component of 9 the Company's total executive compensation and are likely to continue to be so in the 10 future. As such, the Company reserves the right to seek recovery of these costs in future 11 rate case filings. As shown on Schedule (JCZ)-6, this adjustment results in a \$912,841 12 increase to test period operating income.
 - Q62. Are you proposing the inclusion of post-test period plant additions in the cost of service in this proceeding?

14

Yes, I have proposed two adjustments related to post-test period plant additions: 1)

Adjustment No. 14, which reflects Plant Additions from July 2023 through December 2023

and does not include PTF, the Company's proposed second Infrastructure Investment

Program, additions in this proceeding, and 2) Adjustment No. 15, which reflects Plant

Additions from January 2024 through June 2024 and also does not include PTF additions

in this proceeding.

Q63. Why are you proposing the inclusion of these post-test period plant additions in cost of service?

A63.

These plant additions represent known and measurable plant additions that will be providing service to ACE's customers during the rate effective period. The inclusion of these plant additions in the revenue-requirement determination of this proceeding matches the benefits that customers will realize to the associated costs to the Company from this investment. The plant additions will be "used and useful" during the rate effective period and providing a benefit to ACE's customers. These projects and their associated dollars have been evaluated as part of the Company's Asset Management planning process. For those projects that are customer-driven relating to new service requests, I have synchronized those additions with additional revenues associated with the anticipated customer growth forecasted by the Company based on the average revenue per customer, by customer class as reflected in Adjustment No. 2 as in the Testimony of Witness Chen.

I will update as much of the requested post-test period plant expenditures and customer additions as possible during this proceeding. Whether updated to actual or not, the projects included in my adjustments clearly fall within the category of being "known and measurable." These projects will provide service to ACE customers during the rate effective period, and it is appropriate to match the cost of providing that benefit to customers during the time the benefits are being realized.

Q64. Provide the source of your plant additions information.

A64. In their Direct Testimony, Company Witnesses Brubaker and Whitman provide support for the post-test period plant additions, including the nature of the projects, the category type of the projects, and the cost of the projects. They also demonstrate the post-

test period plant additions are major in nature and consequence and should be included in
the proposed revenue requirement. It should be noted that the plant additions reflect the
amount that will be placed in service and are used and useful for customers, not the total
capital expenditures that Company Witness Brubaker and Whitman discuss.

A66.

A65.

Q65. Please describe Adjustment No. 14 - Reflect Plant Additions from July 2023 through December 2023 - Schedule (JCZ)-7.

This adjustment reflects plant closings and related costs for the first six months after the test period. Inclusion of this "known and measurable" post-test period distribution-related plant investment is consistent with Board practice, which was established in the Board's ruling in the Elizabethtown Water Company case, BPU Docket No. WR8504330, and confirmed in the JCP&L Decision, BPU Docket No. ER12111052, dated March 18, 2015. Company Witnesses Brubaker and Whitman discuss these plant additions in greater detail in their Direct Testimony. My proposed adjustment to rate base and operating income is shown on Schedule (JCZ)-7 and results in a \$3,172,131 decrease to test period operating income and a \$113,265,374 increase to net rate base. Schedule (JCZ)-7.1 provides the details of this adjustment by project and by month.

Q66. Please describe Adjustment No. 15 - Reflect Plant Additions from January 2024 through June 2024 - Schedule (JCZ)-8.

This adjustment reflects plant closings and related costs for the next six months after the ones included in Adjustment No. 14. These six months are within the rate effective period and thus would represent plant serving customers during the rate effective period. My proposed adjustment to rate base and operating income is shown on Schedule (JCZ)-8 and results in a \$1,554,552 decrease to test period operating income and a \$69,777,613

1	increase to net rate base. Schedule (JCZ)-8.1 provides the details of this adjustment by
2	project and by month.

A67.

Q67. Please generally describe the Company's credit facility cost as it pertains to this rate proceeding.

Consistent with the treatment submitted in the last base rate case in Docket No. ER20120746, the Company is proposing an adjustment to test period cost of service to recognize ACE's share of the cost of the PHI credit facility. The Board has not yet made a decision on credit facility cost recovery in prior base rate cases. This \$900 million credit facility is vital to the day-to-day working capital needs of the Company. Moreover, it is a requirement by the various credit rating agencies to maintain ACE's separate corporate credit rating. An adjustment is necessary due to the accounting for this cost in the Company's financial statements as interest expense, which is not incorporated in the embedded cost of debt. Without this adjustment, the actual cost would not be included in ACE's cost of service.

This credit facility allows the Company to borrow in the commercial paper market. This market has been ACE's primary source of short-term liquidity for years, and the credit facility assures investors that ACE has a committed line of credit with banks in the event of a liquidity problem. In tight credit periods, where the commercial paper market cannot be relied upon due to liquidity concerns, the credit facility provides the Company with a backstop borrowing mechanism to handle day-to-day cash requirements. The credit facility and its impact on liquidity are vital in maintaining the Company's current credit ratings.

Q68.	Please describe Adjustment No. 16 – Reflect Credit Facilities Cost on
	Schedule (JCZ)-9.
A68.	This adjustment proposes recovery of ACE's allocated portion of the PHI credit
	facility. In terms of the credit facility costs proposed for recovery, they include an
	amortization of the start-up costs as well as the annual maintenance fees. These costs are
	required for the credit facility regardless of whether or not ACE has short-term debt
	outstanding related to the credit facility. For accounting purposes, these costs are included
	in interest expense; however, they are not included in interest expense for ratemaking
	purposes. As such, this adjustment proposes their recovery. As shown on Schedule (JCZ)-
	9, this adjustment results in a \$525,482 decrease to test period operating income and
	\$578,298 increase to net rate base.
Q69.	\$578,298 increase to net rate base. Is there precedent in any of the regulated utilities in other jurisdictions where PHI
Q69.	
Q69. A69.	Is there precedent in any of the regulated utilities in other jurisdictions where PHI
	Is there precedent in any of the regulated utilities in other jurisdictions where PHI operates that allows for the recovery of the cost of credit facilities?
	Is there precedent in any of the regulated utilities in other jurisdictions where PHI operates that allows for the recovery of the cost of credit facilities? Yes. The state regulators overseeing PHI's other utilities (Delmarva Power -
	Is there precedent in any of the regulated utilities in other jurisdictions where PHI operates that allows for the recovery of the cost of credit facilities? Yes. The state regulators overseeing PHI's other utilities (Delmarva Power - Delaware and Maryland; Pepco - Maryland and the District of Columbia) all have
	Is there precedent in any of the regulated utilities in other jurisdictions where PHI operates that allows for the recovery of the cost of credit facilities? Yes. The state regulators overseeing PHI's other utilities (Delmarva Power - Delaware and Maryland; Pepco - Maryland and the District of Columbia) all have authorized the amortization of the jurisdictional cost of the credit facility with rate base
A69.	Is there precedent in any of the regulated utilities in other jurisdictions where PHI operates that allows for the recovery of the cost of credit facilities? Yes. The state regulators overseeing PHI's other utilities (Delmarva Power - Delaware and Maryland; Pepco - Maryland and the District of Columbia) all have authorized the amortization of the jurisdictional cost of the credit facility with rate base treatment of the unamortized balance.
A69.	Is there precedent in any of the regulated utilities in other jurisdictions where PHI operates that allows for the recovery of the cost of credit facilities? Yes. The state regulators overseeing PHI's other utilities (Delmarva Power - Delaware and Maryland; Pepco - Maryland and the District of Columbia) all have authorized the amortization of the jurisdictional cost of the credit facility with rate base treatment of the unamortized balance. Please explain how the enactment of the Inflation Reduction Act ("IRA") impacts

Corporations will now pay the greater of 15% of adjusted financial statement income or

1	their regular federal tax liability. Beginning in 2023, based on current tax guidance and
2	forecasted projections, ACE will be subject to the CAMT.

3 Q71. For CAMT purposes, how is adjusted financial statement income determined?

For purposes of calculating adjusted financial statement income, the starting point is financial statement net income. The financial statement net income is then adjusted for federal income taxes, accelerated tax depreciation, pension and other postemployment benefits. As a result, for purposes of determining adjusted financial statement income, federal income taxes, accelerated tax depreciation, pension and other postemployment benefits are treated the exact same with respect to the calculation of the regular federal income tax liability.

Q72. Why does ACE's CAMT exceed the regular tax liability?

12 A72. Under tax law, certain expenditures capitalized for financial statement purposes
13 qualify for accelerated tax deductions such as tax repairs and certain overhead
14 capitalization. As a result, these expenditures are expensed for regular tax sooner than for
15 CAMT lowering the regular tax below the CAMT.

16 **Q73.** How does ACE calculate the CAMT?

11

17 A73. The Company calculated the CAMT based on its stand-alone separate company books and records.

19 Q74. How is the Company expected to account for the CAMT in its financial statements?

A74. For income tax accounting purposes, a current income tax liability and current income tax expense will be recorded for the CAMT liability but will be equally offset by recording a deferred tax asset and a reduction to deferred income tax expense to reflect the

1	CAMT credit carryforward.	As a result, there is no net incremental income tax expense
2	associated with the CAMT.	

A75.

Corporations are entitled to a tax credit equal to the amount by which the CAMT liability exceeds the regular tax liability. This amount can be carried forward indefinitely and used in future years when the regular tax liability exceeds the CAMT liability. The credits are not permitted to be carried back to prior years. For income tax accounting purposes, a deferred tax asset is established for the CAMT credit carryforward.

Q75. If ACE is below the \$1 billion threshold on a separate company basis, why is it subject to CAMT?

ACE is a subsidiary of Exelon Corporation. Strictly for purposes of determining if Exelon exceeds the \$1 billion in average profits, Exelon must include all of its subsidiaries including ACE because Exelon is considered a "single employer group" under the tax rules. The current tax law specifies that CAMT applies to "applicable corporations." If a "single employer group," in the aggregate exceeds the \$1 billion profits threshold, each corporation that is part of that "single employer group" is considered an "applicable corporation" and separately subject to CAMT. Under the tax rules, when a subsidiary ceases to be a member of an affiliated group of corporations, the departing subsidiary is entitled to its CAMT credit carryforward and can utilize that credit in future tax years when its regular tax exceeds its CAMT liability.

Q76. What is the rate making impact associated with CAMT in Adjustment No. 21?

A76. ACE proposes to include the deferred tax asset associated with the CAMT credit carryforward as an increase of \$12,119,271 to rate base, per Schedule (JCZ)-10.

1 Q77. Why is it appropriate to include the deferred tax asset related to CAMT in ra	ite base	ite l	ra	in	Γ:	IJ	M	N	A	C	0	to	d	te	lai	el	r	et	SSE	a	ax	ta	ed	re	fer	lei	Ċ	he	e 1	d	lu	nc) i	to	te	iai	ri	op	r	p	ap	t a	i i t	is	lV i	/h	W		77	\mathbf{O}^{7}	(1	1
--	----------	-------	----	----	----	----	---	---	---	---	---	----	---	----	-----	----	---	----	-----	---	----	----	----	----	-----	-----	---	----	-----	---	----	----	-----	----	----	-----	----	----	---	---	----	-----	-------	----	------	----	---	--	----	------------------	---	---	---

A77. Accelerated tax deductions related to utility property generate cash tax benefits that reduce the cost of capital. For rate making purposes, rate base is adjusted downward to reflect the lower cost of capital attributable to accelerated tax deductions. The CAMT has the effect of reducing the tax benefits associated with accelerated tax deductions such as tax repairs and certain other overhead capitalization adjustments. The accumulated deferred income taxes ("ADIT") associated with tax repairs and other property related tax adjustments are included in rate base for ACE as a downward adjustment. Therefore, to reflect the appropriate cost of capital, the deferred tax asset associated with the CAMT credit carryforward should likewise be included in rate base as an upward adjustment that offsets ADIT.

Q78. How does the CAMT differ from a Consolidated Tax Adjustment (CTA)?

13 A78. The CAMT is calculated based on the stand-alone separate company books and records and is directly attributable to utility operations. In contrast, the CTA is calculated and allocated based on taxable losses not directly related to the utility.

16 Q79. What is the impact of CAMT on the CTA calculation?

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- 17 A79. Based on current guidance, the CAMT will increase the cash tax obligation for
 18 Exelon and ACE. As a result, there will be less taxable losses allocable to companies that
 19 recognized taxable income.
- Q80. Please describe Adjustment No. 22, which requests a Regulatory Asset for expiring
 EDIT Riders.
- 22 A80. Pursuant to the Amended Order in Docket Nos. AX1801001 and ER18030241,
 23 ACE needed to refund the non-protected EDIT over a five-year amortization period and

the refund related to the unprotected EDITs was to be effectuated through a per kWh credit
to customer bills. The order also states "[A]ny change in the amount should be addressed
in the Company's next base rate case. Additionally, any under- or over-credited amounts
should be reconciled in the Company's base rate case filed after the expiration of the
credit." Schedule (MTN)-5, included with Company Witness Normand's Direct
Testimony, provides a summary of the balances by service classification and when the
entire amounts for the five-year credits are forecasted to be fully paid. The schedule will
be updated at the time of the Company's planned 12+0 update to actuals to include the final
actual balances where the five-year credits for service classifications have been fully paid
and set to zero within the test period. Adjustment No. 22 which results in an increase to
rate base of \$186,703, is detailed on Schedule (JCZ)-11.

A81.

In the Stipulation of Settlement in BPU Docket No. ER20120746, the Company agreed to true-up any under- or over- recovery relating to the estimated \$15.8 million EDIT revenue requirement acceleration for the period from July 15, 2021 through December 31, 2021. The under-recovery amount relating to the accelerated EDIT is trued up based on the actual billing determinants for the period from July 15, 2021 and has been reflected in Schedule (MTN)-5 of Company Witness Normand's Direct Testimony.

Q81. Please describe Adjustment No. 23 with respect to establishing an Electric Vehicle regulatory asset.

On February 17, 2021, the BPU approved a settlement reached between ACE and interested stakeholders associated with the Voluntary Program for Plug-In Vehicle Charging, which is now referred to as EVsmart. In total, ACE was approved to spend no more than \$20.7 million over the 5-year program period, effective as of the date of the

approved order to promote expansion of electric vehicle charging infrastructure in New Jersey. The agreement included approval to defer to a regulatory asset the incremental costs incurred associated with the program, which are to be evaluated for prudency and recovery in a future base rate case. More details about the EV program are provided above in Section II of my Direct Testimony.

The overall EV Charging Program consists of the individual program offerings that include \$13.3 million of investments in EV charging infrastructure utility make-ready work to facilitate the growth of EV charging sites in New Jersey, \$1.5 million for rebates to customers, as well as \$5.9 million for certain administrative costs, data networking and collection costs, and customer education and outreach costs. Pursuant to the order, ACE will neither own nor operate the charging assets or the related stations themselves as part of this program. The agreement also established that ACE may defer to the regulatory asset ACE's incremental depreciation associated with new capital investment placed into service and non-capital O&M costs associated with the EV Charging Program. Additionally, the order states the EV regulatory asset and undepreciated book value of the new make-ready capital investments are permitted to earn a rate of return based on the overall rate of return approved by the BPU in the Company's most recent base rate case and updated with the rate of return approved in subsequent base rate cases.

In this proceeding, the Company is seeking recovery of the costs described above that have been deferred to the regulatory asset as of the end of the June 2023 test period, to be amortized over a period of three years with the unamortized balance included in rate base. As shown on Schedule (JCZ)-12, this adjustment results in a \$374,245 decrease to test period operating income and a \$932,794 increase to net rate base.

1	Q82.	Please explain if ACE is requesting recovery of any of its authorized SEN Program
2		investments and expenses in this filing.
3	A82.	Yes, the Company is requesting recovery of certain capital investments made and
4		the associated O&M expenses that have been incurred, as well as those that are forecasted
5		to be made and incurred during the test period, through the deployment of the SEN
6		Program. The SEN program specifics are discussed further in the Direct Testimony of
7		Company Witnesses Brubaker and Whitman. My Direct Testimony, regarding the SEN
8		and the requested cost recovery treatments, is meant to explain the details of the SEN
9		Regulatory Asset Adjustment 24, and the SEN O&M Incremental Expense Regulatory
10		Asset Adjustment 25.
11	Q83.	Please discuss the rate making treatment of SEN regulatory asset in the Stipulation
12		of Settlement approved in BPU Docket No. EO20080541.
13	A83.	In Paragraph 22 of the Stipulation of Settlement relating to the SEN program and
14		cost recovery mechanism approved by BPU in Docket No. EO20080541, it states in part
15		that:
16		[] the Company will book a regulatory asset ("SEN Regulatory Asset")
17		comprised of: 1) a return on and of its SEN Program Costs ("SEN Investment Deferral"),
18		and 2) a return of the associated stranded costs ("Stranded Cost Deferral") on legacy
19		meters [].
20		Additionally, in paragraph 25, it states that:
21		ACE's Next Base Rate Case will include a request for recovery in base rates of all
22		prudently incurred SEN Program Costs associated with the SEN Program implementation
23		that have been placed into service or will be placed into service consistent with the Board's

1		Elizabethtown Water standards [] The Stranded Cost Deferral component of the SEN
2		Regulatory Asset shall be excluded from cost recovery in the Next Base Rate Case, but
3		shall be subject to recovery in the Future Base Rate Case[].
4		Company Witnesses Brubaker and Whitman provide more details about the
5		deployment of the SEN program in their Direct Testimony.
6	Q84.	Please describe Adjustment No. 24 regarding the SEN regulatory asset which is
7		included as part of the revenue requirement in this proceeding.
8	A84.	The Company proposes to include the SEN regulatory asset specifically related to
9		a return on and of its SEN Program Costs ("SEN Investment Deferral") as described in the
10		Stipulation of Settlement. The SEN Investment Deferral balances as of June 30, 2023
11		include:
12 13 14		• A return on average monthly capitalized SEN program costs net of associated accumulated depreciation, accumulated deferred income tax and accumulated deferred cost of removal. The forecasted balance is currently at \$3,357,985.
15 16		• Monthly Depreciation/Amortization of SEN program costs. The forecasted balance is currently at \$2,141,456.
17 18		• A return on the average monthly investment deferral balances. The forecasted balance is currently at \$174,133.
19		The SEN Investment Deferral balance will be updated to actuals prior to rates going
20		into effect during this proceeding. The Company proposes that the SEN regulatory asset
21		be amortized over a period of five years with the unamortized balance included in rate base
22		earning the Company's overall rate of return. This adjustment results in a \$815,747
23		decrease to test period operating income and \$3,670,860 increase to net rate base, as shown
24		in Schedule (JCZ)-13.

1	Q85.	Please describe Adjustment No. 25, which requests the recovery of SEN incremental
2		O&M costs associated with the SEN implementation.

A86.

A85.

Per the Board Order in Docket No. EO20080541, the Company will defer incremental AMI-related O&M costs associated with the SEN implementation into a separate regulatory asset ("SEN Incremental O&M Regulatory Asset") for recovery in the Company's next base rate case. The SEN Incremental O&M Regulatory Asset associated with SEN deployment includes internal labor costs such as managing the SEN program and network, meter integration and testing, start-up costs etc. In Adjustment No. 25, the Company proposes the SEN Incremental O&M Regulatory Asset be amortized over a period of five years with the unamortized regulatory balance included in rate base to earn the Company's overall rate of return. The forecasted balance of the incremental AMI-related O&M costs balance as of June 30, 2023 will be updated to actuals prior to rates going into effect during this proceeding. This adjustment results in a \$1,824,585 decrease to test period operating income and \$8,210,632 increase to net rate base, as shown in Schedule (JCZ)-14.

86. In Adjustment No. 26, is the Company proposing to recover certain Benchmarking Requirement implementation costs by including them in its requested revenue requirement in this proceeding?

Yes, in Adjustment No. 26, the Company is presenting to the Board the costs that the Company anticipates that it will incur as of September 2023 in order to implement the Benchmarking Requirement. I will update as much of the requested Benchmarking Requirement expenditures as possible during this proceeding.

1	Q87.	Briefly explain the Data Access Services associated with the Benchmarking
2		Requirement, as they relate to the Order Approving the Energy And Water
3		Benchmarking Program, BPU Docket No. QO21071023.
4	A87.	In the referenced Order, the BPU directed the utilities providing data access
5		services to offer benchmarking webpages through which building owners may submit Data
6		Access Request Forms and download Consent Letters to obtain individual tenant data. The
7		Board also directed the regulated electric and gas utilities serving over 50,000 customer
8		accounts to provide the data access services using Web Services beginning on August 1,
9		2023, for the First Reporting Year (2022).
10	Q88.	In its Order Approving the Energy and Water Benchmarking Program, did the
11		Board define a recovery method for costs incurred by the utilities that are associated
12		with implementing the Benchmarking Requirement?
13	A88.	Yes. In the referenced Order, the BPU directed the regulated utilities to file for cost
14		recovery of the reasonable and prudent costs of implementing the Benchmarking
15		Requirement, which may include establishing, operating, and maintaining data aggregation
16		and data access services, for the Board to evaluate in future base rate case proceedings. The
17		Company proposes to create a regulatory asset for the O&M expense associated with
18		implementing the Benchmarking Requirement to be amortized over a period of three years
19		with the unamortized balance included in rate base to earn the Company's overall rate of
20		return. This adjustment also includes the capital investment as well as the on-going O&M
21		maintenance costs to implement the Benchmarking Requirement.
22		As shown on Schedule (JCZ)-15, this adjustment results in a \$176,502 decrease to

test period operating income and a \$765,513 increase to rate base.

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1		E. <u>Revenue Requirement Summary</u>
2	Q89.	Can you summarize the adjustments that are included in this filing?
3	A89.	Yes. Schedule (JCZ)-3 displays all of the pro-forma adjustments included in this
4		filing and details the earnings and rate base effect of each adjustment.
5	Q90.	Please summarize the Company's overall revenue deficiency.
6	A90.	Schedule (JCZ)-2 displays the calculation of the Company's revenue deficiency of
7		\$104,788,395 excluding SUT, and \$111,730,626 including SUT. These calculations
8		include the effects of all the pro-forma adjustments to the test period level of earnings and
9		rate base and uses the rate of return of 7.13% that is reflected in Schedule (JCZ)-16.
10		IV. COMPANY'S CAPITAL STRUCTURE AND RATE OF RETURN
11		REQUEST
12	Q91.	What overall rate of return is ACE requesting?
13	A91.	As shown in Schedule (JCZ)-16, the Company is requesting an overall rate of return
14		("ROR") of 7.13% on its distribution rate base.
15	Q92.	On what capital structure is the overall ROR based?
16	A92.	As reflected in Schedule (JCZ)-16, the overall ROR is the weighted average cost of
17		capital, based on the Company's September 30, 2022 capital structure ratios of 50.20%
18		common equity and 49.80% long-term debt, its embedded long-term debt cost of 1.86%,
19		and its proposed return on common equity of 5.27%, as determined by Company Witness
20		D'Ascendis.

	a Pro Forma Capital Structure?
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- 2 A93. Yes. As shown in Schedule (JCZ)-16, page 3, the Pro Forma Capital Structure includes one new bond in the amount of \$75 million that is projected to occur in March 2023 at an anticipated rate of 6.05%, which reflects current market conditions. ACE's Pro Forma Capital Structure also includes an equity contribution to maintain ACE's target equity ratio of 50.20%.
- 7 Q94. Why are you proposing to use a Pro Forma Capital Structure?

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- A94. ACE is proposing to use a Pro Forma Capital Structure to reflect the known issuance of the new bond noted above. In addition, the new issuance of \$75 million that will occur in Q1 2023 is taking place in an interest rate environment that has changed significantly, such that ACE's interest costs will increase, as compared to the past several years, and will be significantly higher during the rate effective period. It is important to reflect this known and measurable change to the cost of capital in this instant filing.
 - Q95. Is the Pro Forma Capital Structure consistent with the Company's goals and objectives regarding capital structure?
- 16 A95. This capital structure is consistent with ACE's goals and objectives to maintain the
 17 Company's credit ratings and a target equity ratio of at least 50%. In addition, the
 18 Company's current credit ratings are based on its commitment to maintain a minimum
 19 capital structure consistent with this percentage.
- Q96. Are there other reasons this capital structure is appropriate for use in this proceeding?
- 22 A96. Yes. As discussed in the Direct Testimony of Company Witness D'Ascendis, the Company's recommended capital structure is reasonable given a mean common equity

1	ratio of 10.50% (range between 10.05% to 11.05%) for the operating companies
2	comprising the proxy group used by Company Witness D'Ascendis for the purpose of
3	determining his recommended return on equity in this proceeding.

Q97. Has the Company also submitted an alternative capital structure using the PHI data in compliance with the BPU's Order approving the Stipulation of Settlement in the Exelon merger¹⁵?

Yes. These data are contained in Schedule (JCZ)-17. Although submitted in accordance with the terms of the Exelon merger, it should not be used for rate-setting purposes for ACE in this matter. The capital structure that should be used to set rates for ACE is the one used to develop the Company's requested overall ROR, which is the Company's own capitalization.

Q98. Why is PHI's consolidated capital structure inappropriate for use in setting rates for ACE?

The PHI consolidated capital structure reflected in Schedule (JCZ)-17 is inappropriate in this regard because it contains debt obligations of other subsidiaries that obtain capital on their own merits and invest those proceeds in their own operations. The PHI capital structure data presented on Schedule (JCZ)-17 does not provide a reasonable basis to calculate the ROR for ACE and are submitted solely to comply with the terms of the BPU's Order approving the Exelon merger stipulation of settlement. The alternative capital structure has not been adopted since its inception.

A98.

A97.

¹⁵ Docket No. EM14060581

1 Q99. What are the Company's credit ratings by the major rating agencies?

ASP. ACE's long-term corporate credit ratings are A- from Standard and Poor's, Baa1 from Moody's Investors Service, and BBB from Fitch Ratings.

Q100. Please briefly describe the importance of the Company's credit ratings.

A100.

The Company's credit ratings indicate the rating agencies' assessment of ACE's ability to meet its obligations to its long-term debt holders. The higher the credit rating, the greater the perceived likelihood that debt investors will receive their interest and principal payments as expected. As such, a company with a higher credit rating may have access to a larger investor base, may face fewer restrictive covenants, and may issue long-term debt at a lower cost. A higher credit rating at this time is particularly advantageous, given the Company's plans to continue to invest a significant amount of capital in system reliability for the benefit of customers. In addition, given the significant credit commitments associated with the Basic Generation Service procurement process, a high credit rating furthers the Company's ability to obtain favorable pricing, terms, and conditions from wholesale suppliers. These benefits ultimately inure to ACE's customers.

Conversely, lower credit ratings reflect increased investor risk. As a result, investors and lenders expect to be paid more to provide funds to such an issuer. In addition to paying a higher interest rate to issue new debt, the Company would be required to pay higher annual fees on its credit facility if its credit rating were to fall to lower levels than it is today. In addition, lower credit ratings typically result in investors demanding more restrictive terms and covenants from the issuer. Lower credit ratings also limit the pool of investors that may otherwise invest in the Company due to ratings restrictions imposed by

some institutional investors. These additional costs associated with lower credit ratings
will only increase the costs to ACE's customers.

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Q101. How does ACE fund its capital expenditures while maintaining its capital structure as noted above?

A101. ACE uses three principal sources to finance its capital expenditures: internally generated cash flows, externally raised debt financing, and equity contributions from the parent company. Given the Company's significant capital spending program, ACE's internally generated cash flows are insufficient alone to fund them. As a result, the Company must raise funds from the capital markets and/or receive equity contributions from its parent to bridge the gap. Long-term debt and equity are used to finance the Company's rate base, which is itself comprised of long-term assets on a net basis. The Company utilizes short-term debt to fund changes in working capital and temporarily fund its construction requirements. In other words, short-term debt is generally used as a stop gap to provide for temporary financing needs. As utilization of short-term debt increases to such a level where longer-term, permanent financing is better suited as a financing mechanism, the short-term debt is retired and replaced with long-term securities. This method is a cost-effective, lower risk means of financing the Company's construction plan as opposed to solely issuing long-term securities and holding large amounts of unproductive cash. Temporarily financing the construction plan with short-term debt also provides the Company with the ability to continually assess market conditions and take advantage of opportunities to secure favorable terms and conditions for any potential longterm debt issuances. Accordingly, ACE's ratemaking cost of capital reflects the Company's permanent sources of funding (e.g., long-term debt and equity).

1	As noted above, ACE's capital structure is managed consistent with its goals and
2	objectives. The Company's policy is to make equity contributions into ACE and make
3	dividend payments from ACE to PHI to ensure ACE maintains an equity ratio of at leas
4	50%.
5	V. <u>OTHER TOPICS</u>
6	A. <u>Consolidated Tax Adjustment (CTA)</u>
7	Q102. Please address the filing requirement to provide a calculation of a CTA.
8	A102. Pursuant to N.J.A.C. 14:1-5.12, utilities are to include a calculation of the CTA as
9	part of their base rate case petitions. As shown in confidential Schedule (JCZ)-18, the
10	Board's approved calculation method does not result in a rate base reduction related to the
11	CTA, given the Company had a net taxable loss for that period. The tax years used for the
12	calculation include 2017 through 2021, in compliance with the BPU's approved calculation
13	method of using the 5 previous tax years prior to the start of the test period.
14	B. PHISCO Gross Receipts Tax – Proposed One-Time Credit
15	Q103. Is the Company planning to provide a one-time giveback to customers related to a
16	2021 Delaware Gross Receipts Tax Settlement?
17	A103. Yes.
18	Q104. Please provide the background related to the Delaware Gross Receipts Tax
19	Settlement.
20	A104. In late 2017, the Delaware Division of Revenue notified Exelon that PHISCO was
21	selected for a tax and license compliance review. In connection with that review, the
22	Delaware Division of Revenue asserted that PHISCO was subject to Delaware Gross
23	Receipts Tax for the tax years 2011 through 2017. Exelon's position was that PHISCO

qualifies as a Headquarters Management Corporation and is therefore exempt from the
Delaware Gross Receipts Tax. Due to uncertainty with respect to sustaining this position,
PHISCO established a tax reserve of \$3.3 million in 2018 Q4 and has been updating the
interest reserve on a quarterly basis.

A105.

In July 2020, Exelon proposed a settlement of \$70,000 to advance a resolution. In 2021 Q4, the Delaware Division of Revenue accepted the settlement offer of \$70,000. On December 9, 2021, Exelon and the Delaware Division of Revenue executed a binding closing agreement (Settlement Agreement) whereby Exelon paid the sum of \$70,000 in full satisfaction of its liability; thereby, effectively resolving the matter.

As a result, during 2021 Q4, following receipt of the executed settlement documents, Exelon released the tax and interest reserve and recognized an earnings benefit of \$4.6 million.

Q105. What are the regulatory accounting implications related to the settlement of the tax review of PHISCO's Delaware Gross Receipts Tax filing position?

Under Accounting Standard Codification (ASC) 980, Regulated Operations, if, because of an action by a regulator, it is "probable" that the future increase or decrease in taxes payable will be recovered from or returned to customers through future rates, an asset or liability shall be recognized for that probable future recovery or reduction to revenue. If a gain or other reduction of net allowable costs is to be amortized over future periods for rate-making purposes, the regulated entity shall not recognize that gain or other reduction of net allowable costs in income of the current period. Instead, it shall record it as a liability for future reductions of charges to customers that are expected to result.

The earnings benefit associated with remeasurement of the contingency reserve will
be reflected in PHISCO's intercompany billings to Pepco, Delmarva Power, and ACE (the
"PHI Utilities"). On the separate company books and records for the PHI Utilities, the
impact associated with the Delaware Gross Receipts tax reserve adjustment will be
recorded to O&M expenses for GAAP purposes (Account 923 "Outside Services" for
FERC purposes).

Q106. What treatment is the Company proposing for its customers in this proceeding related to the Gross Tax Liability?

A106. To the extent the cost accrued when the tax contingency reserve was established was included in rates charged to customers and as such recovered, then the corresponding benefit should by extension be returned to customers in a future rate case proceeding unless otherwise noted. Specific to ACE, in 2018 Q4, when the loss contingency reserve was established, the expense recorded at ACE was included in the cost-of-service computation and the allocable portion was recovered from electric distribution customers. Therefore, the Company is proposing, in this proceeding, to return the allocable portion of the reserve adjustment, in the amount of \$994,337 to ACE distribution customers as a one-time bill credit. The exact specifics of the proposed one-time credit are discussed in detail in the Direct Testimony of Company Witness Normand.

C. <u>COVID-19 Regulatory Asset</u>

Q107. What is the Company's plan to recover Covid related regulatory as	Q107.	What is the	Company's plan	to recover Covid	d related regulatory	asset
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A107. In accordance with Docket No. AO20060471,¹⁶ the Board authorized each of the State's regulated utilities to create a COVID-19 related regulatory asset by deferring on their books and records the prudently incurred incremental costs related to COVID-19 beginning on March 9, 2020, and through September 30, 2021. In the Order relating to COVID-19 Regulatory Asset, dated September 14, 2022, the Board ordered that the regulatory asset period be extended form September 30, 2021 to December 31, 2022.¹⁷ However, ACE reported to the Board that it stopped deferring costs to its COVID-19 Regulatory Asset as of September 30, 2021.¹⁸ In the most recent Order relating to the COVID-19 Regulatory Asset, dated December 21, 2022, the Board ordered that the regulatory asset period be further extended form December 31, 2022 to March 15, 2023, but indicated that utilities could seek recovery prior to the end of the regulatory asset period.¹⁹

In the Company's recent petition to reconcile and update the level of its Non-Utility Generation Charge and its Societal Benefits Charge for 2023, filed in Docket No. ER23020057 on February 1, 2023, ACE has netted its COVID-19 Regulatory Liability against its Uncollectible (UNC) component of the SBC charges. Thus, the COVID-19 Regulatory Liability is not included in the context of this base case proceeding.

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¹⁶ Docket No. AO20060471, Order Authorizing Establishment of a Regulatory Asset for Incremental COVID-19 Related Expense.

Docket No. AO20060471, Item 64 09.14.22 9A ORDER COVID 19 Regulatory Asset Order re Motion for Extension.

¹⁸ October 2021 Compliance Plan.

¹⁹ Docket No. AO20060471, Item 64 12.21.22 9A ORDER COVID 19 Regulatory Asset Order re Motion for Extension.

Witness Ziminsky

- 1 Q108. Does this conclude your Direct Testimony?
- 2 A108. Yes, it does.

Schedule (JCZ)-1

Atlantic City Electric Company 5+7 Months Ending June 2023 Rate of Return Analysis

(1) (2) (3) (4) <u>5+7 M/E June 2023</u>

Line No.	<u>ltem</u>	S	ystem Electric	<u>Distribution</u>
1	Rate Base			
2	Electric Plant in Service	\$	5,632,236,528	\$ 3,486,545,538
3	Less: Depreciation Reserve	\$	1,336,339,832	\$ 929,929,623
4	Net Plant in Service	\$	4,295,896,696	\$ 2,556,615,916
5				
6	Plant Held For Future Use	\$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$	12,298,643	\$ 6,477,249
7	Materials & Supplies	\$	41,290,109	\$ 35,736,589
8	Cash Working Capital	\$	160,961,428	\$ 121,558,345
9	Customer Advances	\$	(6,319,096)	\$ (6,319,096)
10	Customer Deposits	\$	(18,259,444)	\$ (18,259,444)
11	Def Federal and State Tax Bal ⁽¹⁾	\$	(924,200,865)	\$ (580,613,818)
12	Total Rate Base	\$	3,561,667,470	\$ 2,115,195,742
13				
14	Total Rate Base	\$	3,561,667,470	\$ 2,115,195,742
15				
16	<u>Earnings</u>			
17	Operating Revenues	\$	1,387,681,860	\$ 486,246,812
18				
19	O & M Expense	\$	973,618,472	\$ 254,937,371
20	Deprec and Amort Expense	\$	245,308,516	\$ 122,951,000
21	Taxes Other than Income Taxes	\$	8,618,509	\$ 5,663,172
22	Net ITC Adjustment	\$	(288,671)	\$ (170,035)
23	IOCD	\$	11,532	\$ 11,532
24	State Income Tax	\$ \$ \$ \$ \$ \$ \$ \$	-	\$ -
25	Federal Income Tax	\$	(10,781,010)	\$ (2,168,627)
26	Deferred SIT Expense	\$	7,813,928	\$ 5,845,029
27	Deferred FIT Expense	\$	(1,283,060)	\$ 145,975
28				
29	Total Operating Expenses	\$	1,223,018,216	\$ 387,215,417
30				
31	Operating Income	\$	164,663,644	\$ 99,031,395
32				
33	Rate of Return		4.62%	4.68%

⁽¹⁾ Includes Excess Deferred Income Taxes

Schedule (JCZ)-2

Atlantic City Electric Company 5+7 Months Ending June 2023 Determination of Revenue Requirements

(1)	(2)	(3)
Line <u>No.</u>	<u>ltem</u>	\$
1 2	Adjusted Net Rate Base	\$ 2,235,749,719
3	Required Rate of Return	7.13%
4 5 6	Required Operating Income	\$ 159,408,955
7	Pro Forma Operating Income	\$ 84,302,594
8 9 10	Operating Income Deficiency	\$ 75,106,361
11	Revenue Conversion Factor	 1.3952
12 13 14	Revenue Requirement	\$ 104,788,395
15	Sales & Use Tax Factor	 1.06625
16 17	Revenue Requirement (Adjusted for Sales & Use Tax)	\$ 111,730,626

Atlantic City Electric Company 5+7 Months Ending June 2023 <u>Distribution Adjustments</u>

(1) Line			(2)	(3)		(4)	(5) Rate	(6)	(7)	(8) Rev. Reg. Def. (Exc.)
No.			<u>ltem</u>	Witness		<u>Earnings</u>	Base	ROR	ROE	Exclude Sales & Use Tax
1	Per Bool	ks - 5+7 l	Months Ending June 2023	Ziminsky	\$	99,031,395 \$	2,115,195,742	4.68%	5.62%	\$ 72,246,333
2										
3	<u>Adjustm</u>	ents:		O. 4.	•					(007 770)
4	Adj	1	Reflect the Revenue Annualization Associated with Conservation Incentive Program	Chen/Normand	\$	715,151				\$ (997,779)
5	Adj	2	Reflect Revenue Associated with Customer Counts as of December, 2023	Chen/Normand	\$	934,044				\$ (1,303,179)
6	Adj	3	Annualize Wage and FICA changes through March 2024	Chen	\$	(2,241,425)				\$ 3,127,236
7	Adj	4	Proforma Wage Rate Changes for Rate Effective Period	Chen	\$	(71,744)				\$ 100,098
8	Adj	5	Regulatory Commission Expense Adjustment	Chen	\$	26,507				\$ (36,983)
9	Adj	6	Pension and Other Post-Employment Benefits ("OPEB") Expense Adjustment	Ziminsky	\$	(1,021,822)				\$ 1,425,646
10	Adj	7	Reflection of 5-year Average Inflation on Non-Labor O&M Expense	Ziminsky	\$	(3,327,145)				\$ 4,642,033
11	Adj	8	Remove Executive Incentive Expense	Ziminsky	\$	912,841				\$ (1,273,596)
12	Adj	9	2021 Storm Ida Adjustment	Chen	\$	(1,665,956) \$	4,164,889			\$ 2,738,655
13	Adj	10	Normalize Injuries & Damages Expense	Chen	\$	1,042,783				\$ (1,454,891)
14	Adj	11	Adjust Mays Landing Complex Rent	Chen	\$	·				\$ -
15	Adj	12	Annualize Depreciation Expense @ June 23 Plant	Chen	\$	(4,388,670) \$	(4,388,670)			\$ 5,686,498
16	Adj	13	Servco Assets @ ACE Approved Depreciation Rates	Chen	\$	94,789				\$ (132,250)
17	Adj	14	Reflect Plant Additions from July 2023 - December 2023	Ziminsky		(\$3,172,131)	\$113,265,374			\$ 15,693,142
18	Adj	15	Reflect Plant Additions from January 2024 - June 2024	Ziminsky		(\$1,554,552)	\$69,777,613			\$ 9,110,232
19	Adj	16	Credit Facilities Fee	Ziminsky	\$	(525,482) \$	578,298			\$ 790,680
20	Adj	17	Restate Interest on Customer Deposit Expense	Chen	\$	(239,083)				\$ 333,568
21	Adj	18	Remove Annual IIP Revenue Requirement	Chen/Normand		\$2,229,103	(\$91,518,054)			\$ (12,214,055)
22	Adj	19	Adjust Cash Working Capital	Chen		\$	2,788,756			\$ 277,419
23	Adj	20	Adjust Interest Synchronization	Chen	\$	715,069				\$ (997,664)
24	Adj	21	Corporate Alternative Minimum Tax ("CAMT") Adjustment	Ziminsky		\$	12,119,271			\$ 1,205,598
25	Adj	22	Excess Deferred Income Taxes ("EDIT") – Expiring Riders Regulatory Asset	Ziminsky/Normand		\$	186,703			\$ 18,573
26	Adj	23	Reflection of Electric Vehicle Regulatory Asset	Ziminsky	\$	(374,245) \$	932,794			\$ 614,939
27	Adj	24	AMI SEN Investment Deferral Regulatory Asset	Ziminsky	\$	(815,747) \$	3,670,860			\$ 1,503,299
28	Adj	25	AMI SEN Incremental O&M Expenses/Savings Regulatory Asset	Ziminsky	\$	(1,824,585) \$	8,210,632			\$ 3,362,436
29	Adj	26	Reflection of Benchmarking Requirement Cost Recovery	Ziminsky	\$	(176,502) \$	765,513			\$ 322,407
30			·	•						
31										
32			Adjusted Total		\$	84,302,594 \$	2,235,749,719	3.77%	3.80%	\$ 104,788,395

Atlantic City Electric Company 5+7 Months Ending June 2023 Rate of Return Analysis

(1)	(2)		(3)	(4)	(5)		(6)
Line No.	<u>ltem</u>	<u></u>	ystem Electric	<u>Distribution</u>	Proforma Adjustments		Fully <u>Adjusted</u>
1	Rate Base						
2	Electric Plant in Service	\$	5,632,236,528	\$ 3,486,545,538	\$ 77,426,787	\$	3,563,972,326
3	Less: Depreciation Reserve	\$	1,336,339,832	\$ 929,929,623	\$ (9,032,315)	\$	920,897,308
4 5	Net Plant in Service	\$	4,295,896,696	\$ 2,556,615,916	\$ 86,459,103	\$	2,643,075,018
6	Plant Held For Future Use	\$	12,298,643	\$ 6,477,249	\$ =	\$	6,477,249
7	Materials & Supplies	\$	41,290,109	\$ 35,736,589	\$ =	\$	35,736,589
8	Cash Working Capital	\$	160,961,428	\$ 121,558,345	\$ 28,014,466	\$	149,572,811
9	Customer Advances	\$	(6,319,096)	\$ (6,319,096)	\$ =	\$	(6,319,096)
10	Customer Deposits	\$	(18,259,444)	\$ (18,259,444)	\$ -	\$	(18,259,444)
11	Def Federal and State Tax Bal ⁽¹⁾	\$	(924,200,865)	\$ (580,613,818)	\$ 6,080,409	\$	(574,533,409)
12 13	Total Rate Base	\$	3,561,667,470	\$ 2,115,195,742	\$ 120,553,977	\$	2,235,749,719
14 15	Total Rate Base	\$	3,561,667,470	\$ 2,115,195,742	\$ 120,553,977	\$	2,235,749,719
16	<u>Earnings</u>						
17 18	Operating Revenues	\$	1,387,681,860	\$ 486,246,812	\$ 2,300,989	\$	488,547,801
19	O & M Expense	\$	973,618,472	\$ 254,937,371	\$ 12,067,387	\$	267,004,758
20	Deprec and Amort Expense	\$	245,308,516	\$ 122,951,000	\$ 10,409,689	\$	133,360,689
21	Taxes Other than Income Taxes	\$	8,618,509	\$ 5,663,172	\$ 176,198	\$	5,839,369
22	Net ITC Adjustment	\$	(/ - /	\$ (170,035)	\$ -	\$	(170,035)
23	IOCD	\$	11,532	\$ 11,532	\$ 332,567	\$	344,100
24	State Income Tax	\$	-	\$ - (0.400.00=)	\$ (1,906,953)	\$	(1,906,953)
25	Federal Income Tax	\$	\ , , ,	\$ (2,168,627)	\$ (4,049,098)	\$	(6,217,725)
26	Deferred SIT Expense	\$		\$ 5,845,029	\$ -	\$	5,845,029
27 28	Deferred FIT Expense	<u> </u>	(1,283,060)	\$ 145,975	\$ <u>-</u>	Ф	145,975
29 30	Total Operating Expenses	\$	1,223,018,216	\$ 387,215,417	\$ 17,029,790	\$	404,245,207
31 32	Operating Income	\$	164,663,644	\$ 99,031,395	\$ (14,728,801)	\$	84,302,594
33	Rate of Return		4.62%	4.68%			3.77%

⁽¹⁾ Includes Excess Deferred Income Taxes

Atlantic City Electric Company 5+7 Months Ending June 2023 Proforma Earnings Adjustments

(1)	(2)	(3)	(4)	(5)	(6)		(7)		(8)	(9)	(10)		(11)
No.	<u>Adjustment</u>	Revenue	<u>0&M</u>	Deprec <u>Amort</u>	Other Taxes		<u>SIT</u>		<u>FIT</u>	IOCD	Total Expense	Ea	arnings
1	Reflect the Revenue Annualization Associated with Conservation Incentive Program ("CIP")	\$ 997,792			\$ 3,007	\$	89,531	\$	190,103		\$ 282,641 \$	6	715,151
2	Reflect Revenue Associated with Customer Counts as of December, 2023	\$ 1,303,197			\$ 3,928	\$	116,934	\$	248,290		\$ 369,152 \$	5	934,044
3	Annualize Wage and FICA changes through March 2024		\$ 2,953,226		\$ 164,627	\$	280,607)	\$	(595,822)		\$ 2,241,425 \$	6 (2	2,241,425)
4	Proforma Wage Rate Changes for Rate Effective Period		\$ 95,162		\$ 4,635	\$	(8,982)	\$	(19,071)		\$ 71,744 \$	5	(71,744)
5	Regulatory Commission Expense Adjustment		\$ (36,872)			\$	3,318	\$	7,046		\$ (26,507) \$	5	26,507
6	Pension and Other Post-Employment Benefits ("OPEB") Expense Adjustment		\$ 1,421,368			\$ (127,923)	\$	(271,624)		\$ 1,021,822 \$	6 (*	1,021,822)
7	Reflection of 5-year Average Inflation on Non-Labor O&M Expense		\$ 4,628,106			\$	416,530)	\$	(884,431)		\$ 3,327,145 \$	6 (3	3,327,145)
8	Remove Executive Incentive Expense		\$ (1,269,775)			\$	114,280	\$	242,654		\$ (912,841) \$	5	912,841
9	2021 Storm Ida Adjustment		\$ 2,317,368			\$	208,563)	\$	(442,849)		\$ 1,665,956 \$	6 (*	1,665,956)
10	Normalize Injuries & Damages Expense		\$ (1,450,526)			\$	130,547	\$	277,195		\$ (1,042,783) \$	6	1,042,783
11	Adjust Mays Landing Complex Rent		\$ -			\$	-	\$	-		\$ - \$	5	-
12	Annualize Depreciation Expense @ June 23 Plant			\$ 6,104,702		\$	549,423)	\$	(1,166,609)		\$ 4,388,670 \$	6 (4	4,388,670)
13	Servco Assets @ ACE Approved Depreciation Rates			\$ (131,853)		\$	11,867	\$	25,197		\$ (94,789) \$	5	94,789
14	Reflect Plant Additions from July 2023 - December 2023			\$ 4,412,478		\$	397,123)	\$	(843,225)		\$ 3,172,131 \$	6 (3	3,172,131)
15	Reflect Plant Additions from January 2024 - June 2024			\$ 2,162,404		\$	194,616)	\$	(413,235)		\$ 1,554,552 \$	6 (1	1,554,552)
16	Credit Facilities Fee		\$ 730,952			\$	(65,786)	\$	(139,685)		\$ 525,482 \$	6	(525,482)
17	Restate Interest on Customer Deposit Expense					\$	(29,931)	\$	(63,554)	\$ 332,567	\$ 239,083 \$	6	(239,083)
18	Remove Annual IIP Revenue Requirement			\$ (3,898,500)		\$	534,492	:	\$1,134,905		\$ (2,229,103) \$	5 2	2,229,103
19	Adjust Interest Synchronization					\$ (228,944)	\$	(486,125)		\$ (715,069) \$	5	715,069
20	Corporate Alternative Minimum Tax ("CAMT") Adjustment					\$	-	\$	-		\$ - \$	6	-
21	Excess Deferred Income Taxes ("EDIT") – Expiring Riders Regulatory Asset					\$	-	\$	-		\$ - \$	6	-
22	Reflection of Electric Vehicle Regulatory Asset			\$ 520,580		\$	(46,852)	\$	(99,483)		\$ 374,245 \$	6	(374,245)
23	AMI SEN Investment Deferral Regulatory Asset			\$ 1,134,715		\$ (102,124)	\$	(216,844)		\$ 815,747 \$	3	(815,747)
24	AMI SEN Incremental O&M Expenses/Savings Regulatory Asset		\$ 2,538,023			\$	228,422)	\$	(485,016)		\$ 1,824,585 \$	6 (1	1,824,585)
25	Reflection of Benchmarking Requirement Cost Recovery		\$ 140,355	\$ 105,162		\$	(22,097)	\$	(46,918)		\$ 176,502 \$	3	(176,502)
26													
27	Total	\$ 2,300,989	\$ 12,067,387	\$ 10,409,689	\$ 176,198	\$ (1	906,953)	\$	(4,049,098)	\$ 332,567	\$ 17,029,790 \$	(14	4,728,801)

Atlantic City Electric Company 5+7 Months Ending June 2023 Proforma Rate Base Adjustments

(1) Line	(2)	(3) Plant In	D.	(4)	(5)	(6) Cash Working		(7)		(8)		(9)
No.	<u>Adjustment</u>	Service		Reserve	Net Plant	Capital Capital	<u>D</u>	eferred SIT	De	eferred FIT	<u>R</u>	ate Base
1	Reflect the Revenue Annualization Associated with Conservation Incentive Program ("CIP")	\$ -	\$	-	\$ - ;	-	\$	-	\$	- 9	\$	-
2	Reflect Revenue Associated with Customer Counts as of December, 2023	\$ -	\$	-	\$ - 5	-	\$	-	\$	- 9	\$	-
3	Annualize Wage and FICA changes through March 2024	\$ -	\$	-	\$ - 3	-	\$	-	\$	- \$	\$	-
4	Proforma Wage Rate Changes for Rate Effective Period	\$ -	\$	-	\$ - 3	-	\$	-	\$	- \$	\$	-
5	Regulatory Commission Expense Adjustment	\$ -	\$	-	\$ - ;	-	\$	-	\$	- \$	\$	-
6	Pension and Other Post-Employment Benefits ("OPEB") Expense Adjustment	\$ -	\$	-	\$ - ;	-	\$	-	\$	- \$	\$	-
7	Reflection of 5-year Average Inflation on Non-Labor O&M Expense	\$ -	\$	-	\$ - ;	-	\$	-	\$	- \$	\$	-
8	Remove Executive Incentive Expense	\$ -	\$	-	\$ - ;	-	\$	-	\$	- \$	\$	-
9	2021 Storm Ida Adjustment	\$ -	\$	-	\$ - ;	5,793,419	\$	(521,408)	\$	(1,107,122)	\$	4,164,889
10	Normalize Injuries & Damages Expense	\$ -	\$	-	\$ - ;	-	\$	-	\$	- 9	\$	-
11	Adjust Mays Landing Complex Rent	\$ -	\$	-	\$ - 5	-	\$	-	\$	- 9	\$	-
12	Annualize Depreciation Expense @ June 23 Plant	\$ -	\$	6,104,702	\$ (6,104,702)	-	\$	549,423	\$	1,166,609	\$	(4,388,670)
13	Servco Assets @ ACE Approved Depreciation Rates	\$ -	\$	-	\$ - 5	-	\$	-	\$	- 9	\$	-
14	Reflect Plant Additions from July 2023 - December 2023	\$ 108,413,107	\$	(5,542,072)	\$ 113,955,179	-	\$	(220,855)	\$	(468,949)	\$ 1	113,265,374
15	Reflect Plant Additions from January 2024 - June 2024	\$ 62,266,897	\$	(7,792,146)	\$ 70,059,043	-	\$	(90,106)	\$	(191,324)	\$	69,777,613
16	Credit Facilities Fee	\$ -	\$	-	\$ - :	578,298	\$	-	\$	- 9	\$	578,298
17	Restate Interest on Customer Deposit Expense	\$ -	\$	-	\$ - ;	-	\$	-	\$	- \$	\$	-
18	Remove Annual IIP Revenue Requirement	\$ (93,253,216)	\$	(1,802,799)	\$ (91,450,417)	-	\$	(21,656)	\$	(45,982)	\$	(91,518,054)
19	Adjust Cash Working Capital	\$ -	\$	-	\$ - ;	2,788,756	\$	-	\$	- \$	\$	2,788,756
20	Adjust Interest Synchronization	\$ -	\$	-	\$ - 5	-	\$	-	\$	- 9	\$	-
21	Corporate Alternative Minimum Tax ("CAMT") Adjustment	\$ -	\$	-	\$ - 5	-	\$	-	\$	12,119,271	\$	12,119,271
22	Excess Deferred Income Taxes ("EDIT") – Expiring Riders Regulatory Asset	\$ -	\$	-	\$ - 5	259,707	\$	(23,374)	\$	(49,630)	\$	186,703
23	Reflection of Electric Vehicle Regulatory Asset	\$ -	\$	-	\$ - 5	1,301,451	\$	(118,033)	\$	(250,624)	\$	932,794
24	AMI SEN Investment Deferral Regulatory Asset	\$ -	\$	-	\$ - 5	5,106,217	\$	(459,560)	\$	(975,798)	\$	3,670,860
25	AMI SEN Incremental O&M Expenses/Savings Regulatory Asset	\$ -	\$	-	\$ - ;	11,421,104	\$	(1,027,899)	\$	(2,182,573)	\$	8,210,632
26	Reflection of Benchmarking Requirement Cost Recovery	\$ -	\$	-	\$ - :	765,513	\$	-	\$	- 9	\$	765,513
27												
28	Total	\$ 77,426,787	\$	(9,032,315)	\$ 86,459,103	28,014,466	\$	(1,933,467)	\$	8,013,876	\$ 1	120,553,977

Atlantic City Electric Company 5+7 Months Ending June 2023 Pension and OPEB Expense Adjustment Adjustment No. 6

(1)			(2)	(3)	(4)	(5)	(6)
Line			T	Expense	ACE	ACE Dist	ACE Dist
<u>No.</u> 1	Earnings		Total \$	<u>%</u>	<u>%</u>	<u>%</u>	<u>\$</u>
2	Pension Expense					\$	679,952
3	OPEB Expense					\$	
4	Total					<u>\$</u> \$	1,421,368
5	Impact to State Income Taxes					\$	(127,923)
6	Impact to Federal Income taxes					<u>\$</u>	(271,624)
7	Impact to Earnings					\$	(1,021,822)
8							
9	Pension - 2023 Actuary Report						
10	ACE	\$	16,729,000	43.17%	100.00%	86.55% \$	6,250,232
11	Service Company	\$	29,528,000	74.53%	29.35%	86.55% \$	5,590,563
12	Exelon Business Service Company	\$	9,278,000	3.91%	100.00%	86.55% \$	314,242
13	<u>Total</u>	\$	55,535,000			\$	12,155,037
14							
15	Pension 5+7 M/E June 2023 Expense						
16	<u>ACE</u>	\$	16,221,491	43.17%	100.00%	86.55% \$	6,060,618
17	Service Company	\$	27,263,607	74.53%	29.35%	86.55% \$	5,161,844
18	Exelon Business Service Company	\$	7,458,696	3.91%	100.00%	86.55% \$	252,623
19	<u>Total</u>	\$	50,943,794			\$	11,475,085
20	ODED 2000 A / D /						
21	OPEB - 2023 Actuary Report	¢.	(4.400.000)	40.470/	400.000/	00 EE0/	(447.000)
22	ACE	\$	(1,199,000)	43.17%	100.00%	86.55% \$	(447,966)
23 24	Service Company	\$	1,267,000 2,621,000	74.53% 5.69%	29.35% 100.00%	86.55% \$ 86.55% \$	239,882 129,110
2 4 25	Exelon Business Service Company Total	<u>\$</u> \$	2,689,000	5.09%	100.00%	<u> </u>	
26	<u>Total</u>	φ	2,009,000			φ	(10,914)
27	OPEB - 5+7 M/E June 2023 Expense						
28	ACE	\$	(2,496,827)	43.17%	100.00%	86.55% \$	(932,856)
29	Service Company	\$	175,630	74.53%	29.35%	86.55% \$	33,252
30	Exelon Business Service Company	\$	1,608,079	5.69%	100.00%	86.55% \$	79,214
31	Total	\$	(713,118)	0.0070	.00.0070	\$	
٠.	<u> </u>		\)			Ψ	(020,000)

Atlantic City Electric Company Reflection of 5-year Average Inflation on Non-Labor O&M Expense 5+7 Months Ending June 2023 Adjustment No. 7

(1)		(2)	(3)	(4)
Line <u>No.</u>		<u>ltem</u>	<u>Amount</u>	
1	Earnings			
2				
3		Non-Labor O&M Expense	141,532,289	
4				
5		5-Year Average Inflation Factor (CPI)	3.27%	
6				
7		Adjustment to O&M Expense		\$ 4,628,106
8		,		
9		Adjustment to State Income Taxes		\$ (416,530)
10		•		,
11		Adjustment to Federal Income Taxes		\$ (884,431)
12		•		,
13		Total Expense		\$ 3,327,145
14		•		
15		Earnings		\$ (3,327,145)

Atlantic City Electric Company 5+7 Months Ending June 2023

Remove Executive Incentive Expense Adjustment No. 8

(1) Line	(2)		(3)	
No.	ltem		Detail	
	Earnings:			
1	O & M Expense	\$	(1,269,775)	
2	State Income Tax	\$	114,280	
3	Federal Income Tax	\$ \$ \$	242,654	
4	Total Expense	\$	(912,841)	
5				
6	Earnings	\$	912,841	
7				
8				
9				
10				
11				
12			ACE System O&M	ACE Distribution O&M
13	CC General Ledger		5+7 ME Jun 23	5+7 ME Jun 23
14	1500 710068 - Salaries - Incentive Executive	\$	9,713	\$ 8,407
15	9000 SC7900 and BSC - LTIP Allocation (Exec)	\$	1,457,387	\$ 1,261,368
16	,	\$	1,467,100	\$ 1,269,775
17				
18	ACE Distribut	ion % =	86.55%	

Atlantic City Electric Company 5+7 Months Ending June 2023 Reflect Plant Additions from Jul 2023 -Dec 23 (does not include IIP) Adjustment No. 14

(1)	(2)			(3)						
Line <u>No.</u>	<u>ltem</u>		Ju	ıl 23 - Dec 23 Plant Closing <u>\$</u>	<u>s</u>					
				<u>×</u>						
1 2	Earnings Distribution									
3 4	Book Depreciation Expense	3.26%		\$2,819,717						
5	Tax Depreciation Expense - MACRS	3.75%	\$3,593,702							
7 8	General Book Depreciation Expense	7.24%		\$1,592,762						
9 10 11	Tax Depreciation Expense - MACRS	14.29%	\$3,272,723							
12 13	Deferred State Income Tax Deferred Federal Income Tax			\$220,855 \$468,949						
14 15	State Income Tax Federal Income Tax			(\$617,978) (\$1,312,174)						
16	Total Expense			\$3,172,131						
17				(00.470.404)						
18 19	Earnings			(\$3,172,131)						
20	Rate Base									
21	Plant in Service									
22 23	Distribution Distribution Plant Closings			95,832,054						
24	Retirements		_	(\$9,422,183)						
25	Adjustment to Plant in Service			\$86,409,871						
26 27	General									
28	General Plant Closings			26,468,635						
29	Retirements		-	(\$1,046,065)						
30 31	Adjustment to General Plant Closings Distribution Allocation Ratio			\$25,422,571 86.55%						
32 33	Adjustment to General Plant Closings			\$22,003,235						
34	Depreciation Reserve									
35 36	Depreciation Expense Retirements			\$4,785,479 (\$10,327,551)						
37	Adjustment to Depreciation Reserve		•	(\$5,542,072)						
38										
39 40	Net Plant			\$113,955,179						
41	Deferred State Income Tax			\$220,855						
42 43	Deferred Federal Income Tax			\$468,949						
44 45	Net Rate Base Adjustment		•	\$113,265,374						
46	Plant Closings			Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	
47				Jul-23	Aug-23	Sep-23	Oct-23	Nov-23	Dec-23	Total
48 49	Distribution				(431,263)	(270)	(139)	(90.790)	(25)	(521,504)
50	All Other Project Types Capacity Expansion			- 5,625,541	318,660	(278) 283,656	290,831	(89,789) 278,343	(35) 791,882	7,588,913
51	Corrective Maintenance			3,033,179	3,290,943	2,784,773	2,932,196	2,435,260	2,169,694	16,646,045
52	Facility Relocation			190,338	206,016	186,990	188,873	191,798	186,077	1,150,092
53	New Business Connections			2,305,686	2,294,097	2,034,709	2,060,757	2,078,515	2,657,506	13,431,270
54	Other EED			4,297,704	4,311,853	4,299,133	4,308,658	4,286,052	4,276,139	25,779,538
55	System Performance			3,494,903	6,043,122	7,128,058 (779,167)	5,250,057	4,195,593	10,320,967 (779,167)	36,432,700
56 57	IIP 2.0 Removal Distribution Total			(779,167) 18,168,184	(779,167) 15,254,261	15,937,874	(779,167) 14,252,066	(779,167) 12,596,606	19,623,064	(4,675,000) 95,832,054
58				-	-	-	-	-	-	,,
59	General				4 700					4.700
60 61	All Other Project Types Back Office Allocation			- 276,426	1,730 97,862	100,307	- 149,091	- 149,107	272,928	1,730 1,045,721
62	BSC Originally Contracted Work			39,780	45,203	50,469	46,689	37,932	25,249	245,322
63	Corrective Maintenance			51,911	51,107	50,816	51,611	52,100	52,950	310,494
64 65	New Business Connections Other EED			68 312,003	(67,997) 10,442,170	(891) 408,079	(62,890) 282,635	(4,672) 269,585	(88,777) 2,461,981	(225,158) 14,176,453
66	Preventative Maintenance			11,944	11,780	11,789	11,974	10,738	5,669	63,893
67	Real Estate			38,902	115,286	65,420	66,973	90,561	9,789,485	10,166,628
68	System Performance General Total			50,948	51,052	243,637	51,644 507,727	50,751	235,520	683,553 26,468,635
69 70	General Total			781,981 -	10,748,193	929,625	597,727	656,102	12,755,006	20,408,033
71	Total			18,950,165	26,002,454	16,867,499	14,849,793	13,252,708	32,378,070	122,300,690
				·						

(1)	(2)	(3)	(4) Forecast	(5) Forecast	(6) Forecast	(7) Forecast	(8) Forecast	(9) Forecast	(10)
Line No.	EPS Project ID	EPS Project Name	Jul-2023	Aug-2023	Sep-2023	Oct-2023	Nov-2023	Dec-2023	Total
1	AJ17DAB01	Removal Salvage Cap Eqp ACE	-	(55,162)	(36)	(18)	(9)	(4) \$	(55,229)
2	AJ17DAB02	Salvage Scrap Wire Cable ACE	-	(376,101)	(243)	(121)	(61)	(30) \$	(376,556)
3	AJ17DCB01	Meters ACE	150,949	150,949	150,949	150,949	150,949	150,952 \$	905,696
4	AJ17DCB02	Meter Install ACE	87,816	101,965	89,245	98,770	76,164	66,249 \$	520,209
5	AJ17DEB03	Cape May Sub Establish two ne	3,221	3,576	2,909	3,107	2,991	38,356 \$	54,160
6	AJ17DEB10	Capacity Expansion ACE	140,008	142,465	128,124	130,655	125,894	126,344 \$	793,490
7	AJ17DEB11	ACE Underbuilt Distribution	46	20	34	72	64	41 \$	277
8	AJ17DMB00	Subsurface Silo Transf Replace	66,029	67,756	100,947	102,497	57,724	31,237 \$	426,190
9	AJ17DMB01	Atlantic Region Submarine Ca	41	69	108	116	64	76 \$	475
10	AJ17DMB02	Emergency Restoration OH ACE	1,187,855	1,159,455	1,004,427	1,053,270	803,996	802,151 \$	6,011,155
11	AJ17DMB03	Emergency Restoration UG ACE	168,249	269,993	181,551	198,777	204,749	138,482 \$	1,161,801
12	AJ17DMB05	Cable ACE	155,219	160,138	387,649	506,025	546,621	309,280 \$	2,064,932
13	AJ17DMB06	Planned Pole ACE	384,744	399,047	358,632	243,840	237,211	181,951 \$	1,805,425
14	AJ17DNB02	Solar Projects Dist Line Upg	(9,844)	(9,870)	(9,864)	(9,848)	(9,855)	359,694 \$	310,414
15	AJ17DSB13	Planned Improvements ACE	111,574	101,980	131,591	135,603	132,374	99,085 \$	712,207
16	AJ17DSB14	Priority Feeder Improvemnt ACE	293,470	284,329	263,014	288,082	272,243	247,285 \$	1,648,421
17	AJ17DSB15	Reliability Improvements ACE	51,242	49,000	65,661	66,636	64,917	39,993 \$	337,449
18	AJ17DSB16	Network Xfrmr Prot Planned ACE	57,262	56,325	67,457	74,303	77,067	61,359 \$	393,773
19	AJ17DSB19	Comprehnsve Reliab Improve ACE	58,010	58,675	80,619	80,954	78,972	48,644 \$	405,874
20	AJ17DZB01	Facility Relo Agency ACE	190,511	206,016	186,990	188,873	191,798	186,077 \$	1,150,265
21	AJ17QE105	Cape May Sub Add 2nd 42 45 MV	14,177	15,685	12,913	13,783	13,285	102,030 \$	171,873
22	AJ17QEB03	Williamstown Upgrade T5 UDS	12,047	13,386	10,878	11,604	11,164	10,777 \$	69,856
23	AJ17QMB01	Atlantic Distribution Substati	124,925	136,595	100,333	199,929 1	72,041	37,928 \$	671,750
24	AJ17QMB02	NERC Physical Security Atlant	1,466	1,469	2	·	1	0 \$	2,939
25 26	AJ17QS112 AJ17QS113	Chestnut Neck Retire 69 12 k	- 244	473	263,906	269,958	258,596	321,416 \$ 243 \$	1,113,876
26 27	AJ17QS113 AJ17QSB08	Mullica Hill Retire substati Atlantic Substation Animal Pr		473 1,464	456 59,746	441 324,808	224 229	243 \$ 115 \$	2,081 386,361
28	AJ17QSB08 AJ17QSB14	Penns Grove Retire 69 4 kV Su	-	1,404	39,740	174,652	167,452	169,267 \$	511,371
29	AJ17QSB14 AJ17QSB25	ECA Repl Dist Batteries ACE	19,236	37	19	9	167,432	2 \$	19,308
30	AJ17QSB28	ECA Repl DCntrl House Roof ACE	64,338	1,637	63	32	16	8 \$	66,094
31	AJ17QSB29	SCADA RTU Capability ACE	1,911	1,929	38,761	215,586	152	76 \$	258,416
32	AJ17QSB29 AJ17QSB31	ECA Dist Circuit Switch ACE	2,920	2,924	68,989	1,536	29,189	180,474 \$	286,031
33	AJ17QSB33	ECA Repl Dist Breakers ACE	113,954	115,782	290,656	262,686	216,539	134,962 \$	1,134,579
34	AJ17QSB33	ECA Repl Dist Breakers ACE ECA Repl DistSub Structure ACE	132,704	9,496	8,256	8,286	117,393	8,408 \$	284,543
35	AJ17RAB01	Tools ACE	82,669	82,669	82,669	82,669	82,669	82,678 \$	496,023
36	AJ17RFB06	Office Furniture ACE	-	12,597	15,078	16,629	20,093	517,234 \$	581,631
37	AJ17RFB07	Security Systems Equip ACE	-	24,446	50,342	50,344	70,468	75,495 \$	271,096
38	AJ17RT150	TR TX FIREWALL Repl ATCO	_		-	-		4,627 \$	4,627
39	AJ17RT151	TR TX FIREWALL Repl CARDIFF	-	-	_	_	_	51,001 \$	51,001
40	AJ17RT152	TR TX FIREWALL Repl HIGBEE	-	-	_	_	_	50,104 \$	50,104
41	AJ17RT161	TR TX FIREWALL Repl DACOSTA	_	-	-	_	_	36,607 \$	36,607
42	AJ17RT162	TR TX FIREWALL Repl FAIRTON	-	-	-	_	_	4,738 \$	4,738
43	AJ17RT177	TR TX FIREWALL Repl ROWAN	-	-	-	_	-	31,807 \$	31,807
44	AJ17RT183	TR TX FIREWALL Repl ABSECON	-	-	-	-	-	11 \$	11
45	AJ17RTB04	Fiber Work for Solar ACE	0	0	0	0	0	1 \$	1
46	AJ17TS108	Churchtown Pennsgrove 69kV Reb	-					(14) \$	(14)
47	AJ17TS139	TSOM 0722 2017 CVI P30 REPAIRS	-	-	20	-	-	- \$	20
48	AJ17TS232	TSOM 0760 2016 CVI P40 REPAIRS	-	-	23	-	-	- \$	23
49	AJ17TS258	TSOM 0784 2016 CVI P40 REPAIRS	-	-	17	-	-	- \$	17
50	AJ18DM999	Unbilled Capital ACE NJ - Non-	1,305	1,172	1,559	2,208	1,638	1,369 \$	9,252
			,	-	•		-		*

(1)	(2)	(3)	(4) Forecast	(5) Forecast	(6) Forecast	(7) Forecast	(8) Forecast	(9) Forecast	(10)
Line No.	EPS Project ID	EPS Project Name	Jul-2023	Aug-2023	Sep-2023	Oct-2023	Nov-2023	Dec-2023	Total
51	AJ18DNB02	ACE New Business Commercial	881,899	971,318	796,078	825,838	765,206	856,552 \$	5,096,891
52	AJ18DNB03	ACE New Business Residential	1,186,207	1,138,592	1,056,480	1,079,253	1,034,892	1,175,432 \$	6,670,856
53	AJ18DNB04	ACE New Business Streetlights	218,014	165,830	182,309	199,896	281,032	282,833 \$	1,329,914
54	AJ18DRB01	SGSM LRP Pool (ACE) - Cap	31,130	31,224	31,135	31,116	31,109	31,099 \$	186,814
55	AJ18DS062	Trip Savers - Core Budget	781	794	1,125	1,155	1,111	605 \$	5,570
56	AJ18DSB01	Newport Sub: Dist Line Mod	-	-	-	-	-	592,923 \$	592,923
57	AJ18QSB05	ACE Sub Dist Fire Protection	4,752	72,202	76,117	108,396	133,167	3,889 \$	398,524
58	AJ18QSB10	ACE Dist Switch Budget	-	23,823	15	190,077	1,469	64 \$	215,448
59	AJ18QSB11	ACE Dist LTC Budget	3,503	3,523	238,812	137,982	167	84 \$	384,070
60	AJ18QSB12	ACE Dist LA Budget	-	10,386	33,790	113,585	2,772	45 \$	160,578
61	AJ18RT052	Chambers EHV FW-DC Sys Replace	-	-	-	-	-	37,388 \$	37,388
62	AJ19DCB02	Placeholder for ACE AMI	1,459,326	1,459,326	1,459,326	1,459,326	1,459,326	1,459,326 \$	8,755,954
63	AJ19DEB01	ACE TLM BUDGET-ONLY	17,427	17,744	15,870	16,206	15,575	15,621 \$	98,443
64	AJ19DSB03	Churchtown - Pennsgrove	-	-	-	-	-	1,765,188 \$	1,765,188
65	AJ19DSB04	Monroe to Pinehill Underbuild	-	-	3,046,700	175,818	2,152	2,085 \$	3,226,755
66	AJ19DSB09	Recloser & Battery ACE Capital	11,944	11,780	11,789	11,973	10,738	5,669 \$	63,893
67	AJ19QE001	BEACH HAVEN BATTERY PROJECT	3,762,607	6,440	5,817	6,608	5,810	4,567 \$	3,791,849
68	AJ19QEB01	BEACH HAVEN BATTERY BUDGET	1,491,640	3,145	1,858	2,311	1,702	1,357 \$	1,502,013
69	AJ19QMB04	ACE NJ CM Non-emergency D-Sub	13,529	10,803	688	1,185	1,674	3,331 \$	31,211
70	AJ19QS038	Cardiff AG Install Bus Tie	-	-	-	-	-	12,154 \$	12,154
71	AJ19QS039	Cardiff LA Upgrade Bus Tie	<u>-</u>	-		-	-	4,205 \$	4,205
72	AJ19QSB03	High Street 2nd 69/12kV Xfmr	57,764	271,630	180,658	201,242	195,192	175,426 \$	1,081,912
73	AJ19QSB07	ACE Distr Civil Site Assess	119,121	270,573	493,948	18,670	271,991	273,392 \$	1,447,695
74	AJ19QSB08	ACE Dist Drainage & Driveway	4,761	44,910	2,744	35,782	197,914	5,030 \$	291,141
75	AJ19QSB15	ACE 40MVA 69/12kV Xfmr	-	(39,325)	-	-	-	- \$	(39,325)
76	AJ19QSB19	Dist-Station Transformer Repl	5,322	5,397	4,861	4,937	27,564	5,180 \$	53,262
77	AJ19QSB29	NJ (Dist) Flood Remediation	28,669	207,759	13,374	89	45	22 \$	249,959
78	AJ19RT016	FW Absecon Control House Repl	-	-	-	-	-	83,344 \$	83,344
79	AJ19RT017	FW Cardiff MW Cntl House #1	-	-	-	-	-	31,487 \$	31,487
80	AJ19RT165	FW Tabernacle FW&DC Install	-	-	-	-	-	89,474 \$	89,474
81	AJ19RT177	SG Fairton Control Bld Router	-	-	-	-	-	22,392 \$	22,392
82	AJ20DCB01	Budget - Region 1 ACE AMI	2,337,961	2,337,961	2,337,961	2,337,961	2,337,961	2,337,961 \$	14,027,768
83	AJ20DCB02	Budget - Region 2 ACE AMI	258,657	258,657	258,657	258,657	258,657	258,657 \$ 3,038 \$	1,551,941
84	AJ20DCB03	Budget - Region 3 ACE AMI	3,038	3,038	3,038	3,038	3,038		18,225
85	AJ20DDB01	ACE NJ Dist Smart Fault Sensor	61,350	63,289	63,278	65,562	60,001	57,301 \$	370,780
86 87	AJ20DMB02	CrossArm Repl Program ACE	19,658	20,081	28,108	28,827	28,240	16,156 \$ 6,005 \$	141,070
	AJ20DNB02	ACE Solar LRP place holder	10,318 7,045	9,095	(935)	(1,621)	(2,042)	, ,	20,820
88 89	AJ20DNB03 AJ20DS011	LRP for ACE non-PJM customer Monroe to Pine Hill Underbuild	23,744	5,748	(238)	(943)	(1,882)	2,949 \$ - \$	12,679 23,744
90		Monroe-PHill Undrbuild Winslow	,	-	-	-	-	- \$ - \$,
90 91	AJ20DS024 AJ20DS032	Paulsboro Underbuild	37,335	-	-	-	-	- 5 86,744 \$	37,335 86,744
91	AJ20DS032 AJ20DS085	MDO By Sunoco in Pennsville	-	-	-	-	-	22,014 \$	22,014
93	AJ20DS065 AJ20DSB02	Paulsboro Underbuild	-	-	-	-	-	784,654 \$	784,654
93 94	AJ20DSB02 AJ20DSB05	Unfused Lateral Program ACE	34,328	- 184,056	26,103	- 171,628	31,046	14,080 \$	461,242
		•	34,326	104,030	20,103	171,020	31,040	170,644 \$	
95 96	AJ20DSB13 AJ20QD008	Cumberland-Union Dist Underbld Second St - Upgrade Fdr Relays	1,443,037	- 812,947	-	312,658	- 119,512	170,644 \$	170,644 2,807,153
96 97	AJ20QD008 AJ20QS041	Salem Land Purchase	1,443,037	012,947	-	312,030	118,312	172,006 \$	172,006
98	AJ20QS041 AJ20QS074	Glassboro T-3 Bushings	-	-	_	3,867	-	- \$	3,867
99	AJ20QS074 AJ20QS096	River 34kV DSW D Upgrade	-	-	-	3,007	-	- 5 81,947 \$	3,867 81,947
100	AJ20QS096 AJ20QSB14	Budget 74128 - Williamstown	6,993	- 7,756	639,956	- 652,440	135,818	102,902 \$	1,545,865
100	AJZUQ3D14	Duuget 14126 - Williamstown	6,993	1,106	039,936	05∠,440	133,618	102,902 \$	1,545,665

(1)	(2)	(3)	(4) Forecast	(5) Forecast	(6) Forecast	(7) Forecast	(8) Forecast	(9) Forecast	(10)
Line No.	EPS Project ID	EPS Project Name	Jul-2023	Aug-2023	Sep-2023	Oct-2023	Nov-2023	Dec-2023	Total
101	AJ20RF012	Mays Landing Ctrl Cntr Rebuild	-	10,121,394	90,423	-	-	- \$	10,211,817
102	AJ20RNB01	LRP Ace telecom	927	(859)	(834)	(1,030)	(2,437)	(1,971) \$	(6,203)
103	AJ20RNB02	LRP for ace non-pjm telecom	898	(774)	(57)	(585)	(2,236)	(1,940) \$	(4,694)
104	AJ20RT027	SG Higbee CntlHS PDDN Refresh	-	-	-	-	-	17,827 \$	17,827
105	AJ20RTB06	Sub FO Entr ACE Non-AIIP	219,896	220,231	203,303	166,014	149,052	98,362 \$	1,056,859
106	AJ20RTB07	Router Upg Cores ACE Non-AIIP	92,107	100,545	114,353	116,621	120,532	116,665 \$	660,823
107	AJ20XB002	OT Cyber Security ACE Capex	39,780	45,203	50,469	46,689	37,932	25,249 \$	245,322
108	AJ21DDB01	Budget Dist Auto Placeholder	132,297	154,291	197,173	227,232	220,319	425,675 \$	1,356,987
109	AJ21DE006	NJBPU - Solar Hosting Capacity	-	-	-	-	-	5,326 \$	5,326
110	AJ21DMB02	ACE UG Plan Cap P30/P40	161,800	174,206	164,588	169,065	162,330	144,071 \$	976,060
111	AJ21DMB04	ACE OH PLAN CAP P30/P40	353,829	332,563	268,426	275,949	329,836	343,627 \$	1,904,230
112	AJ21DMB05	ACE NJ DIST Porcelain Cutout	57,283	58,240	53,406	54,705	53,616	54,075 \$	331,325
113	AJ21DN007	Solar - PJM AE1-218 Glassboro	-	(2)	-	-	-	- \$	(2)
114	AJ21DN022	Game Creek Warehouse 3 PH Srv	-	-	-	-	-	110,736 \$	110,736
115	AJ21DN051	2121 Eden Rd Solar Dist Reimb	-	-	-	-	-	(40,587) \$	(40,587)
116	AJ21DNB02	BUDGET PROJ-Quinton-Al Distrib	-	-	-	-	-	(106,887) \$	(106,887)
117	AJ21DS001	Church-Pennsgrove Dist Under	-	-	-	-	-	438,530 \$	438,530
118	AJ21DS040	Beach Haven West 5&6 Cab Repl	-	2,922	-	-	-	- \$	2,922
119	AJ21DS055	Winslow South Reliability Work	-	-	-	-	-	170,267 \$	170,267
120	AJ21DS061	Rio Villas East Zone Work	-	-	-	-	-	38,822 \$	38,822
121	AJ21DS062	Rio Villas West Zone Work	-	-	-	-	-	57,336 \$	57,336
122	AJ21DSB06	Recloser Saturation ACE Budget	187,042	189,638	224,642	230,301	226,837	158,722 \$	1,217,182
123	AJ21QS010	High St.12k Circuit Breaker	-	-	-	-	-	265,433 \$	265,433
124	AJ21QS014	Union - Upgrade Fdr Relays	8,694	3,309	577	574	577	596 \$	14,326
125	AJ21QS015	Cardiff - Upgrade Fdr Relays	-	-	-	-	-	16,875 \$	16,875
126	AJ21QS017	Silver Lake-Upgrade Fdr Relays	-	-	-	-	-	14,261 \$	14,261
127	AJ21QS018	Corson - T4 Relay Replacement	-	-	-	-	-	88,158 \$	88,158
128	AJ21QS020	Williamstown T5	-	-	-	-	-	628,476 \$	628,476
129	AJ21RDB01	Budget Recloser Radio/Control	19,818	19,828	19,121	20,528	19,642	168,136 \$	267,073
130	AJ21RDB02	Budget Radio/Telecom Cor Maint	51,911	51,107	50,816	51,611	52,100	52,950 \$	310,494
131	AJ21RF003	Cape May EV Charging Station	-	-	-	-	-	179,801 \$	179,801
132	AJ21RF004	Pleasantville EV charging Stat	-	-	-	-	-	357,043 \$	357,043
133	AJ21RF005	West Creek EV Charging Station	-	(05.070)	-	-	-	181,545 \$	181,545
134	AJ21RN004	Solar Proj AE1-218 100% Reim	-	(65,872)	-	- (40.004)	-	- \$	(65,872)
135	AJ21RN008	1403 Wheaton Ave- Telecom Reim	-	-	-	(19,924)	-	- \$	(19,924)
136	AJ21RN009	2121 Eden Rd- Telecom 100%Reim	-	-	-	-	-	(84,867) \$	(84,867)
137	AJ21RT019	Rio Grande to Green Creek	-	-	-	-	-	93,303 \$	93,303
138	AJ21RT020	Middle Township ADSS	-	-	-	-	-	87,795 \$	87,795
139	AJ21RT150	Harbor Beach UCOMM Equip	(4.750)	(400)	-	-	-	32,189 \$	32,189
140	AJ21RTB03	Deepwater Relocation - Fiber	(1,756)	(492)	-	-	-	- \$	(2,248)
141	AJ22DD001	DA Reconductoring - NJ1400	-	-	-	-	-	26,737 \$	26,737
142	AJ22DD004	DA Recond-NJ1403/NJ1407/NJ1409	-	-	-	-	-	2,388 \$	2,388
143	AJ22DD007	DA Reconductor - NJ1408/NJ1410	-	-	-	-	-	19,019 \$	19,019
144	AJ22DD015	YFA Device Licenses - ACE	-	-	-	-	-	547,167 \$	547,167
145	AJ22DEB26	NJ2062 CONDUCTOR UPGRADE	-	-	-	-	422.000	508,920 \$	508,920
146	AJ22DGB01 AJ22DMB01	Glassboro Conn Community CAP	- E12.024	- 601 300	- E40.007	620.767	432,929	53,443 \$	486,372
147		Replace Dist UC Equip Emergent	513,831	681,399	540,027	620,767	500,826	434,324 \$	3,291,175
148	AJ22DMB02	Replace Dist UG Equip Emergent	37,383	37,803	35,320	35,764	34,930	34,990 \$	216,190
149	AJ22DN025	1 Technology Dr Dist-100%Reimb	-	-	-	(43,422)	(00.740)	- \$	(43,422)
150	AJ22DN042	312 UNIT APARTMENT COMPLEX	-	-	-	-	(89,719)	- \$	(89,719)

(1)	(2)	(3)	(4) Forecast	(5) Forecast	(6) Forecast	(7) Forecast	(8) Forecast	(9) Forecast	(10)
Line No.	EPS Project ID	EPS Project Name	Jul-2023	Aug-2023	Sep-2023	Oct-2023	Nov-2023	Dec-2023	Total
151	AJ22DS012	2022 NJ0926 Priority Feeder	-	-	-	-	-	76,657 \$	76,657
152	AJ22DS039	NJ1983 Cutout R/P Program	-	-	-	-	-	4,750 \$	4,750
153	AJ22DS042	NJ1191 Cutout R/P Program	-	-	-	-	-	176,194 \$	176,194
154	AJ22DS062	NJ1983 C/O Replacement Program	-	-	-	-	-	305 \$	305
155	AJ22DSB01	Deepwater Distribution Budget	(173)	-	-	-	-	- \$	(173)
156	AJ22DSB08	Budget ACE NJ - DA Reg Install	27,232	27,452	27,014	55,179	41,031	34,098 \$	212,007
157	AJ22DSB09	Budget ACE NJ - DA Cap Install	62,082	62,415	60,977	61,477	61,343	61,631 \$	369,925
158	AJ22QE001	Clayton Land Purchse	213,814	-	-	-	-	- \$	213,814
159	AJ22QEB01	Logan Land Purchase	-	148,846	131,953	134,979	129,298	129,706 \$	674,782
160	AJ22QN004	1236 Haddonfield Berlin D/SRei	-	-	-	-	-	2 \$	2
161	AJ22QS009	Atco 12KV Brk Replacements	-	-	-	-	-	39,241 \$	39,241
162	AJ22QS018	Huron- AG and LG Installs	-	-	-	-	-	12,690 \$	12,690
163	AJ22QS026	Churchtown Dsub Bus Improve	-	-	-	-	-	4,530 \$	4,530
164	AJ22QS042	Pine Hill Sta Svc ATS Install	-	-	-	-	647	- \$	647
165	AJ22QS059	Rep 12KV breakers "J" Williams	-	-	-	85	-	- \$	85
166	AJ22QSB03	NJ DIST SUB OIL CONTAINMENT	28,034		-	-	-	- \$	28,034
167	AJ22QSB04	NJ DIST SUB LIGHTING	79,833	128,348	-	-	-	- \$	208,181
168	AJ22QSB05	ACE NJ Cardiff Sub DA Upgrade	-	-	-	-	-	349,470 \$	349,470
169	AJ22QSB06	ACE NJ Silver Lake Sub DA Upgr	-	-	-	-	-	346,823 \$	346,823
170	AJ22QSB12	Motts Farm Sub Parent	-	2,611,867	122	129	109	120 \$	2,612,346
171	AJ22RB001	Mays Landing Dist Lrng Room	-		-	-	-	122,544 \$	122,544
172	AJ22RF020	Cape May Court House Yard Pave		78,243	-	-	-	- \$	78,243
173	AJ22RF021	ACE NJ: Pleasantville: Yard Pa	38,902	-	-	<u>-</u>	-	- \$	38,902
174	AJ22RN009	1 Technology Dr- TC 100%Reim	-	-	-	(41,351)	-	- \$	(41,351)
175	AJ22RT001	Tuckahoe Diverse Path ADSS	-	-	-	-	-	393,490 \$	393,490
176	AJ22RT003	Berlin to Silver Lake ADSS	-	-	-	-	-	246,346 \$	246,346
177	AJ22RT005	Seal Isle Sub Diverse Path	-	-	-	-	-	154,274 \$	154,274
178	AJ22RT006	Churchtown to Bridgeton Ph 1	•	-	-	-	-	4,085 \$	4,085
179	AJ22RT008	Cedar to Ship Bottom Rebuild	•	-	-	-	-	18,215 \$	18,215
180	AJ22RT012	Core Upg Carneys Point 1830 7	-	-	-	-	-	153,763 \$	153,763
181	AJ22RT013	Core Upg Mays Landing 1830 775	•	-	-	-	-	153,180 \$	153,180
182	AJ22RTB01	Budget for 79873 Monroe- PH	-	-	193,381	-	-	- \$	193,381
183	AJ22RVB01	Bridgeton Fuel Island Replace	-	-	-	-	-	27,276 \$	27,276
184	AJ22RVB03	Pleasantville Fleet Pole Barn	-	-	-	100,608	100,659	100,663 \$	301,929
185	AJ22RVB04	Glassboro Fleet Pole Barn	226,805	50,896	50,580	160	80	40 \$	328,560
186	AJ22TF006	Kennett Data Center (ACE) Cap	-	-	-	-	-	5,314,826 \$	5,314,826
187	AJ23RF001	Winslow Polebarn / Vehicle Sto	-	-	-	-	-	415,250 \$	415,250
188	AJ23RF003	Winslow Window Replacement	-	-	-	-	-	328,442 \$	328,442
189	AJ23RF004	Pleasantville Roof Replacement	-	-	-	-	-	1,377,344 \$	1,377,344
190	AJ23RF005	Pleasantville Window Replaceme	-	-	-	-	-	352,660 \$	352,660
191	AJ23RF006	Bridgeton Entrance & Sidewalk	-	-	-	-	-	83,318 \$	83,318
192	AJ23RF007	West Creek Gate & Opener Repla	-	-	-	-	-	51,665 \$	51,665
193	AJ23RF008	Cape May Paving Project	- (4.5)	- (40)	- (40)	- (40)	- /40	554,863 \$	554,863
194	AJCBAMTLC	AMI Elec Mtr Labor Commercial	(10)	(10)	(10)	(10)	(10)	(10) \$	(60)
195	AJCBAMTLR	AMI Elec Mtr Labor Residential	(32)	(32)	(32)	(32)	(32)	(32) \$	(195)

(1)	(2)	(3)	(4) Forecast	(5) Forecast	(6) Forecast	(7) Forecast	(8) Forecast	(9) Forecast	(10)
Line No.	EPS Project ID	EPS Project Name	Jul-2023	Aug-2023	Sep-2023	Oct-2023	Nov-2023	Dec-2023	Total
196	AJCBAMTRR	AMI Elec Meter Precap Resident	(0)	(0)	(0)	(0)	(0)	(0) \$	(1)
197	CAPOHACE	A&G Pool - ACE	(33,048)	(35,704)	(32,942)	(34,345)	(34,300)	(32,996) \$	(203,336)
198	ITACE229A	PHI LLO - ACE Q4 2021 HW	-	-	-	-	-	454,420 \$	454,420
199	SPIT110A	Fission - IT Apps Target DD	-	1,730	-	-	-	- \$	1,730
200		IIP 2.0 Unfused Laterals	(18,333)	(18,333)	(18,333)	(18,333)	(18,333)	(18,333) \$	(110,000)
201		IIP 2.0 Capacitor Bank Upgrade Project	(45,833)	(45,833)	(45,833)	(45,833)	(45,833)	(45,833) \$	(275,000)
202		IIP 2.0 Capacitor Controller Upgrade Project	(45,833)	(45,833)	(45,833)	(45,833)	(45,833)	(45,833) \$	(275,000)
203		IIP 2.0 ACE NJ Recloser Installation	(320,833)	(320,833)	(320,833)	(320,833)	(320,833)	(320,833) \$	(1,925,000)
204		IIP 2.0 Regulator Controller Upgrade Project	(55,000)	(55,000)	(55,000)	(55,000)	(55,000)	(55,000) \$	(330,000)
205		IIP 2.0 Replace Deteriorated URD Cable	(36,667)	(36,667)	(36,667)	(36,667)	(36,667)	(36,667) \$	(220,000)
206		IIP 2.0 DA Feeder Improvement Project	(45,833)	(45,833)	(45,833)	(45,833)	(45,833)	(45,833) \$	(275,000)
207		IIP 2.0 Strengthen DA Feeder Ties	(137,500)	(137,500)	(137,500)	(137,500)	(137,500)	(137,500) \$	(825,000)
208		IIP 2.0 ACE NJ Distribution Smart Fault Sensors	(73,333)	(73,333)	(73,333)	(73,333)	(73,333)	(73,333) \$	(440,000)
209			\$ 18,950,165 \$	26,002,454 \$	16,867,499 \$	14,849,793 \$	13,252,708 \$	32,378,070 \$	122,300,690

Atlantic City Electric Company 5+7 Months Ending June 2023 Reflect Plant Additions from Jan 2024 - Jun 2024 (does not include IIP) Adjustment No. 15

(1)	(2)			(3)						
Line <u>No.</u>	<u>ltem</u>		<u>Jan 24</u>	- Jun 24 Plant Closin \$	<u>ngs</u>					
1	<u>Earnings</u>									
2	Distribution									
3 4	Book Depreciation Expense	3.26%		\$1,924,755						
5	Tax Depreciation Expense - MACRS	3.75%	2,565,228							
6										
7 8	General Book Depreciation Expense	7.24%	303,186	\$237,649						
9				Ψ201,010						
10	Tax Depreciation Expense - MACRS	14.29%	598,351							
11 12	Deferred State Income Tax			\$90,106						
13	Deferred Federal Income Tax			\$191,324						
14 15	State Income Tax Federal Income Tax			(\$284,722) (\$604,560)						
16	Total Expense		·-	\$1,554,552						
17										
18 19	Earnings			(\$1,554,552)						
20	Rate Base									
21	Plant in Service									
22 23	Distribution Plant Closings Retirements			68,406,073 (\$9,422,183)						
24	Adjustment to Plant in Service			\$58,983,891						
25 26	General									
26	General Plant Closings			4,839,254						
28	Retirements			(\$1,046,065)						
29 30	Adjustment to General Plant Closings Distribution Allocation Ratio			\$3,793,190 86.55%						
31	Adjustment to General Plant Closings			\$3,283,006						
32	B 144 B									
33 34	Depreciation Reserve Depreciation Expense			\$2,535,405						
35	Retirements			(\$10,327,551)						
36 37	Adjustment to Depreciation Reserve			(\$7,792,146)						
38	Net Plant			\$70,059,043						
39	B (10:11 T			****						
40 41	Deferred State Income Tax Deferred Federal Income Tax			\$90,106 \$191,324						
42			•							
43	Net Rate Base Adjustment			\$69,777,613						
44 45	Distribution Plant Closings			Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	
45 46	Distribution Flant Closings			Jan-24	Feb-24	Mar-24	Apr-24	May-24	Jun-24	Total
47	Distribution						·	•		
48 49	All Other Project Types Capacity Expansion			186,292	181,564	177,157	174,748	2,388,419	461,223	3,569,404
50	Corrective Maintenance			2,851,665	2,697,582	3,188,404	3,424,762	3,461,287	3,074,128	18,697,829
51 52	Facility Relocation New Business Connections			203,832 2,859,321	192,283 2,527,366	195,977 2,078,702	200,664 2,002,124	211,473 2,175,214	190,022 2,115,051	1,194,251 13,757,778
53	Other EED			4,305,294	4,288,209	4,282,333	4,295,848	4,293,096	4,282,881	25,747,660
54	System Performance			2,018,114	2,509,192	2,854,627	3,479,612	3,604,443	3,721,379	18,187,366
55 56	IIP 2.0 Removal Distribution Total			(2,124,702) 10.299.816	(2,124,702) 10,271,494	(2,124,702) 10.652.498	(2,124,702) 11.453.056	(2,124,702) 14.009.229	(2,124,702) 11,719,981	(12,748,215) 68,406,073
57	Distribution Fotol			-	-	-	-	-	-	00,100,010
58 59	General									
60	All Other Project Types Back Office Allocation			148,505	152.855	277.487	276.303	274.529	279.150	1,408,829
61	BSC Originally Contracted Work			18,762	18,183	20,714	24,488	26,382	33,979	142,508
62 63	Corrective Maintenance New Business Connections			54,073 (4,878)	54,277 8,205	54,205 9,062	54,255 (4,424)	54,302 (336)	54,700 (4,603)	325,812 3,025
64	Other EED			257,095	265,315	261,419	464,650	567,453	515,940	2,331,873
65	Preventative Maintenance			9,221	11,217	12,366	13,133	13,525	13,810	73,271
66 67	Real Estate System Performance			15,394 70,743	35,851 84,395	35,839 73,762	15,375 121,181	50,473	50,925	102,459 451,478
68	General Total			568,915	630,297	744,853	964,961	986,327	943,901	4,839,254
69 70	Total			10,868,731	10,901,791	11,397,351	12,418,016	14,995,556	12,663,882	73,245,328
70	TOTAL			10,000,731	10,901,791	11,397,337	12,410,016	14,990,000	12,003,002	13,243,328

(1)	(2)	(3)	(4) Forecast	(5) Forecast	(6) Forecast	(7) Forecast	(8) Forecast	(9) Forecast	(10)
Line No.	EPS Project ID	EPS Project Name	Jan-2024	Feb-2024	Mar-2024	Apr-2024	May-2024	Jun-2024	Total
1	AJ17DCB01	Meters ACE	133,010	133,010	133,010	133,010	133,010	133,010	\$ 798,061
2	AJ17DCB02	Meter Install ACE	113,345	96,260	90,384	103,899	101,147	90,932	\$ 595,967
3	AJ17DEB10	Capacity Expansion ACE	186,243	181,477	177,107	174,678	181,000	178,182	\$ 1,078,688
4	AJ17DEB11	ACE Underbuilt Distribution	48	87	50	70	25	20	\$ 300
5	AJ17DMB00	Subsurface Silo Transf Replace	70,135	68,018	98,842	98,041	67,767	66,247	\$ 469,050
6	AJ17DMB01	Atlantic Region Submarine Ca	61	142	54	90	68	60	\$ 476
7	AJ17DMB02	Emergency Restoration OH ACE	1,155,488	1,175,782	1,234,447	1,319,262	1,158,670	1,262,717	\$ 7,306,366
8	AJ17DMB03	Emergency Restoration UG ACE	173,779	151,820	149,464	154,841	170,923	139,889	\$ 940,716
9	AJ17DMB05	Cable ACE	260,338	180,298	157,171	261,453	507,197	553,772	\$ 1,920,229
10	AJ17DMB06	Planned Pole ACE	62,311	86,898	99,327	342,731	353,937	346,431	\$ 1,291,633
11	AJ17DNB02	Solar Projects Dist Line Upg	(29,969)	(29,960)	(30,026)	(29,999)	(30,036)	(30,057)	\$ (180,047)
12	AJ17DSB13	Planned Improvements ACE	90,349	101,496	192,246	189,311	195,792	155,137	\$ 924,330
13	AJ17DSB14	Priority Feeder Improvemnt ACE	332,177	319,623	380,920	348,791	393,031	326,130	\$ 2,100,674
14	AJ17DSB15	Reliability Improvements ACE	78,414	89,994	158,888	158,422	161,074	122,252	\$ 769,044
15	AJ17DSB16	Network Xfrmr Prot Planned ACE	47,784	46,224	75,999	90,210	99,611	87,555	\$ 447,382
16	AJ17DSB19	Comprehnsve Reliab Improve ACE	103,826	127,226	286,897	292,214	298,217	190,894	\$ 1,299,274
17	AJ17DZB01	Facility Relo Agency ACE	203,832	192,283	195,977	200,664	211,473	190,022	\$ 1,194,251
18	AJ17QE105	Cape May Sub Add 2nd 42 45 MV	10,672	9,464	10,528	11,772	10,107	8,740	\$ 61,282
19	AJ17QMB01	Atlantic Distribution Substati	143,412	1,033	156,832	1,287	93,080	44,104	\$ 439,748
20	AJ17QMB02	NERC Physical Security Atlant	-	-	-	-	-	171,692	\$ 171,692
21	AJ17QSB08	Atlantic Substation Animal Pr	-	-	3,626	94,478	16,649	37	\$ 114,791
22	AJ17QSB25	ECA Repl Dist Batteries ACE	9,117	14,047	15,123	3,602	95,824	148,770	\$ 286,483
23	AJ17QSB26	ECA Repl Dist Bushings ACE	1,222	1,194	1,172	1,151	1,193	1,183	\$ 7,115
24	AJ17QSB28	ECA Repl DCntrl House Roof ACE	-	-	-	9,853	105,091	71,244	\$ 186,188
25	AJ17QSB29	SCADA RTU Capability ACE	1,932	16,261	15,877	15,639	16,244	2,547	\$ 68,500
26	AJ17QSB31	ECA Dist Circuit Switch ACE	2,673	3,236	23,915	23,553	17,189	2,648	\$ 73,214
27	AJ17QSB33	ECA Repl Dist Breakers ACE	119,750	390,940	334,653	253,902	120,018	114,707	\$ 1,333,970
28	AJ17QSB34	ECA Repl DistSub Structure ACE	3,172	39,430	37,621	8,451	12,714	7,846	\$ 109,233
29	AJ17RAB01	Tools ACE	84,738	84,738	84,738	84,738	84,738	84,738	\$ 508,428
30	AJ17RTB04	Fiber Work for Solar ACE	0	0	0	0	0	0	\$ 1
31	AJ18DM999	Unbilled Capital ACE NJ - Non-	1,618	2,264	1,883	1,723	1,494	1,213	\$ 10,195
32	AJ18DNB02	ACE New Business Commercial	1,052,897	985,116	884,020	865,859	809,092	902,064	\$ 5,499,049
33	AJ18DNB03	ACE New Business Residential	1,564,452	1,345,176	946,059	988,518	960,050	966,902	\$ 6,771,156
34	AJ18DNB04	ACE New Business Streetlights	200,078	164,144	225,133	178,371	199,447	283,028	\$ 1,250,201
35	AJ18QSB05	ACE Sub Dist Fire Protection	-	5,636	5,122	12,904	74,430	57,269	
36	AJ18QSB10	ACE Dist Switch Budget	-	-	-	-	56,256	32	\$ 56,288
37	AJ18QSB11	ACE Dist LTC Budget	3,513	3,423	4,575	4,469	3,440	3,423	\$ 22,844
38	AJ18QSB12	ACE Dist LA Budget	-	-	12,932	24,340	134,292	86	
39	AJ19DCB02	Placeholder for ACE AMI	1,459,326	1,459,326	1,459,326	1,459,326	1,459,326	1,459,326	\$ 8,755,954
40	AJ19DSB09	Recloser & Battery ACE Capital	9,221	11,217	12,366	13,133	13,525	13,810	
41	AJ19QE001	BEACH HAVEN BATTERY PROJECT	1	-	-	-	-	- :	
42	AJ19QMB04	ACE NJ CM Non-emergency D-Sub	25,890	125	1,432	17,660	43,654	102,631	
43	AJ19QSB07	ACE Distr Civil Site Assess	-	-	-	-	50,518	49,176	
44	AJ19QSB08	ACE Dist Drainage & Driveway	-	-	-	-	-	5,200	
45	AJ19QSB19	Dist-Station Transformer Repl	-	-	-	-	-	17,606	
46	AJ19QSB29	NJ (Dist) Flood Remediation	-	5,109	5,011	124,885	2,995	14,302	
47	AJ20DCB01	Budget - Region 1 ACE AMI	2,337,961	2,337,961	2,337,961	2,337,961	2,337,961	2,337,961	
48	AJ20DCB02	Budget - Region 2 ACE AMI	258,657	258,657	258,657	258,657	258,657	258,657	
49	AJ20DCB03	Budget - Region 3 ACE AMI	3,038	3,038	3,038	3,038	3,038	3,038	
50	AJ20DDB01	ACE NJ Dist Smart Fault Sensor	54,656	53,286	52,593	52,224	52,445	62,591	\$ 327,795

(1)	(2)	(3)	(4) Forecast	(5) Forecast	(6) Forecast	(7) Forecast	(8) Forecast	(9) Forecast	(10)
51	AJ20DMB02	CrossArm Repl Program ACE	8,849	11,083	27,358	26,924	27,907	17,982 \$	120,103
52	AJ20DN043	Repauno Sub Distribution	· -	-	-	-	5,879	- \$	5,879
53	AJ20DNB02	ACE Solar LRP place holder	11,292	8,798	6,081	(115)	2,994	4,560 \$	33,609
54	AJ20DNB03	LRP for ACE non-PJM customer	6,892	5,454	3,425	(458)	1,644	2,496 \$	19,454
55	AJ20DSB05	Unfused Lateral Program ACE	75,264	23,039	22,615	22,375	72,862	38,451 \$	254,606
56	AJ20QN001	Repauno Sub Dist	-	-	-	-	225,066	- \$	225,066
57	AJ20QNB01	Repauno Sub - Dist Sub	-	-	-	-	-	(15,026) \$	(15,026)
58	AJ20QSB14	Budget 74128 - Williamstown	358,233	348,024	232,235	-	-	- \$	938,492
59	AJ20RNB01	LRP Ace telecom	(1,975)	(1,999)	(1,994)	(2,016)	(2,043)	(1,889) \$	(11,916)
60	AJ20RNB02	LRP for ace non-pjm telecom	(2,904)	(2,935)	(2,082)	(2,408)	(2,615)	(2,714) \$	(15,658)
61	AJ20RT020	Repauno Sub Fiber	<u>-</u>	-	-	-	4,322	- \$	4,322
62	AJ20RTB03	Repauno Substation - Fiber	-	13,139	13,139	-	-	- \$	26,278
63	AJ20RTB06	Sub FO Entr ACE Non-AIIP	77,784	93,512	84,638	116,294	185,401	179,479 \$	737,109
64	AJ20RTB07	Router Upg Cores ACE Non-AIIP	88,899	81,391	86,394	99,684	133,076	146,128 \$	635,573
65	AJ20XB002	OT Cyber Security ACE Capex	18,762	18,183	20,714	24,488	26,382	33,979 \$	142,508
66	AJ21DDB01	Budget Dist Auto Placeholder	158,849	156,689	281,570	278,967	204,653	202,449 \$	1,283,178
67	AJ21DMB02	ACE UG Plan Cap P30/P40	191,172	189,524	182,750	201,512	200,310	174,254 \$	1,139,522
68	AJ21DMB04	ACE OH PLAN CAP P30/P40	356,688	330,016	302,728	330,409	375,623	292,751 \$	1,988,216
69	AJ21DMB05	ACE NJ DIST Porcelain Cutout	58,447	57,254	56,209	55,257	57,309	56,236 \$	340,712
70	AJ21DN054	Quinton-Al Distr 100% REIMB	-	-	-	(41,353)	-	- \$	(41,353)
71	AJ21DNB02	BUDGET PROJ-Quinton-Al Distrib	53,678	48,637	44,010	41,301	1,079	1,084 \$	189,789
72	AJ21DSB06	Recloser Saturation ACE Budget	133,735	155,983	252,144	238,210	246,306	187,455 \$	1,213,832
73	AJ21QS013	Woodstown - Upgrade Fdr Relay	-	-	-	-	6,743	- \$	6,743
74	AJ21QS015	Cardiff - Upgrade Fdr Relays	683	683	694	692	-	- \$	2,751
75	AJ21QS017	Silver Lake-Upgrade Fdr Relays	683	683	694	692	-	- \$	2,751
76	AJ21QS025	WINSLOW T2 XFMR UPGRADE	-	-	-	384,911	-	- \$	384,911
77	AJ21QS029	Huron - CAP Fdn Replacement	-	-	-	-	-	24,011 \$	24,011
78	AJ21QS032	Newport-Cap Fdn Replacement	-	-	-	-	-	33,968 \$	33,968
79	AJ21QS033	Paulsboro-Cap Fdn Replacement	-	-	-	-	-	27,615 \$	27,615
80	AJ21RDB01	Budget Recloser Radio/Control	70,742	84,395	73,762	121,181	50,473	50,925 \$	451,477
81	AJ21RDB02	Budget Radio/Telecom Cor Maint	54,073	54,277	54,205	54,255	54,302	54,700 \$	325,812
82	AJ22DEB06	Nortonville 2nd Transformer	-	-	-	-	2,207,393	283,021 \$	2,490,414
83	AJ22DGB01	Glassboro Conn Community CAP	5,563	5,563	13,903	13,909	13,925	41,818 \$	94,681
84	AJ22DMB01	Replace Dist OH Equip Emergent	628,649	647,891	900,883	893,193	929,939	588,298 \$	4,588,853
85	AJ22DMB02	Replace Dist UG Equip Emergent	33,614	32,987	32,405	37,088	37,915	37,551 \$	211,560
86	AJ22DSB03	Winslow Dis Line Budget	-	-	-	-	52,252	- \$	52,252
87	AJ22DSB08	Budget ACE NJ - DA Reg Install	31,426	29,989	29,137	28,654	28,588	28,530 \$	176,323
88	AJ22DSB09	Budget ACE NJ - DA Cap Install	56,995	56,659	56,388	56,095	56,702	56,395 \$	339,234
89	AJ22QS023	Cardiff DA Fdr Relay Upgrade	-	-	-	2,909	-	- \$	2,909
90	AJ22QS024	Silver Lake DA Fdr Relay Upgra	-	-	507	-	-	- \$	507
91	AJ22QS025	Cardiff Dsub Bus Improvements	-	-	-	356	-	- \$	356
92	AJ22QS027	Silver Lake Dsub Bus Improve	-	-	176	-	-	- \$	176

(1)	(2)	(3)	(4) Forecast	(5) Forecast	(6) Forecast	(7) Forecast	(8) Forecast	(9) Forecast	(10)
93	AJ22QS040	ATL Mobile Unit A12 Purchase	-	-	-	-	-	770,077 \$	770,077
94	AJ22QSB03	NJ DIST SUB OIL CONTAINMENT	7,852	7,636	39,222	2,471	2,555	2,568 \$	62,303
95	AJ22QSB04	NJ DIST SUB LIGHTING	7,511	32,918	32,837	33,896	17,698	75,926 \$	200,786
96	AJ22QSB05	ACE NJ Cardiff Sub DA Upgrade	820	113,593	2,470	301,505	311,099	1,041 \$	730,528
97	AJ22QSB06	ACE NJ Silver Lake Sub DA Upgr	2,458	113,593	58,955	77,090	1,049	- \$	253,145
98	AJ22QSB08	ACE NJ Woodstown Sub DA Upgrad	-	-	-	-	108,377	- \$	108,377
99	AJ22RVB01	Bridgeton Fuel Island Replace	90,411	90,411	90,387	248,672	248,976	190,333 \$	959,190
100	AJ22RVB03	Pleasantville Fleet Pole Barn	100,573	100,747	226,374	226,529	226,835	227,096 \$	1,108,155
101	AJ22TF006	Kennett Data Center (ACE) Cap	15,394	35,851	35,839	15,375	-	- \$	102,459
102	AJCBAMTLC	AMI Elec Mtr Labor Commercial	(10)	(10)	(10)	(10)	(10)	(10) \$	(60)
103	AJCBAMTLR	AMI Elec Mtr Labor Residential	(32)	(32)	(32)	(32)	(32)	(32) \$	(195)
104	AJCBAMTRR	AMI Elec Meter Precap Resident	(0)	(0)	(0)	(0)	(0)	(0) \$	(1)
105	CAPOHACE	A&G Pool - ACE	(36,806)	(32,630)	(33,626)	(34,964)	(37,044)	(32,684) \$	(207,754)
106		IIP 2.0 Priority Feeders	(551,001)	(551,001)	(551,001)	(551,001)	(551,001)	(551,001) \$	(3,306,004)
107		IIP 2.0 Unfused Laterals	(138,935)	(138,935)	(138,935)	(138,935)	(138,935)	(138,935) \$	(833,611)
108		IIP 2.0 Capacitor Bank Upgrade Project	(36,667)	(36,667)	(36,667)	(36,667)	(36,667)	(36,667) \$	(220,000)
109		IIP 2.0 Capacitor Controller Upgrade Project	(24,933)	(24,933)	(24,933)	(24,933)	(24,933)	(24,933) \$	(149,600)
110		IIP 2.0 ACE NJ Recloser Installation	(399,667)	(399,667)	(399,667)	(399,667)	(399,667)	(399,667) \$	(2,398,000)
111		IIP 2.0 Regulator Controller Upgrade Project	(36,667)	(36,667)	(36,667)	(36,667)	(36,667)	(36,667) \$	(220,000)
112		IIP 2.0 Replace Deteriorated URD Cable	(403,333)	(403,333)	(403,333)	(403,333)	(403,333)	(403,333) \$	(2,420,000)
113		IIP 2.0 Network Transformer and Protector Replacement	(47,667)	(47,667)	(47,667)	(47,667)	(47,667)	(47,667) \$	(286,000)
114		IIP 2.0 Substation Reverse Power Protection Project (8 Projects)	(183,333)	(183,333)	(183,333)	(183,333)	(183,333)	(183,333) \$	(1,100,000)
115		IIP 2.0 DA Feeder Improvement Project	(110,000)	(110,000)	(110,000)	(110,000)	(110,000)	(110,000) \$	(660,000)
116		IIP 2.0 Strengthen DA Feeder Ties	(128,333)	(128,333)	(128,333)	(128,333)	(128,333)	(128,333) \$	(770,000)
117		IIP 2.0 ACE NJ Distribution Smart Fault Sensors	(64,167)	(64,167)	(64,167)	(64,167)	(64,167)	(64,167) \$	(385,000)
118		<u></u>	10,868,731	10,901,791 \$	11,397,351 \$	12,418,016 \$	14,995,556 \$	12,663,882 \$	73,245,328

Atlantic City Electric Company 5+7 Months Ending June 2023 Reflect Credit Facilities Cost Adjustment No. 16

(1) Line	(2)		(3)
No.	<u>ltem</u>	<u>D</u>	<u>istribution</u>
1	<u>Earnings</u>		
2	Expense	\$	730,952 (1)
3		_	
4	State Income Tax	\$	(65,786)
5	Federal Income Tax	\$	(139,685)
6	Total Expenses	\$	525,482
7		•	(505, 400)
8	Earnings	\$	(525,482)
9	Data Basa		
10	Rate Base	r.	EZO 200 (2)
11 12	Amortizable Balance	\$	578,298 (2)
13			
14			
15	(1) Annual amortization of start-up	coete \$	249,874
16	Annual cost of maintaining cred	tit facility \$	594,669
17	Total ACE expense	costs \$ dit facility \$ \$	844,543
18	Total AGE expense	Ψ	044,040
19	ACE System	\$	844,543
20	Allocation to Distribution	Ψ	86.55%
21	ACE Distribution	\$	730,952
22		•	,
23			
24			
25	(2) June 23 Amortizable Balance	\$	668,167
26	• •	•	•
27	ACE System	\$	668,167
28	Allocation to Distribution		86.55%
29	ACE Distribution	\$	578,298

Atlantic City Electric Company Corporate Alternative Minimum Tax ("CAMT") Adjustment 5+7 Months Ending June 2023 Adjustment No. 21

(1)	(2)	(3)
Line No.	Item	 Amount
	Rate Base	
1	Rate Effective Period	
2	CMT Deferred Tax Asset	\$ 14,002,624
3	Distribution Allocated	12,119,271
4		
5		
6	Adjustment to Rate Base	12,119,271
7		
8	Adjustment to Federal Deferred Income Tax Expense	 12,119,271
9		 _
10	Total Rate Base	\$ 12,119,271

Atlantic City Electric Company Excess Deferred Income Tax (EDIT) Adjustment 5+7 Months Ending June 2023 Adjustment No. 22

(1)	(2)	(3)
Line No.	Item	Amount
1 2	EDIT	
3 4	EDIT Regulatory Asset	259,707
5 6	DSIT	(23,374)
7	DFIT	(49,630)
8 9	Adjustment to Rate Base	186,703
10	Rate Base	\$ 186,703

Atlantic City Electric Company Electric Vehicle Reg Asset 5+7 Months Ending June 2023 Adjustment No. 23

(1) Line	(2)	(3)
No.	Adjustment 23 - Reflection of Electric Vehicle Regulatory Asset	Amount
	Earnings	
1 2	Electric Vehicle Costs Deferred Balance	\$ 1,561,741
3 4	Adjustment to Amortization Expense (3 year amortization period)	520,580
5 6	Adjustment to state income tax expense	(46,852)
7 8	Adjustment to federal income tax expense	 (99,483)
9	Total Expense	 374,245
10 11	Earnings	\$ (374,245)
12 13		
14 15	Rate Base	
16 17	Electric Vehicle Costs Deferred Balance	\$ 1,561,741
18 19	Decline in Balance after year 1	(260,290)
20 21	Total average unamortized rate base balances	1,301,451
22 23	Adjustment to accumulated deferred income taxes	(368,658)
24	Adjustment to rate base, net of accumulated deferred taxes	 932,794
25 26	Rate Base	\$ 932,794

Atlantic City Electric Company 5+7 Months Ending June 2023 SEN Investment Deferral Regulatory Asset Adjustment No. 24

(1)	(2)		(3)
Line	ltom	D:	iatributian
<u>No.</u>	<u>ltem</u>	<u>DI</u>	<u>istribution</u>
1	<u>Earnings</u>		
2			
3	SEN Investment Deferral Regulatory Asset - June 30th, 2023	\$	5,673,575
4	Proposed Amortization period		5
5			
6	Amortization of SEN Investment Deferral	\$	1,134,715
7 8			
9	State Income Tax	Φ.	(102,124)
10	Federal Income Tax	\$ \$ \$	(216,844)
11	Total Expenses	\$	815,747
12	'		•
13	Earnings	\$	(815,747)
14			
15			
16	Rate Base	_	
17	Average Amortizable Balance -SEN Investment Deferral Regulatory Asset	\$	5,106,217
18 19	Deferred State Income Tax	Ф	(459,560)
20	Deferred Federal Income Tax	\$ \$	(459,500)
21	Deferred Federal meetine Tax	Ψ	(373,730)
22	Total Rate Base	\$	3,670,860
23			· · ·
24	(1) SEN Investment Deferral - Amortizable Base	\$	5,673,575
25	Amortization Period (Years)	\$	5
26	Amortization Expense	\$	1,134,715
27	(0) 11	•	
28	(2) Unamortized Balance of SEN Investment Deferral - Beg. Of Period	\$	5,673,575
29 30	Amortization Expense - 1st Year Unamortized Balance - End Of Period	\$ \$ \$	1,134,715
30 31	Average - Year 1	<u>Φ</u>	4,538,860 5,106,217
J 1	Avolage Teal I	Ψ	J, 100,217

Schedule (JCZ)-14

Atlantic City Electric Company 5+7 Months Ending June 2023 AMI SEN Incremental O&M Expenses Adjustment No. 25

(1)	(2)		(3)	
Line <u>No.</u>	<u>ltem</u>	<u>Distribution</u>		
1	<u>Earnings</u>			
2	Ingramental SEN ORM Degulatory Agest - June 20th 2022	\$	12 600 116	
3 4	Incremental SEN O&M Regulatory Asset - June 30th, 2023 Proposed Amortization period	Ф	12,690,116 5	
5	Proposed Amortization period		3	
6	Amortization of SEN O&M Regulatory Asset	\$	2,538,023	
7		*	_,,,,,,	
8				
9	State Income Tax	\$	(228,422)	
10	Federal Income Tax	\$ \$ \$	(485,016)	
11	Total Expenses	\$	1,824,585	
12	Familiana	ф	(4.004.505)	
13	Earnings	\$	(1,824,585)	
14 15				
16	Rate Base			
17	Average Amortizable Balance -Incremental SEN O&M Regulatory Asset	\$	11,421,104	
18	The age this against the second and the second against the second agai	•	,,	
19	Deferred State Income Tax	\$	(1,027,899)	
20	Deferred Federal Income Tax	\$	(2,182,573)	
21				
22	Total Rate Base	\$	8,210,632	
23				
24	(1) SEN O&M Defferal - Amortizable Base	\$	12,690,116	
25	Amortization Period (Years)	\$	5	
26 27	Amortization Expense	\$	2,538,023	
27 28	(2) Unamortized Balance of SEN O&M - Beg. Of Period	\$	12,690,116	
29	Amortization Expense - 1st Year		2,538,023	
30	Unamortized Balance - End Of Period	\$ \$ \$	10,152,093	
31	Average - Year 1	\$	11,421,104	

Schedule (JCZ)-15

Atlantic City Electric Company Benchmark Requirement 5+7 Months Ending June 2023 Adjustment No. 26

(1) Line No.	(2) 	(3) Amount
1 2	Earnings	
3 4 5	Benchmarking Requirement - O&M Related Regulatory Asset	315,485
6 7	Adjustment to Amortization Expense (3 year amortization period)	105,162
8 9	Ongoing O&M Maintenance Expense - PHI	552,360
10 11	ACE Allocation	25.41% 140,355
12 13 14	Ongoing O&M Maintenance Expense - ACE Adjustment to state income tax expense	(22,097)
15 16	Adjustment to federal income tax expense	(46,918)
17 18	Total Expense	176,502
19 20 21	Earnings	(176,502)
22 23 24	Rate Base	
25 26	Benchmarking Requirement - Capital	805,154
27 28	Benchmarking Requirement - O&M related	315,485
29 30	Decline in Balance after year 1	(52,581)
31 32 33	Total average unamortized rate base balances Total Rate Base	262,904 1,068,058
34 35	Adjustment to accumulated deferred income taxes	(302,545)
36 37	Adjustment to Rate Base	765,513

Schedule (JCZ)-16

Atlantic City Electric Company Overall Rate of Return Pro Forma as of September 30, 2022

Type of Capital	Ratios	Cost Rate	Weighted Cost Rate
Long-Term Debt	49.80%	3.73%	1.86%
Common Equity	50.20%	10.50%	5.27%
Total	100.00%		7.13%

Atlantic City Electric Company Cost of Debt Pro Forma as of September 30, 2022

	Pro Forma 6/3	30/23
Type of Capital	Amount	Ratios
	(\$)	
Long-Term Debt	1,823,150,000	
Unamortized Net Discount	(566,882)	
Unamortized Debt Issuance Costs	(10,454,439)	
Unamortized Debt Reacquisition Costs	(2,543,927)	
Total Long-Term Debt	1,809,584,752	49.80%
Common Equity	1,824,119,569	50.20%
Total	3,633,704,321	100.00%

Atlantic City Electric Company Cost of Debt Long-Term Debt Pro Forma as of September 30, 2022

				Current					
				Principal	Unamortized	Unamortized		Effective	Annual
	Coupon			Amount	Debt Issuance	(Premium)/	Net Amount	Cost	Net
Issue	Rate	Maturity	Offering Date	Outstanding	Expense	Discount	Outstanding	Rate	Cost
First Mortgage Bonds	4 000/	40/45/00	10/10/10	* 0=0 000 000	* • • • • • • • • • • • • • • • • • • •	4000 000	00.47.007.004	4.4407	* 44.00=.004
	4.00%	10/15/28	10/16/18	\$350,000,000	\$1,841,087	\$222,992	\$347,935,921	4.11%	\$14,305,601
	3.38%	09/01/24	08/25/14	\$150,000,000	\$302,748	\$14,176	\$149,683,075	3.49%	\$5,223,115
	3.500%	12/01/25	12/08/15	\$150,000,000	\$400,987	\$0	\$149,599,014	3.60%	\$5,385,945
	3.500%	05/21/29	05/21/19	\$100,000,000	\$540,140	\$0	\$99,459,860	3.59%	\$3,572,635
	4.14%	05/21/49	05/21/19	\$50,000,000	\$357,999	\$0	\$49,642,001	4.18%	\$2,077,450
	3.24%	06/09/50	06/09/20	\$100,000,000	\$707,990	\$0	\$99,292,010	3.28%	\$3,255,919
	2.30%	03/15/31	03/10/21	\$350,000,000	\$2,427,079	\$162,179	\$347,410,742	2.39%	\$8,307,309
	2.27%	02/15/32	11/16/21	\$75,000,000	\$471,306	\$0	\$74,528,694	2.35%	\$1,748,033
	3.06%	02/15/52	02/15/22	\$150,000,000	\$1,003,246	\$0	\$148,996,754	3.09%	\$4,611,203
	2.27%	02/15/32	02/15/22	\$25,000,000	\$184,490	\$0	\$24,815,510	2.35%	\$582,490
	5.55%	03/15/53	03/15/23	\$75,000,000	\$750,000	\$0	\$74,250,000	5.62%	\$4,172,364
Total First Mortgage Bonds				\$1,575,000,000	\$8,987,071	\$399,348	\$1,565,613,581		\$53,242,062
• • • •									
Senior Notes					•				
	5.80%	5/15/2034	4/8/2004	\$120,000,000	\$759,673	\$167,534	\$119,072,792	5.91%	\$7,042,351
	5.80%	3/1/2036	3/15/2006	\$105,000,000	\$365,652	\$0	\$104,634,348	5.85%	\$6,120,358
Total Senior Notes				\$225,000,000	\$1,125,326	\$167,534	\$223,707,140		\$13,162,709
Tax Exempt Fixed Rate Bonds									
Tax Exempt Fixed Nate Bollus	2.25%	6/1/2029	6/2/2020	\$23,150,000	\$342,043	\$0	\$22,807,957	2.49%	\$568,486
Total Tax Exempt Fixed Rate Bon		0, 1,2020	0,2,2020	\$23,150,000	\$342,043	\$0	\$22,807,957	2. 10 70	\$568,486
rotal ran Exempt mountate Den				Ψ=0,.00,000	φο .2,ο .ο	40	ψ==,σσ.,σσ.		Ψοσο, .σσ
Unamoutized Daht Daggeristiss C	Pant.						(\$0.540.00Z\		ФE20 225
Unamortized Debt Reacquisition C	JUST						(\$2,543,927)		\$520,235
Total Long-Term Debt Balance				\$1,823,150,000	\$10,454,439	\$566,882	\$1,809,584,752	3.73%	\$67,493,492

Atlantic City Electric Company Calculation of the Effective Cost Rate of Long-Term Debt Pro Forma as of September 30, 2022

					0	riginal		Net	Effective
	Coupon		•	Principal	Debt Issuance	(Premium)/	Net Amount	Amount	Cost
Issue	Rate	Maturity	Offering Date	Amount Issued	Expense	Discount	to Company	Per Unit	Rate
									_
First Mortgage	<u> Bonds</u>								
	4.00%	10/15/2028	10/16/2018	\$350,000,000	\$2,831,904	\$343,000	\$346,825,096	\$99.09	4.11%
	3.38%	9/1/2024	8/25/2014	\$150,000,000	\$1,376,973	\$64,500	\$148,558,527	\$99.04	3.49%
	3.50%	12/1/2025	12/8/2015	\$150,000,000	\$1,252,365	\$0	\$148,747,635	\$99.17	3.60%
	3.50%	5/21/2029	5/21/2019	\$100,000,000	\$767,495	\$0	\$99,232,505	\$99.23	3.59%
	4.14%	5/21/2049	5/21/2019	\$50,000,000	\$381,289	\$0	\$49,618,711	\$99.24	4.18%
	3.24%	6/9/2050	6/9/2020	\$100,000,000	\$743,629	\$0	\$99,256,371	\$99.26	3.28%
	2.30%	3/15/2031	3/10/2021	\$350,000,000	\$2,828,459	\$0	\$347,171,541	\$99.19	2.39%
	2.27%	2/15/2032	11/16/2021	\$75,000,000	\$514,030	\$0	\$74,485,970	\$99.31	2.35%
	3.06%	2/15/2052	2/15/2022	\$150,000,000	\$1,016,406	\$0	\$148,983,594	\$99.32	3.09%
	2.27%	2/15/2032	2/15/2022	\$25,000,000	\$171,312	\$0	\$24,828,688	\$99.31	2.35%
Pro Forma	5.55%	3/15/2053	3/15/2023	\$75,000,000	\$750,000	\$0	\$74,250,000	\$99.00	5.62%
Senior Notes									
	5.80%	5/15/2034	4/8/2004	\$120,000,000	\$1,558,257	\$368,400	\$118,073,343	\$98.39	5.91%
	5.80%	3/1/2036	3/15/2006	\$105,000,000	\$730,537	\$0	\$104,269,463	\$99.30	5.85%
Tax Exempt F									
	2.25%	6/1/2029	6/2/2020	\$23,150,000	\$449,958	\$0	\$22,700,043	\$98.06	2.49%

Schedule (JCZ)-17

Pepco Holdings Inc. (Consolidated) Capitalization and Related Capital Structure Ratios Actual at September 30, 2022

	Actual at September 3 Amount			
	Outstanding (\$ millions)	<u>Ratios</u>		
Long-Term Debt	8,039 (1)	41.65%		
Common Equity	11,263	58.35%		
Total Permanent Capital	19,302	100.00%		

Notes: (1) Excludes unamortized debt issuance costs, discount, premium, reacquired debt costs, and Pepco lease obligations.

Schedule (JCZ)-18 Public

PEPCO HOLDINGS INC. TAXABLE INCOME BY AFFILIATE - 2017 - 2021

REGULATED UTILTIIES	BUS. ACTIVITY	<u>2017</u>	<u>2018</u>	<u>2019</u>	<u>2020</u>	<u>2021</u>	SUM	<u>POSITIVE</u>	<u>NEGATIVE</u>
REGULATED OTHERIES	\$	(98,312,473) \$	6,994,336 \$	10,459,491 \$,	15,462,175	\$ (101,838,386)	\$ - \$	(101,838,386)
	\$	(64,266,344) \$	87,135,112 \$	85,029,781 \$,	20,970,420	\$ 84,099,894	\$ 84,099,894 \$ \$ 514,088,004 \$	-
	\$	(27,358,324) \$ 130,644,654 \$	126,951,414 \$ 51,441,464 \$	105,288,824 \$ (124,383,468) \$		118,807,975 (36,095,859)	\$ 514,988,901 \$ 40,483,714	\$ 514,988,901 \$ \$ 40,483,714 \$	-
	\$	(92,226,336) \$	(72,491,467) \$	(30,701,260) \$		(188,721,801)	\$ (628,613,251)	\$ - \$	(628,613,251)
	\$	(821,727,729) \$	21,029,346 \$	187,089,983 \$,	(34,329,923)	\$ (680,657,108)	\$ - \$	(680,657,108)
	\$	2,792,141 \$	5,364,853 \$	6,034,767 \$	6,363,191 \$	3,817,845	\$ 24,372,797	\$ 24,372,797 \$	-
OTHER (*)									
	\$	(778,493,032) \$	(46,197,560) \$	43,395,821 \$	365,087,444 \$	(451,607,115)	\$ (867,814,442)	\$ - \$	(867,814,442)
	\$	615 \$	- \$	- \$	- \$	-	\$ 615	\$ 615 \$	-
	\$	(22,373) \$	3,056,861 \$	4,381,809 \$	2,172,606 \$	(1,166,031)	\$ 8,422,872	\$ 8,422,872 \$	- (400.000)
	\$	46,504 \$ (1,134,835) \$	191,953 \$	197,663 \$		(741,016)	\$ (100,936) \$ (1,440,445)	\$ - \$	(100,936)
	Ф \$	1,511,423 \$	463,042 \$ - \$	(90,812) \$	(195,043) \$ - \$	(491,797) -	\$ (1,449,445) \$ 1,511,423	τ - τ \$ 1,511,423 \$	(1,449,445)
	\$	222,076,139 \$	221,952,109 \$	221,827,103 \$	221,795,505 \$	221,766,526	\$ 1,109,417,382	\$ 1,109,417,382 \$	-
	\$	9,027 \$	134 \$	(43,229) \$		-	\$ (34,068)	\$ - \$	(34,068)
	\$	60,428 \$	330,295 \$	18 \$		-	\$ 390,741	\$ 390,741 \$	-
	\$	(98,096) \$	(39,640) \$	(93,727) \$		(88,199)	\$ (415,831)	\$ - \$	(415,831)
	\$ ¢	139,943 \$ 4,041 \$	3,315,300 \$ 414 \$	258,261 \$ 1,902 \$		3,048,859 11	\$ 5,340,912 \$ 6,368	\$ 5,340,912 \$ 6,368 \$	-
	\$	1,010,610 \$	- \$	1,902 \$	- \$ - \$	-	\$ 1,010,610	\$ 1,010,610 \$	- -
	\$	660,123 \$	13,326 \$	10,515 \$	т	2,919	\$ 691,639	\$ 691,639 \$	-
	\$	1,511,772 \$	(21,784) \$	3,228 \$		358	\$ 1,494,447	\$ 1,494,447 \$	-
	\$	(1,186,070) \$		- \$	- \$	-	\$ (1,186,070)	\$ - \$	(1,186,070)
	\$	363,866 \$	672,005 \$	367,577 \$	277,331 \$	(6,553,058)	\$ (4,872,279)	- \$	(4,872,279)
	\$ \$	(70,003) \$ (820,460) \$	- \$ (74,866) \$	- \$ (306,138) \$	- \$ 807,120 \$	- (368,925)	\$ (70,003) \$ (763,269)	\$ - \$ ¢ - ¢	(70,003) (763,269)
	\$	(3,724,089) \$	(74,000) \$ - \$	(300,130) \$	- \$	(300,923)	\$ (3,724,089)	\$ - \$	(3,724,089)
	\$	3,342,373 \$	- \$	- \$	- \$	-	\$ 3,342,373	\$ 3,342,373 \$	-
	\$	55,801,535 \$	- \$	- \$	- \$	-	\$ 55,801,535	\$ 55,801,535 \$	-
	\$	(78,858,051) \$	(18,905,440) \$	(13,609,771) \$	100,988,590 \$	635,078,668	\$ 624,693,996	\$ 624,693,996 \$	-
	\$	10,649,367 \$		22,986,142 \$,	628,138,970	\$ 789,413,009	\$ 789,413,009 \$	-
	Ф \$	4,828,405 \$ 5,320 \$	5,203,206 \$ - \$	4,101,052 \$ - \$,	(2,933,435)	\$ 10,861,547 \$ 5,320	\$ 10,861,547 \$ \$ 5,320 \$	-
	\$	(214,618) \$	(18,192) \$	20,649 \$	·	(110,971)	\$ (400,127)	\$ - \$	(400,127)
	\$	21,440 \$	(45,819) \$	171,248 \$		(46,700)	\$ 86,345	\$ 86,345 \$	- '
	\$	260,097,789 \$		243,232,413 \$		222,484,569	\$ 1,182,719,385	\$ 1,182,719,385 \$	-
	\$	2,369,131 \$	1,123,768 \$	239,557 \$		(669,520)	\$ 4,826,790	\$ 4,826,790 \$	-
	\$	3,402,833 \$ 360,573 \$	3,268,184 \$ 697,363 \$	3,018,158 \$ 674,579 \$		24,569,240 51,996	\$ 37,555,168 \$ 1,944,907	\$ 37,555,168 \$ \$ 1,944,907 \$	- -
	\$ ***	186 \$	- \$	- \$		51,990	\$ 1,944,907	\$ 1,944,907 \$	- -
	\$	(70,966) \$		(2,793,552) \$	•	-	\$ (3,780,064)	\$ - \$	(3,780,064)
	\$	4,559,711 \$	- \$	- \$	- \$	-	\$ 4,559,711	\$ 4,559,711 \$	-
	\$	(20,731,430) \$	(25,118,617) \$	(17,283,509) \$		(20,479,340)	\$ (91,407,840)	\$ - \$	(91,407,840)
	\$	12,650,937 \$	2,640,111 \$	21,869,082 \$		(19,428,588)	\$ 35,397,553	\$ 35,397,553 \$	- (34,100,467)
	\$	(32,193,617) \$ 31,847,564 \$	(295,206) \$ (2,256,012) \$	(1,550,370) \$ (2,142,851) \$		(198,176) (149,777)	\$ (34,100,467) \$ 26,843,263	\$ - \$ \$ 26,843,263 \$	(34,100,467)
	\$	9,744,048 \$	453 \$	- \$		(170,111)	\$ 9,744,501	\$ 9,744,501 \$	-
	\$	512,845 \$	24 \$	- \$	- \$	-	\$ 512,869	\$ 512,869 \$	-
	\$	482,646 \$	1,152,587 \$	153,784 \$		-	\$ 1,792,640	\$ 1,792,640 \$	-
	\$	4,093,015 \$	4,841,752 \$	1,236,178 \$,	-	\$ 10,017,028	\$ 10,017,028 \$	-
	\$	4,847,861 \$ 8,606,914 \$	34,000 \$ 71,483,210 \$	- \$	- \$ - \$	-	\$ 4,881,861 \$ 80,090,124	\$ 4,881,861 \$ \$ 80,090,124 \$	-
	\$	- \$	71,463,210 \$	- \$ - \$	- \$	-	\$ -	\$ 60,090,124 \$	-
TOTAL	· ·	(4.040.450.000)	044 404 400	700.050.000 \$	000 045 151	4 400 000 000		ф 4 077 000 400 ÷	(0.101.00= 0==)
TOTAL	<u>\$</u>	(1,242,453,067) \$	911,431,469 \$	769,050,898 \$	688,045,151 \$	1,130,020,300	\$ 2,256,094,751	\$ 4,677,322,426 \$	(2,421,227,675)

(*) Note: All companies are regulated in some fashion e.g., SEC, IRS and State taxing authorities, etc.

Item
Cumulative Losses
Cumulative Gains
Tax Rate
Tax Benefit of Cumulative Losses
AMT
Net Tax Benefit
ACE's % of Total Taxable Income
CTA Balance

\$ (1,850,584,357)	\$ (115,800,278)	\$ 188,668,587	\$ 44,716,519	\$ (688,228,146)	\$ (2,421,227,675)
608,131,290	1,027,231,747	580,382,311	643,328,632	1,818,248,446	\$ 4,677,322,426
21.00%	21.00%	21.00%	21.00%	21.00%	
\$ (388,622,715)	\$ (24,318,058)	\$ 39,620,403	\$ 9,390,469	\$ (144,527,911)	\$ (119,835,097)
\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
\$ (388,622,715)	\$ (24,318,058)	\$ 39,620,403	\$ 9,390,469	\$ (144,527,911)	\$ (119,835,097)
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U.S. BUREAU OF LABOR STATISTICS

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Economic News Release



Consumer Price Index Summary

Transmission of material in this release is embargoed until 8:30 a.m. (ET) Thursday, November 10, 2022 USDL-22-2140

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CONSUMER PRICE INDEX - OCTOBER 2022

The Consumer Price Index for All Urban Consumers (CPI-U) rose 0.4 percent in October on a seasonally adjusted basis, the same increase as in September, the U.S. Bureau of Labor Statistics reported today. Over the last 12 months, the all items index increased 7.7 percent before seasonal adjustment.

The index for shelter contributed over half of the monthly all items increase, with the indexes for gasoline and food also increasing. The energy index increased 1.8 percent over the month as the gasoline index and the electricity index rose, but the natural gas index decreased. The food index increased 0.6 percent over the month with the food at home index rising 0.4 percent.

The index for all items less food and energy rose 0.3 percent in October, after rising 0.6 percent in September. The indexes for shelter, motor vehicle insurance, recreation, new vehicles, and personal care were among those that increased over the month. Indexes which declined in October included the used cars and trucks, medical care, apparel, and airline fares indexes.

The all items index increased 7.7 percent for the 12 months ending October, this was the smallest 12-month increase since the period ending January 2022. The all items less food and energy index rose 6.3 percent over the last 12 months. The energy index increased 17.6 percent for the 12 months ending October, and the food index increased 10.9 percent over the last year; all of these increases were smaller than for the period ending September.

Table A. Percent changes in CPI for All Urban Consumers (CPI-U): U.S. city average

	Seasonally adjusted changes from preceding month							Un- adjusted
	Apr. 2022	May 2022	Jun. 2022	Jul. 2022	Aug. 2022	Sep. 2022	Oct. 2022	12-mos. ended Oct. 2022
All items	0.3	1.0	1.3	0.0	0.1	0.4	0.4	7.7
Food	0.9	1.2	1.0	1.1	0.8	0.8	0.6	10.9
Food at home	1.0	1.4	1.0	1.3	0.7	0.7	0.4	12.4
Food away from home(1)	0.6	0.7	0.9	0.7	0.9	0.9	0.9	8.6
Energy	-2.7	3.9	7.5	-4.6	-5.0	-2.1	1.8	17.6
Energy commodities	-5.4	4.5	10.4	-7.6	-10.1	-4.7	4.4	19.3
Gasoline (all types)	-6.1	4.1	11.2	-7.7	-10.6	-4.9	4.0	17.5
Fuel oil(1)	2.7	16.9	-1.2	-11.0	-5.9	-2.7	19.8	68.5
Energy services	1.3	3.0	3.5	0.1	2.1	1.1	-1.2	15.6
Electricity	0.7	1.3	1.7	1.6	1.5	0.4	0.1	14.1
Utility (piped) gas service	3.1	8.0	8.2	-3.6	3.5	2.9	-4.6	20.0
All items less food and energy	0.6	0.6	0.7	0.3	0.6	0.6	0.3	6.3
Commodities less food and energy commodities	0.2	0.7	0.8	0.2	0.5	0.0	-0.4	5.1
New vehicles	1.1	1.0	0.7	0.6	0.8	0.7	0.4	8.4
Used cars and trucks	-0.4	1.8	1.6	-0.4	-0.1	-1.1	-2.4	2.0
Apparel	-0.8	0.7	0.8	-0.1	0.2	-0.3	-0.7	4.1
Medical care commodities(1)	0.1	0.3	0.4	0.6	0.2	-0.1	0.0	3.1
Services less energy services	0.7	0.6	0.7	0.4	0.6	0.8	0.5	6.7
Shelter	0.5	0.6	0.6	0.5	0.7	0.7	0.8	6.9
Transportation services	3.1	1.3	2.1	-0.5	0.5	1.9	0.8	15.2
Medical care services	0.5	0.4	0.7	0.4	0.8	1.0	-0.6	5.4

Footnotes

(1) Not seasonally adjusted.

Food

The food index increased 0.6 percent in October following a 0.8-percent increase in September. The https://www.bls.gov/news.release/cpi.nr0.htm

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food at home index rose 0.4 percent in October, the smallest monthly increase in this index since December 2021. Four of the six major grocery store food group indexes increased over the month. The index for other food at home increased 0.9 percent in October, after rising 0.5 percent in September. The index for meats, poultry, fish, and eggs rose 0.6 percent over the month while the index for cereals and bakery products increased 0.8 percent in October. The index for nonalcoholic beverages rose 0.5 percent in October, after rising 0.6 percent last month.

In contrast, the index for fruits and vegetables fell 0.9 percent over the month after increasing 1.6 percent in September. The index for fresh fruits fell 2.4 percent and the index for fresh vegetables fell 0.5 percent. The index for dairy and related products also declined in October, falling 0.1 percent.

The food away from home index rose 0.9 percent in October, as it did in August and September. The index for full service meals increased 1.1 percent and the index for limited service meals increased 0.8 percent over the month.

The food at home index rose 12.4 percent over the last 12 months. The index for cereals and bakery products increased 15.9 percent over the year and the index for dairy and related products rose 15.5 percent. The remaining major grocery store food groups posted increases ranging from 8.0 percent (meats, poultry, fish, and eggs) to 15.4 percent (other food at home).

The index for food away from home rose 8.6 percent over the last year. The index for full service meals rose 9.0 percent over the last 12 months, and the index for limited service meals rose 7.1 percent over the same period.

Energy

The energy index increased 1.8 percent in October after falling in the preceding three months. The gasoline index rose 4.0 percent over the month, also following three consecutive declines. (Before seasonal adjustment, gasoline prices rose 3.1 percent in October.) The electricity index also increased over the month, rising 0.1 percent. However, the index for natural gas decreased in October, falling 4.6 percent after increasing 2.9 percent in September.

The energy index rose 17.6 percent over the past 12 months. The gasoline index increased 17.5 percent over the span and the fuel oil index rose 68.5 percent. The index for electricity rose 14.1 percent over the last 12 months, and the index for natural gas increased 20.0 percent over the same period.

All items less food and energy

The index for all items less food and energy rose 0.3 percent in October, following a 0.6-percent increase in September. The shelter index continued to increase, rising 0.8 percent in October, the largest monthly increase in that index since August 1990. The rent index rose 0.7 percent over the month, and the owners' equivalent rent index rose 0.6 percent. The index for lodging away from home increased 4.9 percent in October, after declining 1.0 percent in September.

The shelter index was the dominant factor in the monthly increase in the index for all items less food and energy; other components were a mix of increases and declines. Among the indexes that rose in October was the index for motor vehicle insurance which rose 1.7 percent in October after rising 1.6 percent in September. The index for recreation rose 0.7 percent over the month, following a smaller 0.1-percent increase in the previous month. The new vehicles index increased 0.4 percent in October, and the personal care index rose 0.5 percent.

In contrast, the medical care index fell 0.5 percent in October after rising 0.8 percent in September. The index for hospital and related services decreased 0.2 percent over the month, and the index for prescription drugs declined 0.1 percent. The index for physicians' services was unchanged in October.

Other indexes which declined over the month include the index for used cars and trucks, which fell 2.4 percent in October after decreasing 1.1 percent in September. The apparel index fell 0.7 percent over the month, after declining 0.3 percent the previous month. The index for airline fares fell 1.1 percent in October, following a 0.8-percent increase in September. The index for household furnishings and operations was unchanged over the month.

The index for all items less food and energy rose 6.3 percent over the past 12 months. The shelter index increased 6.9 percent over the last year, accounting for over 40 percent of the total increase in all items less food and energy. Other indexes with notable increases over the last year include medical care (+5.0 percent), household furnishings and operations (+8.4 percent), new vehicles (+8.4 percent), and personal care (+6.4 percent).

Not seasonally adjusted CPI measures

The Consumer Price Index for All Urban Consumers (CPI-U) increased 7.7 percent over the last 12 months to an index level of 298.012 (1982-84=100). For the month, the index increased 0.4 percent prior to seasonal adjustment.

The Consumer Price Index for Urban Wage Earners and Clerical Workers (CPI-W) increased 7.9 percent over the last 12 months to an index level of 293.003 (1982-84=100). For the month, the index increased 0.4 percent prior to seasonal adjustment.

The Chained Consumer Price Index for All Urban Consumers (C-CPI-U) increased 7.5 percent over the last 12 months. For the month, the index increased 0.4 percent on a not seasonally adjusted basis. Please note that the indexes for the past 10 to 12 months are subject to revision.

The Consumer Price Index for November 2022 is scheduled to be released on Tuesday, December 13, 2022, at 8:30 a.m. (ET).

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Starting with January 2023 data, BLS plans to update weights annually for the Consumer Price Index based on a single calendar year of data, using consumer expenditure data from 2021. This reflects a change from prior practice of updating weights biennially using two years of expenditure data.

Technical Note

Brief Explanation of the CPI

The Consumer Price Index (CPI) measures the change in prices paid by consumers for goods and services. The CPI reflects spending patterns for each of two population groups: all urban consumers and urban wage earners and clerical workers. The all urban consumer group represents about 93 percent of the total U.S. population. It is based on the expenditures of almost all residents of urban or metropolitan areas, including professionals, the self -employed, the poor, the unemployed, and retired people, as well as urban wage earners and clerical workers. Not included in the CPI are the spending patterns of people living in rural nonmetropolitan areas, farming families, people in the Armed Forces, and those in institutions, such as prisons and mental hospitals. Consumer inflation for all urban consumers is measured by two indexes, namely, the Consumer Price Index for All Urban Consumers (CPI-U) and the Chained Consumer Price Index for All Urban Consumers (C-CPI-U). The Consumer Price Index for Urban Wage Earners and Clerical Workers (CPI-W) is based on the expenditures of households included in the CPI-U definition that meet two requirements: more than one-half of the household's income must come from clerical or wage occupations, and at least one of the household's earners must have been employed for at least 37 weeks during the previous 12 months. The CPI-W population represents about 29 percent of the total U.S. population and is a subset of the CPI-U population.

The CPIs are based on prices of food, clothing, shelter, fuels, transportation, doctors' and dentists' services, drugs, and other goods and services that people buy for day-to-day living. Prices are collected each month in 75 urban areas across the country from about 6,000 housing units and approximately 22,000 retail establishments (department stores, supermarkets, hospitals, filling stations, and other types of stores and service establishments). All taxes directly associated with the purchase and use of items are included in the index. Prices of fuels and a few other items are obtained every month in all 75 locations. Prices of most other commodities and services are collected every month in the three largest geographic areas and every other month in other areas. Prices of most goods and services are obtained by personal visit, telephone call, or web collection by the Bureau's trained representatives.

In calculating the index, price changes for the various items in each location are aggregated using weights, which represent their importance in the spending of the appropriate population group. Local data are then combined to obtain a U.S. city average. For the CPI-U and CPI-W, separate indexes are also published by size of city, by region of the country, for cross-classifications of regions and population-size classes, and for 23 selected local areas. Area indexes do not measure differences in the level of prices among cities; they only measure the average change in prices for each area since the base period. For the C-CPI-U, data are issued only at the national level. The CPI-U and CPI-W are considered final when released, but the C-CPI-U is issued in preliminary form and subject to three subsequent quarterly revisions.

The index measures price change from a designed reference date. For most of the CPI-U and the CPI-W, the reference base is 1982-84 equals 100. The reference base for the C-CPI-U is December 1999 equals 100. An increase of 7 percent from the reference base, for example, is shown as 107.000. Alternatively, that relationship can also be expressed as the price of a base period market basket of goods and services rising from \$100 to \$107.

Sampling Error in the CPI

The CPI is a statistical estimate that is subject to sampling error because it is based upon a sample of retail prices and not the complete universe of all prices. BLS calculates and publishes estimates of the 1-month, 2-month, 6-month, and 12-month percent change standard errors annually for the CPI-U. These standard error estimates can be used to construct confidence intervals for hypothesis testing. For example, the estimated standard error of the 1-month percent change is 0.03 percent for the U.S. all items CPI. This means that if we repeatedly sample from the universe of all retail prices using the same methodology, and estimate a percentage change for each sample, then 95 percent of these estimates will be within 0.06 percent of the 1-month percentage change based on all retail prices. For example, for a 1-month change of 0.2 percent in the all items CPI-U, we are 95 percent confident that the actual percent change based on all retail prices would fall between 0.14 and 0.26 percent. For the latest data, including information on how to use the estimates of standard error, see www.bls.gov/cpi/tables/variance-estimates/home.htm.

Calculating Index Changes

Movements of the indexes from 1 month to another are usually expressed as percent changes rather than changes in index points, because index point changes are affected by the level of the index in relation to its base period, while percent changes are not. The following table shows an example of using index values to calculate percent changes:

	Item A	Item B	Item C
Year I	112.500	225.000	110.000
Year II	121.500	243.000	128.000
Change in index points	9.000	18.000	18.000
Percent change	$9.0/112.500 \times 100 = 8.6$	$18.0/225.000 \times 100 = 8.0$	$18.0/110.000 \times 100 = 16.4$

Use of Seasonally Adjusted and Unadjusted Data

The Consumer Price Index (CPI) produces both unadjusted and seasonally adjusted data.

Seasonally adjusted data are computed using seasonal factors derived by the X-13ARIMA-SEATS seasonal adjustment method. These factors are updated each February, and the new factors are used to revise the previous 5 years of seasonally adjusted data. The factors are available at www.bls.gov/cpi/tables/seasonal-adjustment/seasonal-factors-2022.xlsx. For more information on data revision scheduling, please see the Factsheet on Seasonal Adjustment at www.bls.gov/cpi/seasonal-adjustment/questions-and-answers.htm and the Timeline of Seasonal Adjustment Methodological Changes at

 $\verb|www.bls.gov/cpi/seasonal-adjustment/timeline-seasonal-adjustment-methodology-changes.htm.|$

For analyzing short-term price trends in the economy, seasonally adjusted changes are usually preferred since they eliminate the effect of changes that normally occur at the same time and in about the same magnitude every year-such as price movements resulting from weather events, production cycles, model changeovers, holidays, and sales. This allows data users to focus on changes that are not typical for the time of year. The unadjusted data are of primary interest to consumers concerned about the prices they actually pay. Unadjusted data are also used extensively for escalation purposes. Many collective bargaining contract agreements and pension plans, for example, tie compensation changes to the Consumer Price Index before adjustment for seasonal variation. BLS advises against the use of seasonally adjusted data in escalation agreements because seasonally adjusted series are revised annually.

Intervention Analysis

The Bureau of Labor Statistics uses intervention analysis seasonal adjustment (IASA) for some CPI series. Sometimes extreme values or sharp movements can distort the underlying seasonal pattern of price change. Intervention analysis seasonal adjustment is a process by which the distortions caused by such unusual events are estimated and removed from the data prior to calculation of seasonal factors. The resulting seasonal factors, which more accurately represent the seasonal pattern, are then applied to the unadjusted data.

For example, this procedure was used for the motor fuel series to offset the effects of the 2009 return to normal pricing after the worldwide economic downturn in 2008. Retaining this outlier data during seasonal factor calculation would distort the computation of the seasonal portion of the time series data for motor fuel, so it was estimated and removed from the data prior to seasonal adjustment. Following that, seasonal factors were calculated based on this "prior adjusted" data. These seasonal factors represent a clearer picture of the seasonal pattern in the data. The last step is for motor fuel seasonal factors to be applied to the unadjusted data.

For the seasonal factors introduced for January 2022, BLS adjusted 72 series using intervention analysis seasonal adjustment, including selected food and beverage items, motor fuels, electricity, and vehicles.

Revision of Seasonally Adjusted Indexes

Seasonally adjusted data, including the U.S. city average all items index levels, are subject to revision for up to 5 years after their original release. Every year, economists in the CPI calculate new seasonal factors for seasonally adjusted series and apply them to the last 5 years of data. Seasonally adjusted indexes beyond the last 5 years of data are considered to be final and not subject to revision. For January 2022, revised seasonal factors and seasonally adjusted indexes for 2017 to 2021 were calculated and published. For series which are directly adjusted using the Census X-13ARIMA-SEATS seasonal adjustment software, the seasonal factors for 2021 will be applied to data for 2022 to produce the seasonally adjusted 2022 indexes. Series which are indirectly seasonally adjusted by summing seasonally adjusted component series have seasonal factors which are derived and are therefore not available in advance.

Determining Seasonal Status

Each year the seasonal status of every series is reevaluated based upon certain statistical criteria. Using these criteria, BLS economists determine whether a series should change its status from "not seasonally adjusted" to "seasonally adjusted", or vice versa. If any of the 81 components of the U.S. city average all items index change their seasonal adjustment status from seasonally adjusted to not seasonally adjusted, not seasonally adjusted data will be used in the aggregation of the dependent series for the last 5 years, but the seasonally adjusted indexes before that period will not be changed. For 2022, 22 of the 81 components of the U.S. city average all items index are seasonally adjusted.

Contact Information

For additional information about the CPI visit www.bls.gov/cpi or contact the CPI Information and Analysis Section at 202-691-7000 or cpi info@bls.gov.

For additional information on seasonal adjustment in the CPI visit www.bls.gov/cpi/seasonal-adjustment/home.htm or contact the CPI seasonal adjustment section at 202-691-6968 or cpiseas@bls.gov.

If you are deaf, hard of hearing, or have a speech disability, please dial 7-1-1 to access telecommunications relay services.

- Table 1. Consumer Price Index for All Urban Consumers (CPI-U): U. S. city average, by expenditure category
- <u>Table 2. Consumer Price Index for All Urban Consumers (CPI-U): U. S. city average, by detailed expenditure category</u>
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U.S. BUREAU OF LABOR STATISTICS Division of Consumer Prices and Price Indexes Suite 3130 2 Massachusetts Avenue NE Washington, DC 20212-0001

https://www.bls.gov/news.release/cpi.nr0.htm 5/5 ECONOMY

Fed officials welcome inflation news but still see tighter policy ahead



WATCH LIVE

Jeff Cox@JEFF.COX.7528@JEFFCOXCNBCCOM

KEY POINTS

- Federal Reserve officials welcomed Thursday's news that inflation might have peaked, but cautioned against getting too excited by the data.
- "It's far from a victory," San Francisco Fed President Mary Daly said.
- Dallas Fed President Lorie Logan called the CPI report "a welcome relief" but noted more rate increases probably are coming, albeit at a slower pace.

Prices of fruit and vegetables are on display in a store in Brooklyn, New York City, March 29, 2022.

Andrew Kelly | Reuters

Federal Reserve officials welcomed Thursday's news showing that inflation rose less than expected last month, and they noted that interest rate increases could slow ahead.

But they also cautioned against getting too excited by the data, saying that prices are still far too high.

"One month of data does not a victory make, and I think it's really important to be thoughtful that this is just one piece of positive information, but we're looking at a whole set of information," San Francisco Fed President Mary Daly said during a question-and-answer session with the European Economics and Financial Centre.

Daly and other Fed officials were speaking after the Bureau of Labor Statistics reported that the consumer price index rose 0.4% in October, below the 0.6% Dow Jones estimate. The data sent a possible signal that while inflation is still running high, price increases may have leveled off and could soon head lower.

Markets staged a massive rally following the report, with the Dow Jones Industrial Average soaring more than 1,000 points. The policy-sensitive 2-year Treasury note yield tumbled 30 basis points, or 0.3 percentage point, to 4.33%.

While Daly said the report was "indeed good news," she noted that inflation running at a 7.7% annual rate is still far too high and well off the central bank's 2% goal.

"It's better than over 8 [percent] but it's not close enough to 2 in any way for me to be comfortable," she said. "So it's far from a victory."

Likewise, Cleveland Fed President Loretta Mester said Thursday's report "suggests some easing in overall and core inflation," though she noted the trend is still "unacceptably high."

Kansas City Fed President Esther George noted that even with the lower monthly gain, inflation is still "uncomfortably close" to the 41-year annual high hit in the summer.

"With inflation still elevated and likely to persist, monetary policy clearly has more work to do," she said.

However, she advocated a more "deliberate" approach going forward, noting that "now is a particularly important time to avoid unduly contributing to financial market volatility."

Both Mester and George are voting members this year on the rate-setting Federal Open Market Committee.

Market pricing in lower hikes

The Fed has <u>raised its benchmark interest rate</u> six times this year for a total of 3.75 percentage points. That has included a string of four straight 0.75 percentage point hikes, the most aggressive policy tightening since the central bank moved to using the overnight rate as its principal policy tool in 1990.

Market pricing immediately reacted to the CPI news, shifting

strongly to the likelihood of a 0.5 percentage point increase in December, according to <u>CME Group data</u> calling for an 85.4% probability of a half-point hike.

"Despite the moves we have made so far, given that inflation has consistently proven to be more persistent than expected and there are significant costs of continued high inflation, I currently view the larger risks as coming from tightening too little," Mester said.

Other officials also were cautious.

Dallas Fed President Lorie Logan called the CPI report "a welcome relief" but noted more rate increases probably are coming, though at a slower pace. "I believe it may soon be appropriate to slow the pace of rate increases so we can better assess how financial and economic conditions are evolving," she said.

No rate cuts in sight

Like Daly, Logan said the public should not interpret a slower pace of rate hikes to mean an easing in policy.

In particular, Daly said rates are likely to stay higher for longer and she does not anticipate a rate cut that market pricing indicates could come as soon as September 2023.

Earlier in the day, Philadelphia Fed President Patrick Harker indicated a slower pace is likely but noted the increases still will be significant.

Historically, the U.S. central bank has preferred to hike in quarter-point increments, but the rapid surge of inflation and a slow-footed response from policymakers when prices began surging early in 2021 made the more aggressive pace

necessary.

"In the upcoming months, in light of the cumulative tightening we have achieved, I expect we will slow the pace of our rate hikes as we approach a sufficiently restrictive stance. But I want to be clear: A rate hike of 50 basis points would still be significant," Harker said.

He added that he expects policy to "hold at a restrictive rate" while the Fed evaluates the impact the moves are having on the economy.





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Analysis: How persistent might inflation be?

October 18, 2022 | Market News

→ Market news

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Key takeaways

- Inflation continues to dominate economic and market headlines in 2022.
- Getting inflation under control is the Federal Reserve's primary focus.
- Higher prices are likely to be a persistent reality for the time being, which may be a consideration for investors.

One of the most notable economic developments of recent times, and one that directly impacts most Americans, is the resurgence of persistent inflation. The trend represents a major departure from what had been a consistent pattern of low inflation over most of the past four decades.

In 2021, the cost-of-living, as measured by the Consumer Price Index (CPI), rose 7.0% for the year. It was the highest calendar-year reading since 1981 and stood in sharp contrast to the trend over the past 40 years, when inflation averaged 2% to 3% annually.

So far in 2022, inflation increased further. Over the 12-month period ending in June, living costs as measured by CPI rose 9.1%, the largest inflation spike for a 12-month period since November 1981. It declined modestly since then, but remains above the 8% level on an annualized basis and continues to represent a challenge for consumers and investors. Of specific concern is that "core" inflation (excluding the volatile food and energy sectors) continues to rise at significant levels. Core inflation was up 0.6% in both August and September after slowing to 0.3% in July.

This high inflation environment has generated several questions, including:

- How long will this environment persist?
- What is the potential impact to you as a consumer?
- What does higher inflation mean for your personal portfolio?

Why inflation matters

Inflation represents increases in the cost-of-living over a given time period. It's a measure of how much purchasing power is lost due to rising prices. CPI is the commonly cited statistic used to illustrate inflation on a broad level. CPI provides a measure of prices of goods and services that meet the primary needs of consumers, including food items, transportation, housing and medical care. Recent CPI data indicates that inflation remains a significant concern.

The U.S. Commerce Department's Personal Consumption Expenditure price index, or PCE, is another important inflation gauge, and is considered the U.S. Federal Reserve's preferred inflation measure. The Federal Reserve (Fed) is the country's central bank and mandated by Congress to promote full employment, stable prices and moderate long term interest rates, so watching inflation is essential to their function.

The broad PCE figure rose 6.2% for the one-year period ending in August, a modest drop from its June peak reading of 7.0%, which was the highest level in more than 40 years. The narrower "core" PCE gauge (excluding the volatile food and energy categories) showed inflation at 4.9% for the 12 months ending in August. This remains high but is below the peak of 5.3% it reached for the 12-month period ending in February. The Fed has made clear that the persistent nature of today's elevated inflation environment requires that it continue to pursue an aggressive monetary policy response.

What's behind inflation's return

One reason inflation is a major concern is the ongoing imbalance between supply and demand across specific segments of the economy. This imbalance affects items such as lumber (reflecting significant new construction and remodeling), airfare, lodging, energy costs and car prices. "In this unusual economic environment, people have spent more on specific items, driving up demand," says Tom Hainlin, national investment strategist at U.S. Bank Wealth Management.

Some of the difficulties are due to supply chain disruptions. For example, a shortage of semiconductor chips, now a key component in the production of motor vehicles, led to a drop in inventory at automobile dealerships. The pandemic may be another factor contributing to the current elevated inflation rate, according to Eric Freedman, chief investment officer at U.S. Bank Wealth Management. "Individual countries are managing the response to COVID-19 in different ways. There's a lack of consistency in COVID protocols, contributing to the persistence of inflation," says Freedman.

In other words, if a country forces business activity to slow or shut down as a precautionary measure, it may contribute to the supply chain disruption that has marked the inflationary surge. China is a recent example, as it shut down some major cities to contain a COVID outbreak. This contributed to production delays for some exported goods.

Russia's invasion of Ukraine added another element of risk to the inflationary environment. Russia is a leading exporter of oil and natural gas and a major supplier for most European nations. Both Russia and Ukraine are major agricultural producers as well. Shipping interruptions on the Black Sea, which borders Ukraine to the south, delayed commodity deliveries, although regular shipping of Ukraine's agricultural products recently resumed.

How long will we live with higher inflation?

One of the biggest questions is how long current inflation trends will persist. "There are reasons to believe that inflation will stop moving higher," says Rob Haworth, senior investment strategy director at U.S. Bank. "Commodity prices flattened out over the summer. There are signs that consumers don't expect inflation to keep rising, which would be a positive development."

The Fed has taken significant steps to tame inflation, including dramatic increases to the target federal funds rate it controls. After maintaining a zero interest rate policy since early 2020, the Fed began raising rates in March. By September, it had lifted the fed funds target rate to 3.00% to 3.25%. Haworth notes market prices indicate another 0.75% rate hike will occur in November, followed by a 0.50% hike in December with additional hikes likely in 2023.

Despite these dramatic steps, Haworth acknowledges that the Fed so far has fallen far short of reaching its stated target annual CPI range of 2%. "Fed officials know that monetary policy works with long and variable legs," says Haworth. "Each rate hike takes 6-12 months to work its way into the economic engine." That, in part, explains the limited impact the Fed's actions have had on inflation to this point.

Another aspect of the Fed's monetary tightening strategy was to <u>end its "quantitative easing" program</u>. Under that program, the Fed purchased \$120 billion in U.S. Treasury and mortgage-backed bonds each month to help add liquidity to the market and boost the economy. Now, the Fed is trimming it's nearly \$9 trillion in assets by \$95 billion per month.

Haworth says, "While the Fed wants to avoid driving the economy into a recession, its attention is fixed on addressing the inflation situation before it gets out of hand." <u>Interest rate hikes</u> and reducing its asset holdings are two strategies the Fed has indicated it will continue to pursue to fight inflation.

Key areas to watch – energy, food and wages

For the 12-month period ending September 2022, energy costs were a major contributor to the elevated inflation rate, jumping 19.8%, though energy prices moderated in recent months. Freedman points out that the Organization of Petroleum Exporting Countries (OPEC) continues to have significant influence on the oil market. "OPEC is not producing up to levels some expected to see, and the U.S. has not brought enough capacity online to add to supply in a meaningful way."

Nevertheless, oil prices stabilized in mid-summer, dropping from a peak of \$124/barrel in March to under \$80/barrel in September. Yet in October, the OPEC cartel of oil producing nations announced a cut in oil production, which prompted oil prices to again top \$90/barrel.

"If higher costs take a toll on profits, that could be a more tangible sign of broader concerns about inflation's impact."

-Tom Hainlin, national investment strategist at U.S. Bank Wealth Management

Like energy costs, food prices are another "non-discretionary" expense for households, and trends there raise more concerns. In the 12 months ending in September 2022, food prices within CPI grew by more than 11%.3

The job market is another area facing its own supply-demand disruptions. While millions remain out of work, the Bureau of Labor Statistics reports there are nearly 10.1 million job openings. In addition, a number of people have stepped away from the work force. Freedman believes labor trends in 2022 will better define whether labor shortages will force more significant wage growth. If that occurs, it could contribute to an extended period of higher inflation.

Hainlin notes that investors are watching closely to see if inflation's impact is reflected in upcoming corporate earnings reports. "If higher costs take a toll on business profits, that could be a more tangible sign of broader concerns about inflation's impact," says Hainlin. Recent profit reports have shown some signs of concern in select sectors of the economy, such as retail outlets.

How to manage inflation in your financial life

Inflation has likely contributed to 2022's challenging investment environment. Stock markets experienced significant volatility and the S&P 500 fell into bear market territory in June (a drop of 20% from its peak) and after a brief recovery, dropped into bear market territory again in September. For much of 2022, bond yields moved up significantly, reflecting the high inflation environment. By mid-June, the yield on the 10-year Treasury note was close to 3.5%, a major jump from the 1.5% yield it paid at the end of 2021. In subsequent weeks, the 10-year Treasury yield temporarily moderated, falling below 3.0%, but hovered near the 4% level again in October.

Freedman notes that U.S. Bank Wealth Management has shifted its position from a "pro-growth" mentality to a more <u>balanced outlook for the months ahead</u>. "We've downgraded our view and have concerns about the impact of economic growth slowing." Freedman believes that the Fed's intention to move more quickly to raise interest rates, combined with uncertainties in the energy market resulting from the conflict in Ukraine, create potential risks that could lead to a "choppy" environment for capital markets.

Stock markets are likely to remain volatile in the near term. Opportunities in the <u>bond market</u> are more attractive given that higher yields can be earned than was the case earlier in the year. Investors should remain cautious about the potential for further interest rate increases, as rising rates reduce the value of bonds already on the market.

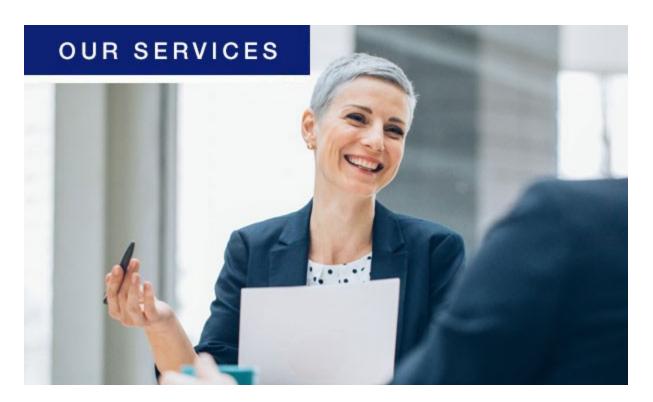
It may be beneficial to consider whether any adjustments are needed to your portfolio. Generally, a consistent <u>long-term strategy</u> tends to work to the benefit of most investors. That should preclude any dramatic changes in your asset mix to respond to the inflationary environment.

Take time to assess how <u>inflation might impact other aspects of your financial plan</u>. For example, if you have variable interest rate loans, consider locking in a long-term fixed rate on the

loan. This may help you avoid future interest rate increases, which could result from the current inflationary environment and shifting Federal Reserve policies.

Be sure to talk to your financial professional about what steps may be most appropriate for your circumstances.

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We use a data- and process-driven three step methodology to develop an investment strategy unique to you.

See our investment management approach



Federal Reserve concludes tapering as it recalibrates monetary policy to fight inflation

September 28, 2022

With the Federal Reserve raising short-term interest rates and no longer providing liquidity to the bond market, investors should prepare for change as the Fed intensifies its focus on fighting inflation.

Read article



Q4 investment outlook

With capital markets experiencing year-to-date losses across most major asset classes, investors are wondering how much more downside risk exists in both economic trajectory and asset prices. Learn more in the fourth quarter investment outlook.

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Feedback, shows survey

What's The US' Projected Inflation Rate In 2023?

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Feb 7, 2023, 08:54am EST

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Key takeaways

• Inflation has decreased in the US six months in a row, a sign that the Fed's aggressive interest rate-raising approach is working

- Stock markets have enjoyed a brief bump thanks to a string of good news for the economy, after pricing in fears of a recession
- However, the Fed is expected to stick to rate increases after the lowest levels of unemployment in 50 years were revealed

Inflation: the boogeyman that affects your housing markets, your grocery prices and your wages. You can't move for hearing about it at the moment.

US inflation rates rose to their highest levels since the 1980s last year, thanks to a string of geopolitical tensions and pandemic-related economic decisions. Now, we're watching a delicate dance between the Fed, unemployment and interest rates unfold, aiming to tame the beast.

Let's get into exactly what's going on at the moment and how we could see US inflation behave this year.

Worried about inflation eating into your investing gains? Q.ai's Inflation Kit is your one-stop shop for defending against your weakening dollars. Our machine-learning technology susses out safe assets to guard against inflation, working hard to bring you solid returns on your investment.

Download Q.ai today for access to AI-powered investment strategies.

Why is inflation going down?

Headline CPI inflation peaked in June 2022 at 9%, then fell for six straight months to 6.5% by the end of the year. Meanwhile, the core PCE inflation rate peaked in Feb 2022 at 5.4% and is now 4.4%.

Both of these are positive signs the runaway inflation train is pulling in at the station.

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The Federal Reserve has been on the warpath to beat spiraling inflation since the whole saga began. It raised interest rates from historic lows at a punishing pace, with four successive three-quarter point increases in 2022.

But the central bank has been helped by serendipitous situations that arose late last year. China unexpectedly and suddenly reopened its markets, jumpstarting its economy, which has a ripple effect on the rest of the world.



00:53

Problems in the global supply chains have also helped to drop the price of everyday items. Gas prices also tumbled globally (though in the US, they've since begun to climb again).

So, could this mean interest rates might fall quicker than expected? Possibly not, thanks to a new spanner in the works.

What's going on with unemployment rates?

Something weird is happening in the US labor market: the unemployment rate is now at its lowest level in *53 years*. Half a million new jobs were added to the US economy in January, double the rate analysts expected and bringing the unemployment rate to 3.4%.

The jobs market has an interesting part to play in the inflation dance. When a lot of people are out of work, employers are flush with choices on who to hire and don't have to sway employees with higher wages. This keeps wage inflation low.

Right now, it should be the opposite but instead, we're getting mixed signals. While the job market is hot, wage growth is cooling down: average hourly earnings went from 4.8% in December to 4.4% a month later.

The outcome? It's pretty hard for the Fed to decide whether or not to continue raising interest rates when unemployment is unusually low and the wage growth isn't matching up. If anything, the news will bolster their resolve to increase them.

What's the Fed doing in 2023 to counter inflation?

After its monumental effort to tame inflation in 2022, the Fed has begun to rein things in. The hikes have slowed recently, with the

Fed announcing a quarter-point interest rate increase last week. Interest rates now sit at a target 4.5% to 4.75% range.

The Fed seems cautiously optimistic about inflation. Its chair, Jerome Powell, said in a press conference last week that while a "couple of more rate hikes" looked likely, "it is gratifying to see the disinflationary process now getting underway".

Disinflation refers to slower price increases, which is in line with the gradually falling inflation we're seeing. The Fed won't want to be too punitive with interest rates when most of the population is experiencing economic hardship, but it risks inflation spiraling upwards again without fiscal tightening.

Despite this, the stock market has reacted positively to Powell's words, enjoying a rally throughout January and spiking after the press conference. The S&P 500 is currently sitting 8% higher than at the start of the year.

This has drawn criticism from economic specialists for the Fed chair, with some arguing his too-upbeat focus on disinflation has given the markets false hope that talk of a recession is overblown.

What's the consensus?

The truth is, there is no consensus right now.

The Fed is still clinging to its target of bringing inflation down to 2%. How quickly that happens depends on a lot of moving parts we're yet to see unfold.

Experts are scratching their heads at how the labor market defies the usual economic pattern. Goldman Sachs' chief economist, Jan Hatzius, told Insider the jobs news would embolden the Fed to stay the course with its interest rates plan. He expects them to hit the 5% mark in 2023.

This won't be popular in a market that's seeing the inflation rate fall six months in a row, the IMF upgrading the US economy's growth forecast for 2023 and a housing market already on its knees.

Equally, we're yet to see the full effect of the interest rates' staggering climb. As borrowing costs, consumer spending and exchange rates are all affected, we're only going to see the impact of the 2022 rate hikes this year. This could mean a slower economy, fewer jobs and less spending.

The housing market is one example of this. Sky-high house prices have now begun to cool off slightly, with month-on-month sales prices dropping 11% from the record of June 2022. Interest rates continuing to increase will impact mortgage approval rates, slowing this section of the US economy further.

In a nutshell, things aren't looking clear - at all. Powell's speech this week at the Economic Club of Washington DC could give us more insight into the Fed's 2023 approach, but you'd need a crystal ball at the moment to predict what the tail end of 2023's US economy is going to look like.

The bottom line

While no one's exactly clear on the exact number for inflation in 2023, most agree that it will continue to trend downwards.

With that said, the timeline isn't certain, and we're still dealing with inflation figures that are super high by historical standards. For investors, that means that setting up your portfolio to protect against inflation is still a worthy objective.

If you're in that boat, our Inflation Kit uses the power of AI to invest in a range of assets that can hold up against rising prices.

The Kit is made up of Treasury Inflation Protected Securities
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ATLANTIC CITY ELECTRIC COMPANY

BEFORE THE NEW JERSEY BOARD OF PUBLIC UTILITIES DIRECT TESTIMONY OF GREGORY W. BRUBAKER AND RYAN P. WHITMAN BPU DOCKET NO. ER23020091

1	Q1.	Please state your name and position.
2	A1.	My name is Gregory W. Brubaker. I am the Senior Manager of Strategic Planning
3		for Atlantic City Electric Company ("ACE" or the "Company").
4		My name is Ryan P. Whitman. I am the Manager of Project Execution for ACE.
5	Q2.	On whose behalf are you submitting Direct Testimony in this case?
6	A2.	We are submitting Direct Testimony on behalf of ACE, the Petitioner in this case.
7	Q3.	Mr. Brubaker, what are your responsibilities as Senior Manager of Strategic
8		Planning?
9	A3.	I am responsible for leading, directing, and organizing the need in ACE for
10		technical and regulatory coordination as well as operations integration of emerging smart
11		grid technology, programs, and reliability-based initiatives. I am also a Deputy Incident
12		Commander during emergency and storm-related situations, where I am responsible for
13		leading all activities related to the restoration efforts for damage to the Company's electric
14		facilities.
15	Q4.	Mr. Whitman, what are your responsibilities as Manager of Project Execution?
16	A4.	I am responsible for the scope, schedule, and budget of the Smart Energy Network
17		("SEN") program, including the safety of day-to-day operations, implementation of the
18		technology, and full utilization of the use cases which will deliver customer benefits and
19		the Company's savings commitments. In addition, I am responsible for the development of

- my team, overseeing PJM interconnections at ACE and several process improvement initiatives.
- 3 Q5. Mr. Brubaker, please state your educational background and professional experience.
- 5 A5. I hold a Bachelor's degree in Electrical Engineering Technology from Southern 6 Illinois University at Carbondale, a Master of Business Administration from the University 7 of Phoenix and I am a registered Professional Engineer in New Jersey. I have worked in the electric utility industry for over 35 years and have held various positions in transmission 8 9 and distribution engineering, including more than 23 years of engineering leadership. Prior 10 to my current role, I was the Manager of Engineering & Design where I was responsible 11 for the design and reliable operation of the electrical distribution system in Southern New 12 Jersey. I oversaw all distribution design activities, including oversight of the New Business 13 and Facility Relocation processes, as well as the day-to-day reliability performance of the 14 distribution system.
 - Q6. Mr. Brubaker, have you previously submitted testimony before the New Jersey Board of Public Utilities ("BPU" or the "Board") or other regulatory agencies?

15

16

17 A6. Yes. I have submitted testimony in previous ACE regulatory proceedings,
18 including ACE's 2020 Base Rate Case, Docket No. ER20120746, ACE's Smart Energy
19 Network Program, Docket No. EO20090621, ACE's 2022 Powering the Future,
20 Infrastructure Investment Program, Docket No. ER22100666, seven (7) PowerAhead Roll21 in filings, Docket Nos. ER190505550, ER19111434, ER20050337, ER20110693,
22 ER21050753, ER21111205 and ER22050323 and three (3) Infrastructure Investment
23 Program ("IIP") roll-in filings, Docket Nos. ER20050336, ER20110694 and ER21111206.

1	Q7.	Mr. Whitman, please state your educational background and professional experience.

- A7. I hold a Bachelor's degree in Business Administration Project Management from Strayer University, a Master of Business Administration from Wilmington University, and a Master of Science in Technology Project Management from Wilmington University. I am a certified Project Management Professional. I have worked at ACE for 6 years as a project manager. Prior to working at the Company, I was a Bomb Technician for the United States Federal Government in various roles for 15 years.
- **Q8.** Mr. Whitman, have you previously submitted testimony before the BPU or other regulatory agencies?
- 10 A8. No, I have not previously submitted testimony before the BPU or other regulatory agencies.

Q9. What is the purpose of your Direct Testimony?

A9.

- The purpose of our Direct Testimony is to describe ACE's investments in, and maintenance of, the Company's electric distribution system in New Jersey. These investments have provided continuing reliability benefits to ACE's customers, which will be discussed in greater detail throughout this Direct Testimony. This testimony was prepared under our direction and supervision, and the source documents for our testimony are Company records and public documents. Our testimony will address the reliability and grid modernization investments made in connection with the Company's revenue requirements in this proceeding, including:
 - ACE's Reliability Performance and Investments
- The Distribution Construction Program
- ACE's SEN Implementation Progress

1		ACE's PowerAhead Program
2		The Capital Budget Process
3		ACE's Street Light Strategy
4		• ACE's storm restoration efforts; and
5		• ACE's post-test year plant adjustments.
6		Reliability Performance and Investments
7	Q10.	How does the Company balance reliability investments with customers' current needs
8		and expectations?
9	A10.	As our Direct Testimony will demonstrate, ACE is committed to providing safe,
10		reliable, and cost-effective service for its customers. As customers' behaviors, needs, and
11		expectations continue to evolve, the Company has made necessary and concentrated
12		investments in distribution assets to replace aging infrastructure as well as modernize and
13		strengthen the electrical grid to meet customers' needs. Reliability is more important to
14		customers than ever given increasingly frequent and damaging storm activity, the post-
15		pandemic hybrid work environment, and the increased local, regional, and national
16		expectation of overall electrification to enable a cleaner carbon-free future.
17		ACE's successful planning and project implementation have led to the system's
18		current reliability performance, but the Company must maintain this performance to meet
19		these evolving customer expectations. To continue delivering customers first quartile
20		service reliability in the years ahead, the Company must continue proactively investing in
21		infrastructure and new technologies. Included among these proactive investments is the

proposed Powering the Future¹ portfolio of projects that will invest \$379 million in ACE's distribution infrastructure; these projects are designed to improve reliability, increase resiliency to storms and other adverse events, advance the modernization of the distribution system, increase safety for workers and the public, prepare the system for advancement of solar and distributed energy resources ("DER"), and proactively replace equipment that is obsolete or near the end of its life. Powering the Future is a recovery mechanism separate from the baseline reliability investments discussed throughout this testimony, but supports the same goals of safe, reliable, cost-effective service while modernizing and strengthening the distribution system. These on-going investments will continue to modernize the grid, minimize the effects of storms due to climate change, and address changing customer expectations in an era of increasing dependence on electrical reliability.

To meet and maintain reliability objectives, as well as evolving customer needs and expectations, ACE has developed and implemented robust practices to ensure that its systems can handle various operating conditions and respond to events that may exceed the original design of the infrastructure. The Company considers the cost of various system designs, equipment upgrades, and replacement strategies against the improved reliability and other customer benefits of these investments. Through alternative analyses, the Company strives to select the most effective investment with the lowest additional cost to deliver value for customers. When assessing which upgrades are critical for system performance, ACE must rely on its professional judgment to strike the right balance between grid modernization, and the need to maintain or replace aging infrastructure. This

¹ On October 31, 2022, the Company filed a Petition for Approval of Powering the Future, an Infrastructure Investment Program, Docket No. ER22100666.

1		analytical process has enabled the Company to provide customers with strong reliability
2		and a positive customer experience, while also maintaining its focus on reasonable rates.
3	Q11.	Please explain how Reliability fits into the overall Distribution Program.
4	A11.	The Reliability categories are a subset of the total Distribution Program and include
5		projects focused on the reliability of the system. There are four categories of Reliability
6		work in which related individual projects are grouped that, when taken together, improve
7		performance for the Company's customers:
8		System Performance Distribution:
9		o Priority Feeder Improvement
10		o Comprehensive Feeder Improvement
11		o Multiple Device Operations ("MDO")
12		o Customers Experiencing Multiple Interruptions ("CEMI")
13		o Planned Underground Residential Development ("URD") Cable
14		Replacement
15		• System Performance Automation:
16		o Automatic Sectionalization & Restoration ("ASR")
17		• System Performance Substation:
18		o Aging Infrastructure
19		Capital Corrective Maintenance
20	Q12.	Please describe the System Performance Distribution programs.
21	A12.	System Performance Distribution projects and programs continually improve
22		performance through upgrades to the electric distribution system, as well as integration of
23		new technology and equipment to either prevent outages, reduce the number of customers

impacted by an outage, reduce the duration of an outage, and/or reduce the number of multiple interruptions that customers experience.

Feeder reliability projects are a large part of System Performance and are designed to maintain and/or increase the performance of the existing distribution system and result in immediate improvement for customers served from these feeders. Major programs include Priority Feeder Improvement, Comprehensive Feeder Improvement, MDO, CEMI, and URD Cable Replacements.

Q13. Can you please describe the Priority Feeder Improvement Program?

A13.

This program leverages operational data to identify work on the poorest performing feeders with the lowest reliability metrics from the previous year. The Priority Feeder Improvement Program is designed to remediate the causes of the outages on the worst-performing feeders in the ACE distribution system, which include equipment, public, weather, and animal-related problems that negatively impact distribution feeder performance. The Priority Feeder Improvement Program identifies the least reliable distribution feeders in each operating district and prioritizes corrective actions to improve feeder reliability. Across ACE's operating areas, 26 feeders are selected based on individual circuit performance as required in N.J.A.C. 14:5-8.5(b) and reported in the Annual System Performance Report.². Feeders are selected for inclusion in the Priority Feeder Improvement Program by using a System Performance Contribution ("SPC") calculation that assigns a value to a feeder based on its overall contribution to system performance. The top eight percent of feeders, or a minimum of five, in each operating district with the highest SPC value are identified for the Program. The Priority Feeder

² Annual System Performance Report regarding worst performing circuits at N.J.A.C. 14:5-8.8(g).

Program benefits customers by prioritizing repairs and upgrades to critical feeders to ensure reliable electric service.

Q14. Can you please describe the Comprehensive Feeder Improvement Program?

A14. This Program involves work on feeders, that have shown a trend in outage history, to prevent outages from occurring in the future. The Comprehensive Feeder Improvement Program is a supplement to the Priority Feeder Improvement Program. In the Comprehensive Feeder Improvement Program, the Company analyzes and initiates corrective actions on feeders that have experienced an increased number of outages events, meaning that they are some of the worst performers in an operating district, but do not yet meet the threshold of being deemed a Priority Feeder. The Comprehensive Feeder Improvement Program also targets circuits for work before they become a priority feeder, whether those circuits are trending towards priority feeder status in the current year or have experienced year over year issues on the circuit. The Comprehensive Feeder Improvement Program benefits customers by proactively identifying which feeders need to be repaired or upgraded to ensure reliable electric service.

Q15. Can you please describe the MDO and CEMI Programs?

- A15. The MDO and CEMI Programs are used to limit the number of customers experiencing multiple outages in a specific timeframe. Typical work includes cable replacement, converting overhead distribution infrastructure to underground, replacing, or upgrading transformers, rebuilding poles to current standards and crossarm replacement.
 - The MDO and CEMI Programs use the following criteria:
 - MDO is leveraged to recognize repetitive device operations within a trailing twelve-month timeframe. When a device has its third operation,

1		the Reliability team will review the outage causes for any trends and
2		determine if a project is necessary to mitigate the issues.
3		o The CEMI portion develops solutions to prevent customers from
4		experiencing multiple outages over successive years.
5	Q16.	What is the Planned URD Cable Replacement Program?
6	A16.	This program was initiated to address reliability concerns in URD areas. Locations
7		for replacement are identified by considering the number of faults and customers impacted
8		by the outage. There are roughly 2,700 miles of URD installed on the distribution system
9		in ACE's service territory.
10		The criterion for replacement is: two or more cable faults in a two-year period
11		causing 50 or more customer interruptions. Residential developments are reviewed for
12		cables of similar age and type as discovery in the locations that have faulted, and sound
13		business judgement is used to determine the overall scope for replacement of identified
14		cables.
15		The Company is replacing URD cables where it has seen issues with degraded
16		neutral conductors, and it has identified and replaced a total of approximately 15.9 miles
17		of cable in the last two years. The Company anticipates replacing approximately ten (10)
18		miles per year of primary cable in residential developments that have experienced multiple
19		faults to prevent outages, during the period from 2023 to 2025.
20	Q17.	Please describe the System Performance Automation category.
21	A17.	The System Performance Automation investments are designed to install and
22		enhance the Company's automation infrastructure. Distribution Automation ("DA")
23		projects support the installation and/or upgrade of distribution and telecommunications

equipment aimed at enhancing operational monitoring and control while also reducing system outage duration and the number of customers impacted by an outage on the system.

Q18. What is the System Performance Automation category strategy?

A18.

The Company's System Performance Automation reliability strategy is a three-part effort designed to limit the duration and impact of mainline feeder outages. Over the last five years, the installation of associated ASR schemes has made ACE's distribution system more reliable and resulted in a reduction of major events caused by severe storms. With the first component of its strategy, ACE saturates the distribution system with reclosers to segment the customers across any given feeder to no more than 750 customers with a goal of 500 customers. These reclosers are the building blocks of the Company's DA efforts. The Company utilizes reclosers to sectionalize the feeder to decrease the number of customers that will experience an outage in the event of a fault.

Second, the Company deploys ASR technology that allows the electric distribution system to self-heal and perform automated switching to isolate the faulted section and automatically restore customers outside of the immediate impacted area. This technology utilizes a centralized restoration algorithm which continuously monitors the state of the Company's distribution system looking for faulted devices. When a recloser or substation breaker registers a permanent fault, an ASR algorithm is enabled and calculates an ideal switching strategy to restore customers outside of the affected zone(s). Within 1-2 minutes, the ASR sends commands to the field devices using ACE's state of the art fiber optic and radio telecommunications network, to isolate the affected zone and close ties to restore customers. The ASR scheme switches between feeders, or sections within a feeder with

the capacity to back-feed customers in the event of a fault. This ASR operation decreases the number of customers impacted by outages on the system.

The third part of the System Performance Automation strategy is to deploy Smart Fault Current Sensors to further enhance the Company's remote visibility along distribution feeders, which allows the Company to operate and respond based on specific fault location data provided by the sensors. These sensors will be installed at selected locations within recloser zones to reduce outage duration by further pinpointing the location of faults and thereby reducing the size of the zone that needs to be patrolled by a first responder. The sensors provide additional outage data allowing the Company to dispatch crews to the outage location and decrease restoration times.

Q19. Please describe System Performance Substation.

A19.

The System Performance Substation category of work is used to improve reliability and resiliency through the replacement of substation equipment. Failures of substation equipment, such as circuit breakers, transformers and switchgear can impact multiple feeders and thousands of customers, which can have significant impacts to the Company meeting the minimum reliability and performance benchmarks. Substation equipment typically includes materials with long lead time for procurement and must be planned well in advance. During 2022, breakers, switches, and transformers were replaced at eight substations. The Equipment Condition Assessment ("ECA") team has identified several equipment types that are being recommended for replacement in 2023 based on their present operating condition, including:

- One (1) transformer
- Fifteen (15) circuit breakers; and

• Eight (8) switches.

A21.

A20.

Q20. Is aging infrastructure a driver for reliability investments?

Yes, aging infrastructure is another driver for reliability investments. As infrastructure ages, it becomes more prone to failures and less resilient and reliable, especially as New Jersey faces severe and frequent storms and other impacts from climate change. Therefore, the replacement of common infrastructure such as poles, substation switchgear, substation transformers, and other mission-critical equipment is required and appropriate to maintain system level reliability improvements to date, avoid future high impact failures, and provide increased resiliency in significant weather events. Aging infrastructure includes an array of projects to upgrade, replace, or repair system infrastructure. These projects are primarily focused on the replacement of infrastructure at or near substations, which can have a significant effect on reliability for many customers.

Q21. What is ACE doing to address the aging of its infrastructure?

As part of its reliability strategy, ACE plans the proactive replacement of equipment that exhibits signs of reduced reliability and/or impending failure. Distribution infrastructure is periodically inspected and evaluated on its ability to perform as required in normal and stressed conditions. In addition, as part of the ECA protocol, critical substation components are periodically assessed and tracked for indications of impending failures. Equipment that exhibits poor physical condition, permanently impaired operations, or is trending towards more frequent and costly required maintenance is scheduled for replacement. By proactively replacing equipment that is trending towards failure, ACE lowers maintenance costs associated with that equipment and avoids potential future outages impacting large numbers of customers, improving long-term reliability.

The benefits of these projects are critical to large customer populations as failures of some elements of the distribution system, such as substation equipment, transformers and cables often result in large and lengthy customer outages. The criticality of this equipment in the overall reliability of the system cannot be overstated and, despite effective condition-based maintenance protocols, it is generally more prudent to proactively replace critical equipment in poor condition as opposed to running it to failure and incurring an emergency replacement, which can extend outage duration and result in significantly higher costs to remediate than planned replacements.

Q22. Please describe Capital Corrective Maintenance.

A22.

This category of work involves capital replacements of the defects in the distribution system that were identified through maintenance inspections. This includes items such as broken cross-arms, poles, transformers, cutouts, lightning arresters, and other capital equipment conditions that can negatively affect reliability. This work directly benefits customers by identifying deteriorated or damaged system equipment to be replaced before it fails, thereby preventing future outages from occurring. This category also includes Emergency Restoration Work, such as the replacement of assets damaged as a result of vehicle accidents, storms, and equipment failures. In 2022, the Company replaced 643 poles through the inspection process and completed 601 emergency replacements. This work benefits customers by helping to avoid service interruptions and more quickly restore service following an interruption.

Q23. What recent reliability and resiliency improvement programs has ACE completed?

A23. In addition to the reliability projects and programs discussed previously, ACE has invested significant incremental funds over the past five years to improve reliability,

resiliency, and system performance for its customers. Included in these investments was PowerAhead, which will be discussed in detail later in this testimony, and the initial Infrastructure Investment Program ("IIP"). Both programs have met the objective of improving the performance of the distribution system and providing significant benefits to customers.

Q24. Please discuss ACE's current IIP.

A24. In April 2019, ACE gained approval for its initial IIP³, consisting of \$96 million of investment in 24 capital projects related to safety, reliability, and resiliency. Projects in the IIP included investments in DA, telecommunications, and substation improvements. The Company has completed three recovery filings to date (Docket Nos. ER20050336, ER20110694 and ER21111206) for a total recovery of \$62 million in the IIP and expects to finalize its investment in the IIP in mid-2023.

Q25. Have these capital investments had a positive impact on system reliability?

A25. Yes. As noted above, these investments have had a significant positive impact on system reliability. The significant investments in reliability through the PowerAhead and the initial IIP, have enabled the Company to accelerate improvements in the distribution system and as a result, customers have benefitted from the improved performance. ACE has regularly exceeded annual minimum reliability performance standards⁴, and, in 2022, the Company had its best performance year on record in terms of System Average Interruption Frequency Index ("SAIFI") and System Average Interruption Duration Index ("SAIDI"). Performance for Customer Average Interruption Duration Index ("CAIDI")

³ On April 19, 2019, the BPU issued an Order approving the Stipulation of Settlement for the IIP in BPU Docket No. EO18020196.

⁴ N.J.A.C. 14:5-8.10(a).

met the minimum performance standards and was below the three-year average. Table 1 shows ACE's reliability indices, which illustrates that the Company has leveraged accelerated and baseline investments to dramatically improve its performance. The Company is delivering on commitments and expects to realize similar benefits with future reliability projects. Table 1 also demonstrates why it is important to support systematic and sustained capital investment to improve performance gains. Continuous improvement in reliability and resiliency of the distribution system is necessary to keep pace with the needs of a remote workforce, electrification trends, and the increasing impacts of storm activity driven by climate change.

ACE System Reliability Performance 2018 - 2022

New Jersey Major Event Exclusion Criteria

Table 1

Index	YEARS					3-year Average (2020-2022)	Minimum Performance Standard (N.J.A.C.	
	2018	2019	2020	2021	2022		14:5-8.10(a))	
SAIFI	0.87	0.90	0.81	0.68	0.64	0.71	1.82	
SAIDI	70	82	72	51	50	58	N/A	
CAIDI	81	91	90	75	78	81	120	

ACE's Distribution Construction Program

2 Q26. Please discuss the Company's Distribution Construction Program.

A26.	The Company's Distribution Construction Program is the cornerstone of
	maintaining the Company's infrastructure and reliability efforts. It is a combination of
	activities designed to provide service to new customers, meet future load growth,
	modernize the distribution system, and continue to maintain a safe and reliable system to
	meet the needs and expectations of customers. These activities are classified by function
	into several distinct work areas, which are: New Business Connections, Facility
	Relocations, System Performance, Capacity Expansion, Corrective Maintenance, and All
	Other Project Types. To meet customers' needs and achieve performance levels adopted
	by the BPU, the Company must continue making investments in each of these areas. With
	the investments in these categories, customers will continue to experience improvements
	in their reliability and resiliency. These categories are described in greater detail in Table
	2.

Atlantic City Electric Company Executive Categories

Table 2

Executive Categories	General Scope of Work
New Business Connections	Customer Requested work that requires ACE to provide electric service for residential, commercial, and street lighting customers in accordance with the Tariff for Electric Service.
Facility Relocations	Relocation of the Company's electric facilities in a safe, cost effective and reliable manner to accommodate requests from Federal, State and Municipal entities.
System Performance	Projects that serve to enhance, increase and/or maintain the performance of the distribution system through modifications to system design and application of new technology and equipment to prevent outages and reduce the number of customers impacted by an outage. These projects include equipment upgrades, optimized or improved performance of capital equipment, and replacement of existing infrastructure.
Capacity Expansion	Projects are proactive additions or upgrades to the system in order to meet all levels of customer load in advance of those load conditions developing on the system. The projects assure the system continues to meet design criteria.
Corrective Maintenance	Project work that undertakes the replacement of infrastructure, which is in deteriorating condition, has reached the end of useful life, or is the result of an equipment failure or emergency replacement. Corrective Maintenance work is designed to address infrastructure replacement as early as feasible so as to minimize the number of equipment failures.
General Plant	Investments and upgrades supporting infrastructure to maintain service centers and buildings across the service territory, new and upgraded IT systems, transportation, mobile equipment, and support for the various telecommunications systems needed for operation of the electric distribution system.
All Other Project Types	Miscellaneous project work that is not classified into the previous categories. This Executive Category also includes the SEN project.

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Q27. Please discuss the Company's recent distribution capital investment in the categories

- 7 **listed above.**
- 8 A27. From 2018-2022, the Company has made actual distribution system related
- 9 investments of \$953 million in New Jersey. That investment is summarized in Table 3.

Atlantic City Electric Company 2018 – 2022 Distribution Capital Spending (1) (2) Dollars in Millions

Table 3

Budget Category	2018	2019	2020	2021	2022	Total
New Business Connections	9.6	20.0	19.5	24.0	22.1	95.3
Facility Relocations	1.6	0.9	1.1	5.6	2.4	11.6
Capacity Expansion	10.1	8.8	15.5	10.6	9.3	54.2
Corrective Maintenance	75.2	37.7	73.4	51.5	53.2	290.9
System Performance Automation	0.5	0.1	1.9	0.9	1.3	4.7
System Performance Distribution	11.3	12.0	20.8	34.6	21.5	100.3
System Performance Substation	24.7	24.5	28.1	18.6	25.1	121.1
General Plant	28.9	24.0	46.6	40.1	64.3	203.9
All Other Project Types	2.1	3.7	5.1	8.0	52.0	71.1
Grand Total	\$164.0	\$131.8	\$212.1	\$194.0	\$251.2	\$953.0

⁽¹⁾ For the years 2018-2022 category reporting may not align in total to previously reported categories due to the PHI/Exelon Merger, system changes and category realignments. Therefore, the Distribution Spending exhibits included in other filings may be slightly different than the historical information presented in this table.

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Q28. Has the Company developed a Construction Program Budget for future years?

A28. Yes, as we will discuss in more detail in the Capital Budget Process Overview section, ACE has developed a five-year budget, or Long Range Plan ("LRP"). The years of 2023 through 2025 of the Company's LRP is shown in table 4 below.

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Atlantic City Electric Company 2023 – 2025 Construction Program Budget Dollars in Millions

Table 4

Budget Category	2023	2024	2025	Total
New Business Connections	26.1	28.4	29.3	83.7
Facility Relocations	2.3	2.4	2.7	7.4
System Performance - Automation	7.8	6.5	5.6	19.8
System Performance - Distribution	28.9	36.0	32.9	97.9
System Performance - Substation	30.3	48.8	50.7	129.8
Capacity Expansion	9.8	23.5	48.6	81.8
Corrective Maintenance	41.2	41.0	43.1	125.2
General Plant	47.6	26.2	21.8	95.6
All Other Project Types	80.5	20.5	4.7	105.7
Grand Total	\$274.6	\$233.1	\$239.2	\$746.9

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⁽²⁾ Excludes spending related to IIP and PowerAhead.

Smart Energy Network

Q29. Please describe the SEN Project.

A29.

The SEN is a program implemented with the goal of deploying a smart electric meter to every customer in the ACE region, approximately 568,000 premises. Installation of smart meters, telecommunication devices, and the associated Information Technology ("IT") Network will significantly improve the customer experience by identifying hazards, increasing accuracy of restoration times, improving storm response, and providing more data to help customers manage their energy usage. SEN will improve grid performance through load modeling, grid analytics, DER forecasting and many other applications. SEN will help reduce greenhouse gas emissions by eliminating an estimated 70,000 truck rolls every year. The SEN program plans to track the operational and customer benefits throughout the lifetime of the program.

In addition to the benefits noted above, SEN implementation will enable several "use cases" that will provide additional functionality to customers such as: high bill alert capabilities, outage detection, remote connect/disconnect for move in/move out situations, and voltage monitoring to name but a few of the use cases.

Finally, ACE is working to help ensure these investments support social equity. At the height of the SEN deployment, the Company expects to hire more than 50 candidates from local communities and through its robust workforce development programs, with a specific focus on providing opportunities for residents of overburdened communities in southern New Jersey.

Q30.	Please provide a status update on the Meter Deployment and IT System Integrati				
	process for the SEN project.				

A30.

Mass meter deployment began in August 2022 in coordination between the ACE SEN Project team and Contract Callers Inc ("CCI"), the Meter Install Vendor performing exchanges. Mass deployment began in the Cape May district and has been continuing north along the coastline. CCI and the ACE SEN Project team have continued to refine processes and resolve any operational issues to ensure efficient meter deployment across the ACE region. As of January 31, 2023, CCI and ACE's internal team have completed more than 134,000 meter exchanges with a continual focus on safety and customer satisfaction. The SEN Project team continues to focus on resolving any deployment issues to ensure the remaining meters are completed to meet the Company's scheduled goals in 2024.

The SEN IT System Integration is also on schedule to go-live in the second quarter of 2023, with activation to start shortly after go-live. The Company is in the process of IT system integration testing, which will be finalized in February of 2023. User Acceptance Testing ("UAT") and some regression testing will begin in the first quarter of 2023. During that time, ACE will be performing deployment planning and finalizing plans for cutover activities. The Company will begin activating the enhanced functionality of installed smart meters immediately following the completion of the IT integration. Meter activation requires checking various aspects of how the meter is performing over the air and completing final checks before introducing the full host of benefits to the customer to minimize any impact to the customer experience.

The SEN telecommunications network represents various devices that are pole mounted to carry digital communications from the meters back to the Company's IT

applications. The SEN telecommunications initial design included 850 devices. All 850 devices have been deployed and are functional. There will be periods of optimizing the telecommunications network throughout the project as regions become saturated with meters. This is necessary to allow the Company's engineering teams to identify any gaps that may exist in the mesh network.

A31.

A32.

Q31. Please describe how ACE is handling potential supply chain issues regarding smart meter availability.

ACE has been closely monitoring the global supply chain challenges with its vendors and appropriate leadership since the start of the program. To date, ACE has received approximately 258,554 smart meters, which is about 40% of the total meters on order. ACE is continuing to focus on shipment schedules to ensure they are aligned with deployment deliverable dates so the Company can meet the scheduled goals in 2024.

Q32. Please describe how the ACE SEN program is utilizing effective change management.

The ACE SEN program includes a change management plan to drive adoption and realization of the benefits provided by new functionality for both customers and employees. ACE is closely coordinating with IT enhancements and following the IT release schedule, while also having the advantage of drawing upon the experience from the five other affiliated Exelon Operating Companies that have already implemented this technology. The first phase of the plan was completed following the deployment of systems and updates, which were required to start large scale smart meter exchanges by ACE's contractors in the third quarter of 2022. The second phase of the change management plan will reinforce the customer benefits of the SEN program by training ACE employees in the processes and procedures necessary to implement the use cases in the second IT release,

such as Enhanced Customer Engagement & Communication, Remote Move in/out and Outage Detection). ACE's employees, in partnership with experienced consultants, are currently developing the training plans and materials required to prepare for the upcoming release and are on schedule.

Q33. Please discuss how the Company keeps customers informed of the changes occurring throughout the SEN deployment process.

A33.

ACE is committed to keeping customers and stakeholders informed throughout the SEN program deployment. The Company is following the plans outlined in the Customer Education & Engagement Strategy submitted to the Board as part of the Company's 2020 Smart Energy Network filing, BPU Docket No. ER20080541.⁵ Consistent with that Strategy, the Company is executing a comprehensive multi-channel customer and stakeholder education campaign to build awareness and understanding of the Company's SEN program and to ensure customers have the information they need to make informed decisions on the installation of their smart meter and can leverage the future benefits of this important system investment. This campaign takes an integrated approach, utilizing earned, owned, and paid channels, as well as direct-to-customer communications, to establish multiple opportunities for customer touchpoints. ACE is using the following efforts to engage and educate customers:

• Stakeholder Outreach: The Company has identified regional and local community, civic, religious, and business organizations whose constituents would be ACE customers and would therefore be affected by the SEN. ACE selected

⁵ Atlantic City Electric Company: Smart Energy Network, Customer Education & Engagement Strategy. In the Matter of the Petition of Atlantic City Electric Company for Approval of the Smart Energy Network Program and Cost Recovery Mechanism and Other Related Relief, BPU Docket No. EO20080541

tactics to engage, including providing educational materials, submitting information to their communication channels, securing speaking opportunities and reserving exhibitor booth or tabling opportunities at events.

• Total number of briefings held in 2022: 121.

- Media Relations: The Company built a media relations plan targeting regional and hyperlocal media outlet, as well as media that serve diverse audiences, to communicate the campaign's key messages and inform about key milestones. ACE distributed a press release about the launch of smart meter deployment and targeted hyperlocal publications that lined up with the deployment schedule.
 - Total number of stories secured since program announcement: 42.
- Advertising: The Company placed advertising in digital and print media, as well as media that serve multicultural audiences, lining up with the deployment schedule. ACE's creative team developed ads in Spanish that included visual assets that more closely resonate with Spanish speakers.
 - Total number of potential impressions from advertising: 6,777,423.
- Direct-to-customer Communications: The Company produced multiple materials that will be distributed directly to customers to educate about the SEN and explain the smart meter installation process, including a bill insert; postcard delivered one month prior to upgrade; a letter and email delivered two weeks before upgrade; a script for a robocall made one week before upgrade; a text-message/push notification alert made one week before upgrade; and a doorhanger placed at the property on the day of upgrade.

1		■ Total number of direct mail pieces distributed (bills, postcards, letters,
2		emails): 749,505.
3		• Collateral Development: The Company developed a Fact Sheet and FAQ to be
4		provided directly to customers at outreach events and shared online and via email.
5		These materials also were translated into Spanish. ACE also developed business-
6		card sized pieces that technicians in the field can provide directly to customers.
7		• Digital Channels: The Company launched a SEN-focused webpage with content
8		and resources for customers to understand the SEN program. The call-to-action on
9		other communications materials drove audiences to the website. Key assets found
10		on the website were translated into Spanish. The full website is being fully
11		translated into Spanish. ACE also has developed organic social media content to
12		promote the SEN.
13		 Total number of visitors to SEN website: 121,854.
14		 Total number of impressions from SEN social media posts: 141,536.
15	Q34.	What is anticipated to be in-service and providing customer benefits by the end of
16		the test period?
17	A34.	While full deployment of the SEN is expected to take 39 months and continue to
18		the Fall of 2024, as noted above, ACE has made significant progress and completed the

⁶ The Company ceased the installation of legacy meters in January 2021 and began installing smart meters as part of routine work at that time to minimize future stranded asset costs.

deployment of the telecommunications network and is on schedule to complete the IT

integration in May 2023. The Company anticipates that approximately 250,000 meters will

be installed by June 2023.6 Upon installation, customers realize immediate safety and

reliability benefits. ACE can currently receive an alarm if a smart meter has an excessively

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high temperature and respond accordingly, determine if a customer is in service during a storm event—allowing for more efficient restoration efforts, and read a smart meter over the air for a host of resolution activities.

As the Company begins mass meter activation immediately following IT integration, customers with smart meters installed will have access to many more benefits and will start to see the SEN technology integrated into Company applications. Meter activation will follow the deployment pattern until the end of the project.

Table 5 below identifies the actual SEN spending prior to the test period, the July 1, 2022, through December 30, 2022 portion of the test period, as well as the forecasted spending through June 30, 2023, the end of the test year period. ACE's proposed recovery of SEN program costs is discussed in detail in Company Witness Ziminsky's Direct Testimony.

Forecasted Data

Table 5

SEN Program		or Jul-Dec 2022 Jan - Jun 2023 Jan 22 - Jun 23				
	Capital Actuals					Total
66668: ACE Smart Energy Network NJ/AMI Program - Install Costs	\$ 6,135,813	\$ 8,262,527	\$ 14,938,558	\$ 29,336,898	\$ 841,969	\$ 30,178,867
68810: PHISCO NJ ACE Smart Energy Network NJ/AMI Program			\$ 174,412	\$ 174,412		\$ 174,412
68989: ACE Smart Energy Network NJ/AMI Program - Meter Purchases	\$ 11,210,086	\$ 18,162,480	\$ 17,588,009	\$ 46,960,575	\$ -	\$ 46,960,575
68994: ACE Smart Energy Network NJ/AMI Program -Comms Network Costs	\$ 4,771,015	\$ 3,393,915	\$ 858,358	\$ 9,023,288		\$ 9,023,288
75270: AMI Contract Cost to Reg Asset				\$ -	\$ 4,815,370	\$ 4,815,370
ACE Smart Energy Network NJ/AMI Program - IT Costs	\$ 6,808,937	\$ 8,656,947	\$ 12,198,735	\$ 27,664,619	\$ 5,100,758	\$ 32,765,377
Grand Total	\$ 28,925,851	\$ 38,475,869	\$ 45,758,072	\$ 113,159,792	\$ 10,758,097	\$ 123,917,889

Q35. Has the Company implemented Opt-Out Fees for the SEN program.

A35. In the SEN Stipulation approved by the Board, the Parties agree that ACE would charge a recurring monthly fee of \$15.00 for customers electing to decline their meter upgrade, and a one-time opt-out fee of \$45.00 for the removal of a smart meter and the installation of a non-AMI meter. The Company has not commenced charging opt-out fees

as of the filing of this case. ACE will provide the cost-based support for these fees in its next base rate case, where the Company will seek recovery of the full implementation cost of the SEN program.

Q36. What steps has the Company taken to pursue funding opportunities and to support equity through the SEN deployment?

A36.

As discussed in Company Witness Ziminsky's Testimony, ACE is committed to ensuring the economic opportunities generated by the SEN program reach all the communities in its service area. The Company has been intentional in leveraging its Workforce Development programs, which are focused on bringing career opportunities to underserved communities, to provide careers to program graduates while also ensuring a trained workforce is available to deliver on the SEN deployment goals. The Company's meter deployment vendor has initially hired 14 candidates from ACE's workforce development programs, as well as 21 additional candidates from local communities, to support the deployment of smart meters installed in 2022. In 2023, the SEN meter deployment contractor, in partnership with the Company's workforce development programs, is expected to hire another 25 meter technicians in the second quarter. As stated earlier, the Company expects to hire more than 50 candidates from local communities and through its robust workforce development programs at the height of SEN deployment.

As discussed in Witness Ziminsky's Direct Testimony, the Company has provided a grant to NJ Shares to support low- and moderate-income customers in funding repairs to customer-owned equipment during the SEN deployment. As further stated in Witness Ziminsky's Direct Testimony, the Company is also seeking funding through the Infrastructure Investment and Jobs Act.

PowerAhead Program

2 Q37. Please discuss the composition of the ACE PowerAhead Program.

A37. In March 2016, ACE filed a petition with the Board for a storm resiliency and grid modernization initiative known as PowerAhead. PowerAhead consisted of several subprograms related to improving the resiliency of ACE's distribution system. On May 31, 2017, the BPU approved a Stipulation of Settlement authorizing ACE to initiate a program to invest \$79 million in the distribution system across six subprograms: Structural Electrical Hardening, Selective Undergrounding, Barrier Island Feeder Ties, Distribution Automation, Electronic Fusing, and the Harbor Beach Substation. The Board-approved Stipulation for PowerAhead included a cost recovery mechanism for PowerAhead project investments, so long as projects totaling at least \$7.0 million were placed into service during the approved roll-in periods.

Q38. Did PowerAhead meet the intent of the approved program?

14 A38. Yes, PowerAhead met the intent of the approved program. The approved 2017

15 Stipulation of Settlement stated that "[t]he projects are intended to improve the storm

16 resiliency of, and restoration times for the Company's distribution infrastructure to benefit

17 it customers." The Company will demonstrate below that the feeders included in the

18 PowerAhead program have realized significant improvement to both the frequency and

19 duration of outages during major events. 10

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⁷ Docket No. ER16030252

⁸ On May 31, 2017, the BPU issued an Order approving the Stipulation of Settlement for PowerAhead in BPU Docket No. ER16030252.

⁹ Docket ER16030252 - Order Approving Stipulation of PowerAhead Grid Resiliency Initiative dated May 31, 2017.

¹⁰ Major Event meeting the definition described in N.J.A.C 14:5-1.2

Q39. Please describe the benefits realized from the PowerAhead Program.

A39.

The projects included in the six subprograms in PowerAhead made improvements
to 101 feeders throughout ACE's distribution system. From a storm resiliency standpoint,
the Company has seen an overall decrease in the frequency of outages, SAIFI, including
major events, of 52% since 2016, which was the year prior to the start of PowerAhead.
CAIDI has declined 57% in the same timeframe. For major events only, considering the
5-year period prior to PowerAhead, 2013-2016, to the most recent 5-year period, 2017-
2022 the Company has experienced a 20% decrease in the number of customers impacted
by storms, and the total minutes of interruption that customers have experienced during
major events has declined approximately 33%. Now that all of the work associated with
PowerAhead is complete, the Company expects even better overall storm performance in
the future

In addition to the improvements in reliability statistics during major events, PowerAhead has contributed to the overall reliability performance improvements shown in Table 1 above. System upgrades associated with the Structural and Electrical Hardening and Selective Undergrounding subprograms and the operating flexibility introduced with the Barrier Island Feeder Ties and Harbor Beach Substation have contributed to the day-to-day performance of the distribution system by replacing aged or degraded equipment and improving system redundancy, which contributes to the resiliency of the infrastructure during all weather and system events. Modernization of the distribution system through DA, Electronic Fusing and the Harbor Beach substation provides operating personnel with more information and visibility into events as they happen and helps minimize the impact of an outage when it occurs.

Q40. Were there any changes to the PowerAhead program since the 2017 Stipulation of

Settlement?

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A40. Yes, on April 21, 2021, ACE submitted a letter notifying the Board and the Division 3 4 of Rate Counsel of the Company's decision to remove one (1) Barrier Island Feeder Tie project¹¹ and two (2) Distribution Automation projects from the Program.¹² In doing so, 5 ACE reduced the Barrier Island Feeder Tie subprogram budget by \$3 million and the 6 7 Distribution Automation subprogram by \$0.68 million. As a result, ACE reduced the overall PowerAhead budget by approximately \$3.68 million from \$79 million to \$75.2 8 9 million, which amount also reflected approximately \$120,000 in projects that were 10 completed under the stipulated budget.

Q41. Has ACE completed all project work under the PowerAhead Program?

Yes. As of May 2022, ACE completed all work associated with PowerAhead. For the five-year program, the Company invested \$73.98 million into the distribution system. Financial recovery for the \$73.98 million investments was accomplished through the 2018 ACE Base Rate Case (Docket No. ER18080925) and seven roll-in filings (Docket Nos. ER19050550, ER19111434, ER20050337, ER20110693, ER21050753, ER21111205 and ER22050232).

¹¹ The Barrier Island Feeder Tie project Ocean City, Merion and Marven was cancelled due to the anticipated cost increase significantly higher than the approved \$3 million and the inability to accomplish the project within the approved timeline of PowerAhead.

Two projects in the DA subprogram were cancelled -1) Franklinville project (\$640,000) was cancelled due to existing conditions met the requirements of the DA subprogram, and 2) Egg Harbor project (\$40,000) cancelled due to increased cost and additional permitting requirements discovered during detailed engineering and conflicts with the Garden State Parkway widening project.

1 Q42. Please provide details of each subprogram completed in Power.	Anea	aa
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- 2 A42. PowerAhead was focused on storm resiliency, system hardening and grid
 3 modernization and consisted of six sub-programs over a five-year timeframe from June
 4 2017 through May 2022. The work completed in each subprogram is as follows:
 - The Structural and Electrical Hardening subprogram addressed vulnerable areas that had experienced extended outages due to severe weather events. Twelve (12) feeders were identified for improvement, and all work was completed by December 31, 2021. Included in these projects was the replacement or installation of 323,829 feet of conductor, 1,198 poles, 1,354 fuse banks and 923 transformers.
 - The Selective Undergrounding subprogram converted critical overhead distribution line sections in vulnerable locations to underground construction to better protect the infrastructure from weather and vegetation. Four feeders were identified for improvement and all work was completed by December 31, 2021. Included in these projects was the installation 100,460 feet of cable, 77 poles, 66 fuse banks and 128 transformers.
 - The Barrier Island Feeder Tie subprogram created new and stronger feeder ties between mainland and barrier island areas to improve resiliency. Four areas were identified for this subprogram and all work was completed by May 30, 2022. Included in these projects was the installation of 105,983 linear feet of conductor, 128 poles, 59 fuse banks and 39 transformers.
 - The Distribution Automation subprogram incorporated new technology and feeder capacity to allow the distribution system to respond more efficiently during outages

1	and prepare the system for enablement of ASR schemes. The Distribution
2	Automation subprogram consisted of the following components:
3	o Reconductoring – Seven projects were completed and placed in service by
4	December 31, 2020. Included in this work was the replacement of
5	installation of 98,000 feet of conductor, 206 poles, 181 fuse banks and 96
6	transformers.
7	o Recloser and Telecommunications - The Company installed 73 new
8	reclosers and added telecommunications equipment to 93 additiona
9	reclosers. All work was completed by December 31, 2020.
10	o Substation Upgrades - Three substations were upgraded to include new
11	relays and telecommunications equipment to allow enablement of ASF
12	schemes.
13	The Electronic Fusing subprogram replaced traditional single operation expulsion
14	fuses with newer technology electronic fuses, known as Tripsavers. The Company
15	installed 245 Tripsavers on 63 feeders and completed this subprogram in December
16	2019.
17	The Harbor Beach Substation included the construction of a new substation on the
18	barrier island of Brigantine to improve resiliency and reduce the possibility of
19	damaging flooding during severe weather events. The substation construction was
20	completed on May 30, 2022 and included the installation of two new substation
21	transformers and associated bus work and relaying, and four new feeders serving
22	approximately 9.600 customers.

	Witnesses Brubaker and Whitman
Q43.	Does the Company report on the reliability performance as a result of PowerAhead
	improvements?
A43.	Yes, the Company reports on the reliability performance of the feeders improved
	by the PowerAhead program on a semi-annual basis. As a condition of the Order adopting
	the PowerAhead Stipulation of Settlement, 13 and amended in the sixth roll-in filing, 14 the
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Company provides the following reports on a semi-annual basis.

- Customer Minutes Interrupted ("CMI") and CAIDI for the most recent semiannual period and cumulative from the beginning of PowerAhead, and CMI,
 CAIDI and SAIDI since the beginning of PowerAhead compared to the 5-year average ending prior to the beginning of PowerAhead.
- SAIDI results for Major Event performance at the circuit level for all circuits improved as part of the PowerAhead Program and affected by a Major Event.
 The SAIDI results are reported and measured against baselines that reflect performance for each circuit under Major Event conditions for the prior five (5) years from the program start and the period 2012 to 2016.
- SAIDI, CAIDI and SAIFI for all circuits improved by PowerAhead on non-Major Event performance for the reporting period.

In addition, whenever the Company experiences a Major Event, the performance of the PowerAhead feeders for that particular event is reported in the Company's Major Event Report that is submitted to the BPU.

¹³ Order Approving Stipulation of Settlement at paragraph 12, approved by the Board in BPU Docket No. ER16030252.

¹⁴ Stipulation of Settlement at paragraph 7, approved by the Board in BPU Docket no. ER21111205 on March 11, 2022.

ACE's Capital Budget Process Overview

Q44. How is the Distribution Construction Program budget developed?

A44.

The Distribution Construction Program budget is developed based upon the needs of ACE's customers, any regulatory requirements of the state, additional targets or commitments the Company has with the BPU, and the condition of the distribution system.

ACE undertakes a planning process each year to develop the Company's 5-year budget, also called the Long Range Plan ("LRP"). The LRP is used to identify and prioritize distribution system capacity and reliability investments, as well as execute needs for new business, facility relocations and emergency work. The objective of this planning process is to ensure that adequate infrastructure exists to reliably supply electric service for all customers at a reasonable overall cost, consistent with goals regarding safety, reliability, quality of service, community relations, and protection of the environment. The planning process is a bottom-up approach that develops the necessary capital projects to meet the reliability and operational performance goals and other customer, stakeholder, and BPU expectations. As part of this process, ACE reviews its five-year project plan to verify the service dates of projects needed to supply customer load or address system performance issues. As system conditions change, projects may be expedited or deferred.

The Company updates and develops its LRP every year which integrates and aligns ACE's operational and financial plans. The Company builds its LRP and funds it as needed to maintain the reliability and quality of all areas of ACE's business. The plan consists of specific projects, with specific need dates and scopes of work. It also consists of programs, which are numerous projects with similarly related work that are implemented over a

defined period of time. The remaining part of the budget relates to blanket projects, which are annual, repeatable scopes of work with short construction times

Each distribution project is forecasted monthly throughout the current year of the LRP to establish a baseline for future year-long range planning. Projects are prioritized and budgeted as part of the LRP process, however the authorization to spend funds is subject to specific project authorization processes. The Company continuously refines its cost estimates as projects progress through study, design & engineering, and implementation phases of the authorization process. Projects may present themselves at any point in the planning process, and occasionally there may be a system need that has been accelerated over its originally contemplated level but was not funded as compared to projects that were further in their life cycle. Generally, the Company does not initiate these projects with additional funding, but rather if a project is accelerated or requires additional funding, the Company will evaluate its projected portfolio to determine if any projects have been delayed and assessing whether funding exists to support those project needs.

Further, ACE has a priority list of work that is critical to maintain the reliability of the system and requires specialized judgment and flexibility to shift projects into closer years, as circumstances warrant. Many of ACE's projects are long lead-time projects that must begin much sooner than when the need is forecasted. Adjustments to current-year budgets are made as the year progresses to account for normal construction lifecycle activity, but the Company does not re-issue its LRP to reflect these shifts. As a result, project deferrals may be filled with accelerated prioritized projects from a preceding year if supported by the business need.

Q45. Please describe ACE's Technical Review Process.

A45.

To advance a smarter, stronger, and cleaner energy system and to help New Jersey
achieve its climate and clean energy goals, while maintaining affordability, ACE must
coordinate with external stakeholders to balance competing priorities, which include grid
modernization goals, changes in climate impacts, customer behavior with further
electrification, changing needs for residential customers to enable remote work, and higher
DER penetration.

Distribution system planning is dynamic. Asset condition is not static, and equipment deteriorates over time. In order to continue providing safe and reliable service to our customers, ACE must continually assess and analyze the outage data for trends and reoccurring issues on the system. ACE exercises business judgment when selecting which projects will be necessary to meet its distribution system reliability targets as set forth in N.J.A.C. 14:5-8.10, and initiates projects to mitigate reliability issues proactively and reactively. The Company must be agile in planning due to the ever-changing conditions that are required to maintain safe, adequate, and reliable service.

When a capital project is being considered for implementation, it must first go through a rigorous technical review process to gain approval. The projects that are submitted for inclusion in the LRP are proposed because they help meet the Company's reliability and operational performance goals and other customer, stakeholder and BPU expectations. The scope of work for new projects are developed through extensive planning and evaluation by ACE's engineers and project managers and are reviewed annually.

Proposed new projects encounter scrutiny and review at multiple challenge sessions overseen by a cross-sectional group of senior managers at ACE. First, the project scope is presented for technical review of alternatives and business case justifications. If approved for technical sufficiency, the project will enter the Company's capital project authorization process. The project manager presents the project background, justification, consideration of alternatives, project benefits, reliability impacts, cost summary, permit requirements and key risks among other meeting criteria. Projects are presented and reviewed to gain senior management approval and they must:

• Exhibit a valid business need

- Demonstrate the scope of work that is the best choice between proposed alternatives
- Accurately identify project resources
- Show through an Alternative Cost Analysis that the recommended scope of work is the most cost-effective technically acceptable solution.

For example, when considering potential capacity overload on the system, the Company might consider rebuilding a substation, installing energy storage, or extending distribution feeders, among other solutions. In this example, the potential alternatives must be able to provide the ultimate capacity required and represent the most cost-effective of these technically sufficient alternatives.

During these meetings with senior leadership, project assumptions are challenged, and the solution is updated based upon the feedback from the meetings. The goal of each challenge session is to ensure that projects are properly researched, developed, planned, reviewed, and authorized by senior management before significant resources are

committed or expended. A quorum is needed at each step in the challenge process in order to review approval of a project by the appropriate Delegation of Authority. Projects whose cost estimate exceeds \$25M go through additional levels of approval within Exelon. Once a project is authorized for approval, its execution timeline may be expedited or deferred based on system conditions or business need which are evaluated annually during the LRP cycle.

Q46. Please discuss the Company's Project Authorization Process

A46.

ACE follows the Exelon Utilities model for project design, review, and implementation in a three-phase process for most projects. In Phase One, a project is initially proposed, which includes the need, objective, and preliminary cost of the project. A project team is identified, which begins to develop the conceptual design and scope of the project. Depending upon the proposed spend and upon whether the project in question is a capital, IT related, or another classification, the project is given a specific designation type. During this phase, a study may be required before an oversight committee grants approval to move forward. During Phase One, project cost estimates are developed with a +/-50% margin.

Phase Two encompasses the design phase of the project where the engineering design is reviewed, materials procurement is specified, required permits are identified, and construction specifications are determined. During this phase, project cost estimates are developed with a +/-25% margin. Upon approval by the oversight committee, the project is authorized to move into Phase Three, implementation, where the final design is completed, materials and contracts are awarded, and construction commences. During this phase, project estimates are developed with a +/-10% margin.

Street Light Strategy

2 Q47. Please discuss proposed changes to the Company's Street light
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A47. ACE is proposing changes to its streetlight offering to advance the adoption of
Light Emitting Diode ("LED") street lighting. The Company has concerns with the
existing streetlight offerings given changes in availability of certain non-LED bulbs.
Availability of both High-Pressure Sodium ("HPS") and Metal Halide ("MH") have
dropped to one approved supplier from three. The remaining approved supplier has
indicated that they plan to discontinue their product by the end of 2023. In addition, the
New Jersey Energy Master Plan has identified energy efficient street lighting as a goal. 15

Q48. Has ACE developed a strategy for new customer street lighting?

11 A48. Yes. ACE's strategy is that all new customer requests for Company-owned Street
12 lighting will have energy efficient LED lighting installed as part of the Company's efforts
13 to better serve New Jersey customers, to better align with State clean energy goals, and to
14 address the discontinuation of HPS and MH supplies.

Q49. Why is ACE adopting this strategy?

16 A49. The Company has adopted this strategy to foster the deployment of energy efficient
17 lighting and maintain affordable service for customers. As material from available
18 manufactures for HPS and MH decreases in favor of LED due to the sunsetting of this
19 technology, the Company may have difficulty maintaining the supply of non-LED material,
20 impacting ACE's ability to provide safe and secure lighting to customers.

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¹⁵ 2019 New Jersey Energy Master Plan, Goal 3.1.7

1	Q50.	What are the benefits for the Company's LED lighting strategy?
2	A50.	The Company's lighting strategy provides the following benefits:
3		• Improved light quality and addresses light pollution problems
4		Meets customers' expectations for utilities to provide more innovative and energy
5		efficient lighting solutions
6		• Reduced environmental emissions (greenhouse gas)
7		• Limits future material availability exposure of HPS and MH lights, and
8		Avoids future re-lamping maintenance costs.
9	Q51.	What is ACE's strategy for existing Company-owned non-LED streetlights which
10		require replacement due to failure?
11	A51.	The Company's strategy for Company-owned non-LED Street Lights is that the
12		Company will replace non-LED (i.e., Incandescent, Mercury Vapor, MH and HPS) street
13		lighting due to failure with equivalent LED lighting.
14	Q52.	How will the Company address a customer requested conversion of non-LED lights
15		to LED lights?
16	A52.	The Company will follow the conversion of the light source as described in Section
17		IV of the existing ACE Tariff for Electric Service in Rate Schedule SPL and Rate Schedule
18		CSL.
19	Q53.	What will happen to the existing tariff service classification options for Incandescent,
20		Induction, Mercury Vapor, MH and HPS?
21	A53.	As referenced in Company Witness Normand's Direct Testimony, the Company
22		proposes to close MH and HPS tariff service classification options. Incandescent and MV
23		lighting options are already closed in the Company's tariff.

1		ACE's Storm Restoration Efforts
2	Q54.	How do storms impact the ACE system?
3	A54.	Every storm that impacts ACE's electric distribution system causes varying degrees
4		of damage and requires different levels of Capital and O&M outlays (labor, material,
5		contracting, etc.) to restore service to customers.
6	Q55.	What does the Company do to minimize the effects of storms on New Jersey
7		customers and communities?
8	A55.	As described above, ACE has made continued capital investments to improve the
9		storm hardening of the distribution system in an effort to reduce storm-related O&M
10		expenses and minimize the impacts of outages when storms occur. The Company's storm
11		hardening projects include, but are not limited to:
12		Overhead to Underground conversion
13		• Utilization of stronger poles (Class 2) and crossarms (fiberglass)
14		• Installation of Reclosers and ASR schemes, and
15		• The portfolio of projects included in PowerAhead.
16	Q56.	Does the Company take actions to prepare for storms?
17	A56.	Yes, if the Company has advanced warning of a storm, it will evaluate the potential
18		impact of the storm and proactively take actions to obtain additional resources so that they
19		are available and ready to respond immediately following the passing of the storm. This
20		allows the Company to quickly restore power to customers in the event of an outage.
21		Depending on the nature of the anticipated storm event, the Company may require some
22		employees to begin preparation in advance of outages which may require extended shifts

or engaging additional resources. Additional resources may also be needed in anticipation

of increased call volumes and to respond to an increase in outreach via social media channels and/or from the media. In anticipation of severe weather events, the Company may also engage contractors and mutual assistance crews from other utilities so that those resources will be in or near the Company's service territory to begin restoration as soon as it is safe to do so. To support arrival of mutual assistance personnel, the Company secures staging sites, housing, and other logistical support, including security, as needed.

7 Q57. Please discuss ACE's storm restoration efforts over the last two years.

A58.

A57. ACE has experienced six storms over the last two years, 2021 and 2022, that met the criteria of major events. 16 Each of the six storms resulted in Governor Phil Murphy declaring a State of Emergency through Executive Order.

Q58. Please discuss Company Witness Chen's Ratemaking Adjustment ("RMA") No. 9 in her Direct Testimony for Tropical Storm Ida occurring in September 2021.

RMA No. 9 addresses costs that the Company incurred for emergency preparations in connection with Tropical Storm Ida.

Tropical Storm Ida occurred on September 1, 2021, and was concentrated mainly in the Glassboro district, but had impacts throughout the ACE footprint. The storm hit the service territory in the evening of September 1, 2021, with strong winds, tornadoes, and heavy and sustained rainfall. A confirmed EF-3 tornado caused significant damage to the Company's distribution system, as well as homes and businesses, in the vicinity of Mullica Hill, New Jersey and other areas of Gloucester County. The storm impacted 7,932 customers during the event and was fully restored in 97 hours with the following totals for customer interruptions for the highest 24-hour period: Cape May, 356; Glassboro, 5,581;

¹⁶ Major Event as defined at N.J.A.C 15:5-1.2.

Pleasantville, 1,469; and Winslow, 526. The Company utilized 65 mutual assistance contractor crews to assist in the restoration efforts.

The tornado experienced during Tropical Storm Ida caused significant damage to the Company's electric distribution system, primarily localized to western Gloucester County, where there was major damage to trees, poles, and other electric facilities. Assessment and restoration crews were hampered by the need to clear roads and right of ways of large trees, before accessing the most heavily damaged areas. Once access was obtained, crews found the damage so severe, that the entire distribution system needed to be rebuilt in these areas.

In addition to the work of contractors and mutual assistance crews, ACE conducted outreach to customers, sending out storm preparedness tips on social media to inform customers of the potential storm impact prior to its arrival in the service territory. Due to the concentrated damage from this tornado, ACE formed teams to canvass hundreds of homes and businesses to assess damage and the ability to restore service, and also met face to face with customers to discuss the process and provide support. In addition, ACE teamed with the County Office of Emergency Management to coordinate resources and support an assistance center that was set up to provide support and information to residents and businesses. Throughout the event, ACE completed dozens of media interviews, resulting in local stories that educated customers on recovery and restoration efforts. ACE also provided regular updates to customers through daily social media posts.

For this storm, ACE incurred actual, incremental storm costs to mobilize these additional mutual assistance crews. These storm costs primarily consisted of crew drive-time to and from the crews' home utilities, rest time upon arrival and for the duration of

their stay, safety preparation, and time spent performing all restoration work. Without this preparation, service restoration to customers would not have been executed at the speed and efficiency seen following the storm.

Based on the above information, the Company should be permitted to recover the storm costs set forth in Witness Chen's testimony, as it was essential to ensuring the return of normal system operations and service to customers.

ACE's Post-Test Year Plant Adjustments

Q59. Please discuss the table below related to the Post-Test Year Adjustment Periods.

Table 6 summarizes the Company's distribution system construction programs and sets out the amount expected to close to electric plant in service for each category during the post-test year adjustment period (July 2023 through June 2024). The distribution plant closings are discussed in Company Witness Ziminsky's Direct Testimony in Adjustments 14 and 15.

Atlantic City Electric Company Plant Closings Dollars in Thousands¹⁷

Table 6

Project Categories	July 23 – Dec. 23 Closings	Jan. 24 – June 24 Closings
New Business Connections	\$13,431	\$13,758
Facilities Relocation	\$1,150	\$1,194
Capacity Expansion	\$7,589	\$3,569
Corrective Maintenance	\$16,646	\$18,698
System Performance	\$36,433	\$18,187
Other	\$25,258	\$25,748
General Plant	\$26,468	\$4,839
PTF Removal	(\$4,675)	(\$12,748)
Total	\$122,300	\$73,245

¹⁷ All numbers are rounded.

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A59.

The Company presents the planned expenditures in this manner to demonstrate that the Company is requesting recovery of only a portion of the amount being invested in the distribution system over the course of the two post-test year adjustment periods. As discussed in the Direct Testimony of Company Witness Ziminsky and this Direct Testimony, the Company is seeking recovery of the costs of capital project closings that are known and measurable, major in nature and consequence, and provide service to customers.

A60.

Q60. Can you please expand upon your statement that these projects are major in nature and consequence?

Yes. The Company's capital investment programs constitute major endeavors that are achieving substantial improvements in reliability for ACE's customers or will prevent a reduction in reliability. The investment program is comprised of interconnected projects that will further enhance reliability performance for customers. In addition, the projects do not compromise the system in providing new service to customers and ensuring that it performs within design limits.

The individual projects are inextricable parts of an overall investment strategy but are not assigned importance by cost consideration or inherent function. Rather, these capital investments work in tandem to replace aging infrastructure, expand system capacity, and improve reliability. However, their successful implementation rests upon the appropriate supporting infrastructure, including properly maintained buildings, telecommunications systems, and IT systems. Without this underlying support structure, efficient management of data and information to respond to customers' needs is hindered, and the safe system operation by ACE's work crews is compromised.

- 1 Q61. Does this conclude your Direct Testimony?
- 2 A61. Yes, it does.

ATLANTIC CITY ELECTRIC COMPANY

BEFORE THE NEW JERSEY BOARD OF PUBLIC UTILITIES DIRECT TESTIMONY OF SHENGRONG CHEN BPU DOCKET NO. <u>ER23020091</u>

1	Q1.	Please state your name and position.
2	A1.	My name is Shengrong Chen. I am a Principal Rate Analyst in the Regulatory
3		Policy and Strategy Department of Pepco Holdings LLC ("PHI"). I am testifying on behalf
4		of Atlantic City Electric Company ("ACE" or the "Company").
5	Q2.	What are your responsibilities as Principal Rate Analyst?
6	A2.	My responsibilities include assisting with the coordination and development of
7		revenue requirement determinations for ACE in New Jersey, and Delmarva Power & Light
8		Company in Maryland and Delaware, as well as coordinating and supporting various other
9		regulatory compliance matters.
10	Q3.	Please state your educational background and professional experience.
11	A3.	In 2008, I joined PHI's Regulatory Affairs department as an Analyst on the Rates
12		and Technical Service team. In 2011, I joined the Regulatory Finance department as Senior
13		Regulatory Affairs Analyst and was promoted to Regulatory Affairs Lead in 2013. In
14		December 2013, I transferred to the Revenue Requirement team and was promoted to
15		Regulatory Affairs Coordinator in 2015. In 2018, I transferred to the transmission revenue
16		requirement team as a Senior Rate Analyst. Most recently, in 2022, I joined the Revenue
17		Policy team as a Principal Rate Analyst.

1		I received a Bachelor of Science Degree in Chemistry from Dalian University of
2		Technology. I have also received Masters Degrees in Accounting, from the University of
3		Delaware, and in Chemistry, from Clemson University.
4	Q4.	Have you previously submitted testimony before the New Jersey Board of Public
5		Utilities ("BPU" or the "Board") or other regulatory agencies?
6	A4.	Yes. I have submitted testimony before the BPU in Docket No. ER22100666.
7	Q5.	What is the purpose of your Direct Testimony?
8	A5.	The purpose of my Direct Testimony is to present and explain the rate making
9		adjustments ("RMAs") for the development of the distribution-related revenue
10		requirement. The \$104,788,395 (excluding Sales and Use Tax) revenue requirement is
11		based on the test period ending June 30, 2023 and described in more detail in the Direct
12		Testimony of Company Witness Ziminsky. The RMAs are presented in Schedule (SC)-1
13		through (SC)-14 and included on the summary revenue requirement schedule presented in
14	Company Witness Ziminsky's Direct Testimony, Schedule (JCZ)-3. Schedule (SC	
15	through Schedule (SC)-14 provide the details of operating income, rate base, and pro-for	
16	6 adjustments. Work papers supporting my Schedules will be provided under separate c	
17		I also sponsor a new lead/lag study, which utilizes 2021 data, to determine the Cash
18		Working Capital ("CWC") requirement in this filing.
19		This Direct Testimony and the attached Schedules were prepared by me or under
20		my direct supervision and control. The sources for my testimony are Company records,
21		public documents, and my personal knowledge and experience.

1		<u>CWC STUDY</u>	
2	Q6.	Have you included a Lead/Lag Study to determine the CWC requirement in this	
3		current filing?	
4	A6.	Yes. The total per books distribution ACE CWC requirement is \$121,558,345 and	
5		is based on the Company's lead/lag study performed on historical data and applied to the	
6		test period operations.	
7	Q7.	What is the time period on which the lead/lag study is based?	
8	A7.	All revenue and disbursement transactions used in preparing the lead/lag study are	
9		based on the calendar year 2021 data.	
10	Q8.	Have the factors developed in the lead/lag study been applied to the test period results	
11		of operations?	
12	A8.	Yes. The factors developed in the lead/lag study are applied to the test period results	
13		of operation consistent with the approach used in the Board's decision in Docket No.	
14		ER12111052 (March 18, 2015).	
15		$\underline{\mathbf{RMAs}}$	
16	Q9.	Please list the RMAs detailed in your Direct Testimony.	
17	A9.	My testimony contains details for each adjustment for which I am listed as the	
18		sponsoring witness.	

Adj	Sponsoring Witness	Adjustment Description	
1	Chen/Normand	Reflect the Revenue Annualization Associated with Conservation Incentive Program ("CIP")	
2	Chen/Normand	Reflect Revenue Associated with Customer Counts as of December 2023	
3	Chen	Reflect Wage and Federal Insurance Contributions Act ("FICA") Expense Changes Within Nine Months After End of Test Period	
4	Chen	Reflect Wage and Federal Insurance Contributions Act ("FICA") Expense Changes for Rate Effective Period	
5	Chen	Normalize Regulatory Commission Expense Adjustment	
9	Chen	2021 Storm Ida Adjustment	
10	Chen	Normalize Injuries & Damages Expense	
11	Chen Adjust Mays Landing Complex Rent		
12	Chen	Annualize Depreciation Expenses on Year-End June 30, 2023 Plant Using Depreciation Rates Approved in Docket No. ER18060638	
13	Chen Restate PHI Service Company assets at ACE Approved Depreciation Rates		
17	Chen	Interest on Customer Deposits	
18	Chen	Remove Annual Infrastructure Investment Program ("IIP") Revenue Requirement	
19	Chen	Adjust Cash Working Capital	
20	Chen	Interest Synchronization	

1 Q10. Please describe Adjustment No. 1 – Reflect Revenue Change Associated with 2 Conservation Incentive Program ("CIP") - Schedule (SC)-1.

A10. Pursuant to the BPU's Order in Docket No. EO20090621 (April 27, 2021), the
Company implemented CIP for lost sales revenue resulting from a decrease in customer
energy usage. This adjustment annualizes the test period distribution revenue to the levels
set by the CIP target. The CIP target is an allowed revenue amount per customer, which is
calculated based on the approved distribution revenue in the last ACE base rate case as

well as the subsequently approved IIP and PowerAhead revenues. This adjustment also			
reflects the annualization of the PowerAhead revenue recently approved by the Board in			
Docket No. ER22050323 (September 28, 2022). Because the Board-authorized			
PowerAhead revenue went into effect on October 1, 2022, it is necessary to annualize the			
test period revenue to reflect a full year amount of PowerAhead revenue. The IIP revenues			
associated with this adjustment were removed from CIP annualization. Witness Normand			
provides additional detail regarding the CIP revenue annualization adjustment in his Direct			
Testimony.			

A11.

As shown on Schedule (SC)-1, this adjustment results in a \$715,151 increase to test period operating income.

Q11. Please describe Adjustment No. 2 – Reflect Revenue Associated with Customer Count Through December 31, 2023 - Schedule (SC)-2.

Consistent with the treatment submitted in the Company's previous cases in Docket Nos. ER11080649, ER12121071, ER16030252, ER17030308, ER18080925, and ER20120746 and the Board's decision in Jersey Central Power & Light Company ("JCP&L") Docket No. ER12111052, this adjustment reflects the change in revenues associated with using a June 30, 2023 customer count to properly match the revenues with year-end rate base as well as the change in revenues related to customer counts as of December 31, 2023 to properly match the post test period plant closings proposed in Adjustment No. 14 presented in Company Witness Ziminsky's Direct Testimony. Given the implementation of the CIP mechanism approved in the stipulation of settlement in BPU Docket No. EO2009062, the revenue associated with customer count has been adjusted to

1		the total of 12 months of CIP targets multiplied by the year end customer counts as well as
2		the additional customer charge revenue relating to the year-end customer counts.
3		As shown on Schedule (SC)-2, this adjustment results in a \$934,044 increase to
4		test period operating income.
5	Q12.	Please describe Adjustment No. 3 – Reflect Wage and FICA Expense Changes
6		Resulting from Increases Becoming Effective by Nine Months After the End of the
7		Test Period (March 31, 2024).
8	A12.	Consistent with the treatment submitted by the Company in the last base rate case
9		in Docket No. ER20120746 and with prior Board decisions, ACE's test period level of
10		wage expense and associated FICA tax was adjusted for any price changes that will become
11		effective by March 31, 2024, nine months after the end of the test period, which is
12		consistent with the post-test year expense related adjustments approved in the Board's
13		decision in Docket No. WR8504330. This adjustment includes a forecasted wage increase
14		of 3.00% for International Brotherhood of Electrical Workers (IBEW Local 210), effective
October 17, 2023. For non-union employees, I included an increase of 4.00%		October 17, 2023. For non-union employees, I included an increase of 4.00%, which will
16		occur on March 1, 2023, and a forecasted increase of 3.00% on March 1, 2024, which will
17		occur within the nine months after the test period. As shown on Schedule (SC)-3, this
18		adjustment results in a \$2,241,425 decrease to test period operating income.
19	Q13.	Please describe Adjustment No. 4 – Reflect Rate-Effective Period Wage and FICA
20		Expense Changes.

To properly present expenses for the rate-effective period, I have incorporated one

additional wage rate change. This wage rate change includes the forecasted increase of

21

22

A13.

1	3.00% for IBEW Local 210, which will occur in October 2024 for the rate-effective period.
2	As shown on Schedule (SC)-4, this adjustment results in a \$71,744 decrease to test period

Q14. Please describe Adjustment No. 5 – Normalize Regulatory Commission Expense on
 Schedule (SC)-5

A14.

operating income.

Consistent with the treatment in prior cases in Docket Nos. ER11080649, ER12121071, ER16030252, ER17030308, ER18080925, and ER20120746, this adjustment amortizes the anticipated incremental costs of this proceeding over a three-year period. These costs include those expenses associated with the cost of capital witness, outside counsel, contractors, and other incremental items associated with this proceeding. The unamortized amount is excluded in the rate base. I have also included 100% of these costs in the adjustment as a prudently incurred, normal and ordinary business expense. This adjustment also reflects a three-year normalization of other regulatory commission expenses, such as the external expenses related to the Company's last base rate case. As shown on Schedule (SC)-5, this adjustment results in a \$26,507 increase to test period operating income.

Q15. Please describe Adjustment No. 9 – Storm Ida Adjustment on Schedule (SC)-6.

18 A15. Consistent with storm treatment submitted in the Company's prior cases and with
19 prior BPU decisions in Docket Nos. ER12121071, ER16030252, ER17030308,
20 ER18080925, and ER20120746, the Company proposes to treat the incremental expenses
21 associated with Storm Ida, which was categorized as a Major Storm for Board reporting
22 purposes, as a regulatory asset. Company Witnesses Brubaker and Whitman provide

additional details related to the impact and storm restoration activities in their Direct Testimony.

A16.

The Storm Ida costs included in this adjustment reflect known and measurable expenses related to the storm restoration activities. Consistent with the Company's prior storm regulatory asset approvals in prior cases, the Company proposes that the regulatory asset associated with Storm Ida be amortized over three years. Based on the precedent set in the JCP&L proceeding in Docket No. ER12111052, the Company proposes that the regulatory asset be included in rate base; however, earning a return at the Company's overall rate of return and not the 7-year Constant Maturity Treasury Securities plus 60 basis points approved in that docket.

As shown in Schedule (SC)-6, the adjustment results in a \$1,665,956 decrease in test period earnings and a \$4,164,889 increase in rate base.

Q16. Please describe Adjustment No. 10 – Normalize Injuries and Damages Expense.

Consistent with the treatment in the prior rate cases cited above, this adjustment normalizes injuries and damages expense in cost of service to the average level using the three most recent years. Normalization is used in ratemaking to provide a reasonable level of expense in cost of service, given the year-to-year volatility that may occur in any particular year due to claims-related accounting. As shown on Schedule (SC)-7, this adjustment results in a \$1,042,783 increase in operating income.

O17. Please describe Adjustment No. 11 – Adjust Mays Landing Complex Rent.

21 A17. This adjustment relates to the rent that ACE pays to Atlantic Southern Properties, 22 an affiliated company, for the Company's occupancy of the Mays Landing Complex ("MLC"). As part of the recommendation made in connection with ACE's Management and Affiliate Relations Audits, BPU Docket No. EA07100794, the Company was to pay the lower of cost versus market rates for its rental of both finished and unfinished space within the MLC. The Company has utilized the Colliers Atlantic County Office Market Report to determine market value per square foot. Colliers provides professional services and investment management solutions. Based on the analysis, the market rates for finished and unfinished space were higher than ACE's current rate, so an adjustment is not needed. Schedule (SC)-8 provides the detail on costs for finished and unfinished space at the MLC and, as a result, this adjustment does not impact test period operating income.

Q18. Please describe Adjustment No. 12 – Annualize Depreciation Expense on Year-End Plant - Schedule (SC)-9.

Consistent with the treatment submitted in the last case in Docket No. ER20120746, this adjustment compares the 12 months ending June 2023 test period amount of depreciation expense to an annualized level of depreciation expense amount based on the year-end June 30, 2023 plant assets using the Company's currently approved¹ depreciation rates. In addition, an adjustment is included to the accumulated depreciation reserve to recognize the difference in annualized depreciation expense to the test period level of depreciation expense. As the Company provides test period updates, this adjustment will be updated to reflect the annualized depreciation expense related to the updated plant asset balances. As shown on Schedule (SC)-9, this adjustment results in a \$4,388,670 decrease to test period operating income and a \$4,388,670 decrease to rate base.

A18.

¹ BPU Docket No. ER18080925

1	Q19.	Please describe Adjustment No. 13 – Restate Depreciation Expense Related to PHI
2		Service Company Assets that are allocated to ACE - Schedule (SC)-10.

A19. Consistent with the decision in BPU Docket No. ER03020110, this adjustment restates the test period ending June 2023 amount of depreciation expense to recognize the approved ACE depreciation rates for similar PHI Service Company assets. As shown on Schedule (SC)-10, this adjustment results in a \$94,789 increase to test period operating income.

Q20. Please describe Adjustment No. 17 – Restate Interest on Customer Deposits ("IOCD").

A20.

A21.

Consistent with the treatment submitted in the last case and with prior Board decisions cited above, this adjustment restates the test period IOCD expense to the 2023 IOCD annual rate of 1.40%. As shown on Schedule (SC)-11, this adjustment results in a \$239,083 decrease to test period operating income.

Q21. Please describe Adjustment No. 18 – Revenue Removal - IIP on Schedule (SC)-12.

The Company's IIP Capital tracker has its own standalone Tariff rate through the Rider IIP, in which the BPU approved roll-in related rate increases are reflected. As a result of the IIP's standalone Tariff rate, these investments will continue to be recovered through Rider IIP and excluded from the base distribution revenue requirement. Therefore, the Company proposes this adjustment to remove the IIP-related revenue requirement, including depreciation, deferred State and Federal income tax expenses and State and Federal income tax expenses from test period earnings, as of June 30, 2023. In addition, this adjustment also removes gross plant, accumulated depreciation and deferred State and

	Federal income tax from rate base from the test period. As shown on Schedule (SC)-12,	
	this adjustment results in a \$2,229,103 increase to test period operating income and a	
	decrease of \$91,518,054 in rate base.	
Q22.	Please describe Adjustment No. 19 – Adjust Cash Working Capital.	
A22.	This adjustment reflects the inclusion of the calculated cash working capital	
	requirement of the pro-forma earnings adjustments by applying the net lag percentage to	
	the applicable data. 2021 data was used in the development of the lead lag study used to	
	develop the cash working capital analysis. This adjustment results in a \$2,788,756 increase	
	to the test period rate base as shown in Schedule (SC)-13.	
Q23.	Please describe Adjustment No. 20 – Adjust Interest Synchronization.	
A23.	Consistent with the treatment submitted in the last case and prior Board decisions	
	cited above, this adjustment synchronizes the interest expense used in the cost of service's	
	A22. Q23.	

income tax calculation to that calculated using the adjusted rate base. As shown in Schedule

(SC)-14, this adjustment results in a \$715,069 increase to the test period operating income.

Q24. Does this conclude your Direct Testimony?

16 **A24.** Yes, it does.

13

14

Schedule (SC)-1

Atlantic City Electric Company 5+7 Months Ending June 2023 Reflect the Revenue Annualization Associated with Conservation Incentive Program ("CIP") Adjustment No. 1

(1) Line	(2)		(3)
No.	<u>Item</u>		<u>\$</u>
1 2 3	Total CIP Deferral Balance CIP Revenue Annualization - excludes IIP Net change in revenue	\$ \$	11,865,106 (10,867,314) 997,792
4 5 6	Revenue tax	\$	3,007
7 8 9	State Income Tax Federal Income Tax	\$ \$	89,531 190,103
10 11	Total Expense	\$	282,641
12 13	Earnings	\$	715,151

Schedule (SC)-2

Atlantic City Electric Company 5+7 Months Ending June 2023 Reflect Revenue Associated with Customer Counts as of December, 2023 Adjustment No. 2

(1) Line	(2)	(3)
No.	<u>Item</u>	<u>\$</u>
1 2	Revenues from Customers as of June 30, 2023	\$ 1,092,382
3 4	Revenue from Customers as of December 31, 2023	\$ 210,814
5 6	Revenue	\$ 1,303,197
7 8	Revenue Tax	\$ 3,928
9 10	State Income Tax	\$ 116,934
10 11 12	Federal Income Tax	\$ 248,290
13	Total Expense	\$ 369,152
14 15	Earnings	\$ 934,044

Atlantic City Electric Company 5+7 Months Ending June 2023 Wage and FICA Adjustment

Proforma Wage Rate Changes effective within Nine Months of End of Test Year (for changes effective by March 31, 2024) Adjustment No. 3

(1) Line	(2)	(3)
<u>No</u>	<u>ltem</u>	<u>Total</u>
1	Salary and Wage Adjustment	
2	Change in Expense due to labor rate change	\$ 3,412,162
3	Distribution Allocation	 86.55%
4	Change in Expense due to labor rate change-Distribution	\$ 2,953,226
5		
6	State Income Tax	\$ (265,790)
7	Federal Income Tax	\$ (564,361)
8	Total Expense	\$ 2,123,074
9		
10	Earnings	\$ (2,123,074)
11		
12	FICA Adjustment	
13	Change in FICA Expense due to labor rate change	\$ 190,211
14	Distribution Allocation	86.55%
15	Change in FICA Expense due to labor rate change-Distribution	\$ 164,627
16		
17	State Income Tax	\$ (14,816)
18	Federal Income Tax	\$ (31,460)
19	Total Expense	\$ 118,351
20		
21	Earnings	\$ (118,351)
22		
23	Total Earnings Adjustment	\$ (2,241,425)

Atlantic City Electric Company 5+7 Months Ending June 2023 Wage and FICA Adjustment Proform Wage Rate Changes effective for Rate Effective Period Adjustment No. 4

(1)	(2)		(3)
Line <u>No</u>	Item		<u>Distribution</u>
110	<u>item</u>		Distribution
1	Salary and Wage Adjustment		
2	Change in Expense due to labor rate change	\$	109,950
3	Distribution Allocation		86.55%
4	Change in Expense due to labor rate change-Distribution	\$	95,162
5			
6	State Income Tax	\$	(8,565)
7	Federal Income Tax	<u>\$</u> \$	(18,185)
8	Total Expense	\$	68,412
9			
10	Earnings	\$	(68,412)
11			
12	FICA Adjustment		
13	Change in FICA Expense due to labor rate change	\$	5,355
14	Distribution Allocation		86.55%
15	Change in FICA Expense due to labor rate change-Distribution	\$	4,635
16			
17	State Income Tax	\$	(417)
18	Federal Income Tax	\$ <u>\$</u> \$	(886)
19	Total Expense	\$	3,332
20			
21	Earnings	\$	(3,332)
22			
23	Total Earnings Adjustment	\$	(71,744)

Atlantic City Electric Company 5+7 Months Ending June 2023 Normalize Regulatory Commission Expense Adjustment No. 5

(1) Line			(3)			
<u>No.</u>	<u>ltem</u>		<u>\$</u>			
1 2	Normalized Regulatory Expense Adjustment to Test Period	\$	535,007	(1)		
3	Current Case Amortization	\$	102,382	. (2)		
4 5	Total Regulatory Expense	\$	637,388			
6 7	Test Year Regulatory Expenses	\$_	674,260			
8 9	Adjustment to O & M Expense	\$	(36,872)			
10 11	Distribution Allocation		100%			
12 13	Distribution Allocation Amount	\$	(36,872)			
14 15	State Income Tax	\$	3,318			
16	Federal Income Tax	\$	7,046			
17			.,	•		
18	Total Expense	\$	(26,507)			
19						
20	Earnings	\$	26,507	:		
21 22						
22	(1)			Less BPU	Internal	Reg Expense to
24	Account 928:	F	FERC 928	Assessments	Expenses	be Normalized
25	12 me June 2021	\$	1,350,566	\$ -	\$ 802,066	\$ 548,499
26	12 me June 2022	\$	778,018	\$ -	\$ 395,758	\$ 382,260
27	5+7 me June 2023	\$	1,480,678	\$ -	\$ 806,418	\$ 674,260
28	3 Yr Average		\$1,203,087	\$0	\$668,081	\$ 535,007
29	•					
30	(2) Cost of outside counsel	\$	150,000			
31	Return on Equity witness	\$	103,645			
32	Cost of depreciation witness					
33	Public notices	\$	15,000			
34	Court reporters	\$	30,000			
35	Miscellaneous	\$	8,500			
36	Total incremental costs	\$	307,145			
37 38	3 Yr. Amortization - Current Base Rate Case	\$	102,382			

Atlantic City Electric Company 5+7 Months Ending June 2023 2021 Storms Adjustment Adjustment No. 9

No. Item Distribution 1 Earnings 2 *** Storm Ida - Amortization Expense** \$ 2,317,368 4 *** Storm Ida - Amortization Expense** \$ 2,317,368 5 Total Operating Expense** \$ 2,317,368 6 *** State Income Tax** \$ (208,563) 8 Federal Income Tax** \$ (442,849) 9 Total Expenses** \$ 1,665,956 10 *** State Income Tax** \$ (1,665,956) 12 *** Average Amortizable Balance -Ida 2021 Storm** \$ 5,793,419 16 *** Average Amortizable Balance -Ida 2021 Storm** \$ 5,793,419 16 *** Total Rate Base** \$ (1,107,122) 19 *** Total Rate Base** \$ 4,164,889 21 *** Total Rate Base** \$ 4,164,889 21 *** Total Rate Base** \$ 6,952,103 23 Amortization Period (Years)** \$ 3	(1) Line	(2)		(3)		
Storm Ida - Amortization Expense \$ 2,317,368		<u>Item</u>	<u>Distribution</u>			
3 Storm Ida - Amortization Expense \$ 2,317,368 4 *** 5 Total Operating Expense \$ 2,317,368 6 *** 7 State Income Tax \$ (208,563) 8 Federal Income Tax \$ (442,849) 9 Total Expenses \$ 1,665,956 10 *** *** 11 Earnings \$ (1,665,956) 12 *** *** 13 Average Amortizable Balance -Ida 2021 Storm \$ 5,793,419 16 *** *** 17 Deferred State Income Tax \$ (521,408) 18 Deferred Federal Income Tax \$ (1,107,122) 19 *** *** 20 Total Rate Base \$ 4,164,889 21 *** *** 22 (1) Storm Ida O&M Deferral - Amortizable Base \$ 6,952,103 23 Amortization Period (Years) \$ 3	1	<u>Earnings</u>				
4 \$ Total Operating Expense \$ 2,317,368 6 \$ (208,563) 7 State Income Tax \$ (442,849) 9 Total Expenses \$ 1,665,956 10 \$ (1,665,956) 11 Earnings \$ (1,665,956) 12 \$ (208,563) 10 \$ (1,665,956) 11 Earnings \$ (1,665,956) 12 \$ (208,563) 13 \$ (1,665,956) 14 Rate Base \$ (5,793,419) 16 \$ (521,408) 17 Deferred State Income Tax \$ (521,408) 18 Deferred Federal Income Tax \$ (521,408) 18 Deferred Federal Income Tax \$ (1,107,122) 19 Total Rate Base \$ 4,164,889 21 \$ (1,107,122) \$ (1,107,122) 22 (1) Storm Ida O&M Deferral - Amortizable Base \$ 6,952,103 23 Amortization Period (Years) \$ 3						
5 Total Operating Expense \$ 2,317,368 6 7 State Income Tax \$ (208,563) 8 Federal Income Tax \$ (442,849) 9 Total Expenses \$ (1,665,956) 10 11 Earnings \$ (1,665,956) 12 13 14 Rate Base 15 Average Amortizable Balance -Ida 2021 Storm \$ 5,793,419 16 17 Deferred State Income Tax \$ (521,408) 18 Deferred Federal Income Tax \$ (1,107,122) 19 20 Total Rate Base \$ 4,164,889 21 22 (1) Storm Ida O&M Deferral - Amortizable Base \$ 6,952,103 23 Amortization Period (Years) 3		Storm Ida - Amortization Expense	\$	2,317,368		
6 \$ (208,563) 7 State Income Tax \$ (208,563) 8 Federal Income Tax \$ (442,849) 9 Total Expenses \$ 1,665,956 10 ** (1,665,956) 11 Earnings \$ (1,665,956) 12 ** (1,665,956) 13 ** (1,665,956) 14 ** Rate Base 15 Average Amortizable Balance -Ida 2021 Storm ** (5,793,419) 16 ** (521,408) 17 Deferred State Income Tax ** (521,408) 18 Deferred Federal Income Tax ** (1,107,122) 19 ** (2,107,122) 20 Total Rate Base ** (4,164,889) 21 ** (2,103,103) 22 ** (1) Storm Ida O&M Deferral - Amortizable Base ** (6,952,103) 23 Amortization Period (Years) ** (3,852,103)			_			
7 State Income Tax \$ (208,563) 8 Federal Income Tax \$ (442,849) 9 Total Expenses \$ 1,665,956 10 Income Tax \$ (1,665,956) 11 Earnings \$ (1,665,956) 12 Income Tax \$ (521,408) 15 Average Amortizable Balance -Ida 2021 Storm \$ (521,408) 16 \$ (521,408) 17 Deferred State Income Tax \$ (1,107,122) 19 \$ (1,107,122) 20 Total Rate Base \$ 4,164,889 21 \$ (1) Storm Ida O&M Deferral - Amortizable Base \$ 6,952,103 22 (1) Storm Ida O&M Deferral - Amortizable Base \$ 6,952,103 23 Amortization Period (Years) \$ 3		Total Operating Expense	_\$_	2,317,368		
8 Federal Income Tax \$ (442,849) 9 Total Expenses \$ 1,665,956 10 \$ (1,665,956) 11 Earnings \$ (1,665,956) 12 \$ (1,665,956) 13 ** Average Amortizable Balance -Ida 2021 Storm \$ 5,793,419 16 ** (521,408) 17 Deferred State Income Tax \$ (521,408) 18 Deferred Federal Income Tax \$ (1,107,122) 19 ** Total Rate Base \$ 4,164,889 21 ** Total Rate Base \$ 6,952,103 22 (1) Storm Ida O&M Deferral - Amortizable Base \$ 6,952,103 23 Amortization Period (Years) \$ 3		Otata Israelia Ta	Φ.	(000 500)		
9 Total Expenses \$ 1,665,956 10 \$ (1,665,956) 11 Earnings \$ (1,665,956) 12 13 14 Rate Base \$ 5,793,419 16 \$ (521,408) 17 Deferred State Income Tax \$ (521,408) 18 Deferred Federal Income Tax \$ (1,107,122) 19 \$ (1,107,122) 20 Total Rate Base \$ 4,164,889 21 \$ (1) Storm Ida O&M Deferral - Amortizable Base \$ 6,952,103 23 Amortization Period (Years) \$ 3				, ,		
10 11 Earnings \$ (1,665,956) 12 13 14 Rate Base 15 Average Amortizable Balance -Ida 2021 Storm \$ 5,793,419 16 17 Deferred State Income Tax \$ (521,408) 18 Deferred Federal Income Tax \$ (1,107,122) 19 20 Total Rate Base \$ 4,164,889 21 22 (1) Storm Ida O&M Deferral - Amortizable Base \$ 6,952,103 23 Amortization Period (Years) \$ 3						
11 Earnings \$ (1,665,956) 12 13 14 Rate Base \$ 5,793,419 15 Average Amortizable Balance -Ida 2021 Storm \$ 5,793,419 16 \$ (521,408) 17 Deferred State Income Tax \$ (521,408) 18 Deferred Federal Income Tax \$ (1,107,122) 19 \$ (1,107,122) 20 Total Rate Base \$ 4,164,889 21 \$ 6,952,103 22 (1) Storm Ida O&M Deferral - Amortizable Base \$ 6,952,103 23 Amortization Period (Years) \$ 3		Total Expenses	Φ	1,005,950		
12 13 14		Farnings	\$	(1 665 956)		
13 Rate Base 15 Average Amortizable Balance -Ida 2021 Storm \$ 5,793,419 16 \$ (521,408) 17 Deferred State Income Tax \$ (1,107,122) 18 Deferred Federal Income Tax \$ (1,107,122) 19 \$ (1,107,122) 20 Total Rate Base \$ 4,164,889 21 \$ (1) Storm Ida O&M Deferral - Amortizable Base \$ 6,952,103 22 (1) Storm Ida O&M Deferral - Amortizable Base \$ 6,952,103 23 Amortization Period (Years) \$ 3		Lamingo	<u> </u>	(1,000,000)		
Rate Base 15 Average Amortizable Balance -Ida 2021 Storm \$ 5,793,419 16 \$ (521,408) 17 Deferred State Income Tax \$ (1,107,122) 18 Deferred Federal Income Tax \$ (1,107,122) 19 \$ 4,164,889 20 Total Rate Base \$ 4,164,889 21 \$ 6,952,103 22 (1) Storm Ida O&M Deferral - Amortizable Base \$ 6,952,103 23 Amortization Period (Years) \$ 3						
15 Average Amortizable Balance -Ida 2021 Storm \$ 5,793,419 16 17 Deferred State Income Tax \$ (521,408) 18 Deferred Federal Income Tax \$ (1,107,122) 19 20 Total Rate Base \$ 4,164,889 21 22 (1) Storm Ida O&M Deferral - Amortizable Base \$ 6,952,103 23 Amortization Period (Years) \$ 3		Rate Base				
16 \$ (521,408) 17 Deferred State Income Tax \$ (521,408) 18 Deferred Federal Income Tax \$ (1,107,122) 19 \$ (4,164,889) 20 Total Rate Base \$ 4,164,889 21 \$ 6,952,103 22 (1) Storm Ida O&M Deferral - Amortizable Base \$ 6,952,103 23 Amortization Period (Years) \$ 3			\$	5,793,419		
18 Deferred Federal Income Tax \$ (1,107,122) 19 20 Total Rate Base \$ 4,164,889 21 22 (1) Storm Ida O&M Deferral - Amortizable Base \$ 6,952,103 23 Amortization Period (Years) \$ 3	16			, ,		
19 \$ 4,164,889 20 Total Rate Base \$ 4,164,889 21 \$ 6,952,103 22 (1) Storm Ida O&M Deferral - Amortizable Base \$ 6,952,103 23 Amortization Period (Years) \$ 3	17	Deferred State Income Tax	\$	(521,408)		
20 Total Rate Base \$ 4,164,889 21 22 (1) Storm Ida O&M Deferral - Amortizable Base \$ 6,952,103 23 Amortization Period (Years) \$ 3	18	Deferred Federal Income Tax	\$	(1,107,122)		
21 22 (1) Storm Ida O&M Deferral - Amortizable Base \$ 6,952,103 23 Amortization Period (Years) \$ 3						
22 (1) Storm Ida O&M Deferral - Amortizable Base \$ 6,952,103 23 Amortization Period (Years) \$ 3		Total Rate Base	\$	4,164,889		
23 Amortization Period (Years) \$ 3			_			
		· · · · ·		_		
24 Amortization Expense \$ 2,317,368		Amortization Expense	\$	2,317,368		
25 26 (2) Unamertized Polance of Storm Ide. Pag. Of Pariod		(2) Unamortized Polongs of Storm Ido, Day Of Paried	Φ.	6.052.402		
26 (2) Unamortized Balance of Storm Ida - Beg. Of Period \$ 6,952,103 27 Amortization Expense - 1st Year \$ 2,317,368		•				
27 Amortization Expense - 1st Year \$ 2,317,368 28 Unamortized Balance - End Of Period \$ 4,634,735		·				
29 Average - Year 1 \$ 5,793,419						

Atlantic City Electric Company 5+7 Months Ending June 2023 Normalize Injuries and Damages Expense Adjustment No. 10

(1) Line	(2)		(3)					
<u>No.</u>	<u>ltem</u>	<u>\$</u>						
1	Normalized Injuries & Damages Expense							
2	Three year average Injuries & Damages Expense	\$	1,663,116	(1)				
3	Test Period Injuries & Damages Expense	\$	3,339,055					
4	Adjustment to O & M Expense	\$	(1,675,940)					
5								
6	Distribution Allocation		86.55%					
7								
8	Distribution Allocation Amount	\$	(1,450,526)					
9								
10	State Income Tax	\$	130,547					
11								
12	Federal Income Tax	\$	277,195					
13								
14	Total Expense	\$	(1,042,783)					
15		•						
16	Earnings	\$	1,042,783					
17								
18								
19	(A) 1 1 1 2 B 5							
20	(1) Injuries & Damages Expense	•						
21	12 me June 2021	\$ \$ \$	1,213,943					
22	12 me June 2022	\$	436,349					
23	5+7 me June 2023	\$	3,339,055					
24	3 Year Average	\$	1,663,116					

Atlantic City Electric Company 5+7 Months Ending June 2023 Adjust Mays Landing Complex Rent Adjustment No. 11

(1)	(2)		(3)	(4)	(5)
Line	lt		•	0/	Φ.
<u>No.</u>	<u>ltem</u>		<u>\$</u>	<u>%</u>	<u>\$</u>
1	Earnings				
2	Expense	\$	=		
3	·				
4	State Income Tax	\$	-		
5	Federal Income Tax	\$ \$	-		
6	Total Expenses	\$	=		
7					
8	Earnings	\$	-		
9					
10	Lower of Cost vs. Market Analysis				
11	Finished Space				
12	# of Square Feet - Mays Landing Complex		85,048		
13					
14	Market Cost/Square Foot	\$ \$	21.32	100%	
15	ACE - Actual Cost/Square Foot	\$	3.00	14%	
16	Difference (no adjustment needed - cost < market)	\$	18.32	86%	\$ 1,558,140
17					
18	<u>Unfinished Space</u>				
19	# of Square Feet - Mays Landing Complex		134,386		
20					
21	Market Cost Per Square Foot				
22	Triple Net Rate	\$	5.75		
23	Common Area Maintenance Rate	\$ \$ \$ \$	3.37		
24	Total	\$	9.12	100%	. , ,
25	ACE - Actual Cost/Square Foot	\$	3.00	33%	
26	Difference	\$	6.12	67%	\$ 822,445
27					
28					
29					
30	Finished & Unfinished Space				
31	Market Cost/Square Foot			100%	
32	ACE - Actual Cost/Square Foot				\$ 658,249
33	Total (no adjustment needed - cost < market)			78%	\$ 2,380,584

Atlantic City Electric Company 5+7 Months Ending June 2023 Annualization of Depreciation on Year-End June 30, 2023 Plant Adjustment No. 12

(1)	(2)		(3)		(4)		(5)	(6)	(7)
Line <u>No.</u>	Plant Category	-				+7 ME Jun 2023 ACE Distribution epreciation Exp Adjustment Allocator		<u>\$</u>	
1 2	Distribution	\$	100,819,407	\$	97,645,303	\$	3,174,104	100.00%	\$ 3,174,104
3 4	General	\$	16,665,885	\$	13,279,868	\$	3,386,017	86.55%	\$ 2,930,598
5 6	Total	\$	117,485,292	\$	110,925,171	\$	6,560,122		\$ 6,104,702
7 8						Sta	te Income Tax		\$ (549,423)
9							leral Income Tax		\$ (1,166,609)
10						Tota	al Expense	•	\$ 4,388,670
11									
12						Ear	nings	:	\$ (4,388,670)
13 14						Rat	e Base		\$ (4,388,670)

Atlantic City Electric Company 5+7 Months Ending June 2023 Depreciation on PHI Service Company Assets Using ACE Depreciation Rates Adjustment No. 13

(1) Line	(2)	(3) ACE	(4) Distribution	(5)
No.	<u>ltem</u>	<u>Total</u>	<u>%</u>	<u>\$</u>
	<u>Earnings</u>			
1	Depreciation	\$ (152,343)	86.55% \$	(131,853)
2				
3	State Income Tax		\$	11,867
4	Federal Income Tax		\$	25,197
5	Total Expense		\$	(94,789)
6				
7	Earnings		\$	94,789

Atlantic City Electric Company 5+7 Months Ending June 2023 Restate Interest on Customer Deposit Expense Adjustment No. 17

(1)	(2)	(3)			
Line <u>No.</u>	<u>ltem</u>	<u>\$</u>			
1 2	Customer Deposit Balance @ 5+7 ending June 23	\$ 24,578,540			
3	2023 Interest Rate	 1.40%			
4 5 6	Annual Interest Expense	\$ 344,100			
7	Interest Expense @ 5+7 ending June 23	\$ 11,532			
8 9 10	IOCD Expense	\$ 332,567			
11	Distribution Allocation	 100%			
12 13 14	Distribution Allocation Amount	\$ 332,567			
15	State Income Tax	\$ (29,931)			
16 17	Federal Income Tax	\$ (63,554)			
18 19 20	Total Expense	\$ 239,083			
21	Earnings	\$ (239,083)			

Atlantic City Electric Company 5+7 Months Ending June 2023 Remove Annual IIP Revenue Requirement Adjustment No. 18

(1) Line	(2)	(3)
No.	<u>ltem</u>	<u>\$</u>
1	<u>Earnings</u>	
2		
3		
4	Depreciation	\$ (3,898,500)
5	Deferred State Income Tax	\$21,656
6	Deferred Federal Income Tax	\$45,982
7	State Income Tax	\$512,837
8	Federal Income Tax	\$1,088,923
9	Total Expense	\$ (2,229,103)
10		
11	Earnings	\$ 2,229,103
12		
13	Rate Base	
14	Gross Plant	(93,253,216)
15	Accumulated Depreciation	(\$1,802,799)
16	Deferred State Income Tax	\$21,656
17	Deferred Federal Income Tax	\$45,982
18		
19	Net Rate Base Adjustment	(91,518,054)

Atlantic City Electric Company 5+7 Months Ending June 2023 <u>Cash Working Capital on Proforma Adjustments</u> Adjustment No. 19

(1)	(2)	(3)		(4)		(5)	(6)		(7)	(8)		(9)	(10)	(11)	(12)	(13)		(14)
Line No.	<u>Adjustment</u>	Revenue		0&M	De	prec/Amort	Other Taxes		SIT	DSIT		<u>FIT</u>	DFIT	IOCD	Total Expense	Interest		<u>Earnings</u>
1	Reflect the Revenue Annualization Associated with Conservation Incentive Program ("CIF \$	997.792					\$ 3.007 \$	6	89.531		\$	190.103			\$ 282.641		\$	715.151
2	Reflect Revenue Associated with Customer Counts as of December, 2023 \$	1.303,197	\$	-			\$ 3.928 \$	5	116.934		\$	248,290			\$ 369,152		\$	934.044
3	Annualize Wage and FICA changes through March 2024		\$	2,953,226			\$ 164,627 \$	3	(280,607)		\$	(595,822)			\$ 2,241,425		\$	(2,241,425)
4	Proform Wage Rate Changes for Rate Effective Period		\$	95,162			\$ 4,635 \$	3	(8,982)		\$	(19,071)			\$ 71,744		\$	(71,744)
5	Regulatory Commission Expense Adjustment		\$	(36,872)			\$	5	3,318		\$	7,046			\$ (26,507)		\$	26,507
6	Pension and Other Post-Employment Benefits ("OPEB") Expense Adjustment		\$	1,421,369			\$	5	(127,923)		\$	(271,624)			\$ 1,021,822		\$	(1,021,822)
7	Reflection of 5-year Average Inflation on Non-Labor O&M Expense		\$	4,628,106			\$	6	(416,530)		\$	(884,431)			\$ 3,327,145		\$	(3,327,145)
8	Remove Executive Incentive Expense		\$	(1,269,775)			\$	5	114,280		\$	242,654			\$ (912,841)		\$	912,841
9	Storms		\$	2,317,368			\$	5	(208,563)		\$	(442,849)			\$ 1,665,956		\$	(1,665,956)
10	Normalize Injury & Damage Expense		\$	(1,450,526)			\$	5	130,547		\$	277,195			\$ (1,042,783)		\$	1,042,783
11	Adjust Mays Landing Complex Rent \$	-					\$	5	-		\$	-			\$ -		\$	-
12	Annualize Depreciation Expense @ June 23 Plant Servco Assets @ ACE Approved Depreciation Rates				Þ	6,104,702	3		(549,423)		\$	(1,166,609) 25,197			\$ 4,388,670 \$ (94,789)		\$	(4,388,670)
13	Reflect Plant Additions from Jul 2023 - Dec 2023				Þ	(131,853) 4.412.478	3		11,867 (617,978) \$	220.855	\$	(1.312.174) \$	468.949		\$ (94,789)		\$	94,789
14	Reflect Plant Additions from Jul 2023 - Dec 2023 Reflect Plant Additions from Jan 2024 - Jun 2024				\$	2,162,404	3		(284,722) \$	90,106		(1,312,174) \$ (604,560) \$	191.324		\$ 3,172,131 \$ 1,554,552		\$	(3,172,131) (1,554,552)
16	Credit Facilities Fee		¢	730,952	φ	2,102,404	4		(65,786)	90,100	φ	(139,685)	191,324		\$ 525,482		φ	(525,482)
17	Interest on Customer Deposit		φ	730,932			ų.	,	(29,931)		φ	(63,554)		\$ 332,567	\$ 239.083		φ	(239,083)
17	Remove Annual IIP Revenue Requirement				\$	(2.000.500)	ą.	,		24 050	ð.	1,088,923 \$	45.982	\$ 332,567			Ф	
10					Ф	(3,898,500)	9		512,837 \$	21,656	Ф		45,962		\$ (2,229,103)		Ф	2,229,103
19	Interest Synchronization						3		(228,944)		\$	(486,125)			\$ (715,069)		\$	715,069
20	Corporate Alternative Minimum Tax ("CAMT") Adjustment						\$		-		\$	-			\$ -		\$	-
21	Excess Deferred Income Taxes ("EDIT") – Expiring Riders Regulatory Asset				_		\$	5	(40.000)		\$	-			\$ -		\$	-
22	Reflection of Electric Vehicle Regulatory Asset				\$	520,580	\$	5	(46,852)		\$	(99,483)			\$ 374,245		\$	(374,245)
23	SEN Investment Deferral Regulatory Asset				\$	1,134,715	\$	5	(102,124)		\$	(216,844)			\$ 815,747		\$	(815,747)
24	AMI SEN Incremental O&M Expenses		\$	2,538,023			\$	5	(228,422)		\$	(485,016)			\$ 1,824,585		\$	(1,824,585)
25	Benchmarking Requirement		\$	140,355	\$	105,162	\$	5	(22,097)		\$	(46,918)			\$ 176,502		\$	(176,502)
26																		
27	<u> </u>																	
28	Total \$	2,300,989	\$	12,067,387	\$			6 (2	2,239,570) \$	332,617	\$	(4,755,354) \$		\$ 332,567	\$ 17,029,790	\$	- \$	(14,728,801)
29	Cash Working Capital Ratio			8.710%		16.397%	17.487%		4.815%	4.815%		4.815%	4.815%					
30	Cash Working Capital Requirement		\$	1,051,027	\$	1,706,918	\$ 30,811								-	\$	- \$	2,788,756
31																		

Atlantic City Electric Company 5+7 Months Ending June 2023 Adjust Interest Synchronization Adjustment No. 20

(1) Line	(2)		(3)
No.	<u>ltem</u>		<u>\$</u>
1 2	Adjusted Rate Base	\$	2,235,749,719
3 4 5	Weighted Cost Rate Long Term Debt		1.86%
6 7	Proforma Interest Expense	\$	41,584,945
8 9	Test Year Interest Expense	\$	39,041,122
10 11	Change in Interest Expense	\$	2,543,823
12 13	Taxable Income	\$	(2,543,823)
14	Operating Expense		
15	State Income Tax	\$	(228,944)
16	Federal Income Tax	\$ \$ \$	(486,125)
17 18	Total Expense	\$	(715,069)
19	Earnings	\$	715,069

ATLANTIC CITY ELECTRIC COMPANY

BEFORE THE NEW JERSEY BOARD OF PUBLIC UTILITIES DIRECT TESTIMONY OF DYLAN W. D'ASCENDIS DOCKET NO. ER23020091

I. <u>Introduction</u>

1	Q1.	Please state your name and business address.
2	A1.	My name is Dylan W. D'Ascendis. My business address is 3000 Atrium Way,
3		Suite 200, Mount Laurel, NJ 08054.
4	Q2.	By whom are you employed and in what capacity?
5	A2.	I am a Partner at ScottMadden, Inc.
6	Q3.	Have you previously submitted testimony before the New Jersey Board of Public
7		Utilities ("BPU" or the "Board") or other regulatory agencies?
8	A3.	Yes, I have provided expert witness testimony before the BPU in eight previous
9		cases. Additionally, I have offered expert testimony on behalf of investor-owned
10		utilities before over 35 state regulatory commissions in the United States, the Federal
11		Energy Regulatory Commission, the Alberta Utility Commission, an American
12		Arbitration Association panel, and the Superior Court of Rhode Island on issues
13		including, but not limited to, common equity cost rate, rate of return, valuation, capital
14		structure, class cost of service, and rate design.
15	Q4.	Please summarize further your professional experience and educational
16		background.
17	A4.	On behalf of the American Gas Association ("AGA"), I calculate the AGA Gas
18		Index, which serves as the benchmark against which the performance of the American
19		Gas Index Fund ("AGIF") is measured on a monthly basis. The AGA Gas Index and

1		AGIF are a market capitalization weighted index and mutual fund, respectively,
2		comprised of the common stocks of the publicly traded corporate members of the AGA.
3		I am a member of the Society of Utility and Regulatory Financial Analysts
4		("SURFA"). In 2011, I was awarded the professional designation "Certified Rate of
5		Return Analyst" by SURFA, which is based on education, experience, and the
6		successful completion of a comprehensive written examination.
7		I am also a member of the National Association of Certified Valuation Analysts
8		("NACVA") and was awarded the professional designation "Certified Valuation
9		Analyst" by NACVA in 2015.
10		I am a graduate of the University of Pennsylvania, where I received a Bachelor
11		of Arts degree in Economic History. I have also received a Master of Business
12		Administration with high honors and concentrations in Finance and International
13		Business from Rutgers University.
14		The details of my educational background and expert witness appearances are
15		shown in Appendix A.
16	Q5.	Please describe the purpose of your testimony.
17	A5.	The purpose of my testimony is to present evidence on behalf of Atlantic City
18		Electric Company ("ACE" or the "Company") and recommend an allowed rate of
19		return on common equity ("ROE") for its New Jersey jurisdictional rate base.
20	Q6.	Have you prepared schedules in support of your recommendation?
21	A6.	Yes. I have prepared Schedules (DWD)-1 through (DWD)-9, which were

prepared by me or under my direction.

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1 Q7. What is your recommended ROE for ACE?

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A8.

I recommend that the Board authorize ACE the opportunity to earn an ROE of 10.50% on its jurisdictional rate base. The ratemaking capital structure and cost of long-term debt is sponsored by Company Witness Jay Ziminsky. 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	49.80%	3.73%	1.86%
Common Equity	<u>50.20%</u>	10.50%	<u>5.27%</u>
Total	100.00%		<u>7.13%</u>

II. Summary

7 Q8. Please summarize your recommended common equity cost rate.

My recommended common equity cost rate of 10.50% 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 ACE. 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 <u>identical</u> 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	<u>12.58%</u>
Indicated Range of Common Equity Cost Rates Before Adjustments	10.04% - 11.04%
Size Adjustment	0.25%
Flotation Cost Adjustment	<u>0.18%</u>
Indicated Cost of Common Equity Cost Rates After Adjustment	<u> 10.47% - 11.47%</u>
Recommended Cost of Common Equity	<u>10.50%</u>

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 0.25% to reflect the Company's smaller relative size, as compared to the Utility Proxy Group companies, and by 0.18% for flotation costs. These adjustments resulted in a Company-specific range of indicated common equity cost rates between 10.47% and 11.47%. From this range, I recommend that the

³ My indicated range of common equity cost rates are 50 basis points above and below the midpoint of my DCF, RPM, and CAPM results.

1		Board authorize an ROE of 10.50% for the Company.
2	Q9.	How is the remainder of your Direct Testimony organized?
3	A9.	The remainder of my Direct Testimony is organized as follows:
4		• Section III – Provides a summary of financial theory and regulatory principles
5		pertinent to the development of the Cost of Capital;
6		• Section IV – Explains my selection of the Utility Proxy Group used to develop my
7		analytical results;
8		• Section V – Supports the reasonableness of the Company's requested capital
9		structure;
10		• Section VI – Describes the analyses on which my recommendation is based;
11		Section VII- Summarizes my common equity cost rate before adjustments to
12		reflect Company-specific factors;
13		• Section VIII – Explains my adjustments to my common equity cost rate to reflect
14		the Company-specific factors; and
15		• Section IX – Presents my conclusions.
		III. <u>General Principles</u>
16	Q10.	What general principles have you considered in arriving at your recommended
17		common equity cost rate?
18	A10.	In unregulated industries, marketplace competition is the principal determinant
19		of the price of products or services. For regulated public utilities, regulation must act
20		as a substitute for marketplace competition. Assuring that the utility can fulfill its
21		obligations to the public, while providing safe and reliable service at all times, requires
22		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 an adequate return attracts 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 at reasonable cost and terms; (2) sufficient to ensure its financial

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⁴ *Hope*, 320 U.S. 591, 603 (1944).

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 standalone 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 standalone 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

Witness D'Ascendis

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 at all times, 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.

A11.

Q11. Within that broad framework, how is the cost of capital estimated in regulatory proceedings?

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

Witness D'Ascendis

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.

Business Risk 1

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2	Q12.	Please define business risk and explain why it is important for determining a fa	
3		rate of return.	

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 at all times (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 period 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.

1 Financial Risk

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A14.

2	Q13.	Please define financial risk and explain why it is important in determining a fair

3 rate of return.

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.

Q14. Can bond and credit ratings be a proxy for a firm's combined business and financial risks to equity owners (i.e., investment risk)?

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.

IV. ACE and the Utility Proxy Group

18 Q15. Why is it necessary to develop a proxy group when estimating the ROE for ACE?

19 A15. Because ACE is not publicly traded and does not have publicly traded equity
20 securities, it is necessary to develop groups of publicly traded, comparable companies

³ 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.

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 Companies: an 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 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

⁶ The development of the Non-Price Regulated Proxy Group is explained in more detail in Section V, part D.

opportunity to earn a fair and reasonable return. Consequently, it is appropriate to consider the Utility Proxy Group's market data in determining the Companies' ROE.

3 Q16. Are you familiar with ACE's operations?

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4 A16. Yes. ACE serves approximately 600,000 customers in New Jersey. ACE is not publicly-traded as they comprise an operating subsidiary of Exelon Corporation ("Exelon"), which operates in five states and the District of Columbia⁸ and serves approximately 10.6 million customers and is publicly-traded under symbol EXC.

8 Q17. Please explain how you chose the companies in the Utility Proxy Group.

- 9 A17. Because the cost of equity is a comparative exercise, my objective in developing
 10 a proxy group was to select companies that are comparable to the Companies. Because
 11 the Companies are 100% rate-regulated vertically integrated electric utilities, I applied
 12 the following criteria to select my Utility Proxy Group:
- 13 (i) They were included in the Eastern, Central, or Western Electric Utility Group 14 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;

⁷ Exelon Corporation SEC Form 10-K for the fiscal year ended December 31, 2021.

⁸ Exelon Corp., Q3 2022 Earnings Conference Call (Presentation Slides), November 3, 2022.

- 1 (v) They have *Value Line* and Bloomberg Professional Services ("Bloomberg")
 2 adjusted Beta coefficients ("beta");
- 3 (vi) They have positive *Value Line* five-year dividends per share ("DPS") growth
 4 rate projections; and
 - (vii) They have *Value Line*, Zacks, or Yahoo! Finance consensus five-year earnings per share ("EPS") growth rate projections.
- 7 The following 13 companies met these criteria:

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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

A summary of financial statistics for the Utility Proxy Group for years 2017 through 2021 inclusive are presented on Schedule (DWD)-2, page 1.

V. Capital Structure

11 Q18. What is ACE's requested capital structure?

12 A18. ACE's requested capital structure consists of 49.80% long-term debt and 50.20% common equity, which is its proposed pro-forma capital structure as of June 30, 2023, as noted in the Direct Testimony of Company Witness Jay Ziminsky.

2	A19.	Yes. The pro-forma capital structure is appropriate for this proceeding because
3		it reflects the relevant financial condition of the Company taking into account
4		investment and issuances which will occur during the rate effective period.
5	Q20.	Does ACE have a capital structure that is recognized by investors and is separate
6		from that of its parent company that is recognized by investors?
7	A20.	Yes. ACE is a separate corporate entity that has its own capital structure and
8		issues its own debt. ACE's actual capital structure is reflected in registrations of its
9		debt with the Securities Exchange Commission.
10	Q21.	What are the typical sources of capital commonly considered in establishing a
11		utility's capital structure?
12	A21.	Common equity and long-term debt are commonly considered in establishing a
13		utility's capital structure, because they are the typical sources of capital financing a
14		utility's rate base.
15	Q22.	Please explain.
16	A22.	Long-lived assets are typically financed with long-lived securities, so that the
17		overall term structure of the utility's long-term liabilities (both debt and equity) closely
18		match the life of the assets being financed. As stated by Brigham and Houston:
19 20 21 22 23		In practice, firms don't finance each specific asset with a type of capital that has a maturity equal to the asset's life. However, academic studies do show that most firms tend to finance short-term assets from short-term sources and long-term assets from long-term sources. ⁹

Q19. Is it appropriate to use a pro-forma capital structure?

⁹ Eugene F. Brigham and Joel F. Houston, <u>Fundamentals of Financial Management</u>, Concise 4th Ed., Thomson South-Western, 2004, at 574.

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Whereas short-term debt has a maturity of one year or less, long-term debt may
have maturities of 30 years or longer. Although there are practical financing
constraints, such as the need to "stagger" long-term debt maturities, the general
objective is to extend the average life of long-term debt. Still, long-term debt has a
finite life, which is likely to be less than the life of the assets included in rate base.
Common equity, on the other hand, is outstanding into perpetuity. Thus, common
equity more accurately matches the life of the going concern of the utility, which is
also assumed to operate in perpetuity. Consequently, it is both typical and important
for utilities to have significant proportions of common equity in their capital structures.
Why is it important that the Company's pro forma capital structure, consisting
of 49.80% long-term debt and 50.20% common equity, be authorized in this
proceeding?

Q23.

A23.

In order to provide safe and reliable service to its customers, ACE must meet the needs and serve the interests of its various stakeholders, including customers, shareholders, and bondholders. The interests of these stakeholder groups are aligned with maintaining a healthy balance sheet, strong credit ratings, and a supportive regulatory environment, so that the Company has access to capital on reasonable terms in order to make necessary investments.

Safe and reliable service cannot be maintained at a reasonable cost if utilities do not have the financial flexibility and strength to access competitive financing markets on reasonable terms. The authorization of a capital structure that understates the Company's actual common equity will weaken the financial condition of its operations and adversely impact the Company's ability to address expenses and

1	investments, to the detriment of customers and shareholders. Safe and reliable service
2	for customers cannot be sustained over the long term if the interests of shareholders
3	and bondholders are minimized such that the public interest is not optimized.

4 Q24. How does the Company's pro forma common equity ratio of 50.20% compare 5 with the common equity ratios maintained by the Utility Proxy Group?

The Company's pro forma common equity ratio of 50.20% is reasonable and consistent with the range of common equity ratios maintained by the Utility Proxy Group from which I derive my ROE recommendation. As shown on pages 2 and 3 of Schedule (DWD)-2, common equity ratios range from 30.78% to 57.15% for fiscal year 2021 for the Utility Proxy Group.

I also considered *Value Line* projected capital structures for the utilities for 2025-2027. That analysis shows a range of projected common equity ratios between 32.00% and 51.00% for the Utility Proxy Group.¹⁰

In addition to comparing the Company's proposed common equity ratio with common equity ratios currently and expected to be maintained by the Utility Proxy Group, I also compared the Company's proposed common equity ratio with the equity ratios maintained by the operating subsidiaries of the Utility Proxy Group. As shown on page 4 of Schedule (DWD)-2, common equity ratios of the operating utility subsidiaries of the companies in the Utility Proxy Group range from 37.33% to 59.53% for fiscal year 2021.

A24.

¹⁰ See, pages 3 through 15 of Schedule (DWD)-3.

- Q25. Given the range of equity ratios present within the Utility Proxy Group, is Atlantic

 City Electric's proposed equity ratio of 50.20% appropriate for ratemaking
- 3 purposes?

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4 A25. Yes, it is. The Company's proposed equity ratio of 50.20% is appropriate for ratemaking purposes in the current proceeding because it is within the range of the common equity ratios currently maintained and expected to be maintained, by the Utility Proxy Group and their operating subsidiaries.

VI. Common Equity Cost Rate Models

8 Q26. Is it important that cost of common equity models be market-based?

A26. Yes. As discussed previously, 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.

Q27. Are the cost of common equity models you use market-based models?

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

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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"). 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.

Q28. What analytical approaches did you use to determine the Company's ROE?

A28.

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 Premiumbased 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.

1 Discounted Cash Flow Model

2 Q29. Please describe the DCF Model, generally.

A29. The theory underlying the DCF model is that the present value of an expected 3 future stream of net cash flows during the investment holding period can be determined 4 by discounting those cash flows at the cost of capital, or the investors' capitalization 5 6 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 7 appreciation. Mathematically, the dividend yield on market price plus a growth rate 8 9 equals the capitalization rate; i.e., the total common equity return rate expected by investors, as shown in Equation [1] below: **10**

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$$K_e = (D_0 (1+g))/P + g$$

where:

 K_e = the required Return on Equity;

14 D_0 = the annualized Dividend Per Share;

15 P =the current stock price; and

16 g =the growth rate.

17 Q30. Which version of the DCF model do you use?

18 A30. I used the single-stage constant growth DCF model.

1	Q31.	Please describe the dividend yield you used in applying the constant growth DCF
2		model.

- 3 A31. The unadjusted dividend yields are based on the proxy companies' dividends
 4 as of December 30, 2022, divided by the average closing market price for the 60 trading
 5 days ended December 30, 2022.¹¹
- 6 Q32. Please explain your adjustment to the dividend yield.

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A32. 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 D₁, 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)-3 have been adjusted upward to reflect one-half the average projected growth rate shown in Column 5.

Q33. Please explain the basis for the growth rates you apply to the Utility Proxy Group in your constant growth DCF model.

21 A33. Investors with more limited resources than institutional investors are likely to rely on widely available financial information services, such as *Value Line*, Zacks, and

¹¹ See, Column 1, page 1 of Schedule (DWD)-3.

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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.

Q34. Please summarize the constant growth DCF model results.

A34.

As shown on page 1 of Schedule (DWD)-3, 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.

- Q35. 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 where it would mis-specify investor return on common equity necessitating the use of multiple common equity cost rate models?
- 5 A35. 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.¹²

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 <u>market</u> value of a utility's equity, whereas regulators authorize returns on <u>book</u> common equity. This means the market-based DCF model will produce the total annual dollar return expected by investors <u>only</u> when market and book values are equal, and again, a rare and unlikely situation.

¹² Roger A. Morin, Modern Regulatory Finance, Public Utility Reports, Inc., 2021, at 481-482. ("Morin")

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."¹³

In addition, Bonbright states:

A36.

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)¹⁴

Q36. Can the under- or overstatement of investors' required rate of return by the DCF model be demonstrated mathematically?

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)-3. Column 1 represents a M/B ratio of 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

¹³ Charles F. Phillips, <u>The Regulation of Public Utilities</u>, Public Utilities Reports, Inc., 1993, at 395.

¹⁴ James C. Bonbright, Albert L. Danielsen and David R. Kamerschen, <u>Principles of Public Utility Rates</u>, Public Utilities Reports, Inc., 1988, at 334.

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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).

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As shown on Schedule (DWD)-8, page 2, the average M/B ratio for the Utility Proxy Group is approximately 2.0 times. As such, the DCF model understates the investor required return at this time. This understatement is plain to see given my other model results.

1 The Risk Premium Model

2 Q37. Please describe the theoretical basis of the RPM.

A37. 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.

Q38. Please explain how you derived your indicated cost of common equity based on the RPM.

A38. 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

4 Q39. Please explain the PRPM.

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The PRPM, published in the Journal of Regulatory Economics, 15 was 5 A39. developed from the work of Robert F. Engle, who shared the Nobel Prize in Economics 6 in 2003 "for methods of analyzing economic time series with time-varying volatility" 7 or ARCH.¹⁶ Engle found that volatility changes over time and is related from one 8 period to the next, especially in financial markets. Engle discovered that volatility of 9 prices and returns clusters over time and is therefore highly predictable and can be used **10** to predict future levels of risk and risk premiums. That is, historical volatility can be 11 used to predict future volatility, which then can be translated to a predicted equity risk 12 premium. 13

14 Q40. How does the PRPM estimate the investor required return?

15 A40. The PRPM estimates the risk-return relationship directly, as the predicted
16 equity risk premium is generated by predicting volatility or risk. The PRPM is not
17 based on an estimate of investor behavior, but rather on an evaluation of the results of
18 that behavior (i.e., the variance of historical equity risk premiums).

19 Q41. Please explain your application of the PRPM.

20 A41. The inputs to the model are the historical returns on the common shares of each
21 Utility Proxy Group company minus the historical monthly yield on long-term U.S.

¹⁵ 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

¹⁶ Autoregressive conditional heteroscedasticity; See also, www.nobelprize.org.

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 series¹⁷ and a GARCH coefficient¹⁸. Multiplying the predicted monthly variance by the GARCH coefficient and then annualizing it¹⁹ produces the predicted annual equity risk premium. I then added the forecasted 30-year U.S. Treasury bond yield of 3.91% ²⁰ 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*²¹.

11 Q42. What are the results of the PRPM as applied to the Utility Proxy Group?

12 A42. The mean PRPM indicated common equity cost rate for the Utility Proxy Group
13 is 11.99%, the median is 11.90%, and the average of the two is 11.95%. Consistent
14 with my reliance on the average of the median and mean results of the DCF models, I
15 relied on the average of the mean and median results of the Utility Proxy Group PRPM
16 to calculate a cost of common equity rate of 11.95%.

17 Q43. Please describe your selection of a risk-free rate of return.

As shown in Schedules (DWD)-4 and (DWD)-5, 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.

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¹⁷ Illustrated on Column 1, page 2 of Schedule (DWD)-4.

¹⁸ Illustrated on Column 2, page 2 of Schedule (DWD)-4.

¹⁹ Annualized Return = $(1 + Monthly Return) ^12 - 1$

²⁰ See, Column 4, page 2 of Schedule (DWD)-4.

²¹ Blue Chip Financial Forecasts ("Blue Chip"), January 1, 2023 at 2 and December 2, 2022 at 14.

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.

Q44. Why do you use the projected 30-year Treasury yield in your analyses?

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. ²²

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

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A44.

²² Morningstar, Inc., 2013 Ibbotson Stocks, Bonds, Bills and Inflation Valuation Yearbook, at 44.

1	expected common stock return is based on long-term cash flows,
2	regardless of an individual's holding time period. ²³

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."²⁴

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. <u>Total Market Approach Risk Premium Model</u>

Q45. Please explain the total market approach RPM.

14 A45. The total market approach RPM adds a prospective public utility bond yield to
15 an average of: (1) an equity risk premium that is derived from a beta-adjusted total
16 market equity risk premium, (2) an equity risk premium based on the S&P Utilities
17 Index, and (3) an equity risk premium based on authorized ROEs for electric utilities.

Q46. Please explain how you determined the expected bond yield applicable to the Utility Proxy Group.

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-

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²³ Morin, at 169.

²⁴ Shannon Pratt and Roger Grabowski, <u>Cost of Capital: Applications and Examples</u>, 3rd Ed. (Hoboken, NJ: John Wiley & Sons, Inc., 2008), at 92. "ERP" is the Equity Risk Premium.

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)-4, 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. 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 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.²⁶ Adding the 0.20% to the 5.88% prospective A2-

²⁵ As shown on line 2 and explained in note 2, page 3 of Schedule (DWD)-4.

²⁶ As shown on line 4 and explained in note 3, page 3 of Schedule (DWD)-4.

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 Yield²⁷

Prospective Yield on Moody's Aaa-Rated Corporate Bonds (<i>Blue Chip</i>)	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	<u>6.08%</u>

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.

8 A. <u>Beta-Derived Equity Risk Premium</u>

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9 Q47. Please explain how the beta-derived equity risk premium is determined.

10 A47. The components of the beta-derived risk premium model are: (1) an expected
11 market equity risk premium over corporate bonds, and (2) the beta. The derivation of
12 the beta-derived equity risk premium that I applied to the Utility Proxy Group is shown
13 on lines 1 through 9, page 8 of Schedule (DWD)-4. The total beta-derived equity risk
14 premium I applied is based on an average of three historical market data-based equity
15 risk premiums, two *Value Line*-based equity risk premiums and a Bloomberg-based
16 equity risk premium. Each of these is described below.

²⁷ As shown on page 3 of Schedule (DWD)-4.

1 Q48. How did you derive a market equity risk premium based on long-term historical data?

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")²⁸ 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%.²⁹ As shown on line 1, page 8 of Schedule (DWD)-4, 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-rated corporate bonds, because they are appropriate for the purpose of estimating the cost of capital as noted in <u>SBBI - 2022</u>. ³⁰ 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

A48.

²⁸ See, <u>SBBI-2022</u>, at page 256-258, 274-276.

²⁹ As explained in note 1, page 9 of Schedule (DWD)-4.

³⁰ SBBI - 2022, at page 201.

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.

Q49. Please explain the derivation of the regression-based market equity risk premium.

A49. To derive the regression-based market equity risk premium of 7.26% shown on line 2, page 8 of Schedule (DWD)-4, 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 bond yield:

 $RP = \alpha + \beta (R_{Aaa/Aa})$

Q50. Please explain the derivation of the PRPM equity risk premium.

A50. 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 2022.³¹ Using the previously

³¹ Data from January 1926 to December 2021 is from <u>SBBI - 2022</u>. Data from January 2022 to December 2022 is from Bloomberg.

1	discussed generalized form of ARCH, known as GARCH, the projected equity risk
2	premium is determined using Eviews [©] statistical software. The resulting PRPM
3	predicted a market equity risk premium of 9.76%. ³²

4 Q51. Please explain the derivation of a projected equity risk premium based on *Value*5 *Line* data for your RPM analysis.

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)-4. 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.³³

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)- 4.

³² Shown on line 3, page 8 of Schedule (DWD)-4.

A51.

³³ As explained in detail in note 1, page 2 of Schedule (DWD)-5.

1	Q52.	Please explain the derivation of an equity risk premium based on the S&P 500	
2		companies.	
3	A52.	Using data from Value Line, I calculated an expected total return on the S&P	
4		500 companies using expected dividend yields and long-term growth estimates as a	
5		proxy for capital appreciation. The expected total return for the S&P 500 is 15.67%.	
6		Subtracting the prospective yield on Moody's Aaa-rated corporate bonds of 5.05%	
7		results in a 10.62% projected equity risk premium.	
8	Q53.	Please explain the derivation of an equity risk premium based on Bloomberg data.	
9	A53.	Using data from Bloomberg, I calculated an expected total return on the S&P	
10		500 using expected dividend yields and long-term growth estimates as a proxy for	
11		capital appreciation, identical to the method described above. The expected total return	
12		for the S&P 500 is 11.06%. Subtracting the prospective yield on Moody's Aaa-rated	

Q54. What is your conclusion of a beta-derived equity risk premium for use in your RPM analysis?

corporate bonds of 5.05% results in a 6.01% projected equity risk premium.

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16 A54. I gave equal weight to all six equity risk premiums based on each source 17 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

2	<u>Keturns</u> -	
3	Historical Spread Between Total Returns of Large Stocks	
	and Aaa and Aa2-Rated Corporate Bond Yields (1928 –	6.13%
4	2021)	
	Regression Analysis on Historical Data	7.26%
5	PRPM Analysis on Historical Data	9.76%
	Prospective Equity Risk Premium using Total Market	
6	Returns from Value Line Summary & Index less	11.53%
	Projected Aaa Corporate Bond Yields	
7	Prospective Equity Risk Premium using Measures of	
	Capital Appreciation and Income Returns from Value	10.620/
	Line for the S&P 500 less Projected Aaa Corporate Bond	10.62%
	Yields	
	Prospective Equity Risk Premium using Measures of	
	Capital Appreciation and Income Returns from	6.010/
	Bloomberg Professional Services for the S&P 500 less	<u>6.01%</u>
	Projected Aaa Corporate Bond Yields	
	Average	<u>8.55%</u>

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)-5, 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 premium of 8.55% results in a beta-adjusted equity risk premium for the Utility Proxy Group of 6.67%.

³⁴ As shown on page 8 of Schedule (DWD)-4.

1 B. S&P Utility Index Derived Equity Risk Premium

2 Q55. How did you derive the equity risk premium based on the S&P Utility Index and

Moody's A2-rated public utility bonds?

A55.

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%. 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% ³⁶, 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 (*i.e.*, historical,

³⁵ As shown on line 1, page 12 of Schedule (DWD)-4.

³⁶ Derived on line 3, page 3 of Schedule (DWD)-4.

Value Line, and Bloomberg) to arrive at my utility-specific equity risk premium of
 4.32%.

<u>Table 6: Summary of the Calculation of the Equity Risk Premium Using S&P Utility</u> Index Holding Returns³⁷

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 <i>Value Line</i> 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%

5 C. Authorized Return Derived Equity Risk Premium

6 Q56. How do you derive an equity risk premium of 4.77% based on authorized ROEs

for electric utilities?

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A56. The equity risk premium of 4.77% shown on line 3, page 7 of Schedule (DWD)-8 4 is the result of a regression analysis based on regulatory awarded ROEs related to the 9 10 yields on Moody's A2-rated public utility bonds. That analysis is shown on page 13 11 of Schedule (DWD)-4. Page 13 of Schedule (DWD)-4 contains the graphical results 12 of a regression analysis of 1207 rate cases for electric utilities which were fully litigated during the period from January 1, 1980 through December 30, 2022. It shows the 13 14 implicit equity risk premium relative to the yields on A2-rated public utility bonds 15 immediately prior to the issuance of each regulatory decision.

³⁷ As shown on page 12 of Schedule (DWD)-4.

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9	Q57.	What is your conclusion of an equity risk premium for use in your total market
8		shown on line 3, page 7 of Schedule (DWD)-4.
7		that the indicated equity risk premium applicable to that bond yield is 4.77%, which is
6		bonds. Given the expected A2-rated utility bond yield of 5.88%, it can be calculated
5		risk premium applicable to the projected yield on Moody's A2-rated public utility
4		financial literature on the subject. ³⁸ I used the regression results to estimate the equity
3		rates decline, the equity risk premium rises and vice versa, a result consistent with
2		on A2-rated public utility bonds and equity risk premiums. In other words, as interest
1		It is readily discernible that there is an inverse relationship between the yield

- 9 Q57. What is your conclusion of an equity risk premium for use in your total market approach RPM analysis?
- 11 A57. The equity risk premium I apply to the Utility Proxy Group is 5.25%, which is
 12 the average of the beta-adjusted equity risk premium for the Utility Proxy Group, the
 13 S&P Utilities Index, and the authorized return utility equity risk premiums of 6.67%,
 14 4.32%, and 4.77%, respectively.³⁹
- 15 Q58. What is the indicated RPM common equity cost rate based on the total market
 16 approach?
- As shown on line 7, page 3 of Schedule (DWD)-4 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.

³⁸ See, e.g., Robert S. Harris and Felicia C. Marston, *The Market Risk Premium: Expectational Estimates Using Analysts' Forecasts*, <u>Journal of Applied Finance</u>, 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.

³⁹ As shown on page 7 of Schedule (DWD)-4.

Table 7: Summary of the Total Market Return Risk Premium Model⁴⁰

Prospective Moody's Baa1-Rated Utility Bond Applicable to the Utility Proxy Group	6.08%
Prospective Equity Risk Premium	<u>5.25%</u>
Indicated Cost of Common Equity	<u>11.33%</u>

common equity cost rate is 11.64%, which gives equal weight to the PRPM (11.95%)

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A60.

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O59. What are the results of your application of the PRPM and the total market 3 approach RPM?

A59. As shown on page 1 of Schedule (DWD)-4, the indicated RPM-derived 5

and the adjusted-market approach results (11.33%).

The Capital Asset Pricing Model 8

O60. Please explain the theoretical basis of the CAPM. 9

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 riskfree rate of return to a market risk premium, which is adjusted proportionately to reflect the systematic risk of the individual security relative to the total market as measured by

⁴⁰ As shown on page 3 of Schedule (DWD)-4.

the beta. The traditional CAPM model is expressed as:

2		$R_{\rm s}$	=	$R_f + \beta (R_m - R_f)$
3	Where:	$R_{\rm s}$	=	Return rate on the common stock
4		R_{f}	=	Risk-free rate of return
5		R_{m}	=	Return rate on the market as a whole
6		β	=	Adjusted beta (volatility of the
7				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.⁴¹

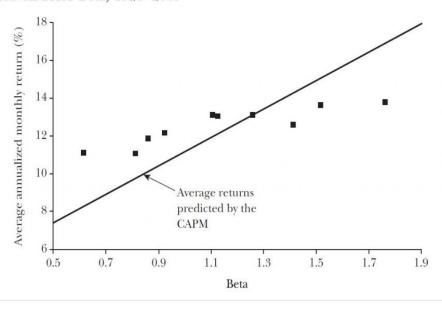
The ECAPM reflects this empirical reality. Fama and French clearly state regarding Figure 2, below, that "[t]he returns on the low beta portfolios are too high, and the returns on the high beta portfolios are too low." 42

⁴¹ Morin, at 205-209.

⁴² 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



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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.⁴³

* * *

Therefore, the empirical evidence suggests that the expected return on a security is related to its risk by the following approximation:

$$K = \ R_F + x \; \beta (R_M \mbox{ - } R_F) + (1\mbox{ - } x) \; \; \beta (R_M \mbox{ - } R_F) \label{eq:K}$$

where x is a fraction to be determined empirically. The value of x that best explains the observed relationship [is] Return = $0.0829 + 0.0520 \,\beta$ is between 0.25 and 0.30. If x = 0.25, the equation becomes:

$$K = R_F + 0.25(R_M - R_F) + 0.75 \beta(R_M - R_F)^{44}$$

⁴³ Morin, at 207.

⁴⁴ Morin, at 221.

1		Fama and French provide similar support for the ECAPM when they state:
2 3 4 5 6 7 8		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). ⁴⁵
9		Finally, Fama and French further note:
10 11 12 13 14 15 16 17 18		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. ⁴⁶
19		Clearly, the justification from Morin, Fama, and French, along with their
20		reviews of other academic research on the CAPM, validate the use of the ECAPM. In
21		view of theory and practical research, I have applied both the traditional CAPM and
22		the ECAPM to the companies in the Utility Proxy Group and averaged the results.
23	Q61.	What Beta coefficients did you use in your CAPM analysis?
24	A61.	For the beta in my CAPM analysis, I considered two sources: Value Line and
25		Bloomberg Professional Services. While both of those services adjust their calculated
26		(or "raw") betas to reflect the tendency of beta to regress to the market mean of 1.00
27		Value Line calculates beta over a five-year period, while Bloomberg calculates it over
28		a two-year period.

⁴⁵ Fama & French, at 32.⁴⁶ Fama & French, at 33.

1 Q62. Please describe your selection of a risk-free rate of return.

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.

Q63. Please explain the estimation of the expected risk premium for the market used in your CAPM analyses.

The basis of the market risk premium is explained in detail in note 1 on Schedule (DWD)-5. 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 <u>SBBI - 2022</u> monthly historical total market return of 12.37%, which results in an historical market equity risk premium of 7.35%. ⁴⁷ 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 <u>SBBI -2022</u>. 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.

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*

A63.

⁴⁷ <u>SBBI - 2022</u>, at 256-258, 274-276.

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 CAPM⁴⁸

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 <i>Value Line</i> Summary & Index less Projected 30-Year Treasury Bond Yields	12.67%
Prospective Equity Risk Premium using Measures of Capital Appreciation and Income Returns from <i>Value Line</i> 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	<u>7.15%</u>
Average	<u>9.75%</u>

⁴⁸ As shown on page 2 of Schedule (DWD)-5.

1	Q64.	What are the results of your application of the traditional and empirical CAPM
2		to the Utility Proxy Group?
3	A64.	As shown on page 1 of Schedule (DWD)-5, the mean result of my
4		CAPM/ECAPM analyses is 11.80%, the median is 11.78%, and the average of the two
5		is 11.79%. Consistent with my reliance on the average of mean and median DCF
6		results discussed above, the indicated common equity cost rate using the
7		CAPM/ECAPM is 11.79%.
8 9	Comn	non Equity Cost Rates for a Proxy Group of Domestic, Non-Price Regulated Companies Based on the DCF, RPM, and CAPM
10	Q65.	Why do you also consider a proxy group of domestic, non-price regulated
11		companies?
12	A65.	Although I am not an attorney, my interpretation of the Hope and Bluefield
13		cases is that they did not specify that comparable risk companies had to be utilities.
14		Since the purpose of rate regulation is to be a substitute for marketplace competition,
15		non-price regulated firms operating in the competitive marketplace make an excellent
16		proxy if they are comparable in total risk to the Utility Proxy Group being used to
17		estimate the cost of common equity. The selection of such domestic, non-price
18		regulated competitive firms theoretically and empirically results in a proxy group
19		which is comparable in total risk to the Utility Proxy Group, since all of these
20		companies compete for capital in the exact same markets.
21	Q66.	How did you select non-price regulated companies that are comparable in total
22		risk to the Utility Proxy Group?
23	A66.	In order to select a proxy group of domestic, non-price regulated companies
24		similar in total risk to the Utility Proxy Group, I relied on the betas and related statistics

1		derived from Value Line regression analyses of weekly market prices over the most
2		recent 260 weeks (i.e., five years). These selection criteria resulted in a proxy group
3		of 50 domestic, non-price regulated firms comparable in total risk to the Utility Proxy
4		Group. Total risk is the sum of non-diversifiable market risk and diversifiable
5		company-specific risks. The criteria used in selecting the domestic, non-price regulated
6		firms was:
7		(i) They must be covered by Value Line Investment Survey (Standard Edition);
8		(ii) They must be domestic, non-price regulated companies, i.e., not utilities;
9		(iii) Their betas must lie within plus or minus two standard deviations of the average
10		unadjusted betas of the Utility Proxy Group; and
11		(iv) The residual standard errors of the Value Line regressions which gave rise to
12		the unadjusted betas must lie within plus or minus two standard deviations of
13		the average residual standard error of the Utility Proxy Group.
14		Betas measure market, or systematic, risk, which is not diversifiable. The
15		residual standard errors of the regressions measure each firm's company-specific,
16		diversifiable risk. Companies that have similar betas and similar residual standard
17		errors resulting from the same regression analyses have similar total investment risk.
18	Q67.	Have you prepared a schedule which shows the data from which you selected the
19		50 domestic, non-price regulated companies that are comparable in total risk to
20		the Utility Proxy Group?
21	A67.	Yes, the basis of my selection and both proxy groups' regression statistics are

shown in Schedule (DWD)-6.

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1	Q68.	Did you calculate common equity cost rates using the DCF model, RPM, an
2		CAPM for the Non-Price Regulated Proxy Group?

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)-7 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)-7 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)-7, the consensus prospective yield on Moody's Baa2-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%. 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% ⁵⁰ 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%.

A68.

⁴⁹ Blue Chip, January 1, 2023 at 2 and December 2, 2022 at 14.

⁵⁰ Derived on page 5 of Schedule (DWD)-7.

1	Page 6 of Schedule (DWD)-7 contains the inputs and calculations that support
2	my indicated CAPM/ECAPM common equity cost rate of 12.59%.

- Q69. 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?
- As shown on page 1 of Schedule (DWD)-7, 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.

VII. Conclusion of Common Equity Cost Rate Before Adjustments

Q70. What is the indicated common equity cost rate before adjustments?

A70.

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 ACE and the Utility Proxy Group are made. I have chosen this indicated ROE before adjustment because of current market data, which is currently understating the investor-required return for the DCF.

VIII. Adjustments to the Common Equity Cost Rate

7 Size Adjustment

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- 8 Q71. Does ACE's smaller size relative to the Utility Proxy Group companies increase
- 9 its business risk?
- 10 A71. Yes. ACE's smaller size relative to the Utility Proxy Group companies
 11 indicates greater relative business risk for the Company because, all else being equal,
 12 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

2	of the magnitude of the size premium based on several measures of size. In discussing
3	"Size as a Predictor of Equity Premiums," Kroll states:
4 5 6	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
7 8	important risk elements to consider when developing cost of equity capital estimates for use in valuing a business simply because size has
9 10	been shown to be a <i>predictor</i> of equity returns. In other words, there is a significant (negative) relationship between size and historical equity
11 12	returns - as size <i>decreases</i> , returns tend to <i>increase</i> , and vice versa. (footnote omitted) (emphasis in original) ⁵¹
13	Furthermore, in "The Capital Asset Pricing Model: Theory and Evidence,"
14	Fama and French note size is indeed a risk factor which must be reflected when
15	estimating the cost of common equity. On page 14, they note:
16 17 18 19	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. ⁵²
20	Based on this evidence, Fama and French proposed their three-factor model
21	which includes a size variable in recognition of the effect size has on the cost of
22	common equity.
23	Also, it is a basic financial principle that the use of funds invested, and not the
24	source of funds, is what gives rise to the risk of any investment. ⁵³ Eugene Brigham, a
25	well-known authority, states:
26 27 28	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

("Kroll") discusses the nature of the small-size phenomenon, providing an indication

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Kroll, <u>Cost of Capital Navigator: U.S. Cost of Capital Module</u>, Size as a Predictor of Equity Returns, at 1.
 Fama & French, at 25-43.
 Brealey, Richard A. and Myers, Stewart C., <u>Principles of Corporate Finance</u> (McGraw-Hill Book Company, 1996), at 204-205, 229.

1	the surface, it would seem to be advantageous to the small firms to
2	provide average returns in a stock market that are higher than those
3	of larger firms. In reality, it is bad news for the small firm; what
4	the small-firm effect means is that the capital market demands
5	higher returns on stocks of small firms than on otherwise similar
6	stocks of the large firms. (emphasis added) ⁵⁴

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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 Commission's authorization of a cost rate of common equity in this proceeding must appropriately reflect the unique risks of ACE, including its small relative size, which is justified and supported above by evidence in the financial literature.

- Q72. 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?
- 16 A72. 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.
- Q73. Is there a way to quantify a relative risk adjustment due to ACE's small size whencompared to the Utility Proxy Group?
- 21 A73. Yes. ACE has greater relative risk than the average utility in the Utility Proxy
 22 Group because of its smaller size, as measured by an estimated market capitalization
 23 of common equity for ACE.

⁵⁴ Brigham, Eugene F., <u>Fundamentals of Financial Management</u>, <u>Fifth Edition</u> (The Dryden Press, 1989), at 623.

<u>Table 9: Size as Measured by Market Capitalization for ACE's</u>
<u>Electric Operations and the Utility Proxy Group</u>

	Market <u>Capitalization*</u> (\$ Millions)	Times Greater than The Company
ACE	\$2,198.677	
Utility Proxy Group	\$ 22,798.483	10.40x
*From page 1 of Schedule (DWD)-8.		

ACE's estimated market capitalization was \$2.199 billion as of December 30, 2022, compared with the market capitalization of the average company in the Utility Proxy Group of \$22.798 billion as of December 30, 2022. The average company in the Utility Proxy Group has a market capitalization 10.40 times the size of ACE'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.⁵⁵ The average size premium for the Utility Proxy Group with a market capitalization of \$22.798 billion falls in the 2nd decile, while the Company's estimated market capitalization of \$2.199 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

⁵⁵ Source: Kroll, Cost of Capital Navigator.

- applied a size premium of 0.25% to the Company's indicated common equity cost rate
- in order to be conservative.
- 3 Q74. Since ACE is part of a larger company, why is the size of the total company not 4 more appropriate to use when determining the size adjustment?
- A74. As discussed previously, rates are set using the stand-alone principle, which 5 6 maintains that the utility operations of a diversified firm should be regulated as though they were independent (i.e., without subsidies to or from affiliated companies). 7 Because of this, the return derived in this proceeding will not apply to Exelon's 8 9 operations as a whole, but only ACE's. Exelon is the sum of its constituent parts, including those constituent parts' ROEs. Potential investors in the Parent are aware that 10 it is a combination of operations in each state, and that each state's operations 11 experience the operating risks specific to their jurisdiction. The market's expectation 12 of Exelon's return is commensurate with the realities of the Company's composite 13 14 operations in each of the states in which it operates.

15 Flotation Cost Adjustment

16 Q75. What are flotation costs?

17 A75. Flotation costs are those costs associated with the sale of new issuances of
18 common stock. They include market pressure and the mandatory unavoidable costs of
19 issuance (e.g., underwriting fees and out-of-pocket costs for printing, legal,
20 registration, etc.). For every dollar raised through debt or equity offerings, the
21 Company receives less than one full dollar in financing.

1	Q76.	Why is it important to recognize flotation costs in the allowed common equity cost
2		rate?
3	A76.	It is important because there is no other mechanism in the ratemaking paradigm
4		through which such costs can be recognized and recovered. Because these costs are
5		real, necessary, and legitimate, recovery of these costs should be permitted. As noted
6		by Morin:
7 8 9		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
10 11 12		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
13	Q77.	Did Exelon recently issue common equity?
14	A77.	Yes, it did. On August 3, 2022, Exelon issued 12,995,000 shares of common
15		equity for net proceeds of \$562,043,050.57
16	Q78.	Should flotation costs be recognized only if there was an issuance during the test
17		year or there is an imminent post-test year issuance of additional common stock?
18	A78.	No. As noted above, there is no mechanism to recapture such costs in the
19		ratemaking paradigm other than an adjustment to the allowed common equity cost rate.
20		Flotation costs are charged to capital accounts and are not expensed on a utility's
21		income statement. As such, flotation costs are analogous to capital investments, albeit
22		negative, reflected on the balance sheet. Recovery of capital investments relates to the
23		expected useful lives of the investment. Since common equity has a very long and

⁵⁶ Morin, at 329. 57 Exelon Corporation SEC Form 10-Q for the fiscal quarter ended September 30, 2022.

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.

A79.

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.

Q79. Do the common equity cost rate models you have used already reflect investors' anticipation of flotation costs?

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.⁵⁸ In addition, Morin confirms the need for such an adjustment even when no new equity issuance is imminent.⁵⁹ Consequently, it is proper to include a flotation cost adjustment when using cost of common equity models to estimate the common equity cost rate.

5 Q80. How did you calculate the flotation cost allowance?

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 Exelon. Based on the issuance costs shown on page 1 of Schedule (DWD)-9, an adjustment of 0.18% is required to reflect the flotation costs applicable to the Utility Proxy Group.

Q81. What is the indicated cost of common equity after your Company-specific adjustments?

A81. Applying the 0.25% size adjustment and the 0.18% 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 10.47% and 11.47%.

IX. Conclusion

17 Q82. What is your recommended ROE for ACE?

A82. Given the discussion above and the results from the analyses in this testimony, I recommend that an ROE of 10.50%, within a range between 10.47% and 11.47%, is appropriate for the Company at this time.

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⁵⁸ Eugene F. Brigham and Phillip R. Daves, <u>Intermediate Financial Management</u>, 9th Edition, Thomson/Southwestern, at p. 342.

⁵⁹ Morin, at 337-339.

- 1 Q83. In your opinion, is your proposed ROE of 10.50% fair and reasonable to ACE and
- 2 its customers?
- 3 A83. Yes, it is.
- 4 Q84. Does this conclude your Direct Testimony?
- 5 A84. Yes, it does.

D'Ascendis Appendix A



Resume & Testimony Listing of: Dylan W. D'Ascendis, CRRA, CVA

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

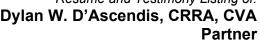
- Provided expert testimony on the cost of capital for ratemaking purposes before numerous state utility regulatory agencies
- Sponsored valuation testimony for a large municipal water company in front of an American Arbitration Association Board to justify the reasonability of their lease payments to 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				1	
ENSTAR Natural Gas Company	08/22	ENSTAR Natural Gas Company	Docket No. TA334-4	Rate of Return	
Cook Inlet Natural Gas Storage		Cook Inlet Natural Gas Storage			
Alaska, LLC	07/21	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				<u>'</u>	
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	on				
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	on				
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	on				
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 L	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 Commis					
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	

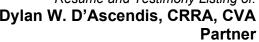




Sponsor	Date	Case/Applicant	Docket No.	Subject			
Lanai Water Company, Inc.	12/19	Lanai Water Company, Inc.	Docket No. 2019-0386	Cost of Service / Rate Design			
Manele Water Resources, LLC	08/19	Manele Water Resources, LLC	Docket No. 2019-0311	Cost of Service / Rate Design			
Kaupulehu Water Company	00/19	Kaupulehu Water Company	Docket No. 2016-0363	Rate Design			
Raupulent Water Company	02/10	Raupulend Water Company	DOCKEL NO. 2010-0303	Cost of Service /			
Aqua Engineers, LLC	05/17	Puhi Sewer & Water Company	Docket No. 2017-0118	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 Commiss				1 1010 011 1010			
maining carry regulatory commission		Aqua Indiana, Inc. Aboite					
Aqua Indiana, Inc.	03/16	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 Commissi	on						
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 Commissi	ion			, ,			
Utilities, Inc. of Louisiana	05/21	Utilities, Inc. of Louisiana	Docket No. U-36003	Rate of Return			
Southwestern Electric Power		Southwestern Electric Power					
Company	12/20	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	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		Turios Energy	DOOKOT 140. 2010 014 040	Oupital Otractare		
Spire Missouri, Inc.	12/20	Spire Missouri, Inc.	Case No. GR-2021-0108	Return on Equity		
Indian Hills Utility Operating	12/20	Indian Hills Utility Operating	0000 110. 011 2021 0100	Trotain on Equity		
Company, Inc.	10/17	Company, Inc.	Case No. SR-2017-0259	Rate of Return		
Raccoon Creek Utility Operating		Raccoon Creek Utility Operating				
Company, Inc.	09/16	Company, Inc.	Case No. SR-2016-0202	Rate of Return		
Public Utilities Commission of Nev	ada					
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 Con	nmission					
Aquarion Water Company of New		Aquarion Water Company of New				
Hampshire, Inc.	12/20	Hampshire, Inc.	Docket No. DW 20-184	Rate of Return		
New Jersey Board of Public Utilitie	1	I		T =		
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	40/44	The Atlantic City Sewerage	B	Cost of Service /		
Company	10/14	Company	Docket No. WR14101263	Rate Design		
Middlesex Water Company	11/13	Middlesex Water Company	Docket No. WR1311059	Capital Structure		
New Mexico Public Regulation Con		Coutburgators Dublic Comics Co	Coop No. 20 00220 LIT	Datum on Fauity		
Southwestern Public Service Co.	01/21	Southwestern Public Service Co.	Case No. 20-00238-UT	Return on Equity		
North Carolina Utilities Commissio	1	O Franklin O to La	D. J. (N. W.054.0. J. 400	D.I. (D.I.)		
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	1					
Duke Energy Ohio, Inc.	10/21	Duke Energy Ohio, Inc.	Case No. 21-887-EL-AIR	Return on Equity		





Sponsor	Date	Case/Applicant	Docket No.	Subject	
Agua Ohio, Inc.	07/21	Aqua Ohio, Inc.	Case No. 21-0595-WW-AIR	Rate of Return	
Agua Ohio, Inc.	05/16	Aqua Ohio, Inc.	Case No. 16-0907-WW-AIR	Rate of Return	
Pennsylvania Public Utility Commis		1 4 2 2 2			
		Borough of Ambler – Bureau of			
Borough of Ambler	06/22	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,	24/24	Community Utilities of Pennsylvania,			
Inc.	04/21	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	00/00	Delaware County Regional Water	Darlot No. A 0040 2045472	Maluratian	
Control Authority	02/20	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	07/19	CST Enterprises	Docket No. R-2019-3008212	Rate of Return	
Lewisburg		C&T Enterprises	Docket No. A-2019-3006880		
Steelton Borough Authority	01/19	Steelton Borough Authority		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 Com	mission				
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,		Utility Services of South Carolina,			
Inc.	09/13	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 Commiss	sion				
Northern States Power Company	06/22	Northern States Power Company	Docket No. EL22-017	Rate of Return	
Tennessee Public Utility Commission	on				
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 B					
Virginia Natural Gas, Inc.	04/21	Virginia Natural Gas, Inc.	PUR-2020-00095	Return on Equity	
<u> </u>		J : : :::: : : : : : : : : : : : : : :	1		



Sponsor	Date	Case/Applicant	Docket No.	Subject
Massanutten Public Service		Massanutten Public Service		
Corporation	12/20	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
				Rate of Return /
Massanutten Public Service Corp.	08/14	Massanutten Public Service Corp.	PUE-2014-00035	Rate Design
Public Service Commission of Wes	t Virginia			
Monongahela Power Company and		Monongahela Power Company and		
The Potomac Edison Company	12/21	The Potomac Edison Company	Case No. 21-0857-E-CN (ELG)	Return on Equity
Monongahela Power Company and		Monongahela Power Company and		
The Potomac Edison Company	11/21	The Potomac Edison Company	Case No. 21-0813-E-P (Solar)	Return on Equity

Atlantic City Electric Company Table of Contents Schedules to the Direct Testimony of Dylan W. D'Ascendis

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Schedule (DWD)-1

Atlantic City Electric Company Recommended Capital Structure and Cost Rates for Ratemaking Purposes at December 30, 2022

Type Of Capital	Ratios (1)	Cost Rate	Weighted Cost Rate
Long-Term Debt Common Equity	49.80% 50.20%	3.73% (1) 10.50% (2)	1.86% 5.27%
Total	100.00%		7.13%

Notes:

- (1) Company-provided.
- (2) From page 2 of this Schedule.

Atlantic City Electric Company Brief Summary of Common Equity Cost Rate

Line No.	Principal Methods	Proxy Group of Thirteen Electric Distribution Companies
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)	0.25%
7.	Flotation Costs (6)	0.18%
8.	Indicated Common Equity Cost Rate after Adjustment	10.47% - 11.47%
9.	Recommended Common Equity Cost Rate	10.50%

Notes: (1) From Schedule (DWD)-3.

- (2) From page 1 of Schedule (DWD)-4.
- (3) From page 1 of Schedule (DWD)-5.
- (4) From page 1 of Schedule (DWD)-7.
- (5) Business risk adjustment to reflect Atlantic City Electric Company's increased business risk due to its smaller size as compared to the Utility Proxy Group as detailed in the accompanying direct testimony.
- (6) From page 1 of Schedule (DWD)-9.

Schedule (DWD)-2

Proxy Group of Thirteen Electric Distribution Companies CAPITALIZATION AND FINANCIAL STATISTICS (1) 2017 - 2021, Inclusive

	2021		<u>2020</u>	JUL	2019 JONS OF DOLI	.AR	<u>2018</u>		<u>2017</u>			
<u>Capitalization Statistics</u>			(.	.1122	nond of Bobi	22 11 (2)					
Amount of Capital Employed												
Total Permanent Capital	\$30,625.456		\$28,277.157		\$26,156.193		\$23,914.865		\$23,059.583			
Short-Term Debt	\$1,129.987		\$980.778		\$903.416	_	\$928.626	_	\$913.929	_		
Total Capital Employed	\$31,755.443		\$29,257.935		\$27,059.609	_	\$24,843.491	_	\$23,973.512	=		
Indicated Average Capital Cost Rates (2)												
Total Debt	3.68	%	4.10	%	4.33	%	4.48	%	4.45	%		
Preferred Stock	9.35	%	4.62	%	4.67	%	4.67	%	4.67	%		
Capital Structure Ratios											5 YEAR AVERAC	_
Based on Total Permanent Capital:											TIVETURE	111
Long-Term Debt	55.85	%	54.65	%	52.86	%	51.99	%	51.80	%	53.43	%
Preferred Stock	0.63		0.81		0.95		0.95		1.09		0.89	
Common Equity	43.52		44.54		46.19		47.06		47.11		45.68	
Total	100.00	%	100.00	%	100.00	%	100.00	%	100.00	%	100.00	%
Based on Total Capital:												
Total Debt, Including Short-Term Debt	57.17	%	55.87	%	54.00	%	53.33	%	53.58	%	54.79	%
Preferred Stock	0.60		0.78		0.93		0.92		1.01		0.85	
Common Equity	42.23		43.36		45.08	_	45.76		45.40		44.36	_
Total	100.00	%_	100.00	_%	100.00	_%	100.00	_%	100.00	%	100.00	_%
Financial Statistics												
Financial Ratios - Market Based												
Earnings / Price Ratio	5.52	%	3.91	%	5.00	%	4.80	%	4.86	%	4.82	%
Market / Average Book Ratio	186.76		189.30		199.14		193.02		203.31		194.31	
Dividend Yield	3.54		3.45		3.21		3.54		3.34		3.42	
Dividend Payout Ratio	67.62		63.75		63.77		46.52		75.68		63.47	
Rate of Return on Average Book Common Equity	10.16	04	7.61	04	9.87	04	8.67	04	9.12	04	9.09	04
Rate of Return on Average book Common Equity	10.16	70	7.61	90	9.07	70	0.07	70	9.12	90	9.09	70
Total Debt / EBITDA (3)	5.25	x	6.11	X	4.67	x	5.31	x	4.22	x	5.11	x
Funds from Operations / Total Debt (4)	5.13	%	11.60	%	13.14	%	18.13	%	17.37	%	13.07	%
Total Debt / Total Capital	57.17	%	55.87	%	54.00	%	53.33	%	53.58	%	54.79	%

Notes:

- (1) All capitalization and financial statistics for the group are the arithmetic average of the achieved results for each individual company in the group, and are based upon financial statements as originally reported in each year.
- (2) Computed by relating actual total debt interest or preferred stock dividends booked to average of beginning and ending total debt or preferred stock reported to be outstanding.
- $(3) \ \ Total\ debt\ relative\ to\ EBITDA\ (Earnings\ before\ Interest,\ Income\ Taxes,\ Depreciation\ and\ Amortization).$
- (4) Funds from operations (sum of net income, depreciation, amortization, net deferred income tax and investment tax credits, less total AFUDC) plus interest charges as a percentage of total debt.

Source of Information: Company Annual Forms 10-K

Capital Structure Based upon Total Permanent Capital for the Proxy Group of Thirteen Electric Distribution Companies 2017 - 2021, Inclusive

						5 YEAR
	<u>2021</u>	<u>2020</u>	<u>2019</u>	<u>2018</u>	<u>2017</u>	<u>AVERAGE</u>
Alliant Energy Corporation						
Long-Term Debt	55.16 %	53.51 %	53.39 %	53.49 %	52.62 %	53.63 %
Preferred Stock	0.00	1.58	1.72	1.94	2.16	1.48
Common Equity	44.84	44.91	44.89	44.57	45.22	44.89
Total Capital	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %
Ameren Corporation						
Long-Term Debt	57.07 %	54.97 %	53.29 %	52.05 %	51.52 %	53.78 %
Preferred Stock	0.56	0.70	0.81	0.88	0.92	0.77
Common Equity	42.37	44.32	45.90	47.07	47.56	45.44
Total Capital	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %
American Electric Power Corporation						
Long-Term Debt	59.86 %	60.19 %	57.30 %	55.06 %	53.62 %	57.21 %
Preferred Stock	0.00	0.00	0.00	0.00	0.00	0.00
Common Equity	40.14	39.81	42.70	44.94	46.38	42.79
Total Capital	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %
Duke Energy Corporation						
Long-Term Debt	56.43 %	55.52 %	55.39 %	55.45 %	55.61 %	55.68 %
Preferred Stock	1.73	1.82	1.87	0.00	0.00	1.08
Common Equity	41.84	42.66	42.74	44.55	44.39	43.24
Total Capital	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %
Edison International						
Long-Term Debt	61.49 %	56.44 %	54.21 %	53.76 %	46.65 %	54.51 %
Preferred Stock	4.63	5.19	6.48	8.01	8.45	6.55
Common Equity	33.88	38.37	39.31	38.22	44.91	38.94
Total Capital	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %
Entergy Corporation						
Long-Term Debt	68.46 %	66.68 %	63.04 %	64.08 %	64.80 %	65.41 %
Preferred Stock	0.76	0.76	0.90	0.87	0.85	0.83
Common Equity	30.78	32.57	36.06	35.05	34.35	33.76
Total Capital	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %
Evergy, Inc.						
Long-Term Debt	51.17 %	52.48 %	51.77 %	42.70 %	49.60 %	49.54 %
Preferred Stock	0.00	0.00	0.00	0.00	0.00	0.00
Common Equity	48.83	47.52	48.23	57.30	50.40	50.46
Total Capital	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %
Eversource Energy						
Long-Term Debt	55.25 %	53.22 %	52.44 %	52.92 %	52.30 %	53.23 %
Preferred Stock	0.47	0.51	0.58	0.63	0.66	0.57
Common Equity	44.28	46.26	46.98	46.45	47.04	46.20
Total Capital	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %
IDACORP, Inc.						
Long-Term Debt	42.85 %	43.86 %	42.70 %	43.63 %	43.68 %	43.34 %
Preferred Stock	0.00	0.00	0.00	0.00	0.00	0.00
Common Equity	57.15	56.14	57.30	56.37	56.32	56.66
Total Capital	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %
NorthWestern Corporation						
Long-Term Debt	52.09 %	52.72 %	52.27 %	51.98 %	50.26 %	51.86 %
Preferred Stock	0.00	0.00	0.00	0.00	0.00	0.00
Common Equity	47.91	47.28	47.73	48.02	49.74	48.14
Total Capital	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %

Capital Structure Based upon Total Permanent Capital for the Proxy Group of Thirteen Electric Distribution Companies 2017 - 2021, Inclusive

	2021	2020	2019	2018	2017	<u>5 YEAR</u> <u>AVERAGE</u>
OGE Energy Corporation						
Long-Term Debt	52.57 %	49.04 %	43.56 %	44.00 %	43.78 %	46.59 %
Preferred Stock	0.00	0.00	0.00	0.00	0.00	0.00
Common Equity	47.43	50.96	56.44	56.00	56.22	53.41
Total Capital	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %
Portland General Electric Company						
Long-Term Debt	54.82 %	53.83 %	50.06 %	49.72 %	50.10 %	51.71 %
Preferred Stock	0.00	0.00	0.00	0.00	0.00	0.00
Common Equity	45.18	46.17	49.94	50.28	49.90	48.29
Total Capital	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %
Xcel Energy Inc.						
Long-Term Debt	58.91 %	57.93 %	57.77 %	57.01 %	56.66 %	57.66 %
Preferred Stock	0.00	0.00	0.00	0.00	0.00	0.00
Common Equity	41.09	42.07	42.23	42.99	43.34	42.34
Total Capital	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %
Proxy Group of Thirteen Electric Distribution Companies						
Long-Term Debt	55.85 %	54.65 %	52.86 %	51.99 %	51.63 %	53.40 %
Preferred Stock	0.63	0.81	0.95	0.95	1.00	0.87
Common Equity	43.52	44.54	46.19	47.06	47.37	45.74
Total Capital	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %	100.00 %

Source of Information Annual Forms 10-K

Atlantic City Electric Company Operating Subsidiary Company Capital Structures of the Proxy Group of Thirteen Electric Companies

2021 Parent Total Company Common Long-Ticker Equity Term Debt Capital Company Name Interstate Power and Light Company 49.21% 50.79% 100.00% LNT Wisconsin Power and Light Company LNT 46.84% 53.16% 100.00% Ameren Illinois Company AEE 43.99% 56.01% 100.00% Union Electric Company AEE 49.07% 50.93% 100.00% Central Illinois Light AEE NA NA NA Illinois Power and Light AEE NA NA NA **AEP Texas Central Company** AEP NA NA NA AEP Texas Inc. AEP 59.53% 40.47% 100.00% **AEP Texas North Company** AEP NA NA NA Appalachian Power Company AEP 52.03% 47.97% 100.00% Columbus Southern Power Company **AEP** NA NA NA 100.00% 55.13% 44.87% Indiana Michigan Power Company AEP Kentucky Power Company AEP 56.09% 43.91% 100.00% Ohio Power Company AEP 51.89% 48.11% 100.00% Public Service Company of Oklahoma 46.58% 100.00% AEP 53.42% Southwestern Electric Power Company AEP 52.85% 47.15% 100.00% Wheeling Power Company **AEP** NA NA NA Duke Energy Carolinas, LLC DUK 49.05% 50.95% 100.00% DUK 100.00% Duke Energy Florida, LLC 51.43% 48.57% Duke Energy Indiana, LLC 100.00% DHK 46.60% 53.40% Duke Energy Kentucky, Inc. DUK 47.32% 52.68% 100.00% Duke Energy Ohio, Inc. DUK 41.84% 100.00% 58.16% Duke Energy Progress, LLC DUK 52.72% 47.28% 100.00% Florida Progress Corporation DUK NA NA NA Piedmont Natural Gas DUK 47.14% 52.86% 100.00% DUK 100.00% Progress Energy, Inc. 55.66% 44.34% Southern California Edison Company EIX 57.33% 42.67% 100.00% 100.00% Entergy Arkansas, LLC **ETR** 53.22% 46.78% Entergy Gulf States Louisiana, L.L.C. **ETR** NA NA NA Entergy Louisiana, LLC ETR 57.30% 42.70% 100.00% Entergy Mississippi, LLC ETR 54.53% 45.47% 100.00% Entergy New Orleans, LLC ETR 55.53% 44.47% 100.00% Entergy Texas, Inc. **ETR** 49.30% 50.70% 100.00% **EVRG** Evergy Kansas South, Inc. NA NA NA Evergy Kansas Central, Inc. **EVRG** 46.81% 53.19% 100.00% Evergy Metro, Inc. **EVRG** 49.73% 50.27% 100.00% Evergy Missouri West, Inc. EVRG NA NA NA Aguarion Water Company of Connecticut, Inc. 44.45% 55.55% 100.00% ES ES 42.01% 57.99% 100.00% **Aquarion Company** The Connecticut Light and Power Company ES 44.30% 55.70% 100.00% Eversource Gas Company of Massachusetts (Bay State) ES NA NΑ NA Eversource Gas Company of Massachusetts (Columbia) ES 43.28% 56.72% 100.00% **NSTAR Electric Company** ES 44.67% 55.33% 100.00%**NSTAR Gas Company** ES 37.33% 62.67% 100.00% Public Service Company of New Hampshire ES 51.06% 48.94% 100.00% Yankee Gas Services Company ES 38.80% 61.20% 100.00% IDA 44.81% 55.19% 100.00% Idaho Power Company NWE 47.79% 100.00% NorthWestern Corporation 52.21% Oklahoma Gas and Electric Company OGE 46.71% 53.29% 100.00% POR Portland General Electric Company 57.11% 100.00% 42.89% Northern States Power Company (Minnesota) XEL 48.70% 51.30% 100.00% Northern States Power Company (Wisconsin) XEL 47.22% 52.78% 100.00% Public Service Company of Colorado XEL 45.42% 54.58% 100.00% Southwestern Public Service Company XEL 49.11% 50.89% 100.00% Maxiumum 59.53% 62.67% 37.33% 40.47% Minimum

Source of Information: S&P Global Market Intelligence. Company Financial Statements

Schedule (DWD)-3

Atlantic Gity Electric Company Indicated Common Equity Cost Rate Using the Discounted Cash Flow Model for the Proxy Group of Thirteen Electric Distribution Companies

	[1]	[2]	[3]	[4]	[2]	[9]	[2]
		Value Line Projected	Zack's Five Year Projected	Yahoo! Finance Projected	Average Projected		Indicated
	Average	Five Year	Growth	Five Year	Five Year	Adjusted	Common
Proxy Group of Thirteen Electric	Dividend	Growth in	Rate in	Growth in	Growth in	Dividend	Equity Cost
Distribution companies	Tiera (T)	EF 3 (2)	5 17	C II	(c) c 1:1	i iciu (+)	Nate (3)
Alliant Energy Corporation	3.20 %	% 00.9	5.90 %	5.53 %	5.81 %	3.29 %	9.10 %
Ameren Corporation	2.81	6.50	06.9	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	98.6
Edison International	4.80	16.00	2.60	4.40	7.67	4.98	12.65
Entergy Corporation	3.90	4.00	08.9	6.19	5.66	4.01	29.6
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	6.79
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	2.00	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	00'9	6.50	08.9	6.43	3.02	9.45
					A	Average	9.24 %
						Median	9.34 %
				Average	Average of Mean and Median	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 5 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, $3.20\% \times (1+(1/2 \times 5.81\%)) = 3.29\%$.
- (5) Column 6 + column 7.

Source of Information:

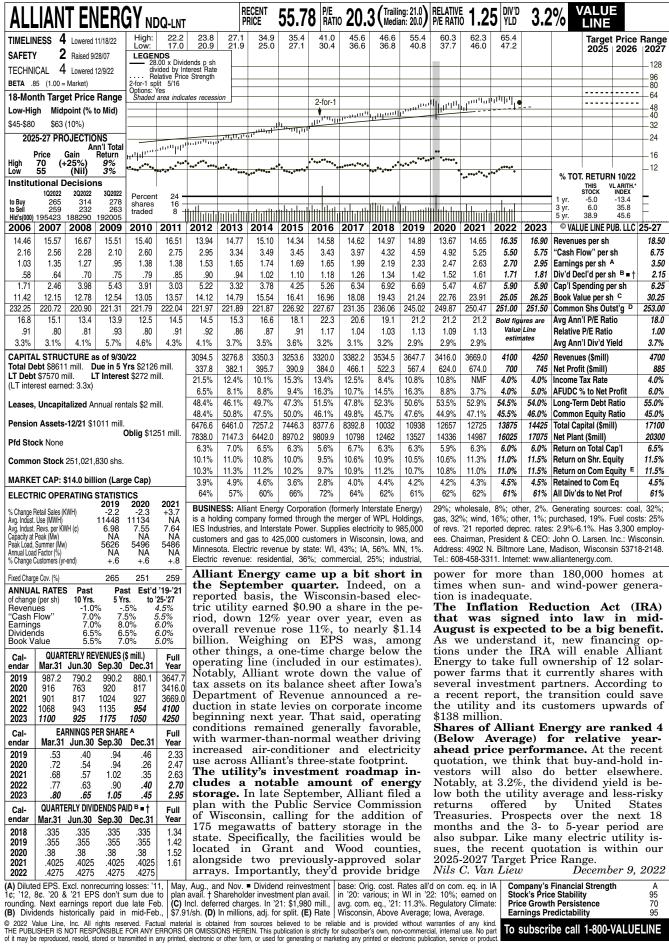
www.yahoo.com Downloaded on 12/30/2022 Bloomberg Professional Services www.zacks.com Downloaded on 12/30/2022 Value Line Investment Survey

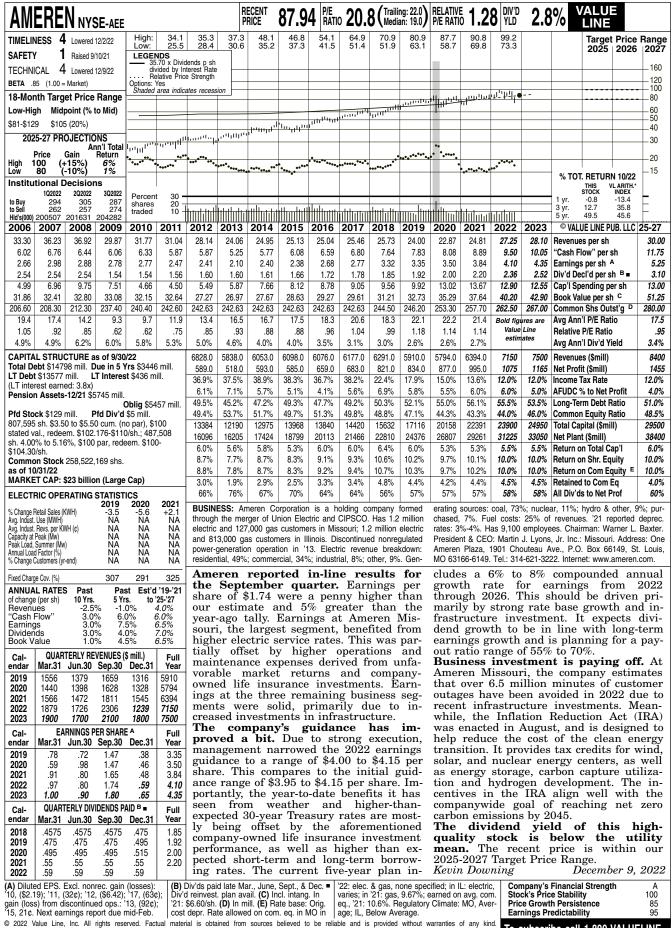
Atlantic City Electric Company Hypothetical Example of the Inadequacy of A DCF Return Rate Related to Book Value When Market Value is Greater / Less than Book Value

		[1]		[2]		[3]
Line No.	_	Market Value	wit	ook Value th Market to ook Ratio of 200%	V	Book Value vith Market to Book atio of 80%
1.	Per Share	\$ 30.00	\$	15.00	9	\$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)

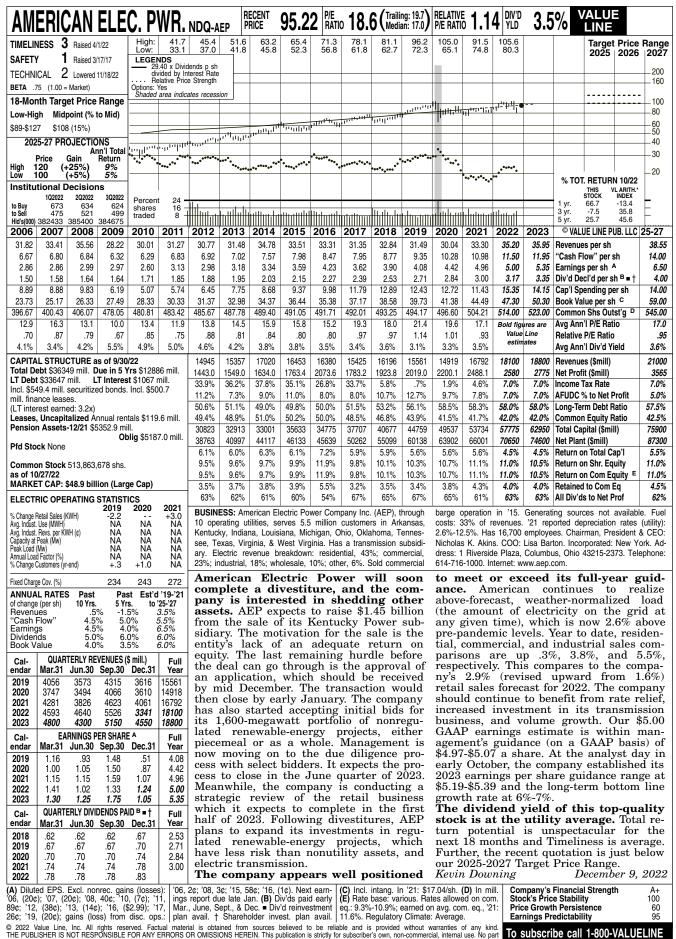
Notes:

- (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%).

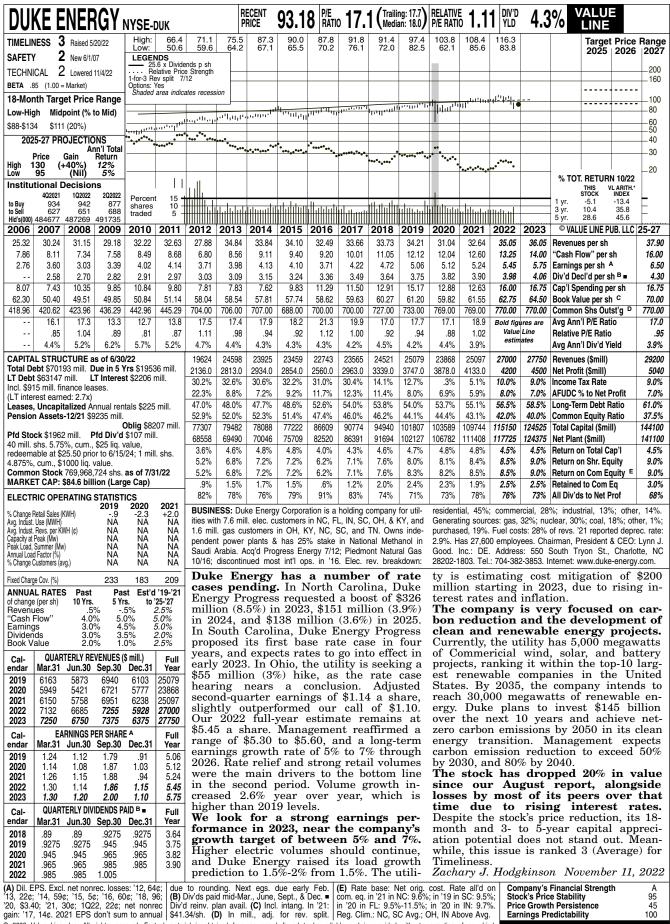




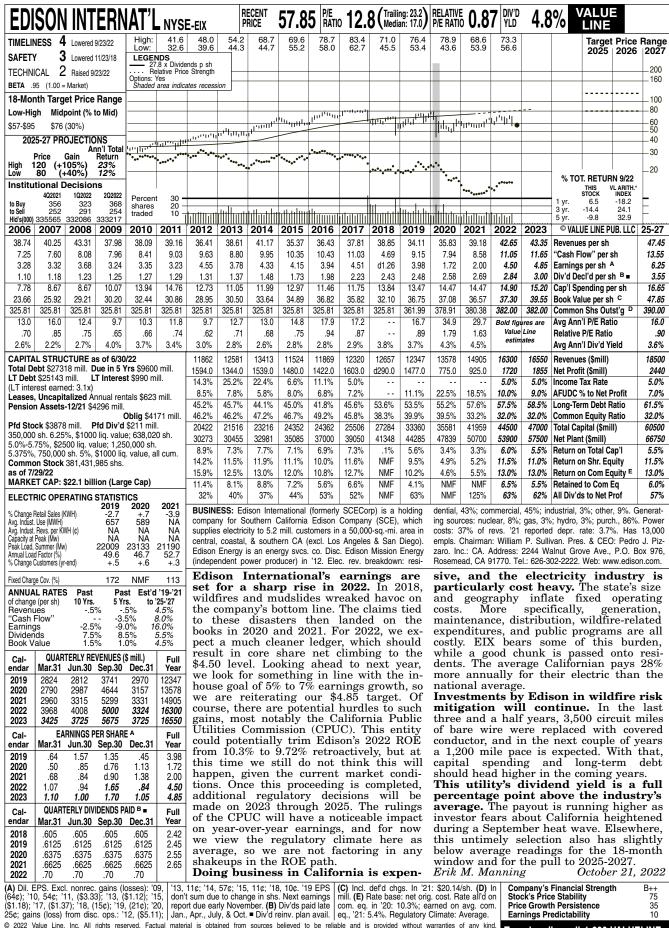
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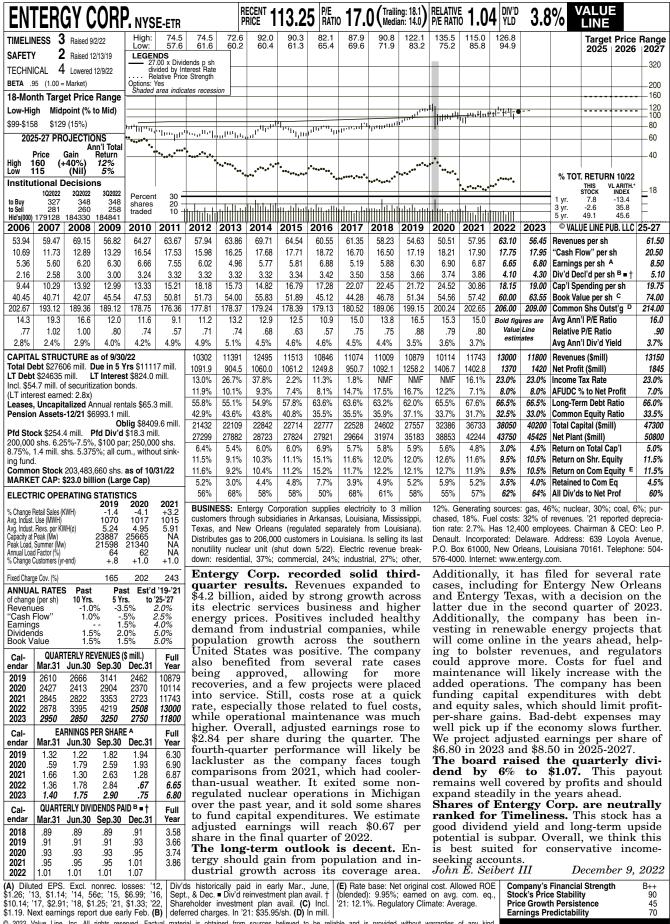
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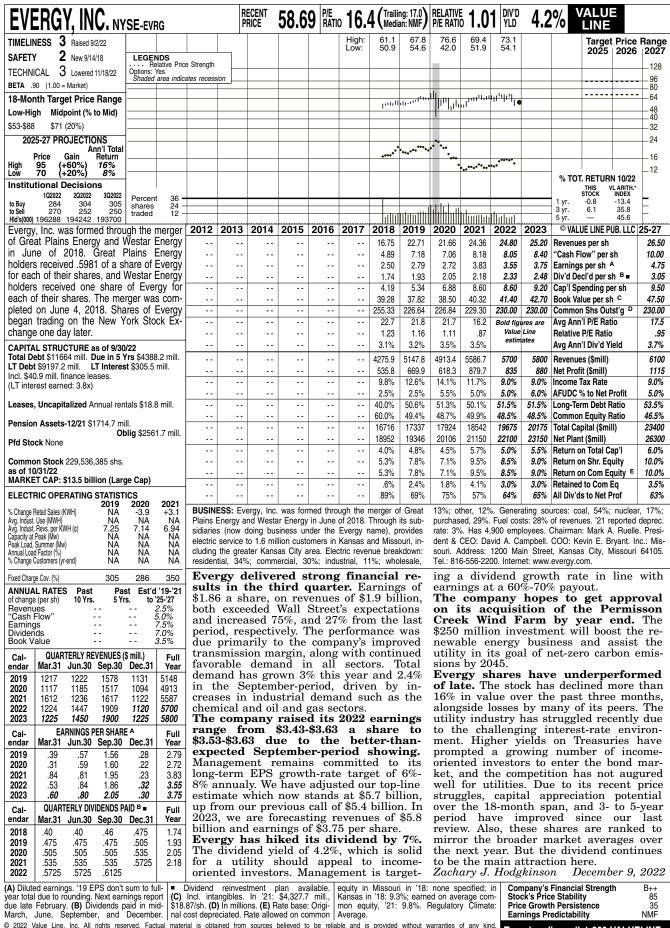
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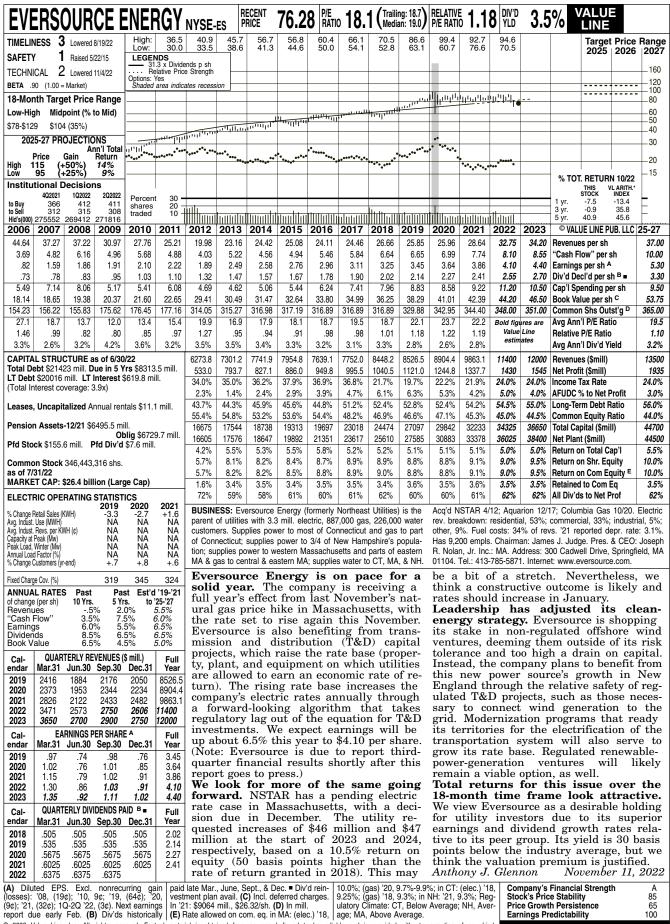
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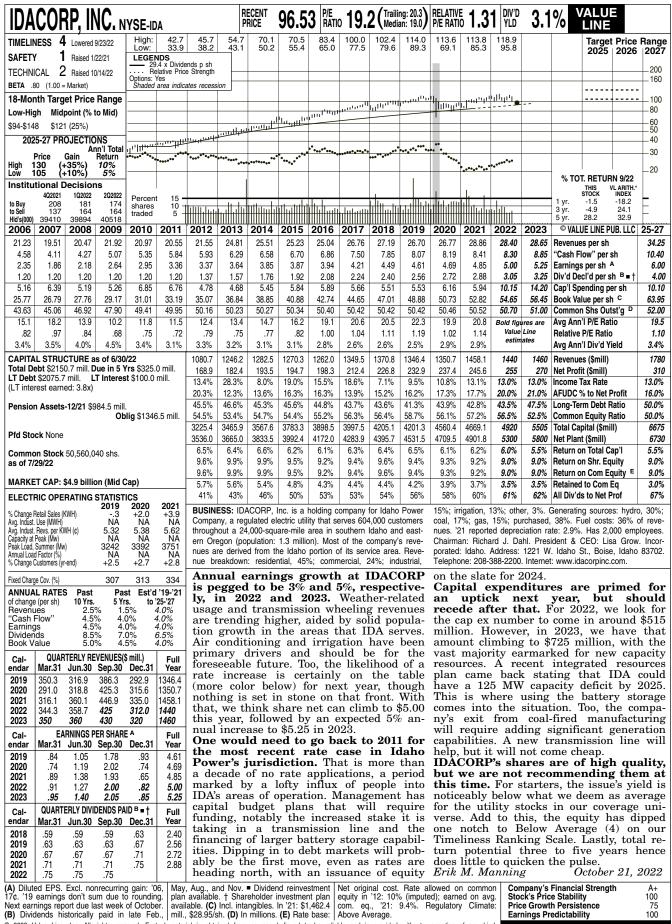
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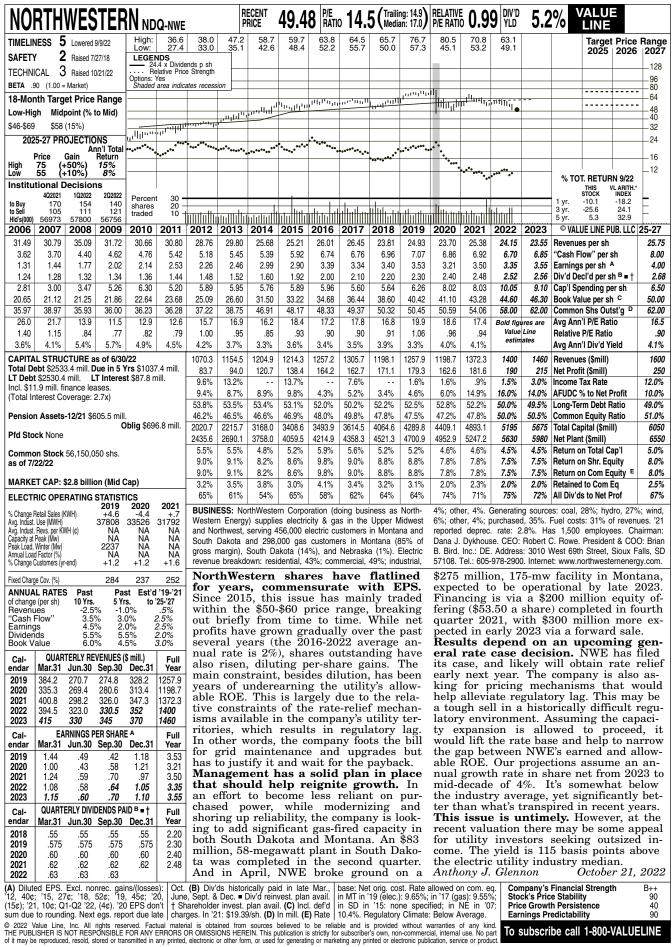
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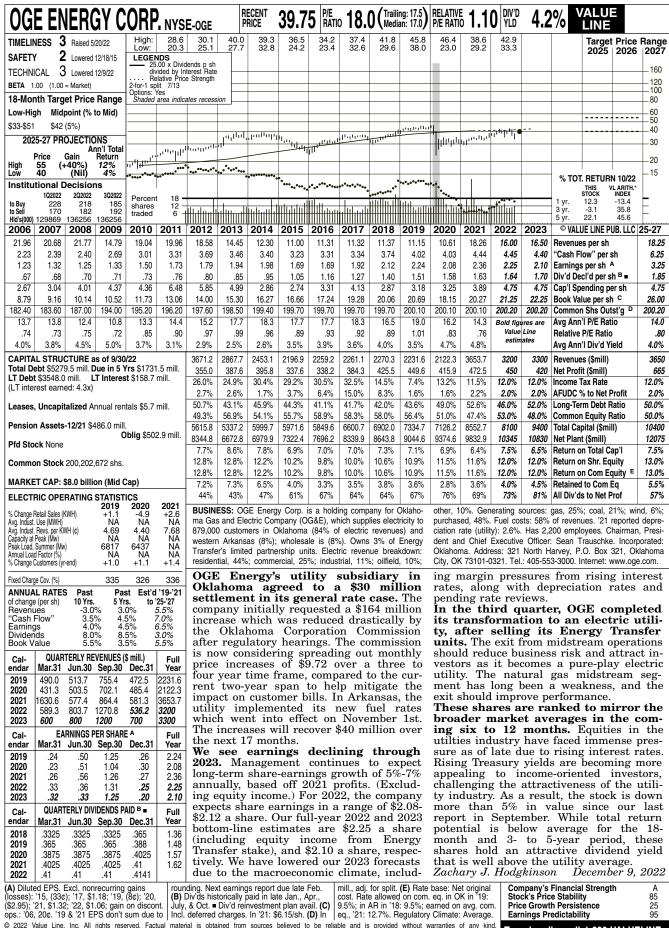
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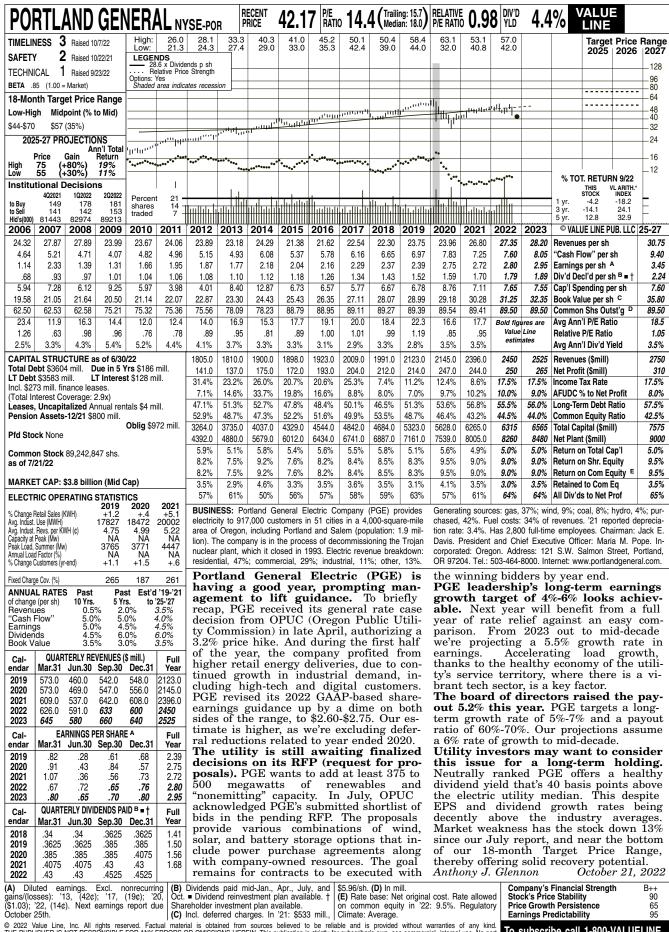


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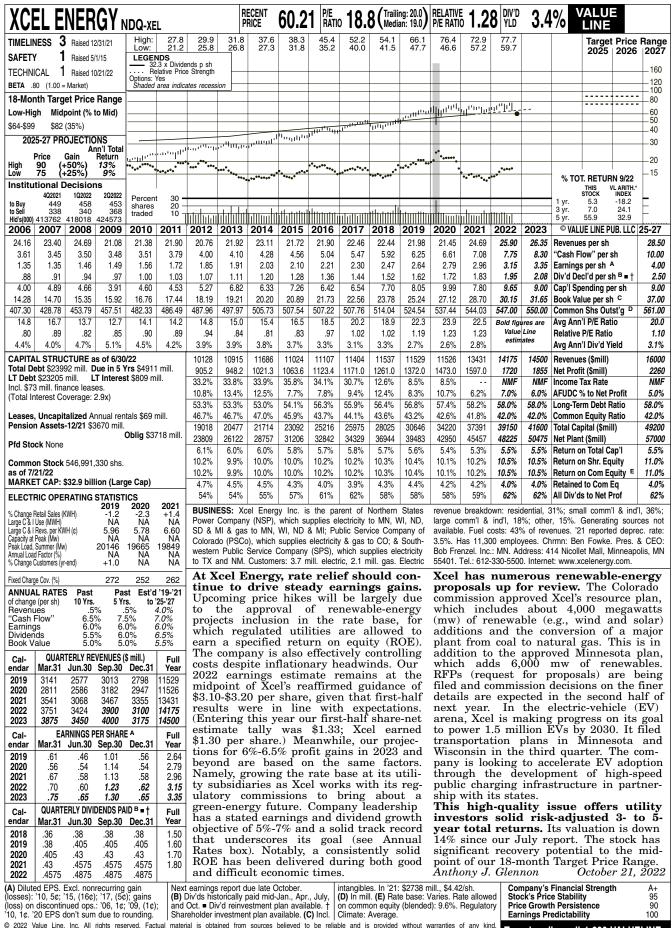


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Schedule (DWD)-4

Atlantic City Electric Company Summary of Risk Premium Models for the Proxy Group of Thirteen Electric Distribution Companies

	_	Proxy Group of Thirteen Electric Distribution Companies
Predictive Risk Premium Model (PRPM) (1)		11.95 %
Risk Premium Using an Adjusted Total Market Approach (2)	_	11.33
	Average	11.64 %

- (1) From page 2 of this Schedule.
- (2) From page 3 of this Schedule.

Atlantic City Electric Company Indicated ROE Derived by the Predictive Risk Premium Model (1)

	[1]	[2]	[3]	[4]	[5]	[6]	[7]
Proxy Group of Thirteen Electric Distribution Companies	LT Average Predicted Variance	Spot Predicted Variance	Recommended Variance (2)	GARCH Coefficient	Predicted Risk Premium (3)	Risk- Free Rate (4)	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%
				Ave	rage of Mean a	nd Median	11.95%

- (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+(Column [3] * Column [4])^{^12}) 1.
- (4) From note 2 on page 2 of Schedule (DWD)-5.
- (5) Column [5] + Column [6].

Atlantic City Electric 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 Distribution Companies
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	<u>11.33</u> %

- (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 Electric Utility Proxy Group as shown on page 5 of this Schedule. The 0.2% 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.

Atlantic City Electric Company Interest Rates and Bond Spreads for Moody's Corporate and Public Utility Bonds

Selected Bond Yields

	[1]	[2]	[3]
	Aaa Rated	A2 Rated	Baa2 Rated
	Corporate	Public Utility	Public Utility
	Bond	Bond	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 Service

Atlantic City Electric Company Comparison of Long-Term Issuer Ratings for Proxy Group of Thirteen Electric Distribution Companies

Moody's	Standard & Poor's
Long-Term Issuer Rating	Long-Term Issuer Rating
December 2022	December 2022

Proxy Group of Thirteen Electric Distribution Companies (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 subsidaries for Utility Proxy Group

Source 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 Dond	Numeroni cal Dan d	Standard &
Moody's Bond	Numerical Bond	Poor's Bond
Rating	Weighting	Rating
Aaa	1	AAA
Aa1	2	AA+
Aa2	3	AA
Aa3	4	AA-
A1	5	A+
A2	6	Α
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	В
В3	16	B-

Atlantic City Electric Company Judgment of Equity Risk Premium for the Proxy Group of Thirteen Electric Distribution Companies

Line No.		Proxy Group of Thirteen Electric Distribution Companies
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:	 From page 8 of this Schedule. From page 12 of this Schedule. From pages 13 of this Schedule. 	

Atlantic City Electric Company Derivation of Equity Risk Premium Based on the Total Market Approach Using the Beta for the Proxy Group of Thirteen Electric Distribution Companies

Line No.	Equity Risk Premium Measure	Proxy Group of Thirteen Electric Distribution Companies
<u>]</u>	Kroll-Based Equity Risk Premiums:	
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.

Atlantic City Electric Company

Derivation of Equity Risk Premium Based on the Total Market Approach Using the Beta for the

Proxy Group of Thirteen Electric Distribution Companies

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)-5).
- (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)-5.

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.

Plus Chip Financial Foregotts January 1, 2022 and December 2, 202

Blue Chip Financial Forecasts, January 1, 2023 and December 2, 2022 Bloomberg Professional Services.

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Consensus

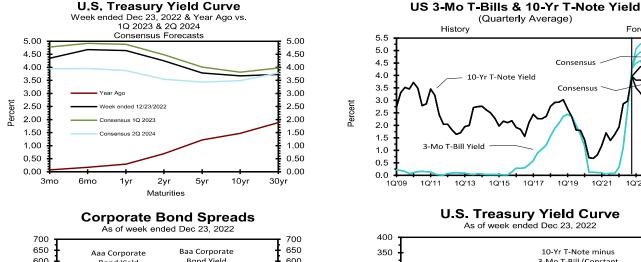
Consensus

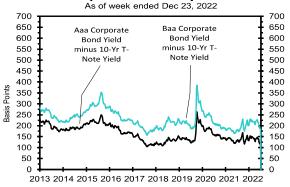
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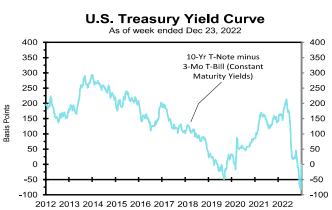
Consensus Forecasts of U.S. Interest Rates and Key Assumptions

				Histor	y				Cons	ensus l	Forecas	sts-Qua	arterly	Avg.
	Av	erage For	Week End	ling	Ave	erage For	Month	Latest Qtr	1Q	2Q	3Q	4Q	1Q	$2\ddot{\mathbf{Q}}$
Interest Rates	Dec 23	<u>Dec 16</u>	Dec 9	Dec 2	<u>Nov</u>	<u>Oct</u>	<u>Sep</u>	4Q 2022*	<u>2023</u>	<u>2023</u>	<u>2023</u>	<u>2023</u>	<u>2024</u>	<u>2024</u>
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
				Histor	y				Co	nsensu	is Fore	casts-Q	Quartei	rly
	1Q	2Q	3Q	4Q	1Q	2Q	3Q	4Q	1Q	2Q	3Q	4Q	1Q	2Q
Key Assumptions	<u>2021</u>	<u>2021</u>	<u>2021</u>	<u>2021</u>	<u>2022</u>	<u>2022</u>	<u>2022</u>	2022**	<u>2023</u>	<u>2023</u>	<u>2023</u>	<u>2023</u>	<u>2024</u>	<u>2024</u>
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.

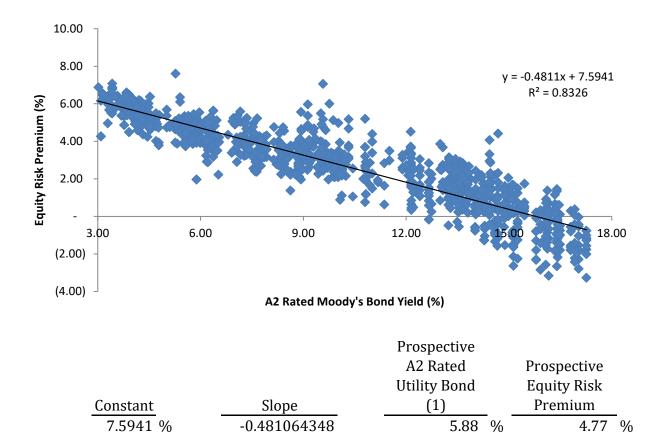
			Ave	rage For The	Year		Five-Year	Averages
		2024	2025	2026	2027	2028	2024-2028	2029-2033
1. Federal Funds Rate	CONSENSUS	3.7	2.9	2.8	2.8	2.7	3.0	2.8
	Top 10 Average	4.5	3.7	3.6	3.5	3.4	3.7	3.4
	Bottom 10 Average	2.7	2.2	2.2	2.2	2.2	2.3	2.3
2. Prime Rate	CONSENSUS	6.8	6.1	5.9	5.9	5.9	6.1	5.9
	Top 10 Average	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
5.55	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
6. Treasury Bill Yield, 6-Mo	Bottom 10 Average CONSENSUS	2.9 3.7	2.2 3.0	2.3 3.0	2.2 3.0	2.2 2.9	2.4 3.1	2.3 3.0
o. Heasury Bill Held, o-Mo	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
7. Heastry Bir Heid, 1 H	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		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
12.6	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
12 Cornerate Pee Pend Viold	Bottom 10 Average CONSENSUS	4.6 6.2	4.4 5.9	4.4 5.9	4.4 6.0	4.5 5.9	4.4	4.5 6.0
13. Corporate Baa Bond Yield	Top 10 Average	6.6	6.4	6.5	6.5	6.5	6.0 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
0 0	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
					hange			Averages
P P 10PP		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
C. GDP Chained Price Index	Bottom 10 Average CONSENSUS	0.5	1.8	1.7	1.7	1.7	1.5	1.6
C. ODF Changed Price Index	Top 10 Average	2.3 2.7	2.1 2.4	2.1 2.3	2.1	2.1 2.3	2.1 2.4	2.1
	Bottom 10 Average	2.7	1.9	2.3 1.9	2.3 1.9	2.3 1.9	1.9	2.2 1.9
D. Consumer Price Index	CONSENSUS	2.0 2.4	2.2	2.2	2.2	2.2	2.2	2.1
2. Consumer race much	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

Atlantic City Electric 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.		Implied Equity Risk Premium
	Equity Risk Premium based on S&P Utility Index Holding Period Returns (1):	
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)	2 22
6.	Average Equity Risk Premium (6)	3.32 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 utility 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.

Atlantic City Electric Company Prediction of Equity Risk Premiums Relative to Moody's A2 Rated Utility Bond Yields - Electric Utilities



Notes:

(1) From line 3 of page 3 of this Schedule.

Source of Information: Regulatory Research Associates.

Schedule (DWD)-5

Atlantic City Electric Company Indicated Common Equity Cost Rate Through Use of the Traditional Capital Asset Pricing Model (ECAPM)

[8]

[9]

[2]

[4]

[3]

[2]

 \Box

Indicated Common Equity Cost Rate (3)	11.78 % 11.87	11.19	12.72	12.30	11.87	11.95	11.27	11.53	12.64	11.44	11.44	11.80 %	11.78 %	11.79 %
ECAPM Cost Rate	12.05 % 12.12	11.54	12.86	12.49	12.12	12.20	11.61	11.83	12.78	11.76	11.76	12.07 %	12.05 %	12.06
Traditional CAPM Cost Rate	11.52 % 11.61	10.83	12.59	12.10	11.61	11.71	10.93	11.22	12.49	11.13	11.13	11.54 %	11.52 %	11.53
Risk-Free Rate (2)	3.91 % 3.91	3.91	3.91	3.91	3.91	3.91	3.91	3.91	3.91	3.91	3.91			
Market Risk Premium (1)	9.75 % 9.75	9.75	9.75	9.75	9.75	9.75	9.75	9.75	9.75	9.75	9.75			
Average Beta	0.78	0.71	0.89	0.84	0.79	0.80	0.72	0.75	0.88	0.74	0.74	0.78	0.78	0.78
Bloomberg Adjusted Beta	0.72	0.66	0.83	0.73	89.0	69.0	0.63	0.61	0.75	0.63	0.68			
Value Line Adjusted Beta	0.85	0.75	0.95	0.95	06.0	0.90	0.80	06.0	1.00	0.85	0.80			
Proxy Group of Thirteen Electric Distribution Companies	Alliant Energy Corporation Ameren Corporation	American Electric Power Corporation Duke Energy Corporation	Edison International	Entergy Corporation	Evergy, Inc.	Eversource Energy	IDACORP, Inc.	NorthWestern Corporation	OGE Energy Corporation	Portland General Electric Company	Xcel Energy Inc.	Mean	Median	Average of Mean and Median

Notes on page 2 of this Schedule.

Atlantic City Electric 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:	Using Prospective Interest Rates
Measure 1: Kroll Arithmetic Mean MRP (1926-2021)	
Arithmetic Mean Monthly Returns for Large Stocks 1926-2021: Arithmetic Mean Income Returns on Long-Term Government Bonds: MRP based on Kroll Historical Data:	12.37 % 5.02 7.35 %
Measure 2: Application of a Regression Analysis to Kroll Historical Data (1926-2022)	<u>8.71</u> %
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, 20	022)
Total projected return on the market 3-5 years hence*: Projected Risk-Free Rate (see note 2): MRP based on Value Line Summary & Index: *Forcasted 3-5 year capital appreciation plus expected dividend yield	16.58 % 3.91 12.67 %
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: Projected Risk-Free Rate (see note 2): MRP based on Value Line data	15.67 % 3.91 11.76 %
Measure 6: Bloomberg Projected MRP	
Total return on the Market based on the S&P 500: Projected Risk-Free Rate (see note 2): MRP based on Bloomberg data	11.06 % 3.91 a 7.15 %
Average of Value Line, Kroll, and Bloomberg MRP	e: <u>9.75</u> %
(2) For reasons explained in the direct testimony, the appropriate risk-free rate for purposes is the average forecast of 30 year Treasury Bonds per the consensus economists reported in Blue Chip Financial Forecasts. (See pages 10-11 of Sche 4.) The projection of the risk-free rate is illustrated below:	of nearly 50
First Quarter 2023 Second Quarter 2023 Third Quarter 2023 Fourth Quarter 2023 First Quarter 2024 Second Quarter 2024 2024-2028 2029-2033	4.00 % 4.00 3.90 3.90 3.80 3.80 3.90 4.00
(3) Average of Column 6 and Column 7.	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

Schedule (DWD)-6

Atlantic City Electric Company Basis of Selection of the Groups of Non-Price Regulated Companies Comparable in Total Risk to the Utility Proxy Groups

The criteria for selection of the proxy group of non-price regulated companies comparable in total risk to the Utility Proxy Group was that the non-price regulated companies be domestic and reported in <u>Value Line Investment Survey</u> (Standard Edition).

The proxy group of non-price regulated companies was 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 Proxy Group of Thirteen Electric Distribution Companies.

These ranges are based upon plus or minus two standard deviations of the unadjusted beta and standard error of the regression. Plus or minus three standard deviations captures 95.50% of the distribution of unadjusted betas and residual standard errors of the regression.

The standard deviation of the Electric 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:

Standard Deviation of the Std. Err. of the Regr. = 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

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).

Atlantic City Electric Company Basis of Selection of Comparable Risk Domestic Non-Price Regulated Companies

[1] [2] [3] [4]

Proxy Group of Thirteen Electric <u>Distribution Companies</u>	Value Line Adjusted Beta	Unadjusted Beta	Residual Standard Error of the Regression	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) 2 std. Devs. of Beta	0.65 0.14	0.93		
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

Atlantic City Electric Company Proxy Group of Non-Price Regulated Companies Comparable in Total Risk to the Proxy Group of Thirteen Electric Distribution Companies

[1] [2] [3] [4]

Aglent Technologies	Proxy Group of Fifty Non-Price Regulated Companies	Value Line Adjusted Beta	Unadjusted Beta	Residual Standard Error of the Regression	Standard Deviation of Beta
Abbott Lalis. 0.90 0.81 2.7622 0.0688 Analog Devices 0.95 0.87 2.84117 0.070 Assurant Inc. 0.95 0.87 2.8417 0.070 Assurant Inc. 0.95 0.85 0.76 0.7272 0.0679 2.6237 0.0653 Ball Corp. 0.95 0.91 0.80 0.691 2.8314 0.0705 Bristol-Myers Squibb 0.85 0.76 0.30330 0.0755 Broad-ridge Fin¹ 0.85 0.70 0.70 0.70 0.70 1.00 0.93 0.77 0.7610 0.0667 Brady Corp. 0.85 0.70 0.72,7610 0.0667 Cooper Cos. 0.95 0.90 0.80 0.29127 0.0725 0.0670					
Analog Pevices 0.95 0.87 2.9417 0.0704 5.0815 2.7366 0.0681 5.mith (A.O.) 0.85 0.76 2.7372 0.06631 5.mith (A.O.) 0.85 0.76 2.7372 0.0679 Air Products & Chem. 0.90 0.79 2.6237 0.0653	9		0.77	2.6442	0.0658
Assurant Inc. 0.95 0.85 2.7366 0.0661 Smith (A.O.) 0.85 0.76 2.7272 Air Products & Chem. 0.90 0.79 2.6237 0.0653 Ball Corp. 0.95 0.91 2.8314 0.0705 Bristol Myers Squibb 0.85 0.76 3.0330 0.0755 Bristol Myers Squibb 0.85 0.76 3.0330 0.0755 Broadridge Fin1 0.85 0.70 2.7610 0.0667 Brady Corp. 1.00 0.93 2.7641 0.0668 CACI Int' 0.90 0.84 2.9846 0.00687 CACI Int' 0.90 0.84 2.9846 0.00687 CAU Int' 0.90 0.80 0.27720 0.0660 CSW Industrials 0.90 0.80 2.9127 0.0725 CSW Industrials 0.90 0.80 2.9127 0.0725 CSW Industrials 0.90 0.80 2.9127 0.0725 CSW Intellegation 0.95 0.98 2.9135 0.0752 Dolby Labs. 0.95 0.88 2.6152 0.0661 Lauder (Estee) 0.95 0.99 2.9395 0.0732 Exponent, Inc. 0.90 0.80 2.8742 0.0752 Exponent, Inc. 0.90 0.80 2.8742 0.0752 Exponent, Inc. 0.90 0.80 2.8742 0.0715 FactSet Research 1.00 0.93 2.6951 0.0071 FactSet Research 1.00 0.93 2.6951 0.0071 Exponent, Inc. 0.90 0.85 2.8617 0.0712 Exponent, Inc. 0.90 0.85 2.9072 0.0724 Exponent, Inc. 0.90 0.80 2.8815 0.0717 Exponent, Inc. 0.90 0.80 2.8815 0.0717 Exponent, Inc. 0.90 0.80 2.8815 0.07					
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 Brady Corp. 1.00 0.93 2.7611 0.0667 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 Cowled Strates 0.90 0.80 2.9127 0.0722 Quest Diagnostics 0.80 0.69 3.0218 0.0752 Lauder (Estee)	9				
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 Bristof-Myers Squibb 0.85 0.76 3.0330 0.0755 Broadridge Fin' 0.85 0.70 2.7610 0.0687 Broadridge Fin' 0.85 0.70 2.7610 0.0687 Broadridge Fin' 0.90 0.84 2.9846 0.0743 CACI Int' 0.90 0.84 2.9846 0.0743 Chemed Corp. 0.85 0.70 2.7215 0.0677 0.00677 0.00677 0.00677 0.00677 0.00670 0	Assurant Inc.	0.95	0.85	2.7366	0.0681
Ball Corp. 0.95 0.91 2.8314 0.0705 Brown-Forman 'I' 0.90 0.80 2.6915 0.0670 Bristol-Myers Squibb 0.85 0.76 3.0330 0.0755 Brady Corp. 1.00 0.93 2.7641 0.0688 Brady Corp. 1.00 0.93 2.7641 0.0688 CACI Int'I 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 0.0752 Quest Diagnostics 0.80 0.69 3.0218 0.0752 Quest Diagnostics 0.80 0.69 3.0218 0.0752 Quest Diagnostics 0.80 0.69 3.0218 0.0752 Lauder (Estee) 0.95 0.92 2.9395 0.0732 Exponent, Inc. 0.90 0.80 2.8742 0.0715 FactSet Research				2.7272	0.0679
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Brady Corp. 1.00 0.93 2.7641 0.0684 CACI Int¹ 0.99 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 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 0.0682 Ingredion Inc. 0.99 0.85 2.8617 0.0712 Hunt (JB.) 0.95 0.90 2.9072 0.0724 Herry (Jack) & Assoc	, i				
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Proxy Group of Thirteen Electric	1				
	Average	0.91	0.82	2.8049	0.0700
Distribution Companies 0.88 0.79 2.8038 0.0700					
	Distribution Companies	0.88	0.79	2.8038	0.0700

Source of Information:

Valueline Proprietary Database, December 2022

Schedule (DWD)-7

Atlantic City Electric 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 Distribution Companies

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 %

- (1) From page 2 of this Schedule.
- (2) From page 3 of this Schedule.
- (3) From page 6 of this Schedule.

$\frac{A tlantic\ City\ Electric\ Company}{DCF\ Results\ for\ the\ Proxy\ Group\ of\ Non-Price-Regulated\ Companies\ Comparable\ in\ Total\ Risk\ to\ the\ Proxy\ Group\ of\ Thirteen\ Electric\ Distribution\ Companies}$

	[1]	[2]	[3]	[4]	[5]	[6]	[7]
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. Brown-Forman 'B'	1.54 1.21	21.50 14.50	5.00 NA	4.51 8.62	10.34 11.56	1.62 1.28	11.96 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 1.83	11.50 4.00	NA NA	12.00 (15.60)	11.75 4.00	0.60	12.35 5.87
Quest Diagnostics Dolby Labs.	1.57	9.50	16.00	16.00	13.83	1.87 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 15.00	9.90	8.95	3.20	12.15
Hunt (J.B.) J&J Snack Foods	0.91 1.88	11.00 9.00	15.00 NA	14.98 73.10	13.66 9.00	0.97 1.96	14.63 10.96
Henry (Jack) & Assoc	1.06	8.00	9.00	9.00	9.00 8.67	1.96	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 Mettler-Toledo Int'l	1.40	10.50 13.50	9.00 12.20	11.18 12.20	10.23 12.63	1.47	11.70 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 Sherwin-Williams	1.61	2.00	12.00	12.00	8.67 11.92	1.68	10.35
Selective Ins. Group	1.03 1.31	11.50 9.50	12.80 6.60	11.46 13.40	9.83	1.09 1.37	13.01 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. Waters Corp.	-	11.00 6.00	NA 7.20	8.00 8.34	9.50 7.18	-	NA NA
Watsco, Inc.	3.35	11.50	7.20 NA	15.00	13.25	3.57	16.82
						Mean	<u>11.57</u> %
						Median	11.87 %
						114 11	44 = 0 0/

NA= Not Available

Average of Mean and Median

11.72 %

Source of Information:

Value Line Investment Survey www.zacks.com Downloaded on 12/30/2022 www.yahoo.com Downloaded on 12/30/2022 Bloomberg Professional Services

⁽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, Bloomberg, www.zacks.com, and www.yahoo.com (excluding any negative growth rates) and then adding that growth rate to the adjusted dividend yield.

Atlantic City Electric Company Indicated Common Equity Cost Rate Through Use of a Risk Premium Model Using an Adjusted Total Market Approach

<u>Line No.</u>			Proxy Group of I Non-Price Regula 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-Regulated Proxy Group	5.88	%
4.		Equity Risk Premium (3)	7.52	_
5.		Risk Premium Derived Common Equity Cost Rate	13.40	<u></u> %
Notes:	(1)	Average forecast of Baa2 corporate bonds based upon the 650 economists reported in Blue Chip Financial Forecasts da and December 2, 2022 (see pages 10 and 11 of Schedule (Eestimates are detailed below.	ated January 1, 20	
		First Quarter 2023 Second Quarter 2023 Third Quarter 2023 Fourth Quarter 2023 First Quarter 2024 Second Quarter 2024 2024-2028 2029-2033	6.10 6.30 6.20 6.10 5.90 5.80 6.00 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		Baa2 Corp.			
	Yield		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	
	Avera	age y	rield spread		0.50	%
		1/	3 of spread		0.17	%

(3) From page 5 of this Schedule.

Atlantic City Electric 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 Distribution Companies

Moody's Long-Term Issuer Rating December 2022 Standard & Poor's Long-Term Issuer Rating December 2022

Proxy Group of Fifty Non-Price Regulated Companies	Long-Term Issuer Rating	Numerical Weighting (1)	Long-Term Issuer Rating	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		NA	5.0
FactSet Research	Baa3	10.0	NA	
Gentex Corp.	NA		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	 	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	7.0	NA	9.0
MSCI Inc.	Ba1	11.0	BB+	11.0
Motorola Solutions	Ваа3	10.0	BBB-	10.0
Mettler-Toledo Int'l	WR	10.0	NR	10.0
Northrop Grumman	Baa1	8.0	BBB+	8.0
Old Dominion Freight	NA	o.u 	NA	6.U
Packaging Corp.	Baa2	9.0	BBB	9.0
Post Holdings	В2	9.0 15.0	В+	9.0 14.0
RLI Corp.	Baa2	9.0	BBB	9.0
Rollins, Inc.	NA	9.0 	NA	9.0
Service Corp. Int'l	Ba3	13.0	BB+	11.0
Sherwin-Williams	Ваа2	9.0	BBB	9.0
Selective Ins. Group	Baa2	9.0	BBB	9.0
Sirius XM Holdings	NA		NA NB	
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 D2		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)-4.

Source of Information: Bloomberg Professional Services

Atlantic City Electric 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 <u>Proxy Group of Thirteen Electric Distribution Companies</u>

Line No.	Equity Risk Premium Measure	Proxy Group of Fifty Non-Price Regulated Companies
Line No.	Equity Risk i Tellium Measure	Companies
	Kroll-Based Equity Risk Premiums:	
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 <u>Value Line</u> Summary and Index (4)	11.53
5	Equity Risk Premium Based on <u>Value Line</u> 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)-4.
- (2) From note 2 of page 9 of Schedule (DWD)-4.
- (3) From note 3 of page 9 of Schedule (DWD)-4.
- (4) From note 4 of page 9 of Schedule (DWD)-4.
- (5) From note 5 of page 9 of Schedule (DWD)-4.
- (6) From note 6 of page 9 of Schedule (DWD)-4.
- (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

Atlantic City Electric 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 Distribution Companies

	[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	12.30	12.64	12.47
Analog Devices	1.00	0.87	0.94	9.75	3.91	13.08	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	13.47	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	11.52	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	13.08	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	13.08	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	11.52	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	13.08	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	12.69	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	12.30	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	13.08	12.98
Sherwin-Williams	0.95	0.84	0.90	9.75	3.91	12.69	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	11.52	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	13.08	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 %	<u>12.78</u> %	12.64 %
rerage of Mean and Median			0.88			12.44 %	12.74 %	12.59 %

NMF = Not Meaningful Figure

Notes:

- (1) From Schedule (DWD)-5, note 1.
 (2) From Schedule (DWD)-5, note 2.
 (3) Average of CAPM and ECAPM cost rates.

Schedule (DWD)-8

Atlantic City Electric Company Derivation of Investment Risk Adjustment Based upon Kroll Associates' Size Premia for the Decile Portfolios of the NYSE/AMEX/NASDAQ

[1]	[2]	[3]	[4]

Line No.		Market Capita December 30 (millions)		Applicable Decile of the NYSE/AMEX/ NASDAQ (2)	Applicable Size Premium (3)	Spread from Applicable Size Premium (4)
1.	Atlantic City Electric Company	\$ 2,198.677		6	1.18%	
2.	Proxy Group of Thirteen Electric Distribution Companies	\$ 22,798.483	10.40 x	2	0.43%	0.75%
			[A]	[B]	[C]	[D]

		Market		Size Premium
		Capitalization of	Market	(Return in
		Smallest	Capitalization of	Excess of
	Decile	Company	Largest Company	CAPM)*
		(millions)	(millions)	
	1	ф. 26.160 г 0.4	ф. 2.224.200.210	0.220/
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 Cos	t of Capital Navigator	i

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
- (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%.

Market Capitalization of Atlantic City Electric Company and the Proxy Group of Thirteen Electric Distribution Companies Atlantic City Electric Company

[9]	Market Capitalization on December 30, 2022 (3)	(millions)		\$ 2,198.677 (6)		\$ 13,828.70	\$ 22,914.68	\$ 47,874.93	\$ 79,199.31	\$ 24,199.66	\$ 22,798.48	\$ 14,429.84	\$ 28,874.76	\$ 5,448.20	\$ 3,418.36	\$ 7,929.78	\$ 4,381.12	\$ 38,141.61	\$ 72 798 483	
[2]	Market-to-Book Ratio on December 30, 2022 (2)			195.9 (5)		230.9 %	236.2	213.4	167.3	174.0	195.9	156.1	197.8	204.2	146.1	195.5	161.8	244.3	195.9 %	2001
[4]	Closing Stock Market Price on December 30, 2022		NA			55.21	88.92	94.95	102.99	63.62	112.50	62.93	83.84	107.85	59.34	39.55	49.00	70.11	70110	2112
	Cl Maa De		(4)			↔	↔	↔	\$	↔	\$	↔	↔	\$	\$	↔	\$	↔	4	}
[3]	Total Common Equity at Fiscal Year End 2021	(millions)	1,122.346 (4)			5,990.00	9,700.00	22,433.20	47,334.00	13,911.00	11,637.28	9,244.40	14,599.84	2,668.44	2,339.71	4,056.30	2,707.00	15,612.00	0 000 000	200000
	Total C at Fis)	↔			\$	↔	↔	↔	↔	↔	↔	↔	↔	↔	↔	↔	\$	4	+
[2]	Book Value per Share at Fiscal Year End 2020 (1)		NA			23.92	37.64	44.49	61.55	36.57	57.43	40.32	42.39	52.82	40.62	20.23	30.28	28.70	40 316	7
	Boo Sha Yea					↔	↔	↔	↔	↔	↔	↔	↔	↔	↔	↔	↔	↔	¥	+
[1]	Common Stock Shares Outstanding at Fiscal Year End 2021	(millions)	NA			250.475	257.700	504.212	200.697	380.378	202.653	229.300	344.403	50.516	57.606	200.500	89.411	544.025	250 475	1
	Exchange					NASDAQ	NYSE	NASDAQ	NYSE	NASDAQ	NYSE	NYSE	NYSE	NYSE	NYSE	NASDAQ	NYSE	NYSE		
	Company		Atlantic City Electric Company	Based upon Proxy Group of Thirteen Electric Distribution Companies	Proxy Group of Thirteen Electric Distribution Companies	Alliant Energy Corporation	Ameren Corporation	American Electric Power Corporation	Duke Energy Corporation	Edison International	Entergy Corporation	Evergy, Inc.	Eversource Energy	IDACORP, Inc.	NorthWestern Corporation	OGE Energy Corporation	Portland General Electric Company	Xcel Energy Inc.	Median	Hedgal

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 Atlantic City Electric Company on December 30, 2022 is assumed to be equal to the market-to-book ratio of Proxy Group of Thirteen Electric Distribution Companies on December 30, 2022 as appropriate.

(6) Column [3] multiplied by Column [5].

Source of Information: 2021 Annual Forms 10K Bloomberg Financial Services

Schedule (DWD)-9

$\label{eq:Atlantic City Electric Company} Atlantic City Electric Company Derivation of the Flotation Cost Adjustment to the Cost of Common Equity$

Equity Issuances since 2010

[Column 10]	Flotation Cost Percentage (7)	5.06% 2.39%	4.48%						
[Column 9]	Total Flotation Costs (6)	\$ 104,100,000 \$ 13,765,050	\$ 117,865,050						
[Column 8]	Total Net Proceeds (5)	\$ 1,951,525,000 \$ 562,043,400	\$ 2,513,568,400						
[Column 7]	Gross Equity Issue before Costs (4)	\$ 2,055,625,000 \$ 575,808,450	\$ 2,631,433,450						
[Column 6]	Net Proceeds per Share (3)	\$ 33.94 \$ 43.25							.0
[Column 5]	Issuance Expense	\$ 0.010 \$ 0.069			[Column 16]	Flotation	Cost Adjustment (11)		0.18 %
[Column 4]	Market Pressure (2)	\$ 1.80 \$ 0.99		ıt	.5 <u>.</u>	Kate Adjusted	for Flotation (10)		6 9.42 %
[Column 3]	Average Offering Price per Share (1)	\$ 33.95 \$ 43.32		Flotation Cost Adjustment	[Column 14] Average DCF Cost	Kate Unadjusted	for Flotation (9)		9.24 %
[Column 2]	Market Price per Share (1)	\$ 35.75 \$ 44.31		Flotation	[Column 13] [Column 14] Average DCF Cost		Adjusted Dividend Yield (8)		3.85 %
[Column 1]	Shares Issued (1)	57,500,000 12,995,000			[Column 12]	Average	Projected EPS Growth Rate (8)		5.39 %
	Transaction (1)	Equity Offering Equity Offering			[Column 11]		Average Dividend Yield (8)		3.75 %
	Date of Offering	6/11/2014 8/3/2022						Proxy Group of Thirteen Electric Distribution	Companies

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)-3
(9) Col. 12 + Col. 13
(10) (Col. 13 / (1 - Col. 10)) + Col. 12
(11) Col. 15 - Col. 14

Source of Information: Company SEC filings.

ATLANTIC CITY ELECTRIC COMPANY

BEFORE THE NEW JERSEY BOARD OF PUBLIC UTILITIES DIRECT TESTIMONY OF JOSHUA L. MASTERS BPU DOCKET NO. <u>ER23020091</u>

1	Q1.	Please state your name and position.
2	A1.	My name is Joshua L. Masters. I am the Senior Manager of Rate
3		Administration for Atlantic City Electric Company ("ACE" or the "Company") and
4		Delmarva Power & Light Company ("Delmarva Power") in the Regulatory Affairs
5		Department of Pepco Holdings, LLC ("PHI"). I am testifying on behalf of ACE.
6	Q2.	What are your responsibilities in your role as Manager of Rate
7		Administration?
8	A2.	I am primarily responsible for the development of electric retail
9		transmission rates and electric and gas distribution rates, including tariff
10		surcharges, for ACE and Delmarva Power. I also participate in the development of
11		PHI's policies and practices with respect to rate design and assist with regulatory
12		compliance matters in other PHI jurisdictions, including tariff administration and
13		periodic filings.
14	Q3.	Please state your educational background and professional experience.
15	A3.	I received a Bachelor of Science Degree in Accounting from the University
16		of Delaware in 2002 and a Master's in Business Administration with a
17		concentration in Accounting from the University of Delaware in 2008. I have had
18		an active license as a Certified Public Accountant in the State of Delaware since
19		August 27, 2004. I joined PHI in 2005, and from that time through mid-2021 held
20		various positions within Accounting at PHI, and the larger Exelon Corporation. In
21		2021, I joined the Regulatory Department of PHI as the Senior Manager of Rate

1		Administration. Prior to joining PHI in 2005, I worked for three years in the Public
2		Accounting industry preparing audits and tax returns for private companies.
3	Q4.	Have you ever submitted testimony to the New Jersey Board of Public Utilities
4		("BPU" or the "Board") or other regulatory agencies?
5	A4.	Yes, I submitted testimony in BPU Docket No. ER17030308.
6	Q5.	What is the purpose of your Direct Testimony?
7	A5.	The purpose of my testimony is to present the Customer Class Cost of
8		Service Study ("CCOSS") for ACE. The CCOSS results presented in my testimony
9		are based on the 12 months of actual data ending September 30, 2022.
10		A central focus of my testimony in this proceeding is to continue to support
11		the movement toward appropriate distribution pricing strategies that reflect the
12		proper and equitable recovery of distribution fixed cost of service from all
13		customers.
14		This testimony has been prepared by me or under my direct supervision and
15		control. The source documents for my testimony are Company records and public
16		documents. I also rely upon my personal knowledge, education, and experience.
17	Q6.	Please outline the organization of the remainder of your testimony.
18	A6.	My testimony is organized into three sections. In the first section, I
19		summarize the schedules presented in my testimony. Next, I present the ACE Class
20		Cost of Service Study and describe the methods I have used to calculate costs by
21		customer class, including a description of the more significant allocation factors. I
22		conclude this section of my testimony with a summary of the CCOSS results in the

1		form of Rates of Return ("ROR"), and Unitized Rates of Return ("UROR") for the
2		various customer classes.
3		In the final section, I discuss the alternative CCOSS based on the peak and
4		average method that has been submitted in accordance with the Board's final Order
5		in BPU Docket No. ER03020110, dated May 26, 2005.
6		SECTION I. COST OF SERVICE - SCHEDULES
7	Q7.	Please summarize the schedules presented in your testimony.
8	A7.	I am sponsoring the following Schedules:
9		Schedule (JLM)-1 contains the ACE CCOSS that assigns the Distribution function
10		costs to the various customer classes under the Company's allocation methods;
11		Schedule (JLM)-2 provides a summary of the demand- and customer-related cost
12		components for each customer class for the Company's CCOSS;
13		Schedule (JLM)-3 presents the results for the Company's CCOSS expressed as
14		Class RORs and URORs;
15		Schedule (JLM)-4 presents a description of the external allocators used in the
16		CCOSS;
17		Schedule (JLM)-5 contains the CCOSS reflecting the peak and average cost
18		allocation method that has been submitted in accordance with BPU Docket No.
19		ER03020110, as discussed in my testimony; and
20		Schedule (JLM)-6 provides a summary of the demand- and customer-related cost
21		components for each customer class for the CCOSS based on the peak and average.

1		SECTION II. ACE CLASS COST OF SERVICE STUDY
2	Q8.	Please describe the objective of performing cost of service analyses.
3	A8.	The CCOSS is a detailed analysis that assigns the Company's revenue
4		requirement to the customer groups on the basis of cost causation. Cost of service
5		studies are among the basic tools in the rate design process. The fundamental
6		principle underlying the CCOSS is that costs should be attributed to the particular
7		customer group(s) that cause the utility to incur such costs. Appropriately allocated
8		costs then provide a basis to derive class rate of return results and class revenue
9		targets, and they serve as an important guide in designing the rates charged to each
10		customer class.
11	Q9.	Please describe the underlying basis for the CCOSS submitted in this case.
12	A9.	The CCOSS presented in this case uses the same basic cost of service model
13		that was submitted in Docket No. ER20120746.
14		The starting point for the cost of service analysis is the Total Distribution
15		Rate Base, Revenues, and Expenses of the Company for the 12 months of actual
16		data ending September 30, 2022.
17	Q10.	What rate schedules ("customer classes") did you use in your CCOSS?
18	A10.	The ACE customer class CCOSS recognized and allocated the Company's
19		costs to the retail customer classes as follows:
20		• Residential;
21		 Monthly General Service Secondary;
22		 Monthly General Service Primary;
23		 Annual General Service Secondary;

Witness Masters

1		 Annual General Service Primary;
2		• Street and Private Lighting;
3		• General Service Subtransmission;
4		General Service Transmission; and
5		Direct Distribution Connection.
6	Q11.	Please briefly describe the key processes involved in cost allocation.
7	A11.	There are three basic steps traditionally followed in the cost allocation
8		process: cost functionalization, classification, and allocation.
9		Cost functionalization is the process of dividing the total revenue
10		requirement into cost categories as related to the electric operations of the
11		Company. In the present analysis, the elements of both Rate Base and Operating
12		Expenses are grouped into these cost categories depending on their use. For
13		example, the Distribution functional categories of Company plant investment
14		include, but are not limited to:
15		Distribution substations;
16		 Overhead and underground conductors;
17		• Line transformers;
18		• Services, meters & equipment on customers' premises;
19		• Street light and traffic signal systems; and
20		• General plant.
21		The Federal Energy Regulatory Commission ("FERC") Uniform System of
22		Accounts provides a starting point to functionalize the plant investment. Plant
23		investment can then be divided into sub-functions to facilitate the allocation of

1		costs. For example, the present analysis recognizes different voltage levels and
2		separates plant investment into primary and secondary systems.
3		The functional categories of operating expenses correspond to the plant
4		categories above, and include additional Operation and Maintenance ("O&M")
5		functional categories, namely:
6		• Customer Accounts Expenses;
7		• Sales Expenses; and
8		Administrative and General Expenses.
9		The functional categories are presented in detail in the first column of the
10		Company's CCOSS (see Schedule (JLM)-1).
11	Q12.	What is the next step in the process?
12	A12.	The next step in the process is to classify the functionalized costs based
13		upon cost causation. The electric distribution system costs are fixed in nature and
14		related to demand and the number of customers served.
15	Q13.	Please describe the process used to develop the demand and customer-related
16		costs in the CCOSS.
17	A13.	The process to develop the demand and customer-related costs starts with
18		the Company's total distribution system costs, shown on column 1 of Schedule
19		(JLM)-1. Within the cost study, the Company's total revenue requirement is
20		classified into customer-related and demand-related cost components.
21		For each functionalized cost component, the cost of service model
22		separately computes the total revenue requirements for the individual cost
23		component. This includes an assignment of the general and common plant and

1		administration and general expenses that support each of these functional
2		categories.
3	Q14.	Pleased describe the demand-related costs.
4	A14.	Demand-related costs are primarily fixed costs that are dependent on
5		kilowatt ("kW") requirements and associated with the demands on the Company's
6		distribution facilities.
7		An example of demand-related costs is the Company's investments in
8		distribution substations. Distribution substations contain power transformers that
9		reduce higher voltage levels to distribution level and provide a source for the
10		distribution circuits extending to the customer's premises. Distribution substations
11		are designed and built to meet the localized area peak load or demand of the
12		customers served by the facility; therefore, this investment is classified as demand-
13		related.
14		Schedule (JLM)-2 contains a summary of the unbundled revenue
15		requirement for the demand- and customer-related cost components by customer
16		class. As shown in that schedule, the revenue requirement for demand-related costs
17		has been grouped into the following categories:
18 19 20 21 22		 Distribution Primary Component, including substations, primary poles and lines; Distribution Secondary Component, including secondary poles and conductors, and street lighting assets; and Distribution transformers.
23	Q15.	Please describe the customer-related costs.
24	A15.	Customer-related costs are generally fixed costs associated with the number
25		of customers served. Examples of customer-related costs include customer

1		accounting and billing, collection activity, meter reading costs, and the investment
2		and O&M expenses associated with customer service lines and customer meters.
3		As shown on Schedule (JLM)-2, the customer-related costs are grouped into the
4		following categories:
5 6 7 8 9		 Customer Meters Component; Customer Services Component; FERC Account 902- Meter Reading Component; FERC Account 903- Customer Records and Collections Component; Customer Services Expense Component; and Customer Other Component (primarily street-lighting).
11	Q16.	Please describe how the customer-related costs have been allocated.
12	A16.	Following the functionalization and classification of costs, the next step is
13		to allocate the costs to the particular customer groups. A complete list of the
14		customer-related allocation factors is provided on page 31, Schedule (JLM)-1.
15		These allocation factors have been developed through separate studies to assign the
16		specific customer-related costs to each customer class. The separate studies are
17		discussed in the Cost of Service Allocation Method section of my Direct
18		Testimony, starting at page 15.
19	Q17.	What are the results of your analysis of the customer-related costs for the
20		residential class?
21	A17.	Schedule (JLM)-2 shows the customer-related costs by customer class that
22		are presented at the existing rate of return and also at the UROR. The results are
23		expressed in total dollar amounts, on a unitized basis (\$/kWh), and on a fixed
24		amount per customer (\$/month/customer). As shown on Schedule (JLM)-2, page

1		4-3, line 14, the customer-related cost for the residential class presented at the
2		UROR is \$17.05 per month/customer.
3	Q18.	How do the ACE customer-related costs compare to the existing ACE
4		customer charges?
5	A18.	The existing rate structure includes a \$6.25 monthly customer charge for
6		the residential class that represents only 37% of the customer-related costs
7		developed in the CCOSS.
8	Q19.	Has the Board increased fixed cost recovery through the Residential Customer
9		Charge levels approved in recent base rate cases?
10	A19.	Yes. In the prior five base rate cases,1 the Board has systematically
11		approved increases in the level of the residential monthly Customer Charge from
12		\$3.00 to the current level of \$6.25.
13	Q20.	Why is it imperative to continue this process of enhanced fixed cost recovery?
14	A20.	Because distribution-related costs are primarily fixed in nature, resulting in
15		the potential for revenue loss, cost shifting, and cross-subsidies, due to the existing
16		rate structures for smaller customers, including the residential customers, that are
17		dominated by variable kilowatt-hour ("kWh") delivery charges.
18		Distribution-related costs are primarily fixed and reflect fixed demand and
19		customer-related costs. For example, customer-related costs vary by the number of
20		customers, not with customer usage.
21		The Company's distribution plant investment is driven by the number and
22		location of customers and their respective demands. The distribution system is not

 $^{^{\}rm 1}$ The referenced cases are BPU Docket Nos. ER140302145, ER16030252, ER17030308, ER18080925, and ER20120746.

Witness Masters

designed or built based on the kWh usage (or the variable consumption) of the customer. Thus, energy usage has no relation to the underlying cost causation of design and construction criteria for the distribution system – which drives the entire class cost of service analysis.

ACE's existing and proposed pricing levels are designed, however, to recover a considerable amount of the fixed costs through the variable kWh distribution charges for the residential and small commercial customer classes while more appropriately reflecting costs for large customer classes through customer and demand charges.

In fact, for the residential class, approximately 12% of the distribution costs are recovered through the fixed monthly Customer Charge. When customers reduce their kWh consumption, the fixed customer costs remain and must be recovered from other customers. Failure to recover fixed costs through fixed charges perpetuates revenue loss, cost shifting, and the cross subsidies that have detrimental implications for customers. For example, without an appropriate fixed charge, customers who can afford a second home, and may have lower kwh charges due to lower usage on that second residence, could be shifting their fixed distribution connection costs to other customers, including those with lower income.

Q21. Why is it particularly important at this time to align the rate design with the cost to serve?

A21. New Jersey continues to be a leader in the national effort to encourage the development of renewable energy technologies, guided by the Energy Master Plan

("EMP").² Moreover, the Clean Energy Act of 2018 enacted by the Legislature and signed by the Governor contains aggressive targets to accelerate the growth of renewables and distributed energy resources ("DER"), including solar ("PV") energy, energy storage, and off-shore wind initiatives.

The prior EMP cautions, however, that accomplishing the State's energy policy goals has potential rate and cost shifting implications for electricity ratepayers. For example, regarding energy efficiency ("EE") and demand response ("DR") programs, that EMP states that the primary benefit of the EE and DR programs is the participants' avoided cost of electricity (wholesale/supply side). The 2011 EMP then carefully explains that, to the extent participants reduce their peak demand, they are able to avoid a portion of transmission and distribution costs and other fixed charges, and that these costs are shifted, at least in the near term, to non-participants.³

The National Association of Utility Regulatory Commissions ("NARUC") expresses the same concern:

The economic pressures that DER may put on the utility and non-DER customers within a rate class is one of the most challenging issues facing regulators today. These economic issues include revenue erosion and cost recovery issues as well as inter-class cost shifting apparent in traditional utility rate design and NEM discussions.⁴

As mentioned, approximately 12% of the costs are recovered through the fixed monthly Customer Charge, with the remaining approximately 88% of the residential revenue requirement recovered through the variable delivery charges.

² Unless specifically referenced as a prior EMP, all references refer to the 2019 EMP.

³ 2011 EMP, at page 55.

⁴ NARUC Manual on Distributed Energy Resources Rate Design and Compensation, 2016.

When customers reduce their kWh consumption, the fixed customer costs remain and must be recovered from other customers – adding to cost shifting and cross subsidy. It is imperative to continue (and accelerate, to the extent practicable) the recovery of fixed costs through fixed charges to help mitigate the adverse impact on non-participants. This will help to develop more appropriate pricing signals to customers regarding the impact of the individual consumption decisions on the cost of the electric distribution system. Otherwise, the underlying pricing structures upon which the State's energy policies are founded could contribute to revenue loss and cost shifting and unintentional subsidies.

To the extent practicable, fixed customer costs should be recovered through the fixed monthly customer charge, instead of the variable kWh distribution charge, thereby supporting a goal of developing pricing strategies that encourage customer behavior and incentivize new technologies that reduce the cost of service for all customers, instead of shifting costs to other customers.

Q22. What are your conclusions on the proposed customer charges in this case?

A22. The Customer Charge proposals presented in the Direct Testimony of Company Witness Normand are reasonable and will serve to continue the Board's process of appropriately reflecting the fixed cost of service in fixed charges.

Q23. Please briefly describe the Company's cost of service model.

A23. The ACE cost of service model enables the Company to directly assign or allocate each element of Rate Base, Revenues, and Operating Expenses to the respective customer classes.

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1		The model is a cost matrix with the Total Distribution component shown in
2		the initial column and the customer classes listed on the horizontal or initial row.
3		The cost model starts with the Rate Base detail, including each plant
4		account, and continues with the remaining items of Rate Base, Revenues, Operating
5		Expenses, Taxes, and the development of the Labor allocator.
6		The cost of service model also contains an important column labeled
7		"ALLOC." This column contains the acronym identifying the method used to
8		apportion the particular Total Distribution cost to the customer groups. Each
9		method used to assign costs is identified in the Allocation Factor table located at
10		the end of the cost studies. (See Schedule (JLM)-1, starting at page 29.)
11	Q24.	Please describe the internally-developed and external allocators used in the
12		ccoss.
10	A24.	The cost study uses both internally developed and external allocators. The
13		, , , , , , , , , , , , , , , , , , ,
13 14		internally developed allocators are detailed on Schedule JLM-1, starting at page 33.
		, , , , , , , , , , , , , , , , , , ,
14		internally developed allocators are detailed on Schedule JLM-1, starting at page 33.
14 15		internally developed allocators are detailed on Schedule JLM-1, starting at page 33. This includes a description of the cost item allocated, together with the acronym
141516		internally developed allocators are detailed on Schedule JLM-1, starting at page 33. This includes a description of the cost item allocated, together with the acronym identifying the particular internal allocator. The internally developed allocators
14151617		internally developed allocators are detailed on Schedule JLM-1, starting at page 33. This includes a description of the cost item allocated, together with the acronym identifying the particular internal allocator. The internally developed allocators represent one or more previously allocated cost items. For example, the PLANT
1415161718		internally developed allocators are detailed on Schedule JLM-1, starting at page 33. This includes a description of the cost item allocated, together with the acronym identifying the particular internal allocator. The internally developed allocators represent one or more previously allocated cost items. For example, the PLANT allocator shown on page 35, line 22, is an internally developed allocator that
141516171819		internally developed allocators are detailed on Schedule JLM-1, starting at page 33. This includes a description of the cost item allocated, together with the acronym identifying the particular internal allocator. The internally developed allocators represent one or more previously allocated cost items. For example, the PLANT allocator shown on page 35, line 22, is an internally developed allocator that represents Total Electric Plant in Service, referenced on page 5, line 25.

1		analysis were then used to allocate the embedded costs contained in FERC Account
2		370-Meters to the respective customer classes.
3		Once all of the Total Distribution costs are fully allocated, the assigned costs
4		are aggregated by customer class to determine the cost to serve that class and to
5		compute the class rate of return.
6		COST OF SERVICE ALLOCATION METHOD
7	Q25.	Has the Company applied the cost of service methodology used in the prior
8		base rate case?
9	A25.	Yes. In this case, the CCOSS incorporates the basic cost of service
10		methodology consistent with the prior base rate cases filed by ACE. A description
11		of the cost allocation methods for Rate Base, Revenues, and O&M expense is
12		provided below.
13		RATE BASE ALLOCATION
14	Q26.	Please describe the cost allocation methods used for the major components of
15		rate base.
16	A26.	Each functionalized Rate Base component, and the associated line-item
17		allocation factors, is detailed on Schedule (JLM)-1, pages 3 through 12. A
18		description of the cost allocation method for each major Rate Base component is
19		provided below, starting with Electric Plant in Service.
20	Q27.	Please describe how distribution pole and line costs (FERC Accounts 364 - 367)
21		have been allocated to the retail customer classes.
22	A27.	ACE first used its Geospatial Information System (infrastructure mapping
23		system) in the process of separating the primary and secondary plant for FERC

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Account 365 (overhead conductors) and FERC Account 367 (underground
conductors). The results from these analyses were then applied to FERC Accounts
364, 365, 366, and 367. The separation of plant investment into primary and
secondary system assets facilitates the cost allocation process. Specifically, the
customers served by only the primary distribution system should not be allocated
costs associated with the lower voltage secondary delivery system.

A28.

Consistent with historical CCOSS filings, the Company has applied the Class Maximum Diversified Demands ("Class MDD") in this case to assign the costs of distribution poles and lines and continues to evaluate the application of this demand measure generally to assign secondary plant costs to each customer class.

Q28. Please describe how the demand measure used in the Company's CCOSS is calculated.

Consistent with the method applied in the prior case, the Company has used the PHI Load Profiling and Settlement System ("LPSS") to calculate the demand measure used in ACE's CCOSS. The LPSS produces the peak load contributions and hourly load obligations for retail customers receiving Basic Generation Service and customers receiving wholesale or retail service from third party suppliers.

The LPSS has been used to determine the Class MDD through a query of the hourly class load data contained in the system. That is, each hour of the year is evaluated to determine the class maximum demand that forms the basis for the demand factor.

1	Q29.	Has the process described above for calculating demand measures used in the
2		Company's CCOSS changed as a result of ACE's Advanced Metering
3		Infrastructure ("AMI") installations?
4	A29.	No, at the time this case is being developed for filing, ACE is still in the
5		process of completing smart meter installations for customers. A population of
6		historical data required to facilitate a change is not yet available. Once the
7		Company has completed its installation of smart meters and a full year of historical
8		data is available, the proposed calculation of demand measures used within the
9		CCOSS will change. Demand measures will no longer rely on "Load Profiling",
10		but will be calculated based on total customer usage as measured through ACE's
11		Smart Energy Network.
12	Q30.	Please explain how Line Transformer asset costs (FERC Account 368) have
13		been allocated.
14	A30.	The Company's approach is consistent with the method used in BPU
15		Docket No. ER09080664 to the present case to allocate line transformer costs using
16		the DEMTRANSF allocator that is based on the Class MDD.
17	Q31.	How have distribution service line costs (FERC Account 369) been allocated?
18	A31.	In this case, the Company has continued to allocate service line costs based
19		on Class MDD.
20	Q32.	How have meter costs (FERC Accounts 370 and 370.1) been allocated?
21	A32.	ACE's investment in customer meters has been allocated based on a detailed
22		analysis of the customer meter and related equipment costs. The results of this
23		analysis were then used to allocate the embedded costs contained in Account 370.1.

The Company's analysis and assignment of AMI meter costs based on the number of meters and the installed cost of the meters for each customer class is consistent with the fundamental principle underlying the entire CCOSS, that costs should be attributed to the particular customer group(s) for which the costs are incurred.

A33.

A34.

For FERC Account 370.0, legacy meters, the Company has consistently allocated these costs on booked plant costs and meter counts. Direct assignment of costs is used when possible, as direct assignment of costs adheres to the principle of cost causation. In this case, the Company was able to make an improvement by directly assigning a large portion of instrument transformer plant. The majority of instrument transformer costs have been directly assigned to the proper customer class using the Company's continuing property records.

Q33. Please describe the allocation methods used for the remaining items of plant in service.

In addition to Distribution plant, the remaining items of plant in service consist of General, Intangible, and Service Company assets. These asset costs continue to be allocated using the Labor allocator that is detailed in Schedule (JLM)-1, starting on page 25.

Q34. How were the remaining elements of Rate Base allocated?

The remaining elements of Rate Base consist of the following: the Depreciation Reserve, Plant Held for Future Use, Materials and Supplies, Cash Working Capital, Customer Advances, Customer Deposits, and Deferred State and Federal Taxes. These Rate Base items are detailed in Schedule (JLM)-1. Each functionalized Rate Base item has been allocated primarily on the corresponding

Plant or Labor allocators. For example, the Depreciation Reserve was allocated on the corresponding plant accounts. Also, a Lead/Lag analysis was conducted to determine Cash Working Capital ("CWC"), as provided by Company Witness Chen. The individual components of CWC are detailed in the current CCOSS and assigned using appropriate allocators. ACE has also reviewed the Deferred Federal and State Income taxes and separated the deferred taxes into the Plant and Labor components.

REVENUES

A35.

Q35. How were Revenues addressed in your cost study?

The Company's retail sales revenues have been directly assigned to the respective customer classes. One of the major components of Other Operating Revenues are Rents from Electric Property that have been allocated consistent with the prior case based on an underlying Distribution plant allocators. Additionally, Conservative Incentive Program ("CIP") revenue, listed under Other Operating Revenues, has been direct assigned to the respective customer classes. The amount of CIP revenue that have been directly assigned is equal to the difference between the most recent approved annualized CIP targets within the test year from the PowerAhead 6th roll-in period, BPU Docket No. ER21111205 and comparing to the actual billed revenues for the historical test year.

OPERATIONS AND MAINTENANCE EXPENSE

Q36. How were the O&M expense allocations developed?

A36. Consistent with the prior case, the Distribution O&M expenses are allocated to the customer classes using the corresponding plant allocations. For example,

FERC Account 593, Maintenance of Overhead Lines, is assigned based on a plant allocator reflecting the Company's investment in distribution overhead lines. Meter reading expenses (FERC Account 902) were allocated to the respective customer classes based on a separate analysis of meter reading expenses. A separate analysis was also conducted to allocate Customer Records and Collection Expenses (FERC Account 903).

Q37. Please describe the allocation of Administrative and General costs.

A38.

A37.

The Administrative and General costs were assigned to each customer class consistent with the allocation methods used since BPU Docket No. ER09080664 based upon the applicable Labor, Plant or Revenue allocator. For example, Property Insurance was allocated on Plant; Employee Pensions and Benefits follow the allocation of Labor. Regulatory Commission expense was apportioned to the customer classes based on a Revenue allocator.

Q38. Please describe the allocation of the remaining operating expenses.

The remaining operating expenses consist of Depreciation and Amortization expenses, Taxes Other Than Income Taxes, Net Investment Tax Credit ("ITC") adjustment, Interest on Customer Deposits, and Federal and State Income Taxes. As shown in Schedule (JLM)-1, the Company has detailed each component of Other Taxes, and has allocated the various components using an appropriate Labor, Plant, Revenue or Expense allocator. Similarly, these schedules show the assignment of Interest on Customer Deposits, and the Net ITC adjustment. Finally, ACE has detailed the applicable Federal and State income taxes, as shown in Schedule (JLM)-1.

1		SUMMARY OF CCOSS RESULTS
2	Q39	Have you prepared a summary of the results on your ACE Distribution
3		CCOSS?
4	A39.	Yes. The summary results for the ACE Distribution CCOSS expressed as
5		Rates of Return and Relative Rates of Return, are provided in Schedule (JLM)-3.
6		CCOSS BASED ON PEAK AND AVERAGE METHOD
7	Q40.	Please describe the Board's directive to submit a CCOSS based on the Peak
8		and Average cost allocation method.
9	A40.	The Board's Order in BPU Docket No. ER03020110 requires ACE to
10		submit a CCOSS based on a Peak and Average method ("P&A" method) that
11		allocates distribution plant and related costs on a combination of coincident peak
12		demand and energy based allocators. Additionally, the Order in Docket No.
13		ER03020110 states that the Company will have the right to file, and support, any
14		CCOSS method it considers more appropriate.
15	Q41.	Have you prepared a CCOSS based on the P&A method?
16	A41.	Yes. Schedule (JLM)-5 provides the CCOSS based on the P&A method
17		and Schedule (JLM)-6 provides the summary of the demand- and customer-related
18		cost components for each customer class based on the P&A method.
19	Q42.	Do you agree with the use of the P&A method for allocating distribution plant
20		costs?
21	A42.	No, I do not. The Company designs and builds its distribution system to
22		serve localized loads. As explained by the Company's witness in prior cases in

1		Direct and Rebuttal testimony, ³ the P&A method does not reflect cost causation
2		and is an incorrect and inappropriate allocation method for distribution facilities
3		such as substations, poles, conductors, and transformers.
4	Q43.	Why is the P&A method inappropriate for these distribution costs?
5	A43.	The P&A method applies an energy weighting method using coincident
6		peak for the demand component to classify and allocate the Company's distribution
7		plant. This method does not reflect the way ACE actually designs, constructs, and
8		operates its distribution system.
9	Q44.	How does ACE design and construct these distribution facilities?
10	A44.	The Company designs and constructs these distribution facilities based
11		upon localized peak demand and the load diversity of the customer mix served by
12		the facilities, not based upon the energy weighting approach embodied in the P&A
13		method.
14	Q45.	Do you know of any Company distribution facilities in FERC Accounts 362
15		through 368 that are based on energy requirements?
16	A45.	No, I do not. For the electric distribution "wires only" business, localized
17		loads or demands form the basis for plant investments along with a consideration
18		for some amount of diversity. The Company applies non-coincident demands to
19		allocate distribution plant costs to the respective customer classes.
20		The Company does not design its distribution facilities based on either the
21		coincident peak or energy (average demand) components that comprise the P&A

⁵ See Tanos Direct Testimony in BPU Docket Nos. ER12121071, ER14030245, ER16030252, and Tanos Rebuttal Testimony in BPU Docket No. ER11080469.

Witness Masters

- method. The P&A method is not consistent with the fundamental principle of cost
- 2 causation that drives the entire cost allocation process and should be rejected.
- 3 Q46. Does this conclude your testimony?
- 4 A46. Yes, it does.

Schedule (JLM)-1

		ALLOC	TOTAL ACE DISTRIBUTION (1)	TOTAL RESIDENTIAL SERVICE (2)	MONTHLY GENERAL SERVICE (3)	ANNUAL GENERAL SERVICE (4)	TRANSM GENERAL SERVICE (5)	STREET LIGHTING SERVICE (6)	DIRECT DISTRIBUTION CONNECTION (7)
	SUMMARY OF RESULTS-1								
	RATE BASE								
1	Total System Electric Distribution		3,257,924,573	2,197,730,128	408,228,311	460,698,323	12,555,461	176,609,721	2,102,629
2	Less: Depreciation Reserve		841,929,265	568,514,886	106,950,395	118,318,687	3,877,619	43,728,650	539,027
3	Total Net Plant		2,415,995,308	1,629,215,242	301,277,916	342,379,636	8,677,842	132,881,071	1,563,602
	ADD:								
4	Working Capital		113,732,356	73,847,388	18,322,612	14,815,322	3,062,496	3,585,892	98,645
5	Plant Held for Future Use		6,390,756	4,328,080	844,434	881,572	43,632	289,044	3,994
6	Materials & Supplies DEDUCT:		31,908,733	21,496,938	3,926,263	4,548,679	91,625	1,824,420	20,809
7	Customer Advances		9,971,369	6,717,719	1,226,944	1,421,446	28,632	570,125	6,503
8	Customer Deposits		18,982,828	8,496,886	4,857,917	5,628,025	0	0,120	0,000
9	Deferred FIT		450,109,122	304,393,074	58,347,325	62,661,862	2,582,340	21,839,843	284,677
10	Deferred SIT		136,718,553	92,217,138	17,104,477	19,346,756	515,225	7,446,641	88,317
11	TOTAL RATE BASE		1,952,245,281	1,317,062,831	242,834,561	273,567,120	8,749,397	108,723,819	1,307,554
	DEVELOPMENT OF RETURN								
12	Revenue - Retail Sales		476,723,799	296,020,547	86,151,215	69,944,842	5,114,341	18,905,207	587,648
13	Settlement Net Base Revenue Increase		0	0	0	0	0	0	0
14	Total Revenue - Retail Sales ACE		476,723,799	296,020,547	86,151,215	69,944,842	5,114,341	18,905,207	587,648
15	Other Operating Revenue		8,680,898	5,992,539	1,149,596	1,372,022	24,155	136,105	6,481
16	Total Electric Operating Revenue		485,404,697	302,013,086	87,300,810	71,316,864	5,138,496	19,041,312	594,129
	LESS:								
17	Operating & Maintenance Expense		251,338,447	182,562,248	32,749,081	27,236,959	2,286,836	6,302,607	200,715
18	Depreciation & Amortization Expense		116,008,720	78,349,613	14,773,643	16,284,250	550,418	5,976,634	74,161
19	Other Taxes		5,484,499	3,906,887	1,062,179	361,982	30,724	120,685	2,041
20	Net ITC Adjustment		(154,673)	(104,183)	(18,980)	(22,075)	(422)	(8,912)	(101)
21	Interest on Customer Deposits		41,011	18,357	10,495	12,159	0	0	0
22	Income Taxes		(1,770,331)	(12,817,001)	7,163,206	3,203,117	545,048	63,081	72,219
23	Total Operating Expenses		370,947,672	251,915,920	55,739,624	47,076,392	3,412,605	12,454,095	349,036
24	OPERATING INCOME		114,457,025	50,097,166	31,561,186	24,240,473	1,725,891	6,587,217	245,093
25 26			5.86% 1.00	3.80% 0.65	13.00% 2.22	8.86% 1.51	19.73% 3.36	6.06% 1.03	18.74% 3.20

		ALLOC	RESIDENTIAL (8)-2	MONTHLY GENERAL SERV SECONDARY (9)	MONTHLY GENERAL SERV PRIMARY (10)	ANNUAL GENERAL SERV SECONDARY (11)	ANNUAL GENERAL SERV PRIMARY (12)	STREET AND PRIVATE LIGHTING (13)	GENERAL SERVICE SUBTRANSMSN (14)	GENERAL SERVICE TRANSMISSION (15)	DIRECT DISTRIBUTION CONNECTION (16)
	SUMMARY OF RESULTS-1										
	RATE BASE										
1	Total System Electric Distribution		2,197,730,128	397.977.754	10,250,557	389.840.586	70.857.737	176,609,721	10,256,767	2,298,694	2,102,629
2	Less: Depreciation Reserve		568,514,886	104,124,940	2,825,455	99,547,031	18,771,657	43,728,650	3,114,928	762,691	539,027
3	Total Net Plant		1,629,215,242	293,852,814	7,425,102	290,293,555	52,086,080	132,881,071	7,141,840	1,536,002	1,563,602
	ADD:										
4			73,847,388	17,597,262	725,350	11,873,478	2,941,845	3,585,892	2,124,731	937,765	98,645
5	Plant Held for Future Use		4,328,080	819,029	25,405	728,760	152,812	289,044	34,060	9,572	3,994
6	Materials & Supplies		21,496,938	3,834,605	91,658	3,877,476	671,202	1,824,420	77,463	14,162	20,809
7	DEDUCT:		6.717.719	1,198,301	28,643	1,211,698	209,748	570,125	24 207	4,426	0.502
8	Customer Advances Customer Deposits		8,496,886	4,744,510	113,407	4,797,554	830,470	570,125 0	24,207 0	4,420	6,503
9	Deferred FIT		304,393,074	56,694,812	1,652,513	52,255,908	10,405,954	21,839,843	2,038,893	543,447	284,677
10			92,217,138	16,677,565	426,912	16,381,697	2,965,059	7,446,641	421,868	93,357	88,317
11	TOTAL RATE BASE		1,317,062,831	236,788,522	6,046,039	232,126,412	41,440,708	108,723,819	6,893,125	1,856,273	1,307,554
	DEVELOPMENT OF RETURN										
12	Revenue - Retail Sales		296,020,547	84,363,933	1,787,281	57,356,426	12,588,416	18,905,207	3,024,915	2,089,427	587,648
13	Settlement Net Base Revenue Increase		0	0	0	0	0	0	-	0	0
14			296,020,547	84,363,933	1,787,281	57,356,426	12,588,416	18,905,207	3,024,915	2,089,427	587,648
15			5,992,539	1,114,697	34,899	1,105,842	266,180	136,105	20,039	4,116	6,481
16	Total Electric Operating Revenue		302,013,086	85,478,631	1,822,180	58,462,268	12,854,596	19,041,312	3,044,953	2,093,542	594,129
	LESS:										
17	1		182,562,248	31,690,451	1,058,630	21,600,378	5,636,582	6,302,607	1,515,181	771,655	200,715
18			78,349,613	14,379,831	393,812	13,685,995	2,598,255	5,976,634	441,031	109,387	74,161
19			3,906,887	1,046,461	15,718	274,333	87,649	120,685	23,839	6,886	2,041
20	Net ITC Adjustment		(104,183)					(8,912)		(63)	(101)
21 22	Interest on Customer Deposits Income Taxes		18,357 (12,817,001)	10,250 7,168,587	245 (5,381)	10,365 2,615,875	1,794 587,242	0 63,081	0 208,210	0 336,838	0 72,219
22	income Taxes		(12,017,001)	7,100,307	(5,361)	2,010,075	367,242	03,001	200,210	330,636	72,219
23	Total Operating Expenses		251,915,920	54,277,038	1,462,587	38,168,107	8,908,285	12,454,095	2,187,902	1,224,703	349,036
24	OPERATING INCOME		50,097,166	31,201,593	359,593	20,294,162	3,946,311	6,587,217	857,051	868,840	245,093
			3.80%					6.06%		46.81%	18.74%
26	RELATIVE RATE OF RETURN		0.65	2.25	1.01	1.49	1.62	1.03	2.12	7.98	3.20

		ALLOC	TOTAL ACE DISTRIBUTION (1)	F	TOTAL RESIDENTIAL SERVICE (2)	MONTHLY GENERAL SERVICE (3)	ANNUAL GENERAL SERVICE (4)	TRANSM GENERAL SERVICE (5)	STREET LIGHTING SERVICE (6)	DIRECT DISTRIBUTION CONNECTION (7)
	DEVELOPMENT OF RATE BASE-2									
	ELECTRIC PLANT IN SERVICE									
	DISTRIBUTION PLANT Distribution - ACE									
	3601 Land and Land Rights									
1	Substations 23/34.5 kV	_PLT362	113,404		79,057	14,077	18,817	635	736	82
2	Substations Remainder	DPRITGSS	10,152,293		7,117,299	1,267,293	1,694,041	0	66,236	7,425
3	Lines 23/34.5 KV	_PLT3647	1,186,005		836,578	147,906	190,251	2,611	7,785	873
4 5	Lines Remainder	DPRITGSS	26,240,962		18,396,313	3,275,613	4,378,643	0	171,201	19,191
5 6	Total Acct 3601 3610 Structures and Improvements		37,692,664		26,429,247	4,704,889	6,281,753	3,246	245,958	27,571
7	23/34.5 KV	DEMPRI	4.789.911		3.238.644	576.667	770.854	170.227	30.140	3.379
8	Remainder	DPRITGSS	43,161,870		30,258,771	5,387,820	7,202,115	0	281.597	31,566
9	Total Acct 3610		47,951,780		33,497,415	5,964,487	7,972,969	170,227	311.737	34,945
10	3620 Station Equipment		, ,				, , , , , , , , , , , , , , , , , , , ,	,	, ,	
11	23/34.5 KV	DEMPRI	79,894,280		54,019,619	9,618,632	12,857,611	2,839,343	502,722	56,354
12	Remainder	DPRITGSS	427,161,194		299,462,766	53,321,779	71,277,359	0	2,786,886	312,403
13	Total Acct 3620		507,055,474		353,482,385	62,940,412	84,134,970	2,839,343	3,289,608	368,757
14	3640 Poles, Towers and Fixtures	DEMODI	0.720.542		0.502.024	4 470 400	4 500 004	240,022	C4 0CE	0.000
15	Demand Primary 23/34.5 KV	DEMPRI	9,736,513		6,583,234	1,172,198	1,566,924	346,023	61,265	6,868
16 17	Demand Primary Remainder	DPRITGSS DEMSEC	292,779,615 56,768,834		205,254,116 41,554,807	36,547,164 7,133,139	48,854,058 7,650,816	0	1,910,154 386,721	214,123 43,350
18	Secondary Total Acct 3640	DEIVISEC	359,284,962		253,392,158	44,852,501	58,071,799	346,023	2,358,140	264,341
19	3650 Overhead Conductors and Devices		333,204,302		200,002,100	44,002,001	30,071,733	340,023	2,330,140	204,041
20	Demand Primary 23/34.5 KV	DEMPRI	9,598,114		6,489,657	1,155,536	1,544,651	341,105	60,395	6.770
21	Demand Primary Remainder	DPRITGSS	501,893,232		351,853,908	62,650,448	83,747,364	0	3,274,453	367,058
22	Secondary	DEMSEC	95,984,196		70,260,467	12,060,643	12,935,926	0	653,864	73,296
23	Total Acct 3650		607,475,542		428,604,032	75,866,627	98,227,942	341,105	3,988,712	447,124
24	3660 Underground Conduit									
25	Demand Primary 23/34.5 KV	DEMPRI	8,343,384		5,641,285	1,004,477	1,342,724	296,513	52,499	5,885
26	Demand Primary Remainder	DPRITGSS	20,595,508		14,438,549	2,570,901	3,436,626	0	134,369	15,062
27	Secondary	DEMSEC	13,538,756		9,910,374	1,701,177	1,824,637	0	92,229	10,339
28 30	Total Acct 3660 3670 Underground Conductors and Devices		42,477,648		29,990,209	5,276,555	6,603,988	296,513	279,097	31,286
31	Demand Primary 23/34.5 KV	DEMPRI	46,808,325		31,648,922	5,635,348	7,532,995	1,663,509	294,534	33,016
32	Demand Primary 25/54.5 RV Demand Primary Remainder	DPRITGSS	84,898,713		59,518,523	10,597,757	14,166,446	1,000,000	553.896	62.090
33	Secondary	DEMSEC	61,617,752		45,104,217	7,742,417	8,304,312	0	419,753	47,053
34	Total Acct 3670	52620	193,324,790		136,271,662	23,975,522	30,003,753	1,663,509	1,268,183	142,160
35	3680 Line Transformers	DEMTRNSF	641,360,322		469,475,992	80,588,450	86,437,039	0	4,369,078	489,762
36	3691 Services	CUST369	226,877,166		167,277,567	28,714,226	30,798,119	0	0	87,253
37	3700 Meters	CUST370	63,306,521		37,296,595	18,847,652	4,624,619	2,537,655	0	0
37	3701 AMI Meters	CUST371	26,519,661		20,335,043	5,541,697	642,921	0	0	0
38	3711 Installations on Customer Premises	CUST3711P	576,123		388,135	70,890	82,128	1,654	32,941	376
39	3712 Installations on Customer Premises	CUST373	31,756,449		0	0	0	0	31,756,449	0
40	372 Leased Property on Customer Premises	CUST372	141,649		0	0	13,606	128,042	0	0
41 42	3730 Street Lighting and Signal Systems	CUST373	118,371,145		0	0	705 220	0	118,371,145	0
42	3740 Asset retirement costs for Dist Plant Total Distribution - ACE	_PLT362	4,370,738 2,908,542,635		3,046,962 1,959,487,402	542,536 357,886,444	725,230 414,620,837	24,475 8,351,793	28,356 166,299,405	3,179 1,896,754

		ALLOC	RESIDENTIAL (8)-2	MONTHLY GENERAL SERV SECONDARY (9)	MONTHLY GENERAL SERV PRIMARY (10)	ANNUAL GENERAL SERV SECONDARY (11)	ANNUAL GENERAL SERV PRIMARY (12)	STREET AND PRIVATE LIGHTING (13)	GENERAL SERVICE SUBTRANSMSN (14)	GENERAL SERVICE TRANSMISSION (15)	DIRECT DISTRIBUTION CONNECTION (16)
	DEVELOPMENT OF RATE BASE-2										
	ELECTRIC PLANT IN SERVICE										
	DISTRIBUTION PLANT Distribution - ACE										
	3601 Land and Land Rights										
1	Substations 23/34.5 kV	PLT362	79,057	13,571	506	14,556	4,261	736	635	0	82
2	Substations Remainder	DPRITGSS	7,117,299	1,221,728	45,565	1,310,393	383,648	66,236	0	0	7,425
3	Lines 23/34.5 KV	_PLT3647	836,578	143,604	4,302	154,026	36,226	7,785	2,611	0	873
4	Lines Remainder	DPRITGSS	18,396,313	3,157,841	117,772	3,387,016	991,627	171,201	0	0	19,191
5	Total Acct 3601		26,429,247	4,536,743	168,146	4,865,991	1,415,762	245,958	3,246	0	27,571
6	3610 Structures and Improvements										
7	23/34.5 KV	DEMPRI	3,238,644	555,933	20,734	596,279	174,574	30,140	170,227	0	3,379
8	Remainder	DPRITGSS	30,258,771	5,194,105	193,715	5,571,059	1,631,056	281,597	0	0	31,566
9	Total Acct 3610		33,497,415	5,750,038	214,449	6,167,339	1,805,630	311,737	170,227	0	34,945
10	3620 Station Equipment									_	
11	23/34.5 KV	DEMPRI	54,019,619	9,272,801	345,831	9,945,761	2,911,850	502,722	2,839,343	0	56,354
12	Remainder	DPRITGSS	299,462,766	51,404,631	1,917,148	55,135,247	16,142,112	2,786,886	0	0	312,403
13	Total Acct 3620		353,482,385	60,677,432	2,262,980	65,081,008	19,053,962	3,289,608	2,839,343	U	368,757
14 15	3640 Poles, Towers and Fixtures	DEMPRI	6,583,234	1,130,053	42,146	1,212,065	354,860	61,265	346,023	0	6,868
	Demand Primary 23/34.5 KV								340,023	0	·
16 17	Demand Primary Remainder	DPRITGSS	205,254,116	35,233,135	1,314,028	37,790,129	11,063,929 0	1,910,154	0	0	214,123
17	Secondary	DEMSEC	41,554,807 253,392,158	7,133,139 43,496,327	•	7,650,816 46,653,010	•	386,721 2,358,140	346,023	0	43,350 264,341
19	Total Acct 3640 3650 Overhead Conductors and Devices		200,092,100	43,490,321	1,356,174	40,000,010	11,418,789	2,336,140	340,023	U	204,341
20	Demand Primary 23/34.5 KV	DEMPRI	6,489,657	1,113,990	41,547	1,194,836	349,816	60,395	341,105	0	6.770
21	Demand Primary Remainder	DPRITGSS	351,853,908	60,397,894	2,252,554	64,781,183	18,966,181	3,274,453	0 + 1, 100	0	367,058
22	Secondary	DEMSEC	70,260,467	12,060,643	2,232,334	12,935,926	10,300,101	653,864	0	0	73,296
23	Total Acct 3650	DEMOLO	428,604,032	73,572,526	2,294,101	78,911,945	19,315,997	3,988,712	341,105	0	447,124
24	3660 Underground Conduit		120,001,002	. 0,0. 2,020	2,20 1,10 1	. 0,0 . 1,0 .0	10,010,001	0,000,7.12	011,100	ŭ	,
25	Demand Primary 23/34.5 KV	DEMPRI	5,641,285	968,361	36,115	1,038,639	304,085	52,499	296,513	0	5,885
26	Demand Primary Remainder	DPRITGSS	14.438.549	2,478,466	92,435	2.658.337	778.289	134.369	0	0	15.062
27	Secondary	DEMSEC	9,910,374	1,701,177	0	1,824,637	0	92,229	Ō	0	10,339
28	Total Acct 3660		29,990,209	5,148,004	128,550	5,521,613	1,082,375	279,097	296,513	0	31,286
30	3670 Underground Conductors and Devices										
31	Demand Primary 23/34.5 KV	DEMPRI	31,648,922	5,432,733	202,615	5,827,005	1,705,990	294,534	1,663,509	0	33,016
32	Demand Primary Remainder	DPRITGSS	59,518,523	10,216,722	381,035	10,958,185	3,208,261	553,896	0	0	62,090
33	Secondary	DEMSEC	45,104,217	7,742,417	0	8,304,312	0	419,753	0	0	47,053
34	Total Acct 3670		136,271,662	23,391,872	583,650	25,089,502	4,914,251	1,268,183	1,663,509	0	142,160
35	3680 Line Transformers	DEMTRNSF	469,475,992	80,588,450	0	86,437,039	0	4,369,078	0	0	489,762
36	3691 Services	CUST369	167,277,567	28,714,226	0	30,798,119	0	0	0	0	87,253
37	3700 Meters	CUST370	37,296,595	17,551,138	1,296,514	2,639,963	1,984,657	0	1,368,153	1,169,501	0
37	3701 AMI Meters	CUST371	20,335,043	5,512,650	29,047	642,921	0	0	0	0	0
38	3711 Installations on Customer Premises	CUST3711P	388,135	69,235	1,655	70,009	12,119	32,941	1,399	256	376
39	3712 Installations on Customer Premises	CUST373	0	0	0	0	0	31,756,449	0	0	0
40	372 Leased Property on Customer Premises	CUST372	0	0	0	0	13,606	0	6,903	121,139	0
41 42	3730 Street Lighting and Signal Systems	CUST373	3,046,962	523.030	19,507	560,988	0 164,242	118,371,145 28,356	0 24,475	0	0 3,179
42	3740 Asset retirement costs for Dist Plant Total Distribution - ACE	_PLT362	1,959,487,402	349,531,672	8,354,772	353,439,447	61,181,390	166,299,405	7,060,897	1,290,896	1,896,754

		ALLOC	TOTAL ACE DISTRIBUTION (1)	TOTAL RESIDENTIAL SERVICE (2)	MONTHLY GENERAL SERVICE (3)	ANNUAL GENERAL SERVICE (4)	TRANSM GENERAL SERVICE (5)	STREET LIGHTING SERVICE (6)	DIRECT DISTRIBUTION CONNECTION (7)
	DEVELOP OF RATE BASE CON'T-3								
	ELECTRIC PLANT IN SERVICE General Plant		244.000		40.070	45.400		40.000	-
1	3891 Land and Land Rights	LABOR LABOR	341,986 28.274.742	233,200 19.280.480	49,276 4,074,061	45,102 3,728,954	4,115 340,194	10,092 834.392	202 16,661
3	3903 Structures and Improvements 3911 Office Furniture and Equipment	LABOR	3,873,572	2,641,379	558,137	510,858	46,606	114,310	2,283
4	3912 Office Furniture and Equipment	LABOR	0,073,372	2,041,573	0.00,107	0 0 0 0 0	40,000	0	2,200
5	3913 Office Furniture and Equipment	LABOR	18,410,146	12,553,836	2,652,688	2,427,983	221,506	543,286	10,848
6	3915 Office Furniture and Equipment	LABOR	0	.2,565,666	2,002,000	2, 127,000	0	0.0,200	0.0,0.0
7	3920 Transportation Equipment	LABOR	22,117,847	15,082,108	3,186,924	2,916,965	266,116	652,701	13,033
8	3931 Stores Equipment	LABOR	86,189	58,772	12,419	11,367	1,037	2,543	51
9	3932 Stores Equipment	LABOR	0	0	0	0	0	0	0
10	3941 Tools, Shop and Garage Equipment	LABOR	12,629,082	8,611,741	1,819,704	1,665,559	151,950	372,686	7,442
11	3942 Tools, Shop and Garage Equipment	LABOR	0	0	0	0	0	0	0
12	3951 Laboratory Equipment	LABOR	0	0	0	0	0	0	0
13	3952 Laboratory Equipment	LABOR	0	0	0	0	0	0	0
14	3960 Power Operated Equipment	LABOR	0	0	0	0	0	0	0
15	3970 Communication Equipment	LABOR	107,044,121	72,993,136	15,423,811	14,117,284	1,287,926	3,158,889	63,076
16	3982 Miscellaneous Equipment	LABOR	2,987,367	2,037,078	430,445	393,982	35,943	88,158	1,760
17	399 Other Tangible Property	LABOR	0	0	0	0	0	0	0
18	3991 Other Tangible Property	LABOR	35,806	24,416	5,159	4,722	431	1,057	21
19	Total General Plant		195,800,857	133,516,146	28,212,622	25,822,775	2,355,823	5,778,114	115,377
	Intangible Plant								
20	3020 000 Franchises and Consents	LABOR	0	0	0	0	0	0	0
21	3030 000 Miscellaneous Intangible Plant	LABOR	84,054,509	57,316,573	12,111,275	11,085,348	1,011,321	2,480,462	49,530
22	Total Intangible Plant		84,054,509	57,316,573	12,111,275	11,085,348	1,011,321	2,480,462	49,530
00			0.400.000.004	0.450.000.404	000 040 040	454 500 000	44.740.000	474 557 004	0.004.000
23	Total pre-Service Co Electric Plant In Service		3,188,398,001	2,150,320,121	398,210,342	451,528,960	11,718,936	174,557,981	2,061,660
24	Service Company Assets	SERVCO	69,526,572	47,410,007	10,017,969	9,169,363	836,525	2,051,740	40,969
25	Total System Electric Distribution		3,257,924,573	2,197,730,128	408,228,311	460,698,323	12,555,461	176,609,721	2,102,629

		ALLOC	RESIDENTIAL (8)-2	MONTHLY GENERAL SERV SECONDARY (9)	MONTHLY GENERAL SERV PRIMARY (10)	ANNUAL GENERAL SERV SECONDARY (11)	ANNUAL GENERAL SERV PRIMARY (12)	STREET AND PRIVATE LIGHTING (13)	GENERAL SERVICE SUBTRANSMSN (14)	GENERAL SERVICE TRANSMISSION (15)	DIRECT DISTRIBUTION CONNECTION (16)
		ALLOO	(0) 2	(0)	(10)	(,	(12)	(10)	(14)	(10)	(10)
	DEVELOP OF RATE BASE CON'T-3										
	ELECTRIC PLANT IN SERVICE										
	General Plant										
1	3891 Land and Land Rights	LABOR	233,200	47,421	1,856	35,631	9,472	10,092	3,128	986	202
2	3903 Structures and Improvements	LABOR	19,280,480	3,920,639	153,422	2,945,867	783,086	834,392	258,635	81,559	16,661
3	3911 Office Furniture and Equipment	LABOR	2,641,379	537,118	21,018	403,577	107,281	114,310	35,432	11,173	2,283
4	3912 Office Furniture and Equipment	LABOR	0	0	0	0	0	0	0	0	0
5	3913 Office Furniture and Equipment	LABOR	12,553,836	2,552,792	99,896	1,918,102	509,880	543,286	168,402	53,104	10,848
6	3915 Office Furniture and Equipment	LABOR	0	0	0	0	0	0	0	0	0
/	3920 Transportation Equipment	LABOR	15,082,108	3,066,910	120,014	2,304,397	612,567	652,701	202,317	63,799	13,033
8 9	3931 Stores Equipment	LABOR	58,772 0	11,951 0	468 0	8,980	2,387	2,543	788 0	249	51
10	3932 Stores Equipment	LABOR LABOR	8,611,741	1,751,177	68,527	1,315,789	349,770	372,686	115,521	36,429	7,442
11	3941 Tools, Shop and Garage Equipment	LABOR	0,011,741	1,731,177	00,527	1,313,769	349,770	372,000	113,321	30,429	7,442
12	3942 Tools, Shop and Garage Equipment 3951 Laboratory Equipment	LABOR	0	0	0	0	0	0	0	0	0
13	3951 Laboratory Equipment 3952 Laboratory Equipment	LABOR	0	0	0	0	0	0	0	0	0
14	3960 Power Operated Equipment	LABOR	0	0	0	0	0	0	0	0	0
15	3970 Communication Equipment	LABOR	72,993,136	14,842,977	580,833	11,152,631	2,964,653	3,158,889	979,155	308,770	63,076
16	3982 Miscellaneous Equipment	LABOR	2,037,078	414,235	16,210	311,245	82,737	88,158	27,326	8.617	1.760
17	399 Other Tangible Property	LABOR	2,037,076	414,233	10,210	311,243	02,737	00,130	27,320	0,017	1,700
18	3991 Other Tangible Property	LABOR	24,416	4,965	194	3,731	992	1,057	328	103	21
19	Total General Plant	LABOR	133,516,146	27,150,185	1,062,437	20,399,951	5,422,825	5,778,114	1,791,032	564,791	115,377
	Intangible Plant										
20	3020 000 Franchises and Consents	LABOR	0	0	0	Λ	0	0	0	٥	n
21	3030 000 Miscellaneous Intangible Plant	LABOR	57,316,573	11.655.186	456,089	8.757.407	2,327,941	2.480.462	768,864	242,457	49,530
22	Total Intangible Plant	LABOR	57,316,573	11,655,186	456,089	8,757,407	2,327,941	2,480,462	768,864	242,457	49,530
22	Total ilitarigible Flant		37,310,373	11,030,100	430,003	0,737,407	2,527,541	2,400,402	700,004	242,437	43,550
23 Total pre-Service Co Electric Plant In Service 2,150,320,121 388,337,044 9,873,298 382,596,805 68,932,156 174,557,981 9,620,793 2,098,143 2,061,660									2,061,660		
23	23 Total pre-Service Co Electric Plant in Service		2, 130,320, 121	300,337,044	3,013,290	302,390,003	00,932,130	174,557,961	9,020,793	2,050,143	2,001,000
24	Service Company Assets	SERVCO	47,410,007	9,640,710	377,259	7,243,781	1,925,581	2,051,740	635,974	200,551	40,969
25	Total System Electric Distribution		2,197,730,128	397,977,754	10,250,557	389,840,586	70,857,737	176,609,721	10,256,767	2,298,694	2,102,629

	ALLOC	TOTAL ACE DISTRIBUTION (1)	TOTAL RESIDENTIAL SERVICE (2)	MONTHLY GENERAL SERVICE (3)	ANNUAL GENERAL SERVICE (4)	TRANSM GENERAL SERVICE (5)	STREET LIGHTING SERVICE (6)	DIRECT DISTRIBUTION CONNECTION (7)
DEVELOP OF RATE BASE CON'T-4								
DEPRECIATION RESERVE								
1 Distribution	DISTPLT	682,540,242	459,827,884	83,984,294	97,298,009	1,959,894	39,025,055	445,106
2 General	GENPLT	62,777,667	42,807,944	9,045,530	8,279,298	755,324	1,852,579	36,992
3 Intangible	INTPLT	43,204,863	29,461,295	6,225,317	5,697,980	519,829	1,274,982	25,459
4 Other	PLANT	0	0	0	0	0	0	0
5 Service Company Assets Reserve	SERVCO	53,406,493	36,417,763	7,695,253	7,043,401	642,572	1,576,034	31,470
6 Total Depreciation Reserve		841,929,265	568,514,886	106,950,395	118,318,687	3,877,619	43,728,650	539,027
7 Total Net Plant		2,415,995,308	1,629,215,242	301,277,916	342,379,636	8,677,842	132,881,071	1,563,602

	ALLOC	RESIDENTIAL (8)-2	MONTHLY GENERAL SERV SECONDARY (9)	MONTHLY GENERAL SERV PRIMARY (10)	ANNUAL GENERAL SERV SECONDARY (11)	ANNUAL GENERAL SERV PRIMARY (12)	STREET AND PRIVATE LIGHTING (13)	GENERAL SERVICE SUBTRANSMSN (14)	GENERAL SERVICE TRANSMISSION (15)	DIRECT DISTRIBUTION CONNECTION (16)
DEVELOP OF RATE BASE CON'T-4										
DEPRECIATION RESERVE										
1 Distribution	DISTPLT	459,827,884	82,023,701	1,960,593	82,940,729	14,357,280	39,025,055	1,656,963	302,931	445,106
2 General	GENPLT	42,807,944	8,704,892	340,639	6,540,632	1,738,666	1,852,579	574,241	181,083	36,992
3 Intangible	INTPLT	29,461,295	5,990,883	234,434	4,501,395	1,196,585	1,274,982	395,204	124,625	25,459
4 Other	PLANT	0	0	0	0	0	0	0	0	0
5 Service Company Assets Reserve	SERVCO	36,417,763	7,405,464	289,790	5,564,275	1,479,126	1,576,034	488,520	154,052	31,470
6 Total Depreciation Reserve		568,514,886	104,124,940	2,825,455	99,547,031	18,771,657	43,728,650	3,114,928	762,691	539,027
7 Total Net Plant		1,629,215,242	293,852,814	7,425,102	290,293,555	52,086,080	132,881,071	7,141,840	1,536,002	1,563,602

		ALLOC	TOTAL ACE DISTRIBUTION (1)	TOTAL RESIDENTIAL SERVICE (2)	MONTHLY GENERAL SERVICE (3)	ANNUAL GENERAL SERVICE (4)	TRANSM GENERAL SERVICE (5)	STREET LIGHTING SERVICE (6)	DIRECT DISTRIBUTION CONNECTION (7)
	DEVELOP OF RATE BASE CON'T-5								
	ADDITIONS AND DEDUCTIONS TO RATE	BASE							
	ADDITIONS TO RATE BASE								
8 9 10	General	DISTPLT GENPLT	3,630,877 2,759,880 6,390,756	2,446,124 1,881,955 4,328,080	446,767 397,667 844,434	517,592 363,981 881,572	10,426 33,206 43,632	207,600 81,444 289,044	2,368 1,626 3,994
11 12 13	MATERIALS & SUPPLIES Distribution Labor Stock Total Materials & Supplies	DISTPLT LABOR	31,908,733 0 31,908,733	21,496,938 0 21,496,938	3,926,263 0 3,926,263	4,548,679 0 4,548,679	91,625 0 91,625	1,824,420 0 1,824,420	20,809 0 20,809
14 15 16 17 18 19 20 21	Cash Working Capital O&M - Distribution Depreciation Deferred Tax Distribution Other Taxes Tax on Sales Revenue Net ITC Adjustment FIT & SIT Cost of Electric Supply Invested Capital Distribution IOCD	DISTOMEXP DISTPLT PLANT OTHTAX CLAIMREV PLANT CLAIMREV BGSNUGRV NETINC CUSTDEP	19,721,119 18,236,949 0 911,317 23,275,125 7,907 0 34,854,402 16,760,102 (34,564)	14,324,636 12,286,246 0 649,177 16,259,676 5,334 0 23,001,991 7,335,798 (15,471)	2,569,637 2,243,996 0 176,494 3,017,224 991 0 5,701,568 4,621,548 (8,845)	2,137,131 2,599,728 0 60,148 2,883,597 1,118 0 3,594,282 3,549,566 (10,248)	179,435 52,367 0 5,105 162,837 30 0 2,409,997 252,725	494,530 1,042,719 0 20,053 934,683 429 0 128,902 964,575 0	15,749 11,893 0 339 17,107 5 0 17,663 35,889 0
	Total Cash Working Capital		113,732,356	73,847,388	18,322,612	14,815,322	3,062,496	3,585,892	98,645

		ALLOC	RESIDENTIAL (8)-2	MONTHLY GENERAL SERV SECONDARY (9)	MONTHLY GENERAL SERV PRIMARY (10)	ANNUAL GENERAL SERV SECONDARY (11)	ANNUAL GENERAL SERV PRIMARY (12)	STREET AND PRIVATE LIGHTING (13)	GENERAL SERVICE SUBTRANSMSN (14)	GENERAL SERVICE TRANSMISSION (15)	DIRECT DISTRIBUTION CONNECTION (16)
	DEVELOP OF RATE BASE CON'T-5										
	ADDITIONS AND DEDUCTIONS TO RATE	BASE									
	ADDITIONS TO RATE BASE										
8 9 10	General Total Plant Held for Future Use	DISTPLT GENPLT	2,446,124 1,881,955 4,328,080	436,338 382,691 819,029	10,430 14,975 25,405	441,216 287,544 728,760	76,376 76,437 152,812	207,600 81,444 289,044	8,814 25,245 34,060	1,611 7,961 9,572	2,368 1,626 3,994
11 12 13	MATERIALS & SUPPLIES Distribution Labor Stock Total Materials & Supplies	DISTPLT LABOR	21,496,938 0 21,496,938	3,834,605 0 3,834,605	91,658 0 91,658	3,877,476 0 3,877,476	671,202 0 671,202	1,824,420 0 1,824,420	77,463 0 77,463	14,162 0 14,162	20,809 0 20,809
14 15 16 17 18 19 20 21	Cash Working Capital O&M - Distribution Depreciation Deferred Tax Distribution Other Taxes Tax on Sales Revenue Net ITC Adjustment FIT & SIT Cost of Electric Supply Invested Capital Distribution IOCD	DISTOMEXP DISTPLT PLANT OTHTAX CLAIMREV PLANT CLAIMREV BGSNUGRV NETINC CUSTDEP	14,324,636 12,286,246 0 649,177 16,259,676 5,334 0 0 23,001,991 7,335,798 (15,471)	2,486,572 2,191,610 0 173,882 2,931,314 966 0 5,252,664 4,568,893 (8,639)	83,065 52,386 0 2,612 85,910 25 0 448,903 52,656 (206)	1,694,861 2,216,112 0 45,584 2,373,471 946 0 2,579,537 2,971,702 (8,735)	442,271 383,615 0 14,564 510,126 172 0 1,014,745 577,864 (1,512)	494,530 1,042,719 0 20,053 934,683 429 0 128,902 964,575 0	118,888 44,273 0 3,961 114,494 25 0 1,717,591 125,499	60,547 8,094 0 1,144 48,343 6 0 692,405 127,225 0	15,749 11,893 0 339 17,107 5 0 17,663 35,889
	Total Cash Working Capital		73,847,388	17,597,262	725,350	11,873,478	2,941,845	3,585,892	2,124,731	937,765	98,645

		ALLOC	TOTAL ACE DISTRIBUTION (1)	TOTAL RESIDENTIAL SERVICE (2)	MONTHLY GENERAL SERVICE (3)	ANNUAL GENERAL SERVICE (4)	TRANSM GENERAL SERVICE (5)	STREET LIGHTING SERVICE (6)	DIRECT DISTRIBUTION CONNECTION (7)
	DEVELOP OF RATE BASE CON'T-6								
	DEDUCTIONS TO RATE BASE								
1 2	CUSTOMER ADVANCES ACE Total Customer Advances	DISTPLT	9,971,369 9,971,369	6,717,719 6,717,719	1,226,944 1,226,944	1,421,446 1,421,446	28,632 28,632	570,125 570,125	6,503 6,503
3 4	CUSTOMER DEPOSITS ACE Total Customer Deposits	CUSPDEP	18,982,828 18,982,828	8,496,886 8,496,886	4,857,917 4,857,917	5,628,025 5,628,025	0 0	0	0
5 6 7	DEFERRED FIT Labor Plant TCJA EDIT Total Deferred FIT	LABOR PLANT LABOR	(3,028,429) 346,451,766 106,685,785 450,109,122	(2,065,079) 233,709,365 72,748,787 304,393,074	(436,361) 43,411,508 15,372,179 58,347,325	(399,398) 48,991,235 14,070,026 62,661,862	(36,437) 1,335,163 1,283,614 2,582,340	(89,369) 18,780,898 3,148,314 21,839,843	(1,785) 223,596 62,865 284,677
8 9 10	DEFERRED SIT Labor Plant Total Deferred SIT	LABOR PLANT	(1,426,262) 138,144,815 136,718,553	(972,565) 93,189,703 92,217,138	(205,508) 17,309,985 17,104,477	(188,099) 19,534,855 19,346,756	(17,160) 532,386 515,225	(42,089) 7,488,730 7,446,641	(840) 89,157 88,317
11	Total Rate Base		1,952,245,281	1,317,062,831	242,834,561	273,567,120	8,749,397	108,723,819	1,307,554

	ALLOC	RESIDENTIAL (8)-2	MONTHLY GENERAL SERV SECONDARY (9)	MONTHLY GENERAL SERV PRIMARY (10)	ANNUAL GENERAL SERV SECONDARY (11)	ANNUAL GENERAL SERV PRIMARY (12)	STREET AND PRIVATE LIGHTING (13)	GENERAL SERVICE SUBTRANSMSN (14)	GENERAL SERVICE TRANSMISSION (15)	DIRECT DISTRIBUTION CONNECTION (16)
DEVELOP OF RATE BASE CON'T-6										
DEDUCTIONS TO RATE BASE										
CUSTOMER ADVANCES 1 ACE 2 Total Customer Advances	DISTPLT	6,717,719 6,717,719	1,198,301 1,198,301	28,643 28,643	1,211,698 1,211,698	209,748 209,748	570,125 570,125	24,207 24,207	4,426 4,426	6,503 6,503
CUSTOMER DEPOSITS 3 ACE 4 Total Customer Deposits	CUSPDEP	8,496,886 8,496,886	4,744,510 4,744,510	113,407 113,407	4,797,554 4,797,554	830,470 830,470	0	0	0	0
DEFERRED FIT 5 Labor 6 Plant TCJA EDIT 7 Total Deferred FIT	LABOR PLANT LABOR	(2,065,079) 233,709,365 72,748,787 304,393,074	(419,929) 42,321,451 14,793,290 56,694,812	(16,433) 1,090,057 578,889 1,652,513	(315,524) 41,456,135 11,115,297 52,255,908	(83,874) 7,535,100 2,954,728 10,405,954	(89,369) 18,780,898 3,148,314 21,839,843	(27,702) 1,090,717 975,877 2,038,893	(8,736) 244,446 307,737 543,447	(1,785) 223,596 62,865 284,677
DEFERRED SIT 8 Labor 9 Plant 10 Total Deferred SIT	LABOR PLANT	(972,565) 93,189,703 92,217,138	(197,769) 16,875,333 16,677,565	(7,739) 434,651 426,912	(148,598) 16,530,295 16,381,697	(39,501) 3,004,560 2,965,059	(42,089) 7,488,730 7,446,641	(13,046) 434,915 421,868	(4,114) 97,471 93,357	(840) 89,157 88,317
11 Total Rate Base		1,317,062,831	236,788,522	6,046,039	232,126,412	41,440,708	108,723,819	6,893,125	1,856,273	1,307,554

		ALLOC	TOTAL ACE DISTRIBUTION (1)	TOTAL RESIDENTIAL SERVICE (2)	MONTHLY GENERAL SERVICE (3)	ANNUAL GENERAL SERVICE (4)	TRANSM GENERAL SERVICE (5)	STREET LIGHTING SERVICE (6)	DIRECT DISTRIBUTION CONNECTION (7)
	OPERATING REVENUES-7								
	ELECTRIC SALES REVENUES								
1	Revenue - Retail Sales ACE		476,723,799	296,020,547	86,151,215	69,944,842	5,114,341	18,905,207	587,648
2	Total Revenue - Retail Sales ACE		476,723,799	296,020,547	86,151,215	69,944,842	5,114,341	18,905,207	587,648
	REVENUE - OTHER								
3	Other Revenues	CUST	0	0	0	0	0	0	0
4	Late Payment Revenue ACE	LPAY	117,067	0	57,438	46,633	0	12,604	392
5	Miscellaneous Service Revenue ACE	CUST	36,858	32,520	3,680	196	3	389	69
5	Miscellaneous Service Revenue ACE - I/C	LABOR	1,313,995	896,010	189,331	173,293	15,810	38,776	774
6	Rent from Electric Property ACE Poll Attach	_PLT364	6,482,057	4,571,587	809,209	1,047,705	6,243	42,545	4,769
7	Rent from Electric Property ACE Other	DISTPLT	730,921	492,422	89,937	104,195	2,099	41,791	477
8	Total Other Revenue		8,680,898	5,992,539	1,149,596	1,372,022	24,155	136,105	6,481
9	Total Revenue		485,404,697	302,013,086	87,300,810	71,316,864	5,138,496	19,041,312	594,129

		ALLOC	RESIDENTIAL (8)-2	MONTHLY GENERAL SERV SECONDARY (9)	MONTHLY GENERAL SERV PRIMARY (10)	ANNUAL GENERAL SERV SECONDARY (11)	ANNUAL GENERAL SERV PRIMARY (12)	STREET AND PRIVATE LIGHTING (13)	GENERAL SERVICE SUBTRANSMSN (14)	GENERAL SERVICE TRANSMISSION (15)	DIRECT DISTRIBUTION CONNECTION (16)
	OPERATING REVENUES-7										
1	ELECTRIC SALES REVENUES Revenue - Retail Sales ACE		296,020,547	84,363,933	1,787,281	57,356,426	12,588,416	18,905,207	3,024,915	2,089,427	587,648
2	Total Revenue - Retail Sales ACE		296,020,547	84,363,933	1,787,281	57,356,426	12,588,416	18,905,207	3,024,915	2,089,427	587,648
	REVENUE - OTHER										
3	Other Revenues	CUST	0	0	0	0	0	0	0	0	0
4	Late Payment Revenue ACE	LPAY	0	56,246	1,192	38,240	8,393	12,604	0	0	392
5	Miscellaneous Service Revenue ACE	CUST	32,520	3,671	10	188	8	389	2	1	69
5	Miscellaneous Service Revenue ACE - I/C	LABOR	896,010	182,201	7,130	136,902	36,392	38,776	12,019	3,790	774
6	Rent from Electric Property ACE Poll Attach	_PLT364	4,571,587	784,741	24,467	841,693	206,013	42,545	6,243	0	4,769
/	Rent from Electric Property ACE Other	DISTPLT	492,422	87,838	2,100	88,820	15,375	41,791	1,774	324	477
8	Total Other Revenue		5,992,539	1,114,697	34,899	1,105,842	266,180	136,105	20,039	4,116	6,481
9	Total Revenue		302,013,086	85,478,631	1,822,180	58,462,268	12,854,596	19,041,312	3,044,953	2,093,542	594,129

		ALLOC	TOTAL ACE DISTRIBUTION (1)	TOTAL RESIDENTIAL SERVICE (2)	MONTHLY GENERAL SERVICE (3)	ANNUAL GENERAL SERVICE (4)	TRANSM GENERAL SERVICE (5)	STREET LIGHTING SERVICE (6)	DIRECT DISTRIBUTION CONNECTION (7)
	OPERATION & MAINTENANCE EXP-8								
	Distribution Expenses - ACE								
	Operation								
1	958000 Operation Supervision & Engineering	TLABDO	922,818	614,743	163,094	110,420	19,255	14,914	392
2	958100 Load dispatching	SALESWOT	3,194,359	2,159,830	384,575	514,077	113,524	20,100	2,253
3	958200 Station expenses	_PLT362 PLTDOHLN	22,205 4.189.793	15,480	2,756	3,684	124	144	16
5	958300 Overhead line expenses	PLTDUHLN	4,189,793	2,955,668 0	523,178 0	677,379 0	2,978 0	27,506 0	3,083 0
6	958400 Underground line expenses 958500 Street lighting	PLTDUGLN PLT373	431.115	0	0	0	0	431,115	0
7	958600 Meter expenses	PLT370	5,611,640	3,600,376	1,523,657	329,075	158,533	431,113	0
8	958700 Customer installations expenses	PLT369	812,500	599.060	102,832	110,295	130,333	0	312
9	958800 Miscellaneous distribution expenses	EXPDISTO	17,174,240	11,235,950	3,055,126	1,968,325	331,354	576.663	6,822
10	958900 Rents	EXPDISTO	3,536,842	2,313,917	629,169	405,354	68,239	118,757	1,405
11	Total Operation	_	35,895,512	23,495,023	6,384,388	4,118,611	694,006	1,189,200	14,284
	Maintenance								
12	959000 Maintenance Supervision & Engineering	TLABDM	2,310	1,564	277	357	6	104	2
13	959200 Maintain equipment	_PLT362	4,453,246	3,104,481	552,778	738,921	24,937	28,891	3,239
14	959300 Maintain overhead lines	PLTDOHLN	63,403,712	44,727,820	7,917,205	10,250,712	45,064	416,250	46,661
15	959400 Maintain underground line	PLTDUGLN	4,469,129	3,151,137	554,410	693,821	37,148	29,325	3,287
16	959500 Maintain line transformers	_PLT368	561,982	411,371	70,614	75,739	0	3,828	429
17	959600 Maintain street lighting & signal systems	_PLT373	1,823,429	0	0	0	0	1,823,429	0
18	959700 Maintain meters	_PLT370	7,608	4,881	2,066	446	215	0	0
19	959800 Maintain distribution plant	_EXPDISTM	1,344,511	924,897	163,695	211,605	1,932	41,418	965
20 21	Total Maintenance		76,065,926 111,961,438	52,326,151 75,821,174	9,261,045 15,645,432	11,971,602 16,090,212	109,302 803,308	2,343,245 3,532,445	54,582 68,866
21	Total Distribution Expenses - ACE		111,901,436	75,621,174	15,045,432	10,090,212	803,308	3,332,443	00,000
	Customer Accounts Expenses								
22	990200 Meter reading expenses	CUST902	7,570,059	6,615,626	785,245	129,795	39,392	0	0
23	990300 Cust records and collection exp	CUST903	50,157,398	44,499,573	4,624,990	288,541	215,834	451,219	77,241
24	990500 Miscellaneous cust accounts exp	_EXP9023	0	0	0	0	0	0	0
25	Total Customer Accounts Expenses		57,727,457	51,115,200	5,410,234	418,337	255,227	451,219	77,241
	Customer Service Expenses								
26	990700 Supervision	CSERV	0	0	0	0	0	0	0
27	990800 Customer assistance expenses	CSERV	5.029.692	3.374.136	673.947	626.992	299.377	46.251	8.989
28	990900 Informational & instructional adv	CSERV	292,300	196,088	39.166	36,438	17,398	2,688	522
29	991000 Miscellaneous customer service & informati	tic CSERV	0	0	0	0	0	0	0
30	Total Customer Service Expenses		5,321,992	3,570,224	713,114	663,430	316,775	48,939	9,511
	Calaa Firmanaa								
31	Sales Expense	CSALES	0	0	0	0	0	0	0
32	991200 Demonstrating & selling expenses 991300 Advertising expense	CSALES	0	0	0	0	0	0	0
33	Total Sales Expense	COALLO	0	0	0	0	0	0	0
55	Total Gales Expense		0	U	0	U	U	0	U

		ALLOC	RESIDENTIAL (8)-2	MONTHLY GENERAL SERV SECONDARY (9)	MONTHLY GENERAL SERV PRIMARY (10)	ANNUAL GENERAL SERV SECONDARY (11)	ANNUAL GENERAL SERV PRIMARY (12)	STREET AND PRIVATE LIGHTING (13)	GENERAL SERVICE SUBTRANSMSN (14)	GENERAL SERVICE TRANSMISSION (15)	DIRECT DISTRIBUTION CONNECTION (16)
	OPERATION & MAINTENANCE EXP-8										
	Distribution Expenses - ACE										
1 2 3 4 5 6	Operation 958000 Operation Supervision & Engineering 958100 Load dispatching 958200 Station expenses 958300 Overhead line expenses 958400 Underground line expenses 958500 Street lighting	TLABDO SALESWOT _PLT362 PLTDOHLN PLTDUGLN PLT373	614,743 2,159,830 15,480 2,955,668 0	155,922 370,748 2,657 507,359 0	7,172 13,827 99 15,820 0	85,143 397,655 2,850 544,179	25,277 116,423 834 133,200 0	14,914 20,100 144 27,506 0 431,115	14,780 113,524 124 2,978 0	4,475 0 0 0 0	392 2,253 16 3,083 0
7 8 9 10 11	958600 Meter expenses 958700 Customer installations expenses 958800 Miscellaneous distribution expenses 958800 Rents Total Operation Maintenance	_PLT370 _PLT369 _EXPDISTO _EXPDISTO	3,600,376 599,060 11,235,950 2,313,917 23,495,023	1,440,846 102,832 2,919,582 601,255 6,101,201	82,811 0 135,544 27,914 283,187	205,089 110,295 1,517,410 312,494 3,175,115	123,986 0 450,915 92,861 943,495	576,663 118,757 1,189,200	85,472 0 243,371 50,120 510,368	73,061 0 87,983 18,119 183,638	0 312 6,822 1,405 14,284
12 13 14 15 16 17 18 19 20 21	959000 Maintenance Supervision & Engineering 959200 Maintain equipment 959300 Maintain overhead lines 959400 Maintain underground line 959500 Maintain line transformers 959600 Maintain street lighting & signal systems 959700 Maintain meters 959900 Maintain distribution plant Total Maintenance Total Distribution Expenses - ACE	TLABDM _PLT362 PLTDOHLN PLTDUGLN _PLT368 _PLT373 _PLT370 _EXPDISTM	1,564 3,104,481 44,727,820 3,151,137 411,371 0 4,881 924,897 52,326,151 75,821,174	269 532,903 7,677,806 540,912 70,614 0 1,953 158,784 8,983,242 15,084,443	8 19,875 239,398 13,498 0 0 1112 4,910 277,802 560,989	288 571,578 8,235,012 580,168 75,739 0 278 170,275 9,633,338 12,808,453	69 167,343 2,015,700 113,653 0 0 168 41,330 2,338,264 3,281,759	104 28,891 416,250 29,325 3,828 1,823,429 0 41,418 2,343,245 3,532,445	6 24,937 45,064 37,148 0 0 116 1,930 109,201 619,569	0 0 0 0 0 0 9 9 2 101 183,739	2 3,239 46,661 3,287 429 0 965 54,582 68,866
22 23 24 25	Customer Accounts Expenses 990200 Meter reading expenses 990300 Cust records and collection exp 990500 Usis records and collection exp Total Customer Accounts Expenses	CUST902 CUST903 _EXP9023	10,326,710 6,615,626 44,499,573 0 51,115,200	751,821 4,597,083 0 5,348,904	33,424 27,907 0 61,331	78,466 259,915 0 338,381	51,329 28,627 0 79,956	0 451,219 0 451,219	23,476 11,553 0 35,029	15,916 204,281 0 220,197	0 77,241 0 77,241
26 27 28 29 30	Customer Service Expenses 990700 Supervision 990800 Customer assistance expenses 990900 Informational & instructional adv 991000 Miscellaneous customer service & informat Total Customer Service Expenses	CSERV CSERV CSERV	0 3,374,136 196,088 0 3,570,224	0 651,007 37,833 0 688,841	0 22,940 1,333 0 24,273	0 468,874 27,249 0 496,122	0 158,118 9,189 0 167,307	0 46,251 2,688 0 48,939	0 158,549 9,214 0 167,763	0 140,828 8,184 0 149,012	0 8,989 522 0 9,511
31 32 33	Sales Expense 991200 Demonstrating & selling expenses 991300 Advertising expense Total Sales Expense	CSALES CSALES	0 0 0	0 0 0	0 0 0	0 0 0	0 0 0	0 0 0	0 0 0	0 0 0	0 0 0

		ALLOC	TOTAL ACE DISTRIBUTION (1)	TOTAL RESIDENTIAL SERVICE (2)	MONTHLY GENERAL SERVICE (3)	ANNUAL GENERAL SERVICE (4)	TRANSM GENERAL SERVICE (5)	STREET LIGHTING SERVICE (6)	DIRECT DISTRIBUTION CONNECTION (7)
	OPERATION & MAINT EXP CON'T-9								
	Administrative & General Expense								
	Operation	LABOR	0.040.550	0.077.405	400.070	404 700	00.055	00.004	4 705
1	992000 Administrative & General salaries	LABOR	3,046,550	2,077,435	438,972	401,788	36,655	89,904	1,795
3	992100 Office supplies & expenses 992300 Outside services employed	LABOR LABOR	2,091,745 59,647,957	1,426,356 40,673,802	301,396 8,594,576	275,865 7,866,543	25,167 717,668	61,728 1,760,221	1,233 35,148
٥									
4	992400 Property insurance	PLANT	422,894	285,276	52,990	59,801	1,630	22,925	273
5	992500 Injuries & damages	LABOR	322,122	219,654	46,414	42,482	3,876	9,506	190
6	992600 Employee pensions & benefits	LABOR	8,391,567	5,722,190	1,209,127	1,106,704	100,965	247,636	4,945
-	992800 Regulatory commission expenses	OLAIMPEV	000 700	407.400	00.004	00.055	4.070	00.050	400
/	Regulatory commission exp - NJ Retail	CLAIMREV	668,768	467,192	86,694	82,855	4,679	26,856	492
8	Total Acct 992800 Regulatory comm Exp	LABOR	668,768	467,192	86,694	82,855	4,679	26,856	492
9	992900 Duplicate charges-Credit	LABOR	0	0	0	0	0	0	0
10	993010 General ad expenses	LABOR	585,376	399,167	84,346	77,201	7,043	17,275	345
11	993020 Miscellaneous general expenses	LABOR	736,055	501,914	106,057	97,073	8,856	21,721	434
12	993100 Rents	LABOR	0	0	0	0	0	0	0
13	Total Operation Maintenance		75,913,034	51,772,986	10,920,572	10,010,312	906,539	2,257,772	44,853
14	993500 Maintenance of general plant	GENPLT	414.526	282.665	59,728	54.669	4,987	12,233	244
15	Total Maintenance	GLINFLI	414.526	282,665	59,728	54,669	4,987	12,233	244
16	Total Maintenance Total Administrative & General Exp		76,327,560	52,055,650	10,980,301	10,064,980	911,526	2,270,004	45,098
10	Total Administrative & General Exp		10,321,300	32,033,030	10,000,301	10,004,900	311,320	2,270,004	43,090
17	Total Operation & Maintenance Expense		251,338,447	182,562,248	32,749,081	27,236,959	2,286,836	6,302,607	200,715

		ALLOC	RESIDENTIAL (8)-2	MONTHLY GENERAL SERV SECONDARY (9)	MONTHLY GENERAL SERV PRIMARY (10)	ANNUAL GENERAL SERV SECONDARY (11)	ANNUAL GENERAL SERV PRIMARY (12)	STREET AND PRIVATE LIGHTING (13)	GENERAL SERVICE SUBTRANSMSN (14)	GENERAL SERVICE TRANSMISSION (15)	DIRECT DISTRIBUTION CONNECTION (16)
	OPERATION & MAINT EXP CON'T-9										
	Administrative & General Expense										
	Operation		0.077.405		40.504	0.17.110	04.070			0.700	4 705
1	992000 Administrative & General salaries	LABOR	2,077,435	422,441	16,531	317,412	84,376	89,904	27,867	8,788	1,795
2	992100 Office supplies & expenses	LABOR LABOR	1,426,356 40,673,802	290,046 8,270,919	11,350	217,933	57,932	61,728 1,760,221	19,134	6,034	1,233
3	992300 Outside services employed				323,656	6,214,556	1,651,987		545,612	172,055	35,148
4	992400 Property insurance	PLANT	285,276	51,659	1,331	50,603	9,198	22,925	1,331	298	273
5	992500 Injuries & damages	LABOR	219,654	44,666	1,748	33,561	8,921	9,506	2,947	929	190
6	992600 Employee pensions & benefits	LABOR	5,722,190	1,163,593	45,534	874,294	232,410	247,636	76,759	24,206	4,945
_	992800 Regulatory commission expenses	0	407.400	0.4.000	0.400	00.407	44.050	00.050		4.000	400
7	Regulatory commission exp - NJ Retail	CLAIMREV	467,192	84,226	2,468	68,197	14,658	26,856	3,290	1,389	492
8	Total Acct 992800 Regulatory comm Exp		467,192	84,226	2,468	68,197	14,658	26,856	3,290	1,389	492
9	992900 Duplicate charges-Credit	LABOR	0	0	0	0		0	0	0	0
10	993010 General ad expenses	LABOR	399,167	81,170	3,176	60,989	16,212	17,275	5,355	1,689	345
11	993020 Miscellaneous general expenses	LABOR	501,914	102,063	3,994	76,688	20,385	21,721	6,733	2,123	434
12	993100 Rents	LABOR	0	0	0	0	0	0	0	0	0
13	Total Operation		51,772,986	10,510,784	409,788	7,914,233	2,096,079	2,257,772	689,028	217,511	44,853
	Maintenance										
14	993500 Maintenance of general plant	GENPLT	282,665	57,479	2,249	43,188	11,481	12,233	3,792	1,196	244
15	Total Maintenance		282,665	57,479	2,249	43,188	11,481	12,233	3,792	1,196	244
16	Total Administrative & General Exp		52,055,650	10,568,263	412,037	7,957,421	2,107,560	2,270,004	692,820	218,707	45,098
17	Total Operation & Maintenance Expense		182,562,248	31,690,451	1,058,630	21,600,378	5,636,582	6,302,607	1,515,181	771,655	200,715

		ALLOC	TOTAL ACE DISTRIBUTION (1)	TOTAL RESIDENTIAL SERVICE (2)	MONTHLY GENERAL SERVICE (3)	ANNUAL GENERAL SERVICE (4)	TRANSM GENERAL SERVICE (5)	STREET LIGHTING SERVICE (6)	DIRECT DISTRIBUTION CONNECTION (7)
	DEPRECIATION & AMORT EXP-10								
	Depreciation & Amortization Acct 403 Depreciation Distribution								
1 2 3	ACE General A/C 403 Total	DISTPLT GENPLT	91,653,327 10,237,634 101,890,961	61,746,917 6,981,019 68,727,935	11,277,635 1,475,124 12,752,759	13,065,437 1,350,168 14,415,605	263,180 123,176 386,356	5,240,389 302,114 5,542,503	59,770 6,033 65,803
	Acct 404 Amortization								
	Amort of Limited Term Plant Amort of Software - Elec A/C 404 Total	LABOR LABOR	0 13,408,659 13,408,659	9,143,333 9,143,333	0 1,932,032 1,932,032	0 1,768,372 1,768,372	0 161,329 161,329	0 395,692 395,692	7,901 7,901
	Acct 405 Amortization of Intangible								
6	Intangible - Software	LABOR	0	0	0	0	0	0	0
7	Misc. Amortization	PLANT	0	0	0	0	0	0	0
8	General	PLANT	0	0	0	0	0	0	0
9	A/C 405 Total		0	0	0	0	0	0	0
	Acct 407 Amortization - Other								
10	Misc. Amortization	PLANT	709,100	478,344	88,852	100,273	2,733	38,440	458
11	A/C 407 Total		709,100	478,344	88,852	100,273	2,733	38,440	458
12	Total Depreciation and Amortization		116,008,720	78,349,613	14,773,643	16,284,250	550,418	5,976,634	74,161

		ALLOC	RESIDENTIAL (8)-2	MONTHLY GENERAL SERV SECONDARY (9)	MONTHLY GENERAL SERV PRIMARY (10)	ANNUAL GENERAL SERV SECONDARY (11)	ANNUAL GENERAL SERV PRIMARY (12)	STREET AND PRIVATE LIGHTING (13)	GENERAL SERVICE SUBTRANSMSN (14)	GENERAL SERVICE TRANSMISSION (15)	DIRECT DISTRIBUTION CONNECTION (16)
	DEPRECIATION & AMORT EXP-10										
	Depreciation & Amortization Acct 403 Depreciation Distribution										
1	ACE	DISTPLT	61,746,917	11,014,362	263,274	11,137,503	1,927,934	5,240,389	222,501	40,678	59,770
2	General	GENPLT	6,981,019	1,419,573	55,551	1,066,631	283,538	302,114	93,646	29,531	6,033
3	A/C 403 Total		68,727,935	12,433,935	318,824	12,204,133	2,211,471	5,542,503	316,147	70,209	65,803
	Acct 404 Amortization										
4	Amort of Limited Term Plant	LABOR	0	0	0	0	0	0	0	0	0
5	Amort of Software - Elec	LABOR	9,143,333	1,859,275	72,757	1,397,011	371,361	395,692	122,652	38,677	7,901
	A/C 404 Total		9,143,333	1,859,275	72,757	1,397,011	371,361	395,692	122,652	38,677	7,901
	Acct 405 Amortization of Intangible										
6	Intangible - Software	LABOR	0	0	0	0	0	0	0	0	0
7	Misc. Amortization	PLANT	0	0	0	0	0	0	0	0	0
8	General	PLANT	0	0	0	0	0	0	0	0	0
9	A/C 405 Total		0	0	0	0	0	0	0	0	0
	Acct 407 Amortization - Other										
10	Misc. Amortization	PLANT	478,344	86,621	2,231	84,850	15,422	38,440	2,232	500	458
11	A/C 407 Total		478,344	86,621	2,231	84,850	15,422	38,440	2,232	500	458
12	Total Depreciation and Amortization		78,349,613	14,379,831	393,812	13,685,995	2,598,255	5,976,634	441,031	109,387	74,161

		ALLOC	TOTAL ACE DISTRIBUTION (1)	TOTAL RESIDENTIAL SERVICE (2)	MONTHLY GENERAL SERVICE (3)	ANNUAL GENERAL SERVICE (4)	TRANSM GENERAL SERVICE (5)	STREET LIGHTING SERVICE (6)	DIRECT DISTRIBUTION CONNECTION (7)
	OTHER TAXES & EXPENSES-11								
	Other Taxes								
1	Payroll Taxes - FICA	LABOR	2,284,834	1,558,023	329,218	301,330	27,491	67,426	1,346
2	Payroll Taxes - FUTA/SUTA	LABOR	0	0	0	0	0	0	0
3	Property Taxes - New Jersey	PLANT	1,338,533	902,947	167,722	189,280	5,158	72,561	864
4	Franchise Tax	PLANT	0	0	0	0	0	0	0
5	Misc. Amortization	PLTDOHLN	0	0	0	0	0	0	0
6	Misc. Tax	TEFAREV	2,072,644	1,599,551	592,799	(105,708)	0	(13,997)	0
7	Sales & Use Taxes	DISTOMEXP	(211,512)	(153,634)	(27,560)	(22,921)	(1,924)	(5,304)	(169)
8	Total Other Taxes		5,484,499	3,906,887	1,062,179	361,982	30,724	120,685	2,041
	Net ITC Adjustment								
9	Distribution - ACE	DISTPLT	(157,134)	(105,861)	(19,335)	(22,400)	(451)	(8,984)	(102)
10	General	GENPLT	2,461	1,678	355	325	30	73	1
11	Total Net ITC Adjustment		(154,673)	(104,183)	(18,980)	(22,075)	(422)	(8,912)	(101)
	IOCD								
12	ACE	CUSTDEP	41,011	18,357	10,495	12,159	0	0	0
13	Total Interest on Customer Deposits		41,011	18,357	10,495	12,159	0	0	0

		ALLOC	RESIDENTIAL (8)-2	MONTHLY GENERAL SERV SECONDARY (9)	MONTHLY GENERAL SERV PRIMARY (10)	ANNUAL GENERAL SERV SECONDARY (11)	ANNUAL GENERAL SERV PRIMARY (12)	STREET AND PRIVATE LIGHTING (13)	GENERAL SERVICE SUBTRANSMSN (14)	GENERAL SERVICE TRANSMISSION (15)	DIRECT DISTRIBUTION CONNECTION (16)
	OTHER TAXES & EXPENSES-11										
	Other Taxes										
1 2	Payroll Taxes - FICA Payroll Taxes - FUTA/SUTA	LABOR LABOR	1,558,023 0	316,820 0	12,398 0	238,051 0	63,280 0	67,426 0	20,900 0	6,591 0	1,346 0
3 4	Property Taxes - New Jersey Franchise Tax	PLANT PLANT	902,947 0	163,511 0	4,211 0	160,168 0	29,112 0	72,561 0	4,214 0	944 0	864 0
5	Misc. Amortization	PLTDOHLN	0	0	0	0	0	0	0	0	0
6	Misc. Tax	TEFAREV DISTOMEXP	1,599,551	592,799	0	(105,708)		(13,997)	(4.275)	0	0 (460)
8	Sales & Use Taxes Total Other Taxes	DISTOMEXP	(153,634) 3,906,887	(26,669) 1,046,461	(891) 15,718	(18,178) 274,333	(4,743) 87,649	(5,304) 120,685	(1,275) 23,839	(649) 6,886	(169) 2,041
	Net ITC Adjustment										
9	Distribution - ACE	DISTPLT	(105,861)	(18,883)		(19,095)		(8,984)	(381)	(70)	(102)
10	General	GENPLT	1,678	341	13	256	68	73	23	7	1 (101)
11	Total Net ITC Adjustment		(104,183)	(18,542)	(438)	(18,838)	(3,237)	(8,912)	(359)	(63)	(101)
	IOCD										
12	ACE	CUSTDEP	18,357	10,250	245	10,365	1,794	0	0	0	0
13	Total Interest on Customer Deposits		18,357	10,250	245	10,365	1,794	0	0	0	0

		ALLOC	TOTAL ACE DISTRIBUTION (1)	TOTAL RESIDENTIAL SERVICE (2)	MONTHLY GENERAL SERVICE (3)	ANNUAL GENERAL SERVICE (4)	TRANSM GENERAL SERVICE (5)	STREET LIGHTING SERVICE (6)	DIRECT DISTRIBUTION CONNECTION (7)
	DEVELOPMENT OF INCOME TAXES-12								
	FEDERAL & STATE TAX CALCULATION								
1	OPERATING REVENUES		485.404.697	302.013.086	87.300.810	71.316.864	5.138.496	19.041.312	594.129
•	OPERATING EXPENSES		100,101,001	302,010,000	01,000,010	. 1,010,001	0,100,100	10,011,012	00 1,120
2	Operation & Maintenance Expense		251,338,447	182,562,248	32,749,081	27,236,959	2,286,836	6,302,607	200,715
3	Depreciation and Amortization		116,008,720	78,349,613	14,773,643	16,284,250	550,418	5,976,634	74,161
4	Taxes Other than Income Tax		5,484,499	3,906,887	1,062,179	361,982	30,724	120,685	2,041
5	OPERATING INC BEFORE FED TAX		112,573,032	37,194,338	38,715,907	27,433,673	2,270,517	6,641,386	317,211
6	Less: Interest Expense	PLANT	35,225,686	23,762,537	4,413,891	4,981,213	135,754	1,909,559	22,734
	Schedule M								
7	Labor	LABOR	13,053	8,901	1,881	1,722	157	385	8
8	Plant (Flow Through)	PLANT	1,617,508	1,091,138	202,679	228,729	6,234	87,684	1,044
9	Timing Labor	LABOR	5,396,695	3,679,993	777,601	711,731	64,932	159,257	3,180
10 11	Timing Plant	PLANT	(110,912,272)	(74,819,179)	(13,897,660)	(15,683,941)	(427,436)	(6,012,474)	(71,582)
	Total Schedule M TAXABLE INCOME		(103,885,016) (26,537,670)	(70,039,146) (56,607,344)	(12,915,500) 21,386,516	(14,741,759) 7,710,702	(356,114) 1,778,650	(5,765,147) (1,033,320)	(67,350) 227,127
12	State Income Taxes		(2,388,390)	(5,094,661)	1,924,786	693,963	160,078	(92,999)	20,441
	NJ Depreciation Amortization	PLANT	(4,345,502)	(2,931,388)	(544,505)	(614,491)	(16,747)	(235,567)	(2,805)
	NJSA Amortization	PLANT	(4,545,502)	(2,331,300)	(344,303)	(014,431)	(10,747)	(233,307)	(2,003)
13	State Income Taxes Sub Total	1 27 (14)	(6,733,892)	(8,026,049)	1,380,281	79.472	143,332	(328,565)	17.637
	New Jersey NOL		6,733,892	8,026,049	(1,380,281)	(79,472)	(143,332)	328,565	(17,637)
15	Total State Income Taxes		0	0	0	0	0	0	0
16	Federal Income Taxes		(5,572,911)	(11,887,542)	4,491,168	1,619,247	373,516	(216,997)	47,697
17	Federal NOL		5,572,911	11,887,542	(4,491,168)	(1,619,247)	(373,516)	216,997	(47,697)
18	Total Federal Income Taxes		0	0	0	0	0	0	0
	Deferred State Income Taxes								
19	State NOL		(6,733,892)	(8,026,049)	1,380,281	79,472	143,332	(328,565)	17,637
20	Timing Labor	LABOR	(485,703)	(331,199)	(69,984)	(64,056)	(5,844)	(14,333)	(286)
21	Timing Plant	PLANT	9,982,104	6,733,726	1,250,789	1,411,555	38,469	541,123	6,442
22	Timing State Only	PLANT	4,345,502	2,931,388	544,505	614,491	16,747	235,567	2,805
23	Total Deferred State Income Taxes-Current Year	DLANT	7,108,012	1,307,866 0	3,105,592 0	2,041,462 0	192,704 0	433,791 0	26,598 0
24 25	State Deferred Income Taxes-Prior Year	PLANT	7 109 013	-	•	2.041.462	•	433.791	26.598
25	Total State Deferred Income Tax Deferred Federal Income Taxes		7,108,012	1,307,866	3,105,592	2,041,462	192,704	433,791	20,598
26	FED NOL		(5,572,911)	(11,887,542)	4,491,168	1,619,247	373,516	(216,997)	47.697
27	Timing Labor	LABOR	(1,031,308)	(703,247)	(148,600)	(136,012)	(12,408)	(30,434)	(608)
28	Timing East	PLANT	21,195,335	14,297,945	2,655,843	2,997,201	81,683	1,148,984	13,679
29	Timing State Only	PLANT	(912,555)	(615,591)	(114,346)	(129,043)	(3,517)	(49,469)	(589)
30	NOL Payable Netting Entry - FBOS	PLANT	(22,556,903)	(15,216,431)	(2,826,452)	(3,189,739)	(86,930)	(1,222,793)	(14,558)
31	Total Deferred Federal Income Taxes-Current Year		(8,878,343)	(14,124,867)	4,057,614	1,161,655	352,344	(370,710)	45,621
32	Federal Deferred Income Taxes-Prior Year	PLANT	o´) o	0	0	0) o	0
33	Total Federal Deferred Income Tax		(8,878,343)	(14,124,867)	4,057,614	1,161,655	352,344	(370,710)	45,621
34	Total Income Taxes		(1,770,331)	(12,817,001)	7,163,206	3,203,117	545,048	63,081	72,219
35	Total Expenses		370,947,672	251,915,920	55,739,624	47,076,392	3,412,605	12,454,095	349,036
36	Net Operating Income		114,457,025	50,097,166	31,561,186	24,240,473	1,725,891	6,587,217	245,093

		ALLOC	RESIDENTIAL (8)-2	MONTHLY GENERAL SERV SECONDARY (9)	MONTHLY GENERAL SERV PRIMARY (10)	ANNUAL GENERAL SERV SECONDARY (11)	ANNUAL GENERAL SERV PRIMARY (12)	STREET AND PRIVATE LIGHTING (13)	GENERAL SERVICE SUBTRANSMSN (14)	GENERAL SERVICE TRANSMISSION (15)	DIRECT DISTRIBUTION CONNECTION (16)
	DEVELOPMENT OF INCOME TAXES-12										
	FEDERAL & STATE TAX CALCULATION										
1	OPERATING REVENUES OPERATING EXPENSES		302,013,086	85,478,631	1,822,180	58,462,268	12,854,596	19,041,312	3,044,953	2,093,542	594,129
2			182,562,248	31,690,451	1,058,630	21,600,378	5,636,582	6,302,607	1,515,181	771,655	200,715
3	•		78,349,613	14,379,831	393,812	13,685,995	2,598,255	5,976,634	441,031	109,387	74,161
4	Takee Outer than moonto Tak		3,906,887	1,046,461	15,718	274,333	87,649	120,685	23,839	6,886	2,041
5		PLANT	37,194,338	38,361,888	354,019	22,901,563	4,532,110	6,641,386	1,064,902	1,205,615	317,211 22.734
6	Less: Interest Expense Schedule M	PLANT	23,762,537	4,303,058	110,832	4,215,077	766,136	1,909,559	110,899	24,854	22,734
7	Labor	LABOR	8,901	1,810	71	1,360	362	385	119	38	8
8		PLANT	1.091.138	197.590	5.089	193,550	35.180	87.684	5,092	1.141	1.044
9		LABOR	3,679,993	748,318	29,283	562,267	149,465	159,257	49,365	15,567	3,180
10	Timing Plant	PLANT	(74,819,179)	(13,548,692)	(348,968)	(13,271,672)	(2,412,270)	(6,012,474)	(349,180)	(78,256)	(71,582)
11	Total Schedule M		(70,039,146)	(12,600,975)	(314,525)	(12,514,495)	(2,227,264)	(5,765,147)	(294,603)	(61,511)	(67,350)
12	TAXABLE INCOME		(56,607,344)	21,457,855	(71,338)	6,171,991	1,538,711	(1,033,320)	659,399	1,119,250	227,127
	State Income Taxes		(5,094,661)	1,931,207	(6,420)	555,479	138,484	(92,999)	59,346	100,733	20,441
	NJ Depreciation Amortization	PLANT	(2,931,388)	(530,833)	(13,672)	(519,979)	(94,512)	(235,567)	(13,681)	(3,066)	(2,805)
40	NJSA Amortization	PLANT	0	0	(00,000)	0	0	(000 505)	0	0	0
13			(8,026,049)	1,400,374	(20,093)	35,500	43,972	(328,565)	45,665	97,666	17,637 (17,637)
15	New Jersey NOL Total State Income Taxes		8,026,049 0	(1,400,374)	20,093	(35,500)	(43,972) 0	328,565 0	(45,665) 0	(97,666) 0	(17,037)
16			(11,887,542)	4.506.149	(14,981)	1,296,118	323.129	(216,997)	138,474	235.043	47.697
	Federal NOL		11,887,542	(4,506,149)	14,981	(1,296,118)	(323,129)	216,997	(138,474)	(235,043)	(47,697)
18			0	(1,000,110)	0	(1,200,110)	0	0	(100,111)	(200,010)	0
	Deferred State Income Taxes										
19	State NOL		(8,026,049)	1,400,374	(20,093)	35,500	43,972	(328,565)	45,665	97,666	17,637
20		LABOR	(331,199)	(67,349)	(2,635)	(50,604)	(13,452)	(14,333)	(4,443)	(1,401)	(286)
21	•	PLANT	6,733,726	1,219,382	31,407	1,194,450	217,104	541,123	31,426	7,043	6,442
22		PLANT	2,931,388	530,833	13,672	519,979	94,512	235,567	13,681	3,066	2,805
23		DLANT	1,307,866	3,083,241	22,351 0	1,699,326	342,136 0	433,791 0	86,329 0	106,375 0	26,598
24 25		PLANT	1,307,866	3,083,241	22,351	1,699,326	342,136	433,791	86,329	106,375	0 26,598
25	Deferred Federal Income Taxes		1,307,000	3,003,241	22,331	1,099,320	342,130	433,791	00,329	100,373	20,596
26			(11,887,542)	4,506,149	(14,981)	1,296,118	323,129	(216,997)	138,474	235,043	47,697
27		LABOR	(703,247)	(143,004)	(5,596)	(107,449)	(28,563)	(30,434)	(9,434)	(2,975)	(608)
28	Timing Plant	PLANT	14,297,945	2,589,155	66,688	2,536,216	460,985	1,148,984	66,728	14,955	13,679
29	Timing State Only	PLANT	(615,591)	(111,475)	(2,871)	(109,196)	(19,847)	(49,469)	(2,873)	(644)	(589)
30		PLANT	(15,216,431)	(2,755,480)	(70,972)	(2,699,141)	(490,598)	(1,222,793)	(71,015)	(15,915)	(14,558)
31			(14,124,867)	4,085,346	(27,732)	916,549	245,106	(370,710)	121,881	230,463	45,621
32		PLANT	0	0	0	0	0	0 (070 740)	0	0	0
33			(14,124,867)	4,085,346	(27,732)	916,549	245,106	(370,710)	121,881	230,463	45,621
34	Total Income Taxes Total Expenses		(12,817,001) 251.915.920	7,168,587 54,277,038	(5,381) 1,462,587	2,615,875 38.168.107	587,242 8,908,285	63,081 12,454,095	208,210 2,187,902	336,838 1,224,703	72,219 349.036
55	i otai Expelises		231,313,920	54,211,030	1,402,307	30,100,107	0,500,200	12,454,095	2,107,902	1,224,703	348,030
36	Net Operating Income		50,097,166	31,201,593	359,593	20,294,162	3,946,311	6,587,217	857,051	868,840	245,093

		ALLOC	TOTAL ACE DISTRIBUTION (1)	TOTAL RESIDENTIAL SERVICE (2)	MONTHLY GENERAL SERVICE (3)	ANNUAL GENERAL SERVICE (4)	TRANSM GENERAL SERVICE (5)	STREET LIGHTING SERVICE (6)	DIRECT DISTRIBUTION CONNECTION (7)
	DEVELOPMENT OF LABOR ALLOCATOR-1	3							
	Distribution Labor - ACE								
1	Operation Labor 958000 Operation Supervision & Engineering	LABDO	142.071	94.642	25.109	17.000	2.964	2.296	60
2	958100 Load dispatching	EXP581	2,314,814	1,565,136	278,685	372,530	82,266	14,566	1,633
3	958200 Station expenses	EXP582	2,436	1,698	302	404	14	16	1,033
4	958300 Overhead line expenses	EXP583	1,835,174	1,294,614	229,158	296,699	1,304	12,048	1,351
5	958400 Underground line expenses	EXP584	0	0	0	0	0	0	0
6	958500 Street lighting	EXP585	0	0	0	Ō	0	0	Ö
7	958600 Meter expenses	EXP586	2,515,060	1,613,639	682,882	147,487	71,052	0	Ō
8	958700 Customer installations expenses	_EXP587	367,307	270,817	46,487	49,861	0	0	141
9	958800 Miscellaneous distribution expenses	_EXP588	4,999,040	3,270,536	889,280	572,936	96,450	167,854	1,986
10	958900 Rents	_EXP589	0	0	0	0	0	0	0
11	Total Operation Labor		12,175,904	8,111,082	2,151,903	1,456,917	254,050	196,779	5,172
40	Maintenance Labor	LABBM	4.500	4.004	400	005		20	
12	959000 Maintenance Supervision & Engineering	LABDM	1,522	1,031	182	235	4	69	1
13 14	959200 Maintain equipment 959300 Maintain overhead lines	_EXP592 EXP593	2,114,073 8,263,506	1,473,778 5,829,447	262,418 1.031.862	350,785 1,335,991	11,838 5.873	13,715 54,251	1,537 6.081
15	959400 Maintain underground line	EXP594	2,192,500	1,545,909	271.987	340,380	18,224	14,387	1,613
16	959500 Maintain underground line 959500 Maintain line transformers	EXP595	191,059	139,855	24,007	25,749	0	1,302	1,013
17	959600 Maintain street lighting & signal systems	EXP596	521,038	0	0	20,1.0	0	521,038	0
18	959700 Maintain meters	EXP597	5,239	3,361	1,422	307	148	021,000	0
19	959800 Maintain distribution plant	EXP598	453,494	311,961	55,213	71,373	652	13,970	325
20	Total Maintenance Labor	_	13,742,430	9,305,343	1,647,092	2,124,822	36,739	618,730	9,704
21	Total Distribution Labor - ACE		25,918,334	17,416,425	3,798,995	3,581,738	290,789	815,509	14,876
	Customer Accounts Labor								
22	990200 Meter reading expenses	_EXP902	1,081,552	945,190	112,190	18,544	5,628	0	0
23	990300 Customer records and collection expenses		275,982	244,851	25,448	1,588	1,188	2,483	425
24	990500 Miscellaneous customer accounts expense	s _EXP905	0	0	0	0	0	0	0
25	Total Customer Accounts Labor		1,357,533	1,190,040	137,638	20,132	6,816	2,483	425
	Customer Service Labor								
26	990700 Supervision	_EXP907	0	0	0	0	0	0	0
27	990800 Customer assistance expenses	_EXP908	643,727	431,840	86,255	80,246	38,316	5,919	1,150
28	991000 Miscellaneous customer service & informat	ic_EXP910	0	0	0	0	0	0	0
29	Total Customer Service Labor		643,727	431,840	86,255	80,246	38,316	5,919	1,150
	Sales Labor								
30	991200 Demonstrating & selling expenses	_EXP912	0	0	0	0	0	0	0
31	991300 Advertising expense	_EXP913	0	0	0	0	0	0	0
32	Total Sales Labor		0	0	0	0	0	0	0

		ALLOC	RESIDENTIAL (8)-2	MONTHLY GENERAL SERV SECONDARY (9)	MONTHLY GENERAL SERV PRIMARY (10)	ANNUAL GENERAL SERV SECONDARY (11)	ANNUAL GENERAL SERV PRIMARY (12)	STREET AND PRIVATE LIGHTING (13)	GENERAL SERVICE SUBTRANSMSN (14)	GENERAL SERVICE TRANSMISSION (15)	DIRECT DISTRIBUTION CONNECTION (16)
[DEVELOPMENT OF LABOR ALLOCATOR-1:	3									
	Distribution Labor - ACE										
	Operation Labor										
1	958000 Operation Supervision & Engineering	LABDO	94,642	24,005	1,104	13,108	3,892	2,296	2,275	689	60
2	958100 Load dispatching	_EXP581	1,565,136	268,665	10,020	288,163	84,366	14,566	82,266	0	1,633
3	958200 Station expenses	_EXP582	1,698	292	11	313	92	16	14	0	2
4	958300 Overhead line expenses	_EXP583	1,294,614	222,228	6,929	238,356	58,343	12,048	1,304	0	1,351
5	958400 Underground line expenses	_EXP584	0	0	0	0	0	0	0	0	0
6 7	958500 Street lighting	_EXP585	•	-	-	_	-	0	0	-	-
8	958600 Meter expenses	_EXP586 EXP587	1,613,639 270,817	645,767 46,487	37,115 0	91,918 49,861	55,569 0	0	38,307 0	32,745 0	0 141
9	958700 Customer installations expenses	EXP588	3.270.536	849.826	39,454	441.684	131,251	167.854	70.840	25.610	1,986
10	958800 Miscellaneous distribution expenses 958900 Rents	EXP589	3,270,330	049,020	39,434	441,004	131,231	167,654	70,040	25,610	1,960
11	Total Operation Labor	_EVE.208	8,111,082	2,057,270	94,633	1,123,404	333,512	196,779	195,006	59,044	5,172
	Maintenance Labor		0,111,002	2,037,270	34,033	1,123,404	333,312	130,773	193,000	33,044	3,172
12	959000 Maintenance Supervision & Engineering	LABDM	1,031	177	5	190	46	69	4	0	1
13	959200 Maintain equipment	EXP592	1,473,778	252.983	9,435	271,343	79.442	13,715	11.838	0	1,537
14	959300 Maintain equipment	EXP593	5,829,447	1,000,661	31,201	1,073,282	262,709	54,251	5,873	ő	6.081
15	959400 Maintain underground line	EXP594	1.545.909	265.365	6.622	284.623	55.757	14.387	18,224	0	1,613
16	959500 Maintain line transformers	EXP595	139,855	24,007	0,022	25,749	0	1,302	0	Ŏ	146
17	959600 Maintain street lighting & signal systems	EXP596	0	0	0	0	0	521,038	0	0	0
18	959700 Maintain meters	EXP597	3,361	1,345	77	191	116	0	80	68	Ō
19	959800 Maintain distribution plant	EXP598	311,961	53.557	1.656	57.433	13.940	13.970	651	1	325
20	Total Maintenance Labor	_	9,305,343	1,598,095	48,997	1,712,812	412,010	618,730	36,671	69	9,704
21	Total Distribution Labor - ACE		17,416,425	3,655,365	143,630	2,836,216	745,522	815,509	231,677	59,113	14,876
	Customer Accounts Labor										
22	990200 Meter reading expenses	_EXP902	945,190	107,414	4,775	11,211	7,334	0	3,354	2,274	0
23	990300 Customer records and collection expenses	_EXP903	244,851	25,295	154	1,430	158	2,483	64	1,124	425
24	990500 Miscellaneous customer accounts expenses	EXP905	0	0	0	0	0	0	0	0	0
25	Total Customer Accounts Labor		1,190,040	132,709	4,929	12,641	7,491	2,483	3,418	3,398	425
	Customer Service Labor										
26	990700 Supervision	EXP907	0	0	0	0	0	0	0	0	0
27	990800 Customer assistance expenses	EXP908	431,840	83,319	2,936	60,009	20,237	5,919	20,292	18,024	1,150
28	991000 Miscellaneous customer service & informati	EXP910	0	0	0	0	0	0	0	0	0
29	Total Customer Service Labor	_	431,840	83,319	2,936	60,009	20,237	5,919	20,292	18,024	1,150
	Sales Labor										
30	991200 Demonstrating & selling expenses	EXP912	0	0	0	0	0	0	0	0	0
31	991300 Advertising expense	_EXP913	0	0	0	0	0	0	0	0	0
32	Total Sales Labor		0	0	0	Ö	0	Ö	0	Ö	Ö

		ALLOC	TOTAL ACE DISTRIBUTION (1)	TOTAL RESIDENTIAL SERVICE (2)	MONTHLY GENERAL SERVICE (3)	ANNUAL GENERAL SERVICE (4)	TRANSM GENERAL SERVICE (5)	STREET LIGHTING SERVICE (6)	DIRECT DISTRIBUTION CONNECTION (7)
	DEVEL OF LABOR ALLOC CON'T-14								
	Administrative & General Labor								
	Operation Labor								
1	992000 Administrative & General salaries	_EXP920	3,092,042	2,108,456	445,527	407,787	37,203	91,247	1,822
2	992100 Office supplies & expenses	EXP921	0	0	0	0	0	0	0
3	992300 Outside services employed	EXP923	0	0	0	0	0	0	0
4	992800 Regulatory commission expenses	EXP923	0	0	0	0	0	0	0
5	992900 Duplicate charges-Credit	EXP923	0	0	0	0	0	0	0
6	993020 Miscellaneous general expenses	EXP9302	0	0	0	0	0	0	0
7	Total Operation Labor	_	3,092,042	2,108,456	445,527	407,787	37,203	91,247	1,822
	Maintenance Labor								
8	993500 Maintenance of general plant	EXP935	0	0	0	0	0	0	0
9	Total Maintenance Labor	_	0	0	0	0	0	0	0
10	Total Administrative & General Labor		3,092,042	2,108,456	445,527	407,787	37,203	91,247	1,822
11	Total Operation & Maintenance Labor		31,011,635	21,146,762	4,468,415	4,089,903	373,124	915,158	18,274

		ALLOC	RESIDENTIAL (8)-2	MONTHLY GENERAL SERV SECONDARY (9)	MONTHLY GENERAL SERV PRIMARY (10)	ANNUAL GENERAL SERV SECONDARY (11)	ANNUAL GENERAL SERV PRIMARY (12)	STREET AND PRIVATE LIGHTING (13)	GENERAL SERVICE SUBTRANSMSN (14)	GENERAL SERVICE TRANSMISSION (15)	DIRECT DISTRIBUTION CONNECTION (16)
	DEVEL OF LABOR ALLOC CON'T-14										
	Administrative & General Labor										
	Operation Labor	EVDOOO	0.400.450	400.740	10 770	202.454	05.000	04.047	20.204	0.040	4.000
1	992000 Administrative & General salaries	_EXP920	2,108,456	428,749	16,778	322,151	85,636	91,247	28,284	8,919	1,822
2	992100 Office supplies & expenses	_EXP921	0	0	0	0	0	0	0	0	0
3	992300 Outside services employed	_EXP923	0	0	0	0	0	0	0	0	0
4	992800 Regulatory commission expenses	_EXP923	0	0	0	0	0	0	0	0	0
5	992900 Duplicate charges-Credit	_EXP923	0	0	0	0	0	0	0	0	0
6	993020 Miscellaneous general expenses	EXP9302	0	0	0	0	0	0	0	0	0
7	Total Operation Labor	_	2,108,456	428,749	16,778	322,151	85,636	91,247	28,284	8,919	1,822
	Maintenance Labor					·	•	•	·		
8	993500 Maintenance of general plant	EXP935	0	0	0	0	0	0	0	0	0
9	Total Maintenance Labor		0	0	0	0	0	0	0	0	0
10	Total Administrative & General Labor		2,108,456	428,749	16,778	322,151	85,636	91,247	28,284	8,919	1,822
11	Total Operation & Maintenance Labor		21,146,762	4,300,143	168,273	3,231,017	858,886	915,158	283,670	89,454	18,274

ALLOC		TOTAL RESIDENTIAL SERVICE	MONTHLY GENERAL SERVICE	ANNUAL GENERAL SERVICE	TRANSM GENERAL SERVICE	STREET LIGHTING SERVICE	DIRECT DISTRIBUTION CONNECTION (7)
ALLOG	(1)	(2)	(5)	(4)	(5)	(0)	(7)
DEMPRI DEMSEC DEMTRNSF DPRITGSS	2,601,527 1.00000 1.00000 2,509,072	1,758,993 0.73200 0.73200 1,758,993	313,203 0.12565 0.12565 313,203	418,671 0.13477 0.13477 418,671	92,455 0.00000 0.00000 0	16,370 0.00681 0.00681 16,370	1835 0.00076 0.00076 1,835
	2,402,995 2,601,527	1,758,993 1,758,993	301,942 313,203	323,855 418,671	0 92,455	16,370 16,370	1,835 1,835
DEMPRIS DEMSECS DEMTRNSFS DPRITGSSS	1.00000 1.00000 1.00000 1.00000	0.64522 0.72175 0.72175 0.68021	0.12193 0.12840 0.12840 0.12786	0.17853 0.14481 0.14481 0.18711	0.04969 0.00000 0.00000 0.00000	0.00343 0.00371 0.00371 0.00356	0.00120 0.00132 0.00132 0.00126
CUST369S	1.00000	0.72393	0.12911	0.14563	0.00000	0.00000	0.00133
	DEMPRI DEMSEC DEMTRNSF DPRITGSS DEMPRIS DEMSECS DEMTRNSFS DPRITGSSS	DEMPRI 2,601,527 DEMSEC 1.00000 DEMTRNSF 1.00000 DPRITGSS 2,509,072 DEMPRIS 1.00000 DEMTRNSF 1.00000 DEMTRNSF 1.00000 DEMTRNSF 1.00000 DEMTRNSF 1.00000 DEMTRNSFS 1.00000 DEMTRNSFS 1.00000 DPRITGSSS 1.00000	ALLOC (1) RESIDENTIAL SERVICE (2) DEMPRI 2,601,527 1,758,993 DEMSEC 1.00000 0.73200 DEMTRNSF 1.00000 0.73200 DPRITGSS 2,509,072 1,758,993 2,402,995 1,758,993 DEMPRIS 1.00000 0.64522 DEMSECS 1.00000 0.72175 DEMTRNSFS 1.00000 0.72175 DEMTRNSFS 1.00000 0.72175 DEMTRNSFS 1.00000 0.68021	ALLOC (1) SERVICE SERVICE (2) (3) DEMPRI 2,601,527 1,758,993 313,203 DEMSEC 1.00000 0.73200 0.12565 DEMTRNSF 1.00000 0.73200 0.12565 DPRITGSS 2,509,072 1,758,993 313,203 2,402,995 1,758,993 313,203 DEMPRIS 1.00000 0.64522 0.12193 DEMPRIS 1.00000 0.72175 0.12840 DEMTRNSFS 1.00000 0.72175 0.12840 DEMTRNSFS 1.00000 0.72175 0.12840 DPRITGSSS 1.00000 0.68021 0.12786	ALLOC (1) RESIDENTIAL SERVICE SERVICE (3) SERVICE (4) DEMPRI 2,601,527 1,758,993 313,203 418,671 DEMSEC 1.00000 0.73200 0.12565 0.13477 DEMTRNSF 1.00000 0.73200 0.12565 0.13477 DPRITGSS 2,509,072 1,758,993 313,203 418,671 DEMPRIS 1.00000 1,758,993 313,203 418,671 DEMPRIS 1.00000 0.64522 0.12193 0.17853 DEMSECS 1.00000 0.72175 0.12840 0.14481 DEMTRNSFS 1.00000 0.72175 0.12840 0.14481 DPRITGSSS 1.00000 0.68021 0.12786 0.18711	ALLOC OLITRIBUTION RESIDENTIAL SERVICE SERVICE (3) GENERAL SERVICE (3) GENERAL SERVICE (3) GENERAL SERVICE (4) (5) (5) CENTRIBUTION (2) GENERAL SERVICE (3) GENERAL SERVICE (4) (4) (5) CENTRIBUTION (2) CENTRIPUT (4) CENTRIPUT (4) CENTRIPUT (4) CENTRIPUT (5) CENTRIPUT (4) CENTRIPUT (4) CENTRIPUT (5) CENTRIPUT (6) CENTRIPUT (ALLOC OLITRIBUTION SERVICE SERVICE SERVICE SERVICE (1) SERVICE (2) SERVICE (3) SERVICE SERVICE (4) SERVICE (6) SERVICE (7) SERVICE (8) SER

	ALLOC	RESIDENTIAL (8)-2	MONTHLY GENERAL SERV SECONDARY (9)	MONTHLY GENERAL SERV PRIMARY (10)	ANNUAL GENERAL SERV SECONDARY (11)	ANNUAL GENERAL SERV PRIMARY (12)	STREET AND PRIVATE LIGHTING (13)	GENERAL SERVICE SUBTRANSMSN (14)	GENERAL SERVICE TRANSMISSION (15)	DIRECT DISTRIBUTION CONNECTION (16)
ALLOCATION FACTOR TABLE-15										
CAPACITY-DISTRIBUTION RELATED 1 Distribution Primary-Class ACED 2 Distribution Secondry-Class ACED 3 Dist Line Transformer 4 Distr Pri-Class ACED - NONTGSS	DEMPRI DEMSEC DEMTRNSF DPRITGSS	1,758,993 0.73200 0.73200 1,758,993	301,942 0.12565 0.12565 301,942	11,261 0.00000 0.00000 11,261	323,855 0.13477 0.13477 323,855	94,816 0.00000 0.00000 94,816	16,370 0.00681 0.00681 16,370	92,455 0.00000 0.00000 0	0.00000 0.00000 0.00000	1,835 0.00076 0.00076 1,835
5 6 Class Maximum Diversified Demands SEC 7 Class Maximum Diversified Demands PRI 8		1,758,993 1,758,993	301,942 301,942	0 11,261	323,855 323,855	0 94,816	16,370 16,370	0 92,455	0	1,835 1,835
9 Class Maximum Diversified Dem NJ Pri 10 Class Maximum Diversified Dem NJ Sec 11 Dist Line Transformer NJ 12 Distr Pri-Class ACED - NONTGSS NJ	DEMPRIS DEMSECS DEMTRNSFS DPRITGSSS	0.64522 0.72175 0.72175 0.68021	0.11616 0.12840 0.12840 0.12180	0.00577 0.00000 0.00000 0.00606	0.13113 0.14481 0.14481 0.13743	0.04739 0.00000 0.00000 0.04968	0.00343 0.00371 0.00371 0.00356	0.04969 0.00000 0.00000 0.00000	0.00000 0.00000 0.00000 0.00000	0.00120 0.00132 0.00132 0.00126
13 14 15 16 17 18 19 20 21 22 23 24 25 26 27 28 29 30 31 32 33 34 35 36 37 38 39 40 41 42 43 44	CUST369S	0.72393	0.12911	0.00000	0.14563	0.00000	0.00000	0.00000	0.00000	0.00133

	ELECTRIC DISTRIBUTION							
	ALLOC	TOTAL ACE DISTRIBUTION (1)	TOTAL RESIDENTIAL SERVICE (2)	MONTHLY GENERAL SERVICE (3)	ANNUAL GENERAL SERVICE (4)	TRANSM GENERAL SERVICE (5)	STREET LIGHTING SERVICE (6)	DIRECT DISTRIBUTION CONNECTION (7)
45								
ALLOCATION FACTOR TABLE CUSTOMER RELATED-16 1 Number of Meters 2 Number of Customers 3 Customer Service Expenses Allocator 4 Sales Expense Allocator 5 Acct 369-Services-Class MDD 6 Acct 370-Meters Direct Assignment 6 Acct 370-Meters Direct Assignment 7 Acct 3730 Street Light & Signal Sys Dir Assign 8 Acct 990200 Meter reading expenses 9 Acct 990200 Meter reading expenses 10 D.A. 372-Leased Prop Cust Prem 11 D.A. Customer Deposits 12 Acct 371.1 Based on Dist Plt 13 14 15 16 17 18 19 20 21 22 23 24 24 25 26 27 28 29 30 31 31 32 33 34 35 36 37 38 39 40 40 41 41 42 43 44 45	CUST CSERV CSALES CUST369 CUST370 CUST371 CUST373 CUST902 CUST372 CUSPDEP CUST3711P	560,076 568,813 1.0000 1.0000 2,385,708 63,274,614 26,492,974 1 7,570.084 50,150,408 141,649 (20,534,018) 2,908,542,635	500,038 501,866 0,6708 0,6708 1,758,993 37,277,797 20,314,580 0 6,615,649 44,493,371 0 (9,191,213) 1,959,487,402	56,852 56,799 0.1340 0.1340 301,942 18,838,153 5,536,121 0 785,247 4,624,345 0 (5,254,884) 357,886,444	3,087 3,026 0.1247 0.1247 323,855 4,622,288 642,274 0 129,796 288,501 13,606 (6,087,921) 414,620,837	99 52 0.0595 0.0595 0 2,536,376 0 0 39,392 215,804 128,042 0 8,351,793	0 6,006 0,92% 0,92% 0 0 451,156 0 0 166,299,405	0 1,064 0 0 918 0 0 0 77,230 0 0 1,896,754

	ALLOC	RESIDENTIAL (8)-2	MONTHLY GENERAL SERV SECONDARY (9)	MONTHLY GENERAL SERV PRIMARY (10)	ANNUAL GENERAL SERV SECONDARY (11)	ANNUAL GENERAL SERV PRIMARY (12)	STREET AND PRIVATE LIGHTING (13)	GENERAL SERVICE SUBTRANSMSN (14)	GENERAL SERVICE TRANSMISSION (15)	DIRECT DISTRIBUTION CONNECTION (16)
45										
ALLOCATION FACTOR TABLE										
CUSTOMER RELATED-16 1 Number of Meters 2 Number of Customers 3 Customer Service Expenses Allocator 4 Sales Expense Allocator 5 Acct 369-Services-Class MDD 6 Acct 3701-AMI Meters Direct Assignment 6 Acct 3701-AMI Meters Direct Assignment 7 Acct 3730 Street Light & Signal Sys Dir Assign 8 Acct 990200 Meter reading expenses 9 Acct 990300 Cust records and collection exp 10 D.A. 372-Leased Prop Cust Prem 11 D.A. Customer Deposits 12 Acct 371.1 Based on Dist Plt 13 14 15 16 17 18 19 20 21 22 23 24 25 26 27 28 29 30 31 31 32 33 34 35 36 37 38 39 40 41 42 43 44	CUST CSERV CSALES CUST369 CUST371 CUST371 CUST373 CUST902 CUST903 CUST372 CUST972 CUST971 CUST3711P	500,038 501,866 0,6708 1,758,933 37,277,797 20,314,580 0,6,615,649 44,493,371 0,(9,191,213) 1,959,487,402	0.1294 301,942 17,542,292 5,507,103 0 751,823 4,596,442	168 154 0.0046 0.0046 0.0046 1.295,861 29,018 0 33,424 27,903 0 (122,674) 8,354,772	2,958 2,908 0,0932 0,0932 323,855 2,638,632 642,274 0,78,466 259,879 0,(5,189,588) 353,439,447	129 118 0.0314 0.0314 0 1,983,656 0 0 51,329 28,623 13,606 (898,333) 61,181,390	0 6,006 0.0092 0.0092 0 0 0 451,156 0 166,299,405		40 16 0.0280 0.0280 0 1,168,912 0 0 15,916 204,253 121,139 0 1,290,896	0 1,064 0.0018 918 0 0 0 0 77,230 0 0 1,896,754

(3)	SERVICE (5)	SERVICE (6)	DISTRIBUTION CONNECTION (7)
28,714,226 30,798,119 80,588,450 86,437,039 384,575 514,077 2,756 3,684 523,178 677,379 0 0 0 1,523,657 329,075 102,832 110,295 3,055,126 1,968,325 629,169 405,354 552,778 738,921 7,917,205 10,250,712 554,410 693,821 70,614 75,739 0 0 0 2,066 446 163,695 211,605 75,886,444 414,620,837 4,468,444 414,620,837 4,468,444 414,620,837 4,468,444 414,620,837 4,468,444 414,620,837 4,468,444 41,620,837 4,468,445 2,089,903 28,212,622 25,822,775 32,749,081 27,236,959 21,386,516 7,710,702	2,839,343 2,647,151 687,128 1,960,023 0 2,537,655 0 0 113,524 124 2,978 0 0 158,533 0 331,354 68,239 24,937 45,064 37,148 0 0 215 1,932 8,351,793 373,124 2,355,823 2,286,836 1,778,650 346,023 3,877,619	3,289,608 7,894,133 6,346,852 1,547,281 118,371,145 0 4,369,078 20,100 431,115 0 576,663 118,757 28,891 416,250 29,325 3,828 1,823,429 0 41,418 166,299,405 915,158 5,778,114 6,302,607 (1,033,320,2),2,358,140 43,728,650	368,757 884,912 711,466 173,446 0 0 87,253 489,762 2,253 16 3,083 0 0 0 312 6,822 1,405 3,239 46,661 3,287 429 0 0 965 1,896,754 18,274 115,377 200,715 227,127 264,341 539,027
	28,714,226 30,798,119 80,588,450 86,437,039 384,575 514,077 2,756 3,684 523,178 677,379 0 0 0 1,523,657 3229,075 102,832 110,295 3,055,126 1,968,325 629,169 405,354 552,778 738,921 7,917,205 10,250,712 554,410 693,821 70,614 75,739 2,066 446 163,695 211,605 57,886,444 414,620,837 4,468,444 414,620,837 4,468,444 414,620,837 4,468,444 414,620,837 4,468,444 414,620,837 4,468,445 2,989,903 28,212,622 25,822,775 32,749,081 27,236,595 41,386,516 7,710,702 44,852,501 58,071,799	28,714,226 30,798,119 0 80,588,450 86,437,039 0 384,575 514,077 113,524 2,756 3,684 124 523,178 677,379 2,978 0 0 0 0 0 0 1,523,657 329,075 158,533 102,832 110,295 0 3,055,126 1,968,325 331,354 629,169 405,354 68,239 552,778 738,921 24,937 7,917,205 10,250,712 45,064 554,410 693,821 37,148 70,614 75,739 0 0 0 0 0 2,066 446 215 163,695 211,605 1,932 27,786,444 414,620,837 8,351,793 4,468,415 4,089,903 373,124 28,212,622 25,822,775 2,355,823 32,749,081 27,236,959 2,286,836	24,389,350 5,267,540 2,537,655 0 28,714,226 30,798,119 0 0 80,588,450 86,437,039 0 4,369,078 384,575 514,077 113,524 20,100 2,756 3,684 124 144 523,178 677,379 2,978 27,506 0 0 0 0 0 1,523,657 329,075 158,533 0 0 102,832 110,295 0 0 0 3,055,126 1,968,325 313,354 576,663 629,169 405,354 68,239 118,757 552,778 738,921 24,937 28,891 7,917,205 10,250,712 45,064 416,250 554,410 693,821 37,148 29,325 57,0614 75,739 0 3,828 0 0 0 1,823,429 2,066 446 215 0 163,695 211,605

	ALLOC	RESIDENTIAL (8)-2	MONTHLY GENERAL SERV SECONDARY (9)	MONTHLY GENERAL SERV PRIMARY (10)	ANNUAL GENERAL SERV SECONDARY (11)	ANNUAL GENERAL SERV PRIMARY (12)	STREET AND PRIVATE LIGHTING (13)	GENERAL SERVICE SUBTRANSMSN (14)	GENERAL SERVICE TRANSMISSION (15)	DIRECT DISTRIBUTION CONNECTION (16)
ALLOCATION FACTOR TABLE										
INTERNALLY DEVELOPED-17 1 Acct 3620 Station Equipment 2 Accts 364 - 367 Distribution Plant 3 Accts 364 8 365 Overhead Lines 4 Accts 366 8 367 Underground Lines 5 Acct 3730 Street Lighting and Signal Systems 6 Acct 3730 Meters 7 Acct 368 Services 8 Acct 3680 Line Transformers 9 Acct 3680 Line Transformers 10 Acct 958100 Load dispatching 11 Acct 958200 Station expenses 12 Acct 958400 Underground line expenses 13 Acct 958500 Street lighting 14 Acct 958500 Street lighting 15 Acct 958600 Meter expenses 16 Acct 958700 Customer installations expenses 17 Acct 958900 Rents 18 Acct 959200 Maintain equipment 18 Acct 959300 Maintain equipment 19 Acct 959300 Maintain overhead lines 20 Acct 959400 Maintain underground line	PLT362 PLT3647 PLTDOHLN PLTDUGLN PLT373 PLT370 PLT368 EXP581 EXP582 EXP583 EXP584 EXP585 EXP586 EXP587 EXP586 EXP587 EXP588 EXP589 EXP592 EXP593 EXP594	353,482,385 848,258,061 681,996,190 166,261,871 0 57,631,638 167,277,567 469,475,992 2,159,830 15,480 2,955,668 0 0 3,600,376 599,060 11,235,950 2,313,917 3,104,481 44,727,820 3,151,137	60,677,432 145,608,729 117,068,853 28,539,876 0 23,063,788 28,714,226 80,588,450 370,748 2,657 507,359 0 0 1,440,846 102,832 2,919,582 601,255 532,903 7,677,806 540,912	2,262,980 4,362,475 3,650,274 712,200 0 1,325,561 0 0 13,827 99 15,820 0 0 82,811 0 135,544 27,914 19,875 239,398 13,498	65,081,008 156,176,070 125,564,954 30,611,116 0 3,282,883 30,798,119 86,437,039 397,655 2,850 544,179 0 205,089 110,295 1,517,410 312,494 571,578 8,235,012 580,168	19,053,962 36,731,412 30,734,786 5,996,625 0 1,984,657 0 116,423 834 133,200 0 123,986 0 450,915 92,861 167,343 2,015,700 113,653	3,289,608 7,894,133 6,346,852 1,547,281 118,371,145 0 0 4,369,078 20,100 144 27,506 0 431,115 0 576,663 118,757 28,891 416,250 29,325	2,839,343 2,647,151 687,128 1,960,023 0 1,368,153 0 0 113,524 124 2,978 0 0 85,472 0 243,371 50,120 24,937 45,064 37,148	0 0 0 0 0 1,169,501 0 0 0 0 0 73,061 0 87,983 18,119 0 0	368,757 884,912 711,466 173,446 0 87,253 489,762 2,253 16 3,083 0 0 312 6,822 1,405 3,239 46,661 3,287
21 Acct 959500 Maintain line transformers 22 Acct 959600 Maint street lighting & signal sys 23 Acct 959700 Maintain meters 24 Acct 959800 Maintain distribution plant 25 Total Distribution Plant 26 Total Operation & Maintenance Labor 27 Total General Plant 28 Dist O&M Expense 29 Taxable Income 30 Acct 364 Poles 31 Depreciation Reserve 32 33 34 35 36 37 38 39 40 41 42 43 44	EXP595 EXP596 EXP597 EXP598 DISTPLT LABOR GENPLT DISTOMEXP TAXINC PLT364 DEPRERES	411,371 0 4,881 924,897 1,959,487,402 21,146,762 133,516,146 182,562,244 (56,607,344) 253,392,158 568,514,886	70,614 0 1,953 158,784 349,531,672 4,300,143 27,150,185 31,690,451 21,457,855 43,496,327 104,124,940	0 0 112 4,910 8,354,772 168,273 1,062,437 1,058,630 (71,338) 1,356,174 2,825,455	75,739 0 278 170,275 353,439,447 3,231,017 20,399,951 21,600,378 6,171,991 46,653,010 99,547,031	0 168 41,330 61,181,390 858,886 5,422,825 5,636,582 1,538,711 11,418,789 18,771,657	3,828 1,823,429 0 41,418 166,299,405 915,158 5,778,114 6,302,607 (1,033,320) 2,358,140 43,728,650	0 116 1,930 7,060,897 283,670 1,791,032 1,515,181	0 99 2 1,290,896 89,454 564,791 771,655 1,119,250 0 762,691	429 0 0 965 1,896,754 115,377 200,715 227,127 264,341 539,027

	ALLOC	TOTAL ACE DISTRIBUTION (1)	TOTAL RESIDENTIAL SERVICE (2)	MONTHLY GENERAL SERVICE (3)	ANNUAL GENERAL SERVICE (4)	TRANSM GENERAL SERVICE (5)	STREET LIGHTING SERVICE (6)	DIRECT DISTRIBUTION CONNECTION (7)
ALLOCATION FACTOR TABLE								
INTERNALLY DEVELOPED CON'T-18								
1 Distribution Operating Exp Acct 581 - 587	EXPDISTO	14,261,613	9,330,413	2,536,999	1,634,511	275,159	478,865	5,665
2 Distribution Maintenance Exp Acct 592 - 597	EXPDISTM	74,719,105	51,399,690	9,097,073	11,759,639	107,364	2,301,723	53,616
3 Distribution Operating Labor Acct 581 - 589	LABDO	12,033,832	8,016,440	2,126,794	1,439,917	251,086	194,483	5,112
4 Distribution Maintenance Labor Acct 592 - 598	LABDM	13,740,908	9,304,313	1,646,909	2,124,586	36,735	618,662	9,703
5 Total Distribution Operating Labor	TLABDO	12,175,904	8,111,082	2,151,903	1,456,917	254,050	196,779	5,172
6 Total Distribution Maintenance Labor 7 Acct 990200 Meter reading expenses	TLABDM EXP902	13,742,430 7,570,059	9,305,343 6,615,626	1,647,092 785,245	2,124,822 129,795	36,739 39,392	618,730 0	9,704 0
Acct 990200 Meter reading expenses Acct 990300 Cust records and collection exp	EXP902	50,157,398	44,499,573	4,624,990	288,541	215,834	451,219	77,241
9 Acct 990500 Miscellaneous cust accounts exp	EXP905	00,107,000	0	4,024,330	200,541	213,034	431,219	0
10 Acct 990700 Supervision	EXP907	0	0	0	0	0	0	0
11 Acct 990800 Customer assistance expenses	EXP908	5,029,692	3,374,136	673,947	626,992	299,377	46,251	8.989
12 Acct 991000 Misc cust service & informat exp	EXP910	0	0	0	0	0	0	0
13 Acct 991200 Demonstrating & selling expenses	EXP912	0	0	0	0	0	0	0
14 Acct 991300 Advertising expense	EXP913	0	0	0	0	0	0	0
15 Acct 992000 Administrative & General salaries	EXP920	3,046,550	2,077,435	438,972	401,788	36,655	89,904	1,795
16 Acct 992100 Office supplies & expenses	EXP921	2,091,745	1,426,356	301,396	275,865	25,167	61,728	1,233
17 Acct 992300 Outside services employed	EXP923	59,647,957	40,673,802	8,594,576	7,866,543	717,668	1,760,221	35,148
18 Acct 993020 Miscellaneous general expenses	EXP9302	736,055	501,914	106,057	97,073	8,856	21,721	434
 19 Acct 993500 Maintenance of general plant 20 Total Intangible Plant 	EXP935 INTPLT	414,526 84.054.509	282,665 57,316,573	59,728 12,111,275	54,669 11.085.348	4,987 1,011,321	12,233 2,480,462	244 49.530
20 Total Intangible Plant 21 Service Company Assets Reserve	SERVCO	31,011,635	21,146,762	4,468,415	4,089,903	373,124	915,158	49,530 18,274
22 Total System Electric Distribution	PLANT	3,257,924,573	2,197,730,128	408,228,311	460,698,323	12,555,461	176,609,721	2,102,629
23 Accts 902 & 903 Mtr Read & Cust Rec	EXP9023	57,727,457	51,115,200	5,410,234	418,337	255,227	451,219	77,241
24 Total Customer Deposits	CUSTDEP	18,982,828	8,496,886	4,857,917	5,628,025	0	0	0
25 Sales Revenue Required Claimed ROR	CLAIMREV	511,238,818	357,144,278	66,273,414	63,338,288	3,576,728	20,530,346	375,764
26 Residential Distribution Plant	RESDIST	1,959,487,402	1,959,487,402	0	0	0	0	0
27 Non-Residential Distribution Plant	NRESDIST	949,055,233	0	357,886,444	414,620,837	8,351,793	166,299,405	1,896,754
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	ALLOC	RESIDENTIAL (8)-2	MONTHLY GENERAL SERV SECONDARY (9)	MONTHLY GENERAL SERV PRIMARY (10)	ANNUAL GENERAL SERV SECONDARY (11)	ANNUAL GENERAL SERV PRIMARY (12)	STREET AND PRIVATE LIGHTING (13)	GENERAL SERVICE SUBTRANSMSN (14)	GENERAL SERVICE TRANSMISSION (15)	DIRECT DISTRIBUTION CONNECTION (16)
ALLOCATION FACTOR TABLE										
INTERNALLY DEVELOPED CON'T-18										
1 Distribution Operating Exp Acct 581 - 587	EXPDISTO	9,330,413	2,424,442	112,557	1,260,068	374,443	478,865	202,097	73,061	5,665
2 Distribution Maintenance Exp Acct 592 - 597	EXPDISTM	51,399,690	8,824,189	272,884	9,462,775	2,296,864	2,301,723	107,265	99	53,616
3 Distribution Operating Labor Acct 581 - 589	LABDO	8,016,440	2,033,266	93,529	1,110,296	329,621	194,483	192,731	58,355	5,112
4 Distribution Maintenance Labor Acct 592 - 598	LABDM	9,304,313	1,597,918	48,992	1,712,622	411,964	618,662	36,667	69	9,703
5 Total Distribution Operating Labor	TLABDO	8,111,082	2,057,270	94,633	1,123,404	333,512	196,779	195,006	59,044	5,172
6 Total Distribution Maintenance Labor	TLABDM	9,305,343	1,598,095	48,997	1,712,812	412,010	618,730	36,671	69	9,704
7 Acct 990200 Meter reading expenses	EXP902	6,615,626	751,821	33,424	78,466	51,329	0	23,476	15,916	0
8 Acct 990300 Cust records and collection exp	EXP903	44,499,573	4,597,083	27,907	259,915	28,627	451,219	11,553	204,281	77,241
9 Acct 990500 Miscellaneous cust accounts exp	EXP905	0	0	0	0	0	0	0	0	0
10 Acct 990700 Supervision	EXP907	•	0	0	•	•	•	0	0	0
11 Acct 990800 Customer assistance expenses	EXP908 EXP910	3,374,136	651,007 0	22,940 0	468,874 0	158,118 0	46,251 0	158,549 0	140,828	8,989 0
12 Acct 991000 Misc cust service & informat exp 13 Acct 991200 Demonstrating & selling expenses	EXP910 EXP912	0	0	0	0	0	0	0	0	0
14 Acct 991300 Advertising expense	EXP913	0	0	0	0	0	0	0	0	0
15 Acct 992000 Administrative & General salaries	EXP920	2.077.435	422.441	16,531	317.412	84,376	89,904	27.867	8.788	1,795
16 Acct 992100 Office supplies & expenses	EXP921	1,426,356	290,046	11,350	217,933	57,932	61,728	19,134	6,034	1,233
17 Acct 992300 Outside services employed	EXP923	40,673,802	8,270,919	323,656	6,214,556	1,651,987	1,760,221	545,612	172,055	35,148
18 Acct 993020 Miscellaneous general expenses	EXP9302	501,914	102,063	3,994	76,688	20,385	21,721	6,733	2,123	434
19 Acct 993500 Maintenance of general plant	EXP935	282,665	57,479	2,249	43,188	11,481	12,233	3,792	1,196	244
20 Total Intangible Plant	INTPLT	57,316,573	11,655,186	456,089	8,757,407	2,327,941	2,480,462	768,864	242,457	49,530
21 Service Company Assets Reserve	SERVCO	21,146,762	4,300,143	168,273	3,231,017	858,886	915,158	283,670	89,454	18,274
22 Total System Electric Distribution	PLANT	2,197,730,128	397,977,754	10,250,557	389,840,586	70,857,737	176,609,721	10,256,767	2,298,694	2,102,629
23 Accts 902 & 903 Mtr Read & Cust Rec	EXP9023	51,115,200	5,348,904	61,331	338,381	79,956	451,219	35,029	220,197	77,241
24 Total Customer Deposits	CUSTDEP	8,496,886	4,744,510	113,407	4,797,554	830,470	0	0	0	0
25 Sales Revenue Required Claimed ROR	CLAIMREV	357,144,278	64,386,389	1,887,025	52,133,356	11,204,932	20,530,346	2,514,863	1,061,865	375,764
26 Residential Distribution Plant	RESDIST	1,959,487,402	0	0	0	0	0	0	0	0
27 Non-Residential Distribution Plant	NRESDIST	0	349,531,672	8,354,772	353,439,447	61,181,390	166,299,405	7,060,897	1,290,896	1,896,754
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		ALLOC	TOTAL ACE DISTRIBUTION (1)	TOTAL RESIDENTIAL SERVICE (2)	MONTHLY GENERAL SERVICE (3)	ANNUAL GENERAL SERVICE (4)	TRANSM GENERAL SERVICE (5)	STREET LIGHTING SERVICE (6)	DIRECT DISTRIBUTION CONNECTION (7)
	ALLOCATION FACTOR TABLE								
	INTERNALLY DEVELOPED CON'T-19								
1 2	<u>Claimed Revenues</u> Claimed Revenues Residential	CREVRES	357,144,278	357,144,278	0	0	0	0	0
3		CREVGSS	64,386,389	0	64,386,389	0	0	0	0
4 5		CREVCOM CREVGSSL	1,887,025 52,133,356	0	1,887,025 0	0 52,133,356	0	0	0 0
6		CREVGSP	11,204,932	0	0	11,204,932	0	0	0
7		CREVLTG	20,530,346	0	0	0	0	20,530,346	0
8 9		CREVGSST CREVGST	2,514,863	0	0 0	0	2,514,863	0	0
10		CREVDDC	1,061,865 375,764	0	0	0	1,061,865 0	0	375,764
11		0.12.7220	511,238,818	357,144,278	66,273,414	63,338,288	3,576,728	20,530,346	375,764
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25									
26 27	REVENUE REQUIREMENTS INPUTS								
28									
29 30	Current Revenue - Retail Sales ACE		476,723,799	296,020,547	86,151,215	69,944,842	5,114,341	18,905,207	587,648
	Claimed Rate of Return		7.13%	7.13%	7.13%	7.13%	7.13%	7.13%	7.13%
33									
34			568,813	501,866	56,799	3,026	52	6,006	1,064
35 36			8,778,187,173	4,032,550,392	1,475,895,885	2,141,846,944 2,141,847	1,044,186,603	68,752,713 68,753	14,954,636
37	Total MVV H Sales @ Meter		8,778,187	4,032,550	1,475,896	2,141,047	1,044,187	00,733	14,955
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	ALLOC	RESIDENTIAL (8)-2	MONTHLY GENERAL SERV SECONDARY (9)	MONTHLY GENERAL SERV PRIMARY (10)	ANNUAL GENERAL SERV SECONDARY (11)	ANNUAL GENERAL SERV PRIMARY (12)	STREET AND PRIVATE LIGHTING (13)	GENERAL SERVICE SUBTRANSMSN (14)	GENERAL SERVICE TRANSMISSION (15)	DIRECT DISTRIBUTION CONNECTION (16)
ALLOCATION FACTOR TABLE										
INTERNALLY DEVELOPED CON'T-19										
1 <u>Claimed Revenues</u> 2 Claimed Revenues Residential	CREVRES	357,144,278	0	0	0	0	0	0	0	0
3 Claimed Revenues MGSS	CREVGSS CREVCOM	0	64,386,389	0	0	0	0	0	0	0
4 Claimed Revenues MGSP 5 Claimed Revenues AGSS	CREVGOM	0	0	1,887,025 0	52,133,356	0	0	0	0	0
6 Claimed Revenues AGSP	CREVGSP	0	0	0	02,100,000	11,204,932	0	ő	0	0
7 Claimed Revenues Lighting	CREVLTG	0	0	0	0	0	20,530,346	0	0	0
8 Claimed Revenues GSST 9 Claimed Revenues GST	CREVGSST CREVGST	0	0	0	0	0	0	2,514,863	1 061 865	0
9 Claimed Revenues GST 10 Claimed Revenues DDC	CREVDDC	0	0	0	0	0	0	0	1,061,865 0	375,764
11 Total Claimed Revenue	0.12.7550	357,144,278	64,386,389	1,887,025	52,133,356	11,204,932	20,530,346	2,514,863	1,061,865	375,764
12 13 14 15 16 17 18 19 20 21 22 23 24 25 26 REVENUE REQUIREMENTS INPUTS										
27 REVENUE REQUIREMENTS INPUTS 28 29 Current Revenue - Retail Sales ACE		296,020,547	84,363,933	1,787,281	57,356,426	12,588,416	18,905,207	3,024,915	2,089,427	587,648
30 31 Claimed Rate of Return		7.13%	7.13%	7.13%	7.13%	7.13%	7.13%	7.13%	7.13%	7.13%
32		7.1370	7.1370	7.1370	7.1370	7.1370	7.1370	7.1370	7.1370	7.1370
32 BILLING DETERMINANTS 34 Average Number of Customers (12 Months) 35 Total KWH Sales @ Meter 36 Total MWH Sales @ Meter 37 38 39 40 41 42 43 44 45		501,866 4,032,550,392 4,032,550	56,645 1,398,199,951 1,398,200	154 77,695,934 77,696	2,908 1,591,748,317 1,591,748	118 550,098,627 550,099	6,006 68,752,713 68,753	36 552,866,415 552,866	16 491,320,188 491,320	1,064 14,954,636 14,955

	ALLOC	TOTAL ACE DISTRIBUTION (1)	TOTAL RESIDENTIAL SERVICE (2)	MONTHLY GENERAL SERVICE (3)	ANNUAL GENERAL SERVICE (4)	TRANSM GENERAL SERVICE (5)	STREET LIGHTING SERVICE (6)	DIRECT DISTRIBUTION CONNECTION (7)
RATIO TABLE								
CAPACITY-DISTRIBUTION RELATED-20 1 Distribution Primary-Class ACED 2 Distribution Secondry-Class ACED 3 Dist Line Transformer 4 Distr Pri-Class ACED - NONTGSS 5 6 Class Maximum Diversified Dem NJ Pri 7 Class Maximum Diversified Dem NJ Sec 8 Dist Line Transformer NJ 9 Distr Pri-Class ACED - NONTGSS NJ 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24 25 26 27 28 29 30 31 31 32 33 34 35 36	DEMPRI DEMSEC DEMTRNSF DPRITGSS DEMPRIS DEMSECS DEMTRNSFS DPRITGSSS	1.000000 1.000000 1.000000 1.000000 1.000000 1.000000 1.000000	0.676139 0.732000 0.732000 0.701053 0.645220 0.721752 0.721752 0.680212	0.120392 0.125652 0.125652 0.124828 0.121933 0.128404 0.128404 0.127859	0.160933 0.134771 0.134771 0.166863 0.178527 0.144807 0.144807 0.187109	0.035539 0.000000 0.000000 0.000000 0.049689 0.000000 0.000000 0.000000	0.006292 0.006812 0.006812 0.006524 0.003430 0.003712 0.003712 0.003562	0.000705 0.000764 0.000764 0.000731 0.001202 0.001325 0.001325 0.001258
37 38 39 40 41								
42 43 44 45								

	ALLOC	RESIDENTIAL (8)-2	MONTHLY GENERAL SERV SECONDARY (9)	MONTHLY GENERAL SERV PRIMARY (10)	ANNUAL GENERAL SERV SECONDARY (11)	ANNUAL GENERAL SERV PRIMARY (12)	STREET AND PRIVATE LIGHTING (13)	GENERAL SERVICE SUBTRANSMSN (14)	GENERAL SERVICE TRANSMISSION (15)	DIRECT DISTRIBUTION CONNECTION (16)
RATIO TABLE CAPACITY-DISTRIBUTION RELATED-20 Distribution Primary-Class ACED	DEMPRI	0.676139 0.676139	0.116063	0.004329	0.124487	0.036446	0.006292	0.035539	0.000000	0.000705
Distribution Secondry-Class ACED Dist Line Transformer Distr Pri-Class ACED - NONTGSS	DEMSEC DEMTRNSF DPRITGSS	0.732000 0.732000 0.701053	0.125652 0.125652 0.120340	0.000000 0.000000 0.004488	0.134771 0.134771 0.129074	0.000000 0.000000 0.037789	0.006812 0.006812 0.006524	0.000000 0.000000 0.000000	0.000000 0.000000 0.000000	0.000764 0.000764 0.000731
6 Class Maximum Diversified Dem NJ Pri 7 Class Maximum Diversified Dem NJ Sec 8 Dist Line Transformer NJ 9 Distr Pri-Class ACED - NONTGSS NJ 10	DEMPRIS DEMSECS DEMTRNSFS DPRITGSSS	0.645220 0.721752 0.721752 0.680212	0.116161 0.128404 0.128404 0.121795	0.005772 0.000000 0.000000 0.006064	0.131133 0.144807 0.144807 0.137430	0.047394 0.000000 0.000000 0.049679	0.003430 0.003712 0.003712 0.003562	0.049689 0.000000 0.000000 0.000000	0.000000 0.000000 0.000000 0.000000	0.001202 0.001325 0.001325 0.001258
11 12 13 14 15										
17 18 19 20 21										
22 23 24 25 26 27										
28 29 30 31 32										
33 34 35 36 37 38										
39 40 41 42 43 44										
22 23 24 25 26 27 28 29 30 31 32 33 34 35 36 37 38 39 40 41 41										

	ALLOC	TOTAL ACE DISTRIBUTION (1)	TOTAL RESIDENTIAL SERVICE (2)	MONTHLY GENERAL SERVICE (3)	ANNUAL GENERAL SERVICE (4)	TRANSM GENERAL SERVICE (5)	STREET LIGHTING SERVICE (6)	DIRECT DISTRIBUTION CONNECTION (7)
RATIO TABLE								
CUSTOMER RELATED-21 Number of Meters Number of Customers Customer Service Expenses Allocator Sales Expense Allocator Acat 369-Services-Class Max NCD Acat 370-Meters Direct Assignment Acat 3703 Street Light & Signal Sys Dir Assign Acat 990200 Meter reading expenses Acat 990300 Cust records and collection exp D.A. 372-Leased Prop Cust Prem D.A. Customer Deposits Acat 3711 Based on Dist Pit Acat 3711 Based on Dist Pit Sales Acat 371 B	CUST CSERV CSALES CUST369 CUST370 CUST371 CUST373 CUST902 CUST903 CUST972 CUSPDEP CUST3711P	1.000000 1.000000 1.000000 1.000000 1.000000 1.000000 1.000000 1.000000 1.000000 1.000000 1.000000 1.000000 1.000000	0.892804 0.882304 0.670844 0.670844 0.737305 0.589143 0.766791 0.000000 0.873920 0.887199 0.000000 0.447609 0.673701	0.101508 0.099855 0.133994 0.133994 0.126563 0.297721 0.208966 0.000000 0.103730 0.092210 0.000000 0.255911 0.123047	0.005512 0.005320 0.124658 0.124658 0.135748 0.073051 0.024243 0.00000 0.017146 0.005753 0.096057 0.296480 0.142553	0.000177 0.00091 0.059522 0.059522 0.00000 0.040085 0.000000 0.005204 0.004303 0.903943 0.000000 0.002871	0.000000 0.010559 0.009196 0.000000 0.000000 1.000000 0.000000 0.000000 0.000000 0.000000	0.000000 0.001871 0.001787 0.000385 0.000000 0.000000 0.000000 0.000000 0.001540 0.000000 0.000000 0.000000 0.000000

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	ALLOC	RESIDENTIAL (8)-2	MONTHLY GENERAL SERV SECONDARY (9)	MONTHLY GENERAL SERV PRIMARY (10)	ANNUAL GENERAL SERV SECONDARY (11)	ANNUAL GENERAL SERV PRIMARY (12)	STREET AND PRIVATE LIGHTING (13)	GENERAL SERVICE SUBTRANSMSN (14)	GENERAL SERVICE TRANSMISSION (15)	DIRECT DISTRIBUTION CONNECTION (16)
RATIO TABLE										
CUSTOMER RELATED-21 1 Number of Meters 2 Number of Customers 3 Customer Service Expenses Allocator 4 Sales Expenses Allocator 5 Acct 369-Services-Class Max NCD 6 Acct 3701-Meters Direct Assignment 6 Acct 3701-Meters Direct Assignment 7 Acct 3703 Street Light & Signal Sys Dir Assign 8 Acct 990200 Meter reading expenses 9 Acct 990200 Cust records and collection exp 10 D.A. 372-Leased Prop Cust Prem 11 D.A. Customer Deposits 12 Acct 3711 Based on Dist Pit 13 14 15 16 17 18 19 20 21 22 23 24 25 26 27 28 29 30 31 31 32 33 34 35 36 37 38 39 40 41 42 43 44 45	CUST CSERV CSALES CUST369 CUST370 CUST371 CUST371 CUST902 CUST903 CUST907 CUST907 CUST907 CUST907	0.892804 0.882304 0.670844 0.670844 0.737305 0.589143 0.766791 0.000000 0.873920 0.887199 0.000000 0.447609 0.673701	0.101208 0.099585 0.129433 0.129563 0.277241 0.207870 0.00000 0.099315 0.000000 0.249937 0.120174	0.000300 0.000271 0.004561 0.004561 0.000000 0.020480 0.001095 0.000000 0.004415 0.000556 0.000000 0.00574 0.002872	0.005281 0.005112 0.093221 0.093221 0.135748 0.041701 0.024243 0.000000 0.010365 0.005182 0.000000 0.252731 0.121518	0.000230 0.000207 0.031437 0.031437 0.000000 0.031350 0.000000 0.000000 0.0006781 0.000571 0.096057 0.043749 0.021035	0.000000 0.010559 0.009196 0.000196 0.000000 0.000000 1.000000 0.000000 0.000000 0.000000 0.000000	0.000105 0.000063 0.031523 0.031523 0.000000 0.021612 0.000000 0.000000 0.003101 0.000230 0.048735 0.000000 0.002428	0.000071 0.00028 0.027999 0.027999 0.000000 0.018474 0.000000 0.002102 0.004073 0.855208 0.000000 0.0004074	0.000000 0.001871 0.001787 0.000385 0.000000 0.000000 0.000000 0.000000 0.000000

	ALLOC	TOTAL ACE DISTRIBUTION (1)	TOTAL RESIDENTIAL SERVICE (2)	MONTHLY GENERAL SERVICE (3)	ANNUAL GENERAL SERVICE (4)	TRANSM GENERAL SERVICE (5)	STREET LIGHTING SERVICE (6)	DIRECT DISTRIBUTION CONNECTION (7)
RATIO TABLE INTERNALLY DEVELOPED-22 1 Acct 3620 Station Equipment	PLT362	1.000000	0.697128	0.124129	0.165929	0.005600	0.006488	0.000727
2 Accts 364 - 367 Distribution Plant	PLT3647	1.000000	0.705375	0.124710	0.160414	0.002201	0.006564	0.000727
3 Accts 364 & 365 Overhead Lines	PLTDOHLN	1.000000	0.705445	0.124870	0.161674	0.000711	0.006565	0.000736
4 Accts 366 & 367 Underground Lines	PLTDUGLN	1.000000	0.705090	0.124053	0.155248	0.008312	0.006562	0.000736
5 Acct 3730 Street Lighting and Signal Systems	PLT373	1.000000	0.000000	0.000000	0.000000	0.000000	1.000000	0.000000
6 Acct 3700 Meters	PLT370	1.000000	0.641591	0.271517	0.058641	0.028251	0.000000	0.000000
7 Acct 369 Services	PLT369	1.000000	0.737305	0.126563	0.135748	0.000000	0.000000	0.000385
8 Acct 3680 Line Transformers	PLT368	1.000000	0.732000	0.125652	0.134771	0.000000	0.006812	0.000764
9 Acct 958100 Load dispatching	EXP581	1.000000	0.676139	0.120392	0.160933	0.035539	0.006292	0.000705
10 Acct 958200 Station expenses	EXP582	1.000000	0.697128	0.124129	0.165929	0.005600	0.006488	0.000727
11 Acct 958300 Overhead line expenses	EXP583	1.000000	0.705445	0.124870	0.161674	0.000711	0.006565	0.000736
12 Acct 958400 Underground line expenses	EXP584	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
13 Acct 958500 Street lighting	EXP585	1.000000	0.000000	0.000000	0.000000	0.000000	1.000000	0.000000
14 Acct 958600 Meter expenses	EXP586	1.000000	0.641591	0.271517	0.058641	0.028251	0.000000	0.000000
15 Acct 958700 Customer installations expenses	EXP587	1.000000	0.737305	0.126563	0.135748	0.000000	0.000000	0.000385
16 Acct 958800 Miscellaneous distribution exp	EXP588	1.000000	0.654233	0.177890	0.114609	0.019294	0.033577	0.000397
17 Acct 958900 Rents	EXP589 EXP592	1.000000	0.654233	0.177890 0.124129	0.114609 0.165929	0.019294	0.033577 0.006488	0.000397 0.000727
18 Acct 959200 Maintain equipment 19 Acct 959300 Maintain overhead lines	EXP592 EXP593	1.000000 1.000000	0.697128 0.705445	0.124129	0.161674	0.005600 0.000711	0.006565	0.000727
20 Acct 959400 Maintain overnead lines	EXP593	1.000000	0.705090	0.124053	0.155248	0.000711	0.006562	0.000736
21 Acct 959500 Maintain underground line 21 Acct 959500 Maintain line transformers	EXP595	1.000000	0.732000	0.125652	0.134771	0.000000	0.006812	0.000730
22 Acct 959600 Maint street lighting & signal sys	EXP596	1.000000	0.000000	0.000000	0.000000	0.000000	1.0000012	0.000000
23 Acct 959700 Maintain meters	EXP597	1.000000	0.641591	0.271517	0.058641	0.028251	0.000000	0.000000
24 Acct 959800 Maintain distribution plant	EXP598	1.000000	0.687906	0.121750	0.157385	0.001437	0.030805	0.000718
25 Total Distribution Plant	DISTPLT	1.000000	0.673701	0.123047	0.142553	0.002871	0.057176	0.000652
26 Total Operation & Maintenance Labor	LABOR	1.000000	0.681898	0.144088	0.131883	0.012032	0.029510	0.000589
27 Total General Plant	GENPLT	1.000000	0.681898	0.144088	0.131883	0.012032	0.029510	0.000589
28 Dist O&M Expense	DISTOMEXP	1.000000	0.726360	0.130299	0.108368	0.009099	0.025076	0.000799
29 Taxable Income	TAXINC	1.000000	2.133094	-0.805893	-0.290557	-0.067024	0.038938	-0.008559
30 Acct 364 Poles	PLT364	1.000000	0.705268	0.124838	0.161632	0.000963	0.006563	0.000736
31 Other Taxes	OTHTAX	1.000000	0.712351	0.193669	0.066001	0.005602	0.022005	0.000372
32 Depreciation Reserve	DEPRERES	1.000000	0.675253	0.127030	0.140533	0.004606	0.051939	0.000640
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CONNECTION (16)
0.000727 0.000736 0.000736 0.000736 0.000736 0.000000 0.000000 0.000385 0.000727 0.000736 0.000000 0.000000 0.000000 0.000385 0.000397 0.000727 0.000736 0.000727 0.000736 0.000736 0.000736 0.000736 0.000736 0.000736 0.000736 0.000736 0.000736 0.000736 0.000589 0.000589 0.000589 0.000589 0.000736 0.000736 0.000736 0.000736 0.000736 0.000736 0.000736 0.000736 0.000736 0.000736 0.000736 0.000736

	ALLOC	TOTAL ACE DISTRIBUTION (1)	TOTAL RESIDENTIAL SERVICE (2)	MONTHLY GENERAL SERVICE (3)	ANNUAL GENERAL SERVICE (4)	TRANSM GENERAL SERVICE (5)	STREET LIGHTING SERVICE (6)	DIRECT DISTRIBUTION CONNECTION (7)
RATIO TABLE								
INTERNALLY DEVELOPED CON'T-23 I Distribution Operating Exp Acct 581 - 587 Distribution Maintenance Exp Acct 592 - 597 Distribution Maintenance Exp Acct 591 - 598 Distribution Operating Labor Acct 591 - 598 Total Distribution Maintenance Labor Acct 592 - 598 Total Distribution Maintenance Labor Acct 592 - 598 Acct 990200 Meter reading expenses Acct 990300 Cust records and collection exp Acct 990500 Miscellaneous cust accounts exp Acct 990700 Supervision Acct 990700 Supervision Acct 991000 Misc cust service & informat exp Acct 991200 Demonstrating & selling expenses Acct 991200 Advertising expense Acct 992000 Administrative & General salaries Acct 992100 Office supplies & expenses Acct 993000 Miscellaneous guerral expenses Acct 993500 Maintenance of general plant Total Intangible Plant Service Company Assets Reserve Total System Electric Distribution Accts 902 & 903 Mtr Read & Cust Rec Total Customer Deposits Sales Revenue Required Claimed ROR Residential Distribution Plant Non-Residential Distribution Plant Non-Residential Distribution Plant Non-Residential Distribution Plant	EXPDISTO EXPDISTM LABDO LABDM TLABDM EXP902 EXP903 EXP905 EXP907 EXP908 EXP910 EXP912 EXP913 EXP920 EXP921 EXP923 EXP935 INTPLT SERVCO PLANT EXP9023 CUSTDEP CLAIMREV RESDIST NRESDIST	1.000000 1.000000 1.000000 1.000000 1.000000 1.000000 1.000000 0.000000 0.000000 0.000000 1.000000	0.654233 0.887906 0.666159 0.677125 0.666159 0.677125 0.873920 0.887199 0.000000 0.000000 0.0700000 0.000000 0.000000 0.0881898 0.681898 0.681898 0.681898 0.681898 0.681898 0.681898 0.681898 0.681898 0.681898 0.681898 0.681898 0.681898 0.681898 0.681898 0.68100000000000000000000000000000000000	0.177890 0.121750 0.176735 0.119854 0.176735 0.119854 0.103730 0.092210 0.000000 0.133994 0.000000 0.000000 0.000000 0.144088 0.144088 0.144088 0.144088 0.144088 0.144088 0.144088 0.144088 0.144088 0.145333 0.000000 0.255911 0.129633 0.00377098	0.114609 0.157385 0.119656 0.154618 0.119656 0.154618 0.017146 0.005753 0.000000 0.124658 0.000000 0.000000 0.000000 0.131883 0.131883 0.131883 0.131883 0.131883 0.131883 0.131883 0.131883 0.131883 0.131883 0.131883 0.131883 0.141409 0.007247 0.296480 0.123892 0.000000 0.436877	0.019294 0.001437 0.020865 0.002673 0.020865 0.002673 0.005204 0.004303 0.00000 0.000000 0.059522 0.000000 0.012032 0.003854 0.004421 0.000000 0.006996 0.0000000 0.0068800	0.033577 0.030805 0.016161 0.045023 0.016161 0.045023 0.00000 0.008996 0.000000 0.009196 0.000000 0.00929510 0.0175226	0.000397 0.000718 0.000718 0.000425 0.000706 0.000425 0.000706 0.000000 0.001540 0.000000 0.001787 0.000000 0.000000 0.000089 0.000589

0.014171	0.000397 0.000718 0.000425 0.000706 0.000425 0.000706 0.000000 0.001540 0.000000 0.001787 0.000000 0.000000 0.000000 0.000589
	0.001436

	ALLOC	TOTAL ACE DISTRIBUTION (1)	TOTAL RESIDENTIAL SERVICE (2)	MONTHLY GENERAL SERVICE (3)	ANNUAL GENERAL SERVICE (4)	TRANSM GENERAL SERVICE (5)	STREET LIGHTING SERVICE (6)	DIRECT DISTRIBUTION CONNECTION (7)
ALLOCATION FACTOR TABLE INTERNALLY DEVELOPED CON'T-24 1	CREVRES CREVGSS CREVCOM CREVGSSL CREVGSP CREVLTG CREVGST CREVGST CREVDDC	1.000000 1.000000 1.000000 1.000000 1.000000 1.000000 1.000000 1.000000	1.000000 0.000000 0.000000 0.000000 0.000000	0.000000 1.000000 1.000000 0.000000 0.000000 0.000000 0.000000	0.000000 0.000000 0.000000 1.000000 0.000000 0.000000 0.000000 0.000000	0.000000 0.000000 0.000000 0.000000 0.000000	0.000000 0.000000 0.000000 0.000000 1.000000 0.000000 0.000000 0.000000	0.000000 0.000000 0.000000 0.000000 0.000000
26 27 REVENUE REQUIREMENTS INPUTS 28 29 Current Revenue - Retail Sales ACE 30		1.000000	0.620948	0.180715	0.146720	0.010728	0.039657	0.001233
31 Claimed Rate of Return 32 33 BILLING DETERMINANTS 34 Average Number of Customers (12 Months 35 Total KWH Sales @ Meter 36 Total MWH Sales @ Meter 37 38 39 40 41 42 43 44 45)	1.00000 1.00000 1.00000	0.882304 0.459383 0.459383	0.099855 0.168132 0.168132	0.005320 0.243996 0.243996	0.000091 0.118952 0.118952	0.010559 0.007832 0.007832	0.001871 0.001704 0.001704

	ALLOC	RESIDENTIAL (8)-2	MONTHLY GENERAL SERV SECONDARY (9)	MONTHLY GENERAL SERV PRIMARY (10)	ANNUAL GENERAL SERV SECONDARY (11)	ANNUAL GENERAL SERV PRIMARY (12)	STREET AND PRIVATE LIGHTING (13)	GENERAL SERVICE SUBTRANSMSN (14)	GENERAL SERVICE TRANSMISSION (15)	DIRECT DISTRIBUTION CONNECTION (16)
ALLOCATION FACTOR TABLE										
INTERNALLY DEVELOPED CON'T-24										
Claimed Revenues Claimed Revenues Residential	CREVRES	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
3 Claimed Revenues MGSS	CREVGSS	0.000000	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
4 Claimed Revenues MGSP 5 Claimed Revenues AGSS	CREVCOM CREVGSSL	0.000000 0.000000	0.000000 0.000000	1.000000 0.000000	0.000000 1.000000	0.000000 0.000000	0.000000 0.000000	0.000000 0.000000	0.000000	0.000000 0.000000
6 Claimed Revenues AGSP 7 Claimed Revenues Lighting	CREVGSP CREVLTG	0.000000 0.000000	0.000000 0.000000	0.000000 0.000000	0.000000 0.000000	1.000000 0.000000	0.000000 1.000000	0.000000 0.000000	0.000000 0.000000	0.000000 0.000000
8 Claimed Revenues GSST	CREVGSST	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	1.000000	0.000000	0.000000
9 Claimed Revenues GST 10 Claimed Revenues DDC	CREVGST CREVDDC	0.000000 0.000000	0.000000 0.000000	0.000000 0.000000	0.000000 0.000000	0.000000 0.000000	0.000000 0.000000	0.000000 0.000000	1.000000 0.000000	0.000000 1.00000
11 12										
13										
14 15										
16 17										
18										
19 20										
21										
22 23										
24 25										
26										
27 REVENUE REQUIREMENTS INPUTS 28										
29 Current Revenue - Retail Sales ACE 30		0.620948	0.176966	0.003749	0.120314	0.026406	0.039657	0.006345	0.004383	0.001233
31 Claimed Rate of Return										
32 33 BILLING DETERMINANTS										
 34 Average Number of Customers (12 Months) 35 Total KWH Sales @ Meter)	0.882304 0.459383	0.099585 0.159281	0.000271 0.008851	0.005112 0.181330	0.000207 0.062667	0.010559 0.007832	0.000063 0.062982	0.000028 0.055971	0.001871 0.001704
36 Total MWH Sales @ Meter		0.459383	0.159281	0.008851	0.181330	0.062667	0.007832	0.062982	0.055971	0.001704
37 38										
39										
40 41										
42 43										
44										
45										

	ALLOC	TOTAL ACE DISTRIBUTION (1)	TOTAL RESIDENTIAL SERVICE (2)	MONTHLY GENERAL SERVICE (3)	ANNUAL GENERAL SERVICE (4)	TRANSM GENERAL SERVICE (5)	STREET LIGHTING SERVICE (6)	DIRECT DISTRIBUTION CONNECTION (7)
ALLOCATED DIRECT ASSIGNMENT								
BASED ON CLAIMED REV-25 1 Revenues Residential 2 Revenues MGSS 3 Revenues MGSP 4 Revenues AGSP 6 Revenues AGSP 6 Revenues Lighting 7 Revenues GST 8 Revenues GST 9 Revenues DDC 10 Revenue 11 Revenue 12 13 14 15 16 17 18 19 20	CREVRES CREVGSS CREVCOM CREVGSSL CREVGSP CREVLTG CREVGST CREVGST CREVDDC REVENUES	296,020,547 84,363,933 1,787,281 57,356,426 12,588,416 18,905,207 3,024,915 2,089,427 587,648 476,723,799 1,000000	296,020,547 0 0 0 0 0 0 0 0 296,020,547 0.620948	84,363,933 1,787,281 0 0 0 0 0 0 0 86,151,215 0.180715	0 0 0 57,356,426 12,588,416 0 0 0 0 69,944,842 0.146720	0 0 0 0 0 3,024,915 2,089,427 0 5,114,341 0.010728	0 0 0 0 18,905,207 0 0 18,905,207 0.039657	0 0 0 0 0 0 0 0 587,648 587,648 0.001233

	ALLOC	RESIDENTIAL (8)-2	MONTHLY GENERAL SERV SECONDARY (9)	MONTHLY GENERAL SERV PRIMARY (10)	ANNUAL GENERAL SERV SECONDARY (11)	ANNUAL GENERAL SERV PRIMARY (12)	STREET AND PRIVATE LIGHTING (13)	GENERAL SERVICE SUBTRANSMSN (14)	GENERAL SERVICE TRANSMISSION (15)	DIRECT DISTRIBUTION CONNECTION (16)
ALLOCATED DIRECT ASSIGNMENT										
BASED ON CLAIMED REV-25										
1 Revenues Residential	CREVRES	296,020,547	0	0	0	0	0	0	0	0
2 Revenues MGSS	CREVGSS	0	84,363,933	0	0	0	0	0	0	0
3 Revenues MGSP	CREVCOM	0	0	1,787,281	0	0	0	0	0	0
4 Revenues AGSS	CREVGSSL	0	0	0	57,356,426	0	0	0	0	0
5 Revenues AGSP	CREVGSP	0	0	0	0	12,588,416	0	0	0	0
6 Revenues Lighting	CREVLTG	0	0	0	0	0	18,905,207	0	0	0
7 Revenues GSST	CREVGSST	0	0	0	0	0	0	3,024,915	0	0
8 Revenues GST	CREVGST	0	0	0	0	0	0	0	2,089,427	0
9 Revenues DDC	CREVDDC	0	0	0	0	0	0	0	0	587,648
10 Revenue		296,020,547	84,363,933	1,787,281	57,356,426	12,588,416	18,905,207	3,024,915	2,089,427	587,648
11 Revenue	REVENUES	0.620948	0.176966	0.003749	0.120314	0.026406	0.039657	0.006345	0.004383	0.001233
12										
13										
14										
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17 18										
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		ALLOC	TOTAL ACE DISTRIBUTION (1)	TOTAL RESIDENTIA SERVICE (2)	L GE	ONTHLY ENERAL ERVICE (3)	ANNUAL GENERAL SERVICE (4)	TRANSM GENERAL SERVICE (5)	STREET LIGHTING SERVICE (6)	DIRECT DISTRIBUTION CONNECTION (7)
	ALLOCATED DIRECT ASSIGNMENT									
	BASED ON CLAIMED REV-26									
1	Revenues Residential	CREVRES	0		0	0	0	0	0	0
2	Revenues MGSS	CREVGSS	84,363,933			84,363,933	0	0	0	0
3		CREVCOM	1,787,281		0	1,787,281	0	0	0	0
4		CREVGSSL	57,356,426		0	0	57,356,426	0	0	0
5		CREVGSP	12,588,416		0	0	12,588,416	0	0	0
6		CREVLTG	18,905,207		0	0	0	0	18,905,207	0
7		CREVGSST CREVGST	0		0	0	0	0	0	0
8 9		CREVDDC	587,648		0	0	0	0	0	587,648
10		CKEVDDC	175,588,912			86,151,215	69,944,842	0	18,905,207	587,648
11		LPAY	1.000000	0.0000		0.490642	0.398344	0.000000	0.107667	0.003347
12		LIAI	1.000000	0.0000	00	0.430042	0.530544	0.000000	0.107007	0.003347
13										
14		CREVRES	310.873.893	310,873,8	93	0	0	0	0	0
15		CREVGSS	70.990.209	5.5,5.5,5		70,990,209	0	0	0	0
16		CREVCOM	6,066,967		0	6,066,967	0	0	0	Ö
17	Revenues AGSS	CREVGSSL	34,862,669		0	0	34,862,669	0	0	0
18	Revenues AGSP	CREVGSP	13,714,362		0	0	13,714,362	0	0	0
19		CREVLTG	1,742,122		0	0	0	0	1,742,122	0
20		CREVGSST	23,213,393		0	0	0	23,213,393	0	0
21		CREVGST	9,357,917		0	0	0	9,357,917	0	0
	Revenues DDC	CREVDDC	238,711	0.40.070.6	0	0	0	0	0	238,711
23		DOON!!!OD!/	471,060,244	310,873,8		77,057,176	48,577,031	32,571,311	1,742,122	238,711
24 25		BGSNUGRV	1.000000	0.6599	45	0.163582	0.103123	0.069145	0.003698	0.000507
26										
27		CREVRES	50,097,166	50,097,1	66	0	0	0	0	0
28		CREVGSS	31.201.593	00,001,1		31,201,593	0	0	0	0
29		CREVCOM	359,593		0	359,593	Õ	Õ	Ö	0
30	Revenues AGSS	CREVGSSL	20,294,162		0	0	20,294,162	0	0	0
31	Revenues AGSP	CREVGSP	3,946,311		0	0	3,946,311	0	0	0
32	Revenues Lighting	CREVLTG	6,587,217		0	0	0	0	6,587,217	0
33		CREVGSST	857,051		0	0	0	857,051	0	0
34		CREVGST	868,840		0	0	0	868,840	0	0
	Revenues DDC	CREVDDC	245,093		0	0	0	0	0	245,093
36			114,457,025	50,097,1		31,561,186	24,240,473	1,725,891	6,587,217	245,093
37		NETINC	1.000000	0.4376	94	0.275747	0.211787	0.015079	0.057552	0.002141
38										
39 40										
41										
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45										

	ALLOC	RESIDENTIAL (8)-2	MONTHLY GENERAL SERV SECONDARY (9)	MONTHLY GENERAL SERV PRIMARY (10)	ANNUAL GENERAL SERV SECONDARY (11)	ANNUAL GENERAL SERV PRIMARY (12)	STREET AND PRIVATE LIGHTING (13)	GENERAL SERVICE SUBTRANSMSN (14)	GENERAL SERVICE TRANSMISSION (15)	DIRECT DISTRIBUTION CONNECTION (16)
ALLOCATED DIRECT ASSIGNMENT										
BASED ON CLAIMED REV-26										
1 Revenues Residential	CREVRES	0	0	0	0	0	0	0	0	0
2 Revenues MGSS	CREVGSS	0	84,363,933	0	0	0	0	0	0	0
3 Revenues MGSP	CREVCOM	0	0	1,787,281	0	0	0	0	0	0
4 Revenues AGSS	CREVGSSL	0	0	0	57,356,426	0	0	0	0	0
5 Revenues AGSP	CREVGSP	0	0	0	0	12,588,416	0	0	0	0
6 Revenues Lighting	CREVLTG	0	0	0	0	0	18,905,207	0	0	0
7 Revenues GSST	CREVGSST	0	0	0	0	0	0	0	0	0
8 Revenues GST	CREVGST	0	0	0	0	0	0	0	0	0 587.648
9 Revenues DDC 10 Late Pay Assign Rev W/O Res	CREVDDC	0	84,363,933	1,787,281	57,356,426	12,588,416	18,905,207	0	0	587,648 587.648
10 Late Pay Assign Rev W/O Res 11 Late Pay Assign Rev W/O Res	LPAY	0.000000	0.480463	0.010179	0.326652	0.071693	0.107667	0.000000	0.000000	0.003347
12	LIAI	0.000000	0.400403	0.010173	0.320032	0.07 1033	0.107007	0.000000	0.000000	0.003347
13										
14 Revenues Residential	CREVRES	310,873,893	0	0	0	0	0	0	0	0
15 Revenues MGSS	CREVGSS	0	70,990,209	0	0	0	0	0	0	0
16 Revenues MGSP	CREVCOM	0	0	6,066,967	0	0	0	0	0	0
17 Revenues AGSS	CREVGSSL	0	0	0	34,862,669	0	0	0	0	0
18 Revenues AGSP	CREVGSP	0	0	0	0	13,714,362	0	0	0	0
19 Revenues Lighting	CREVLTG	0	0	0	0	0	1,742,122	0	0	0
20 Revenues GSST	CREVGSST	0	0	0	0	0	0	23,213,393		0
21 Revenues GST	CREVGST	0	0	0	0	0	0	0	9,357,917	0
22 Revenues DDC 23 BGS & NUGS Revenue	CREVDDC	0	70.990.209	0	34.862.669	0	0	0	0 9.357.917	238,711 238,711
24 Revenue BGS & NUGS	BGSNUGRV	310,873,893 0.659945	0.150703	6,066,967 0.012879	0.074009	13,714,362 0.029114	1,742,122 0.003698	23,213,393 0.049279	0.019866	0.000507
25 Revenue BGS & NOGS	BGSNUGRV	0.059945	0.130703	0.012079	0.074009	0.029114	0.003096	0.049279	0.019600	0.000307
26										
27 Revenues Residential	CREVRES	50,097,166	0	0	0	0	0	0	0	0
28 Revenues MGSS	CREVGSS	0	31,201,593	0	0	0	0	0	0	0
29 Revenues MGSP	CREVCOM	0	0	359,593	0	Ō	0	0	0	0
30 Revenues AGSS	CREVGSSL	0	0	0	20,294,162	0	0	0	0	0
31 Revenues AGSP	CREVGSP	0	0	0	0	3,946,311	0	0	0	0
32 Revenues Lighting	CREVLTG	0	0	0	0	0	6,587,217	0	0	0
33 Revenues GSST	CREVGSST	0	0	0	0	0	0	857,051	0	0
34 Revenues GST	CREVGST	0	0	0	0	0	0	0	868,840	0
35 Revenues DDC 36 Net Income	CREVDDC	0 50,097,166	0 31,201,593	0 359,593	0 20,294,162	0 3,946,311	0 6,587,217	0 857,051	0	245,093
37 Net Income	NETINC	0.437694	0.272605	0.003142	0.177308	0.034479	0.057552	0.007488	868,840 0.007591	245,093 0.002141
38	INLTING	0.437094	0.272003	0.003142	0.177300	0.034479	0.037332	0.007400	0.007391	0.002141
39										
40										
41										
42										
43										
44										
45										

		TOTAL ACE	TOTAL RESIDENTIAL	MONTHLY GENERAL	ANNUAL GENERAL	TRANSM GENERAL	STREET LIGHTING	DIRECT DISTRIBUTION
	ALL 00	DISTRIBUTION	SERVICE	SERVICE	SERVICE	SERVICE	SERVICE	CONNECTION
	ALLOC	(1)	(2)	(3)	(4)	(5)	(6)	(7)
ALLOCATED DIRECT ASSIGNMENT								
BASED ON PRIMARY DEMAND-27								
1 MWH Sales @ Meter Residential	DEMPRI	4,032,550	2,726,564	485,487	648,970	143,312	25,374	2,844
2 MWH Sales @ Meter MGSS	DEMPRI	1,398,200	945,377	168,332	225,016	49,690	8,798	986
3 MWH Sales @ Meter MGSP	DEMPRI	77,696	52,533	9,354	12,504	2,761	489	55
4 MWH Sales @ Meter AGSS	DEMPRI	1,591,748	1,076,243	191,634	256,165	56,569	10,016	1,123
5 MWH Sales @ Meter AGSP	DEMPRI	550,099	371,943	66,227	88,529	19,550	3,461	388
6 MWH Sales @ Meter Lighting	DEMPRI	68,753	46,486	8,277	11,065	2,443	433	48
7 MWH Sales @ Meter GSST	DEMPRI	552,866	373,814	66,561	88,974	19,648	3,479	390
8 MWH Sales @ Meter GST	DEMPRI	491,320	332,201	59,151	79,070	17,461	3,092	347
9 MWH Sales @ Meter DDC	DEMPRI	14,955	10,111	1,800	2,407	531	94	11
10 ACE MWH		8,778,187	5,935,272	1,056,824	1,412,698	311,966	55,235	6,192
11 ACE Allocator	SALES	1.000000	0.676139	0.120392	0.160933	0.035539	0.006292	0.000705
12 Sales without Trans		8,778,187	5,935,272	1,056,824	1,412,698	311,966	55,235	6,192
13	SALESWOT	1.000000	0.676139	0.120392	0.160933	0.035539	0.006292	0.000705
14								
15								

	ALLOC	RESIDENTIAL (8)-2	MONTHLY GENERAL SERV SECONDARY (9)	MONTHLY GENERAL SERV PRIMARY (10)	ANNUAL GENERAL SERV SECONDARY (11)	ANNUAL GENERAL SERV PRIMARY (12)	STREET AND PRIVATE LIGHTING (13)	GENERAL SERVICE SUBTRANSMSN (14)	GENERAL SERVICE TRANSMISSION (15)	DIRECT DISTRIBUTION CONNECTION (16)
ALLOCATED DIRECT ASSIGNMENT BASED ON PRIMARY DEMAND-27										
## Sales @ Meter Residential MWH Sales @ Meter MGSS	DEMPRI DEMPRI DEMPRI DEMPRI DEMPRI DEMPRI DEMPRI DEMPRI SALES SALESWOT	2,726,564 945,377 52,533 1,076,243 371,943 46,486 373,814 332,201 10,111 5,935,272 0.676139 5,935,272 0.676139	468,031 162,280 9,018 184,744 63,846 7,980 64,168 57,024 1,736 0.116063 1,018,826 0.116063	17,455 6,052 336 6,890 2,381 298 2,393 2,127 65 37,997 0.004329 37,997 0.004329	501,998 174,057 9,672 198,151 68,480 8,559 68,824 61,163 1,862 1,092,766 0.124487 1,092,766 0.124487	146,972 50,959 2,832 58,013 20,049 2,506 20,150 17,907 545 319,932 0.036446 319,932 0.036446	25,374 8,798 489 10,016 3,461 433 3,479 3,092 94 55,235 0.006292 55,235 0.006292	143,312 49,690 2,761 56,569 19,550 2,443 19,648 17,461 531 311,966 0.035539 311,966 0.035539	0 0 0 0 0 0 0 0 0.000000 0 0.000000	2,844 986 55 1,123 388 48 390 347 11 6,192 0.000705 6,192 0.000705

ATLANTIC CITY ELECTRIC ACE RETAIL COST OF SERVICE STUDY 12 MONTHS ENDED SEPTEMBER 30, 2022 ELECTRIC DISTRIBUTION

		ALLOC	TOTAL ACE DISTRIBUTION (1)	TOTAL RESIDENTIAL SERVICE (2)	MONTHLY GENERAL SERVICE (3)	ANNUAL GENERAL SERVICE (4)	TRANSM GENERAL SERVICE (5)	STREET LIGHTING SERVICE (6)	DIRECT DISTRIBUTION CONNECTION (7)
	REVENUE REQUIREMENTS-28								
	Present Rates								
1 2 3 4 5 6 7	Rate Base Net Operating Income (Present Rates) Rate of Return (Present Rates) Relative Rate of Return Sales Revenue (Present Rates) Revenue Present Rates \$/KWH Revenue Required - \$/Mo/Customer		1,952,245,281 114,457,025 5.86% 1.00 476,723,799 \$0.0543 \$69.84	1,317,062,831 50,097,166 3.80% 0.65 296,020,547 \$0.0734 \$49.15	242,834,561 31,561,186 13.00% 2.22 86,151,215 \$0.0584 \$126.40	273,567,120 24,240,473 8.86% 1.51 69,944,842 \$0.0327 \$1,926.22	8,749,397 1,725,891 19.73% 3.36 5,114,341 \$0.0049 \$8,196.06	108,723,819 6,587,217 6.06% 1.03 18,905,207 \$0.2750 \$262.31	1,307,554 245,093 18.74% 3.20 587,648 \$0.0393 \$46.03
	Claimed Rate of Return								
8 9 10 11 12 13 14 15	Claimed Rate of Return Return Required Claimed Rate of Return Sales Revenue Required Claimed ROR Revenue Deficiency Sales Revenue Percent Increase Required Annual Booked KWH Sales Sales Revenue Required \$KWH Revenue Deficiency \$/KWH		7.13% 139,195,089 511,238,818 34,515,019 7.24% 8,778,187,173 \$0,0582 \$0,0039	7.13% 93,906,580 357,144,278 61,123,732 20.65% 4,032,550,392 \$0.0886 \$0.0152	7.13% 17,314,104 66,273,414 (19,877,801) -23.07% 1,475,895,885 \$0.0449 (\$0.0135)	7.13% 19,505,336 63,338,288 (6,606,554) -9.45% 2,141,846,944 \$0.0296 (\$0.0031)	7.13% 623,832 3,576,728 (1,537,613) -30.06% 1,044,186,603 \$0.0034 (\$0.0015)	7.13% 7,752,008 20,530,346 1,625,139 8.60% 68,752,713 \$0.2986 \$0.0236	7.13% 93,229 375,764 (211,884) -36.06% 14,954,636 \$0.0251 (\$0.0142)

ATLANTIC CITY ELECTRIC

BPU Assessment	0.2483%
Ratepayer Advocate Assessment	0.0531%
STATE TAX RATE	9.00%
FEDERAL TAX RATE - CURRENT	21.00%
EFFECTIVE STATE TAX RATE	8.9729%
1 - INCREMENTAL TAX RATE	0.7167
INCREMENTAL TAX RATE	0.2833
EFFECTIVE INCREMENTAL FEDERAL RATE	0.1905
FACTOR FOR TAXABLE BASIS	1.3952

ATLANTIC CITY ELECTRIC ACE RETAIL COST OF SERVICE STUDY 12 MONTHS ENDED SEPTEMBER 30, 2022 ELECTRIC DISTRIBUTION

		ALLOC	RESIDENTIAL (8)-2	MONTHLY GENERAL SERV SECONDARY (9)	MONTHLY GENERAL SERV PRIMARY (10)	ANNUAL GENERAL SERV SECONDARY (11)	ANNUAL GENERAL SERV PRIMARY (12)	STREET AND PRIVATE LIGHTING (13)	GENERAL SERVICE SUBTRANSMSN (14)	GENERAL SERVICE TRANSMISSION (15)	DIRECT DISTRIBUTION CONNECTION (16)
	REVENUE REQUIREMENTS-28										
	Present Rates										
1 2 3 4 5 6 7	Rate Base Net Operating Income (Present Rates) Rate of Return (Present Rates) Relative Rate of Return Sales Revenue (Present Rates) Revenue Present Rates) Revenue Required - \$/Mo/Customer		1,317,062,831 50,097,166 3.80% 0.65 296,020,547 \$0,0734 \$49.15	236,788,522 31,201,593 13.18% 2.25 84,363,933 \$0.0603 \$124.11	6,046,039 359,593 5.95% 1.01 1,787,281 \$0.0230 \$967.14	232,126,412 20,294,162 8.74% 1.49 57,356,426 \$0.0360 \$1,643.64	41,440,708 3,946,311 9.52% 1.62 12,588,416 \$0.0229 \$8,890.12	108,723,819 6,587,217 6.06% 1.03 18,905,207 \$0,2750 \$262.31	6,893,125 857,051 12.43% 2.12 3,024,915 \$0,0055 \$7,002.12	1,856,273 868,840 46.81% 7.98 2,089,427 \$0.0043 \$10,882.43	1,307,554 245,093 18.74% 3.20 587,648 \$0.0393 \$46.03
	Claimed Rate of Return										
8 9 10 11 12 13 14 15	Claimed Rate of Return Return Required Claimed Rate of Return Sales Revenue Required Claimed ROR Revenue Deficiency Sales Revenue Percent Increase Required Annual Booked KWH Sales Sales Revenue Required \$/KWH Revenue Deficiency \$/KWH		7.13% 93,906,580 357,144,278 61,123,732 20.65% 4,032,550,392 \$0.0886 \$0.0152	7.13% 16,883,022 64,386,389 (19,977,544) -23.68% 1,398,199,951 \$0.0460 (\$0.0143)	7.13% 431,083 1,887,025 99,744 5.58% 77,695,934 \$0.0243 \$0.0013	7.13% 16,550,613 52,133,356 (5,223,070) -9.11% 1,591,748,317 \$0.0328 (\$0.0033)	2,954,722 11,204,932 (1,383,483) -10.99% 550,098,627 \$0.0204	7.13% 7,752,008 20,530,346 1,625,139 8.60% 68,752,713 \$0.2986 \$0.0236	7.13% 491,480 2,514,863 (510,052) -16.86% 552,866,415 \$0.0045 (\$0.0009)	7.13% 132,352 1,061,865 (1,027,561) -49.18% 491,320,188 \$0.0022 (\$0.0021)	7.13% 93,229 375,764 (211,884) -36.06% 14,954,636 \$0.0251 (\$0.0142)

ATLANTIC CITY ELECTRIC
BPU Assessment BPU Assessment
Ratepayer Advocate Assessment
STATE TAX RATE
FEDERAL TAX RATE - CURRENT
EFFECTIVE STATE TAX RATE
1 - INCREMENTAL TAX RATE
INCREMENTAL TAX RATE
EFFECTIVE INCREMENTAL FEDERAL RATE
FACTOR FOR TAXABLE BASIS

Schedule (JLM)-2

ATLANTIC CITY ELECTRIC ACE RETAIL COST OF SERVICE STUDY 12 MONTHS ENDED SEPTEMBER 30, 2022 ELECTRIC DISTRIBUTION

Schedule	(JLM)-2
Page	1 of 4

	TOTAL ACE DISTRIBUTION (1)	RESIDENTIAL (8)-2	MONTHLY GENERAL SERV SECONDARY (9)	MONTHLY GENERAL SERV PRIMARY (10)	ANNUAL GENERAL SERV SECONDARY (11)	ANNUAL GENERAL SERV PRIMARY (12)	STREET AND PRIVATE LIGHTING (13)	GENERAL SERVICE SUBTRANSMSN (14)	GENERAL SERVICE TRANSMISSION (15)	DIRECT DISTRIBUTION CONNECTION (16)
PRESENT RATE OF RETURN SUMMARY SCHEDULE										
RATE OF RETURN	5.86%	3.80%	13.18%	5.95%	8.74%	9.52%	6.06%	12.43%	46.81%	18.74%
REVENUES REQUIRED										
1 DEMAND DISTRIBUTION 331,719,929 2 DEMAND DISTRIBUTION PRIMARY 3 DEMAND DISTRIBUTION SECONDARY 4 DEMAND DISTRIBUTION TRANSFORMERS 5 CUSTOMER COMPONENTS 145,003,877 6 CUSTOMER METERS COMPONENT 7 CUSTOMER SERVICES COMPONENT	331,719,927 248,483,582 37,676,361 45,559,984 145,003,872 38,959,991 20,108,313	200,795,722 151,095,496 24,495,885 25,204,341 95,224,824 22,463,900 11,901,305	61,834,456 43,544,932 6,898,289 11,391,235 22,529,478 11,575,793 4,597,693	1,125,321 1,125,321 0 661,961 554,405	51,776,713 37,290,705 5,955,361 8,530,648 5,579,713 1,454,045 3,590,889	11,437,024 11,437,024 0 0 1,151,392 902,511 0	2,329,219 1,713,741 275,729 339,749 16,575,988 0	1,951,585 1,951,585 0 0 1,073,329 735,554 0	0 0 0 0 2,089,427 1,273,783 0	469,888 324,779 51,097 94,012 117,760 0 18,426
8 CUSTOMER 902-METER READING COMPONENT 9 CUSTOMER 903-CUST REC & COLLECT COMP 10 CUSTOMER SERVICE EXPENSE COMP 11 CUSTOMER OTHER COMPONENT 12 TOTAL ACE DISTRIBUTION	11,612,447 52,334,702 7,955,295 14,033,123 476,723,799	10,060,618 46,106,421 5,153,322 (460,741) 296,020,547	1,214,870 4,984,667 1,054,678 (898,224) 84,363,933	51,898 29,416 35,758 (9,517) 1,787,281	121,578 272,125 728,936 (587,859) 57,356,426	80,399 30,261 248,467 (110,245) 12,588,416	466,529 70,717 16,038,742 18,905,207	41,539 13,743 281,324 1,168 3,024,915	41,544 347,014 367,284 59,802 2,089,427	(0) 84,526 14,809 (1) 587,648
13 AVG. NUMBER OF CUSTOMER 14 CUSTOMER \$/MONTH/CUSTOMER	568,813 \$21.24	501,866 \$15.81	56,645 \$33.14	154 \$358.20	2,908 \$159.90	118 \$813.13	6,006 \$229.99		16 \$10,882.43	

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	TOTAL ACE DISTRIBUTION (1)	RESIDENTIAL (8)-2	MONTHLY GENERAL SERV SECONDARY (9)	MONTHLY GENERAL SERV PRIMARY (10)	ANNUAL GENERAL SERV SECONDARY (11)	ANNUAL GENERAL SERV PRIMARY (12)	STREET AND PRIVATE LIGHTING (13)	GENERAL SERVICE SUBTRANSMSN (14)	GENERAL SERVICE TRANSMISSION (15)	DIRECT DISTRIBUTION CONNECTION (16)
PRESENT RATE OF RETURN SUMMARY SCHEDULE										
RATE OF RETURN	5.86%	3.80%	13.18%	5.95%	8.74%	9.52%	6.06%	12.43%	46.81%	18.74%
\$/KWH										
1 DEMAND DISTRIBUTION 2 DEMAND DISTRIBUTION PRIMARY 3 DEMAND DISTRIBUTION PRIMARY 4 DEMAND DISTRIBUTION SECONDARY 5 CUSTOMER COMPONENTS 6 CUSTOMER METERS COMPONENT 7 CUSTOMER SERVICES COMPONENT 8 ACCT 902 - METER READING COMP 9 ACCT 903 - CUST RECORDS & COLL COMP 10 CUSTOMER SERVICES EXP COMP 11 CUSTOMER OTHER COMPONENT	\$0.0378 \$0.0283 \$0.0043 \$0.0052 \$0.0165 \$0.0044 \$0.0023 \$0.0013 \$0.0060 \$0.0009	\$0.0498 \$0.0375 \$0.0061 \$0.0063 \$0.0236 \$0.0056 \$0.0030 \$0.0025 \$0.0114 \$0.0013	\$0.0442 \$0.0311 \$0.0049 \$0.0081 \$0.0161 \$0.0083 \$0.0033 \$0.0009 \$0.0036 \$0.0008	\$0.0145 \$0.0000 \$0.0000 \$0.0005 \$0.0005 \$0.0007 \$0.0000 \$0.0007 \$0.0004 \$0.0005 -\$0.0001	\$0.0325 \$0.0234 \$0.0037 \$0.0054 \$0.0035 \$0.0009 \$0.0023 \$0.0001 \$0.0002 \$0.0005 -\$0.0004	\$0.0208 \$0.0208 \$0.0000 \$0.0000 \$0.0021 \$0.0016 \$0.0001 \$0.0001 \$0.0001 \$0.0001	\$0.0339 \$0.0249 \$0.0040 \$0.0449 \$0.2411 \$0.0000 \$0.0000 \$0.0000 \$0.0000 \$0.0010 \$0.2333	\$0.0035 \$0.0000 \$0.0000 \$0.0019 \$0.0013 \$0.0000 \$0.0001 \$0.0000	\$0.0000 \$0.0000 \$0.0000 \$0.0000 \$0.0026 \$0.0000 \$0.0001 \$0.0007 \$0.0007	\$0.0217 \$0.0034 \$0.0063 \$0.0079 \$0.0000 \$0.0012 \$0.0000 \$0.0057 \$0.0010
12 TOTAL ACE DISTRIBUTION	\$0.0543	\$0.0734	\$0.0603	\$0.0230	\$0.0360	\$0.0229	\$0.2750	\$0.0055	\$0.0043	\$0.0393

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ATLANTIC CITY ELECTRIC ACE RETAIL COST OF SERVICE STUDY 12 MONTHS ENDED SEPTEMBER 30, 2022 ELECTRIC DISTRIBUTION

Schedule	(JLM)-2
Page	3 of 4

			TOTAL ACE DISTRIBUTION (1)	RESIDENTIAL (8)-2	MONTHLY GENERAL SERV SECONDARY (9)	MONTHLY GENERAL SERV PRIMARY (10)	ANNUAL GENERAL SERV SECONDARY (11)	ANNUAL GENERAL SERV PRIMARY (12)	STREET AND PRIVATE LIGHTING (13)	GENERAL SERVICE SUBTRANSMSN (14)	GENERAL SERVICE TRANSMISSION (15)	DIRECT DISTRIBUTION CONNECTION (16)
CLAIMED R	RATE OF RETURN SUMMARY	SCHEDULE										
RATE OF R	ETURN		7.13%	7.13%	7.13%	7.13%	7.13%	7.13%	7.13%	7.13%	7.13%	7.13%
REVENUES	S REQUIRED											
1 DEMAND D	DISTRIBUTION	361,760,367	361,760,365	254,371,667	44,798,120	1,206,825	46,944,704	10,079,345	2,514,930	1,573,144	0	271,631
2 DEMANI	D DISTRIBUTION PRIMARY		267,120,471	185,437,821	32,601,658	1,206,825	34,191,541	10,079,345	1,832,658	1,573,144	0	197,480
3 DEMAND	D DISTRIBUTION SECONDARY	Y	40,773,738	29,740,732	5,225,549	0	5,481,932	0	293,883	0	0	31,642
4 DEMAND	D DISTRIBUTION TRANSFORM	MERS	53,866,155	39,193,114	6,970,912	0	7,271,231	0	388,389	0	0	42,509
5 CUSTOMER	R COMPONENTS	149,478,458	149,478,453	102,661,851	19,569,250	679,690	5,168,264	1,121,301	18,171,102	941,112	1,061,865	104,017
6 CUSTON	MER METERS COMPONENT		38,541,525	24,550,338	9,994,053	573,121	1,395,454	848,948	0	625,913	553,699	0
7 CUSTON	MER SERVICES COMPONENT	•	23,090,796	16,943,396	3,001,553	0	3,136,716	0	0	0	0	9,131
8 CUSTON	MER 902-METER READING CC	DMPONENT	11,710,505	10,217,203	1,175,480	52,335	120,618	79,370	0	38,767	26,734	(0)
9 CUSTON	MER 903-CUST REC & COLLEC	CT COMP	52,562,528	46,569,679	4,868,653	29,607	270,684	29,988	467,915	12,923	232,116	80,962
10 CUSTON	MER SERVICE EXPENSE COM	ΛΡ	7,841,843	5,230,273	1,021,572	36,051	723,397	245,394	71,047	262,772	237,373	13,963
11 CUSTON	MER OTHER COMPONENT		15,731,255	(849,039)	(492,060)	(11,424)	(478,605)	(82,399)	17,632,140	737	11,944	(39)
12 TOTAL ACE	DISTRIBUTION		511,238,818 511,238,818	357,144,278	64,386,389	1,887,025	52,133,356	11,204,932	20,530,346	2,514,863	1,061,865	375,764
13 AVG. NUME	BER OF CUSTOMER		568,813	501,866	56,645	154	2,908	118	6,006	36	16	1,064
14 CUSTOMER	R \$/MONTH/CUSTOMER		\$21.90	\$17.05	\$28.79	\$367.80	\$148.10	\$791.88	\$252.12		\$5,530.55	

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	TOTAL ACE DISTRIBUTION (1)	RESIDENTIAL (8)-2	MONTHLY GENERAL SERV SECONDARY (9)	MONTHLY GENERAL SERV PRIMARY (10)	ANNUAL GENERAL SERV SECONDARY (11)	ANNUAL GENERAL SERV PRIMARY (12)	STREET AND PRIVATE LIGHTING (13)	GENERAL SERVICE SUBTRANSMSN (14)	GENERAL SERVICE TRANSMISSION (15)	DIRECT DISTRIBUTION CONNECTION (16)
CLAIMED RATE OF RETURN SUMMARY SCHEDULE										
RATE OF RETURN	7.13%	7.13%	7.13%	7.13%	7.13%	7.13%	7.13%	7.13%	7.13%	7.13%
Average Number of Customers (12 Months) \$/MONTH/CUSTOMER	568,813 \$21.90	501,866 \$17.05	56,645 \$28.79	154 \$367.80	2,908 \$148.10	118 \$791.88	6,006 \$252.12		16 \$5,530.55	
\$/KWH										
1 DEMAND DISTRIBUTION 2 DEMAND DISTRIBUTION PRIMARY 3 DEMAND DISTRIBUTION SECONDARY 4 DEMAND DISTRIBUTION TRANSFORMERS 5 CUSTOMER COMPONENTS 6 CUSTOMER METERS COMPONENT 7 CUSTOMER SERVICES COMPONENT 8 ACCT 902 - METER READING COMP 9 ACCT 903 - CUST RECORDS & COLL COMP 10 CUSTOMER SERVICES EXP COMP 11 CUSTOMER OTHER COMPONENT	0.0412 0.0304 0.0046 0.0061 0.0170 0.0044 0.0026 0.0013 0.0060 0.0009	0.0631 0.0460 0.0074 0.0097 0.0255 0.0061 0.0042 0.0025 0.0115 0.0013 (0.0002)	0.0320 0.0233 0.0037 0.0050 0.0140 0.0071 0.0021 0.0008 0.0035 0.0007 (0.0004)	0.0155 0.0155 0.0000 0.0000 0.0087 0.0074 0.0000 0.0007 0.0004 0.0005 (0.0001)	0.0295 0.0215 0.0034 0.0046 0.0032 0.0009 0.0020 0.0001 0.0002 0.0005 (0.0003)	0.0183 0.0183 0.0000 0.0000 0.0020 0.0015 0.0000 0.0001 0.0001 0.0004 (0.0001)	0.0366 0.0267 0.0043 0.0056 0.2643 0.0000 0.0000 0.0000 0.0000 0.0068 0.0010 0.2565	0.0028 0.0028 0.0000 0.0000 0.0017 0.0011 0.0000 0.0001 0.0000 0.0005 0.0000	0.0000 0.0000 0.0000 0.0000 0.0022 0.0011 0.0000 0.0001 0.0005 0.0005	0.0182 0.0132 0.0021 0.0028 0.0070 0.0000 0.0006 0.0000 0.0054 0.0009 (0.0000)
12 TOTAL ACE DISTRIBUTION	0.0582	0.0886	0.0460	0.0243	0.0328	0.0204	0.2986	0.0045	0.0022	0.0251

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Schedule (JLM)-3

Atlantic City Electric Company Customer Class Rate of Return & Relative Rate of Return

(1)	(2)		(3)			
Line No.		Customer Class Rate of Return - %				
	Customer Class	Rate of Return	Relative Rate of Return			
1	Residential	3.80	0.65			
2	Monthly General Service Secondary	13.18	2.25			
3	Monthly General Service Primary	5.95	1.01			
4	Annual General Service Secondary	8.74	1.49			
5	Annual General Service Primary	9.52	1.62			
6	General Service Subtransmission	12.43	2.12			
7	General Service Transmission	46.81	7.98			
8	Street and Private Lighting	6.06	1.03			
9	Direct Distribution Connection	18.74	3.20			
	Total Company	5.86	1.00			

Schedule (JLM)-4

ATLANTIC CITY ELECTRIC COMPANY DESCRIPTION OF ALLOCATORS

Demand Related Allocators

1.	DEMPRI	Distribution Primary system-related allocator based on Class Maximum Diversified Demand (Class MDD).
2.	DPRITGSS	Distribution Primary system-related allocator based on Class MDD. Excluding General Service Subtransmission and General Service Transmission.
3.	DEMSEC	Distribution Secondary-related allocator based on a Class MDD. Excluding Monthly General Service Primary (MGSP), Annual General Service Primary (AGSP), General Service Subtransmission (GSST), and General Service Transmission (GST).
3.	DEMTRNSF	Distribution Secondary-related allocator for Line Transformers based on Class MDD. Excluding MGSP, AGSP, GSST, and GST.
Custo	mer Related Allocato	ars

Customer Related Allocators

1.	CUST369	Customer-related allocator for Account 369 Services based on Class MDD. Excluded MGSP, AGSP, Street Lighting, GSST, and GST.
2.	CUST370	Customer-related direct assignment allocator for Account 370- Meters.
3.	CUST371	Customer-related direct assignment allocator for Account 370.1 AMI meters.
4.	CUST902	Customer-related direct assignment allocator for Account 902- Meter Reading Expenses.
5.	CUST903	Customer-related direct assignment allocator for Account 903- Customer Records and Collection Expense.
6.	CSERV	Customer-related allocator that was weighted 50% on the number of customers and 50% on MWH Sales at the Meter.
7.	CSALES	Customer-related allocator that was weighted 50% on the number of customers and 50% on MWH Sales at the Meter.

Customer Related - Continued

8.	CUST3711P	Customer-related allocator for assigning Account 371- Installations on Customer Premises to the rate classes.
9.	CUST372	Customer-related allocator for assigning Account 372- Leased Property on Customer Premises to the rate classes.
10.	CUST373	Customer-related allocator for assigning Account 373- Street Lighting and Signal Systems to the Street Lighting class.
11.	CUSTDEP	Customer-related allocator for assigning Customer Deposits to the rate classes.

Miscellaneous Other Allocators

12. BGSNUGR Revenue-related allocator based on Basic Generation Service (BGS) and NUG revenues.

Schedule (JLM)-5

		ALLOC	TOTAL ACE DISTRIBUTION (1)	TOTAL RESIDENTIAL SERVICE (2)	MONTHLY GENERAL SERVICE (3)	ANNUAL GENERAL SERVICE (4)	TRANSM GENERAL SERVICE (5)	STREET LIGHTING SERVICE (6)	DIRECT DISTRIBUTION CONNECTION (7)
	SUMMARY OF RESULTS-1								
	RATE BASE								
1	Total System Electric Distribution		3,257,924,573	2,147,200,545	416,341,531	506,946,756	15,012,966	168,675,627	3,747,149
2	Less: Depreciation Reserve		841,929,265	555,724,702	108,990,893	130,031,208	4,497,242	41,734,183	951,038
3	Total Net Plant		2,415,995,308	1,591,475,843	307,350,638	376,915,548	10,515,724	126,941,444	2,796,111
	ADD:								
4	Working Capital		113,732,356	73,410,416	18,393,985	15,215,037	3,082,871	3,517,272	112,775
5	Plant Held for Future Use		6,390,756	4,237,004	858,663	965,111	47,989	275,159	6,830
6	Materials & Supplies DEDUCT:		31,908,733	20,988,773	4,008,506	5,013,492	116,460	1,743,944	37,558
7	Customer Advances		9,971,369	6.558.919	1,252,644	1,566,699	36,393	544,976	11,737
8	Customer Deposits		18,982,828	8,496,886	4,658,942	5,827,000	0	0	0
9	Deferred FIT		450,109,122	297,770,810	59,393,020	68,731,076	2,901,163	20,818,548	494,505
10	Deferred SIT		136,718,553	90,091,731	17,445,983	21,291,976	618,639	7,112,657	157,568
11	TOTAL RATE BASE		1,952,245,281	1,287,193,690	247,861,203	300,692,437	10,206,849	104,001,638	2,289,464
	DEVELOPMENT OF RETURN								
12	Revenue - Retail Sales		476,723,799	296,020,547	86,151,215	69,944,842	5,114,341	18,905,207	587,648
13	Settlement Net Base Revenue Increase		0	0	0	0	0	0	0
14	Total Revenue - Retail Sales ACE		476,723,799	296,020,547	86,151,215	69,944,842	5,114,341	18,905,207	587,648
15	Other Operating Revenue		8,680,898	5,839,049	1,172,898	1,517,572	27,938	112,687	10,753
16	Total Electric Operating Revenue		485,404,697	301,859,596	87,324,113	71,462,414	5,142,279	19,017,894	598,402
	LESS:		054 000 447	470.050.440	00 107 010	00.074.750		5 000 470	070.540
17	Operating & Maintenance Expense		251,338,447	179,958,110	33,137,213	29,671,750	2,375,651	5,922,178	273,543
18	Depreciation & Amortization Expense		116,008,720	76,594,089	15,053,371	17,892,014	635,402	5,703,242	130,602
19	Other Taxes		5,484,499 (154,673)	3,860,790 (101,710)	1,069,218	404,307	32,927	113,832 (8,520)	3,426 (183)
20 21	Net ITC Adjustment Interest on Customer Deposits		41,011	18.357	(19,381) 10,065	(24,337) 12,589	(543) 0	(8,520)	(163)
22	Income Taxes		(1,770,331)	(10,989,703)		1,516,445	466,551	340,891	16,346
23	Total Operating Expenses		370,947,672	249,339,933	56,129,626	49,472,767	3,509,988	12,071,624	423,734
24	OPERATING INCOME		114,457,025	52,519,663	31,194,487	21,989,646	1,632,291	6,946,271	174,667
25	RATE OF RETURN		5.86%	4.08%	12.59%	7.31%	15.99%	6.68%	7.63%
26	RELATIVE RATE OF RETURN		1.00	0.70	2.15	1.25	2.73	1.14	1.30

		ALLOC	RESIDENTIAL (8)-2	MONTHLY GENERAL SERV SECONDARY (9)	MONTHLY GENERAL SERV PRIMARY (10)	ANNUAL GENERAL SERV SECONDARY (11)	ANNUAL GENERAL SERV PRIMARY (12)	STREET AND PRIVATE LIGHTING (13)	GENERAL SERVICE SUBTRANSMSN (14)	GENERAL SERVICE TRANSMISSION (15)	DIRECT DISTRIBUTION CONNECTION (16)
	SUMMARY OF RESULTS-1										
	RATE BASE										
1	Total System Electric Distribution		2,147,200,545	403,365,799	12,975,732	415,517,792	91,428,964	168,675,627	12,714,272	2,298,694	3,747,149
2	Less: Depreciation Reserve		555,724,702	105,466,231	3,524,662	105,981,588	24,049,619	41,734,183	3,734,550	762,691	951,038
3	Total Net Plant		1,591,475,843	297,899,569	9,451,070	309,536,203	67,379,345	126,941,444	8,979,722	1,536,002	2,796,111
	ADD:										
4	Working Capital		73,410,416	17,644,937	749,048	12,094,319	3,120,718	3,517,272	2,145,106	937,765	112,775
5 6	Plant Held for Future Use		4,237,004	828,063	30,599	773,092	192,019	275,159	38,416	9,572	6,830
ь	Materials & Supplies DEDUCT:		20,988,773	3,889,908	118,598	4,138,921	874,570	1,743,944	102,298	14,162	37,558
7	Customer Advances		6.558.919	1,215,583	37.062	1,293,399	273,300	544,976	31,968	4,426	11,737
8	Customer Deposits		8,496,886	4,521,099	137,843	4,810,518	1,016,482	0	0	0	0
9	Deferred FIT		297,770,810	57,370,760	2,022,260	55,534,139	13,196,937	20,818,548	2,357,716	543,447	494,505
10	Deferred SIT		90,091,731	16,904,616	541,367	17,462,944	3,829,032	7,112,657	525,282	93,357	157,568
11	TOTAL RATE BASE		1,287,193,690	240,250,419	7,610,785	247,441,535	53,250,902	104,001,638	8,350,576	1,856,273	2,289,464
	DEVELOPMENT OF RETURN										
12	Revenue - Retail Sales		296,020,547	84,363,933	1,787,281	57,356,426	12,588,416	18,905,207	3,024,915	2,089,427	587,648
13	Settlement Net Base Revenue Increase		0	0	0	0	0	0	0	0	0
14	Total Revenue - Retail Sales ACE		296,020,547	84,363,933	1,787,281	57,356,426	12,588,416	18,905,207	3,024,915	2,089,427	587,648
15	Other Operating Revenue		5,839,049	1,127,791	45,107	1,174,358	343,214	112,687	23,822	4,116	10,753
16	Total Electric Operating Revenue		301,859,596	85,491,725	1,832,388	58,530,784	12,931,629	19,017,894	3,048,737	2,093,542	598,402
	LESS:										
17	Operating & Maintenance Expense		179,958,110	31,908,445	1,228,769	22,751,162	6,920,588	5,922,178	1,603,996	771,655	273,543
18	Depreciation & Amortization Expense		76,594,089	14,563,344	490,027	14,567,485	3,324,529	5,703,242	526,015	109,387	130,602
19	Other Taxes		3,860,790	1,050,761	18,457	295,986	108,320	113,832	26,041	6,886	3,426
20 21	Net ITC Adjustment		(101,710)	(18,812)	(569) 298	(20,113)	(4,224)	(8,520)	(480)	(63)	(183)
22	Interest on Customer Deposits Income Taxes		18,357 (10,989,703)	9,768 6,991,922	(112,783)	10,393 1,739,851	2,196 (223,407)	0 340,891	0 129,714	336,838	16,346
22	income raxes		(10,303,703)	0,331,322	(112,700)	1,700,001	(225,407)	340,031	123,7 14	330,030	10,540
23	Total Operating Expenses		249,339,933	54,505,428	1,624,198	39,344,765	10,128,003	12,071,624	2,285,286	1,224,703	423,734
24	OPERATING INCOME		52,519,663	30,986,297	208,190	19,186,020	2,803,627	6,946,271	763,451	868,840	174,667
25			4.08%	12.90%	2.74%		5.26%	6.68%	9.14%	46.81%	7.63%
26	RELATIVE RATE OF RETURN		0.70	2.20	0.47	1.32	0.90	1.14	1.56	7.98	1.30

		ALLOC	TOTAL ACE DISTRIBUTION (1)	SER'	ENTIAL	MONTHLY GENERAL SERVICE (3)	ANNUAL GENERAL SERVICE (4)	TRANSM GENERAL SERVICE (5)	STREET LIGHTING SERVICE (6)	DIRECT DISTRIBUTION CONNECTION (7)
	DEVELOPMENT OF RATE BASE-2									
	ELECTRIC PLANT IN SERVICE									
	DISTRIBUTION PLANT Distribution - ACE									
	3601 Land and Land Rights									
1	Substations 23/34.5 kV	_PLT362	113,404		76,513	14,394	21,066	888	402	142
2	Substations Remainder	DPRITGSSS	10,152,293	6,	905,708	1,298,065	1,899,581	0	36,164	12,775
3	Lines 23/34.5 KV	_PLT3647	1,186,005		813,501	151,329	211,773	3,650	4,249	1,503
4	Lines Remainder	DPRITGSSS	26,240,962		849,407	3,355,150	4,909,910	0	93,474	33,021
5	Total Acct 3601		37,692,664	25,	645,129	4,818,938	7,042,330	4,538	134,288	47,442
6	3610 Structures and Improvements	DE140010	. =00 044			501015	055 400	222.224	40.400	
7	23/34.5 KV	DEMPRIS	4,789,911		090,547	584,047	855,128	238,004	16,430	5,755
8	Remainder	DPRITGSSS	43,161,870		359,204	5,518,646	8,075,957	0	153,749	54,314
9 10	Total Acct 3610		47,951,780	32,	449,751	6,102,692	8,931,085	238,004	170,178	60,069
10	3620 Station Equipment 23/34.5 KV	DEMPRIS	79,894,280	51	549,399	9,741,723	14,263,278	3,969,841	274,041	95.997
12	Remainder	DPRITGSSS	427.161.194		559.999	54.616.522	79.925.533	3,909,041	1.521.607	537.532
13	Total Acct 3620	DENIIGGGG	507,055,474		109,399	64,358,246	94,188,811	3,969,841	1,795,648	633,529
14	3640 Poles, Towers and Fixtures		001,000,414	042,	100,000	04,000,240	04,100,011	0,000,041	1,700,040	000,020
15	Demand Primary 23/34.5 KV	DEMPRIS	9,736,513	6.	282,194	1,187,199	1,738,229	483,794	33,397	11,699
16	Demand Primary Remainder	DPRITGSSS	292,779,615	·	152.090	37,434,591	54,781,584	0	1,042,921	368,429
17	Secondary	DEMSECS	56,768,834		972,997	7,289,358	8,220,516	Ō	210,753	75,211
18	Total Acct 3640		359,284,962		407,282	45,911,147	64,740,329	483,794	1,287,071	455,338
19	3650 Overhead Conductors and Devices									
20	Demand Primary 23/34.5 KV	DEMPRIS	9,598,114	6,	192,897	1,170,324	1,713,522	476,918	32,922	11,533
21	Demand Primary Remainder	DPRITGSSS	501,893,232		393,598	64,171,707	93,908,540	0	1,787,813	631,574
22	Secondary	DEMSECS	95,984,196		276,747	12,324,775	13,899,168	0	356,339	127,165
23	Total Acct 3650		607,475,542	416,	863,242	77,666,806	109,521,230	476,918	2,177,074	770,272
24	3660 Underground Conduit			_						
25	Demand Primary 23/34.5 KV	DEMPRIS	8,343,384		383,319	1,017,331	1,489,518	414,572	28,618	10,025
26 27	Demand Primary Remainder	DPRITGSSS	20,595,508		009,304	2,633,327	3,853,597	0	73,364	25,917
28	Secondary	DEMSECS	13,538,756 42,477,648		771,619 164,242	1,738,433 5,389,091	1,960,505 7,303,620	•	50,262 152,245	17,937 53,879
30	Total Acct 3660 3670 Underground Conductors and Devices		42,477,040	29,	104,242	3,369,091	7,303,020	414,572	132,243	33,079
31	Demand Primary 23/34.5 KV	DEMPRIS	46,808,325	30	201,674	5,707,464	8,356,545	2,325,844	160,555	56,242
32	Demand Primary Remainder	DPRITGSSS	84,898,713		749,089	10,855,088	15,885,279	0	302,421	106,835
33	Secondary	DEMSECS	61,617,752		472,711	7,911,979	8,922,672	0	228.755	81,635
34	Total Acct 3670	220200	193,324,790		423,475	24,474,532	33,164,497	2,325,844	691,730	244,712
35	3680 Line Transformers	DEMTRNSFS	641,360,322		902,840	82,353,369	92,873,363	0	2,381,037	849,711
36	3691 Services	CUST369S	226,877,166	164,	242,356	29,291,806	33,040,617	0	0	302,387
37	3700 Meters	CUST370	63,306,521	37,	296,595	18,847,652	4,624,619	2,537,655	0	0
37	3701 AMI Meters	CUST371	26,519,661	20,	335,043	5,541,697	642,921	0	0	0
38	3711 Installations on Customer Premises	CUST3711P	576,123		378,960	72,375	90,520	2,103	31,488	678
39	3712 Installations on Customer Premises	CUST373	31,756,449		0	0	0	0	31,756,449	0
40	372 Leased Property on Customer Premises	CUST372	141,649		0	0	13,606	128,042	0	0
41	3730 Street Lighting and Signal Systems	CUST373	118,371,145		0	0	0	0	118,371,145	0
42	3740 Asset retirement costs for Dist Plant	_PLT362	4,370,738		948,929	554,758	811,893	34,219	15,478	5,461
	Total Distribution - ACE		2,908,542,635	1,913,	167,243	365,383,109	456,989,441	10,615,531	158,963,832	3,423,480

		ALLOC	RESIDENTIAL (8)-2	MONTHLY GENERAL SERV SECONDARY (9)	MONTHLY GENERAL SERV PRIMARY (10)	ANNUAL GENERAL SERV SECONDARY (11)	ANNUAL GENERAL SERV PRIMARY (12)	STREET AND PRIVATE LIGHTING (13)	GENERAL SERVICE SUBTRANSMSN (14)	GENERAL SERVICE TRANSMISSION (15)	DIRECT DISTRIBUTION CONNECTION (16)
	DEVELOPMENT OF RATE BASE-2										
	ELECTRIC PLANT IN SERVICE										
	DISTRIBUTION PLANT Distribution - ACE										
	3601 Land and Land Rights										
1	Substations 23/34.5 kV	PLT362	76,513	13,711	682	15,473	5,593	402	888	0	142
2	Substations Remainder	DPRITGSSS	6,905,708	1,236,502	61,563	1,395,227	504,354	36,164	0	0	12,775
3	Lines 23/34.5 KV	_PLT3647	813,501	145,521	5,807	164,188	47,585	4,249	3,650	0	1,503
4	Lines Remainder	DPRITGSSS	17,849,407	3,196,026	159,125	3,606,289	1,303,620	93,474	0	0	33,021
5	Total Acct 3601		25,645,129	4,591,760	227,178	5,181,177	1,861,153	134,288	4,538	0	47,442
6	3610 Structures and Improvements										
7	23/34.5 KV	DEMPRIS	3,090,547	556,401	27,646	628,117	227,011	16,430	238,004	0	5,755
8	Remainder	DPRITGSSS	29,359,204	5,256,913	261,733	5,931,726	2,144,231	153,749	0	0	54,314
9	Total Acct 3610		32,449,751	5,813,314	289,378	6,559,842	2,371,243	170,178	238,004	0	60,069
10	3620 Station Equipment	DE14DD10	E4 E40 000		404.404	40.470.004		071011			05.007
11	23/34.5 KV	DEMPRIS	51,549,399	9,280,602	461,121	10,476,801	3,786,478	274,041	3,969,841	0	95,997
12	Remainder	DPRITGSSS	290,559,999	52,026,227	2,590,296	58,704,662	21,220,871	1,521,607	0	0	537,532
13 14	Total Acct 3620		342,109,399	61,306,829	3,051,417	69,181,462	25,007,349	1,795,648	3,969,841	U	633,529
15	3640 Poles, Towers and Fixtures	DEMPRIS	6,282,194	1,131,003	56,196	1,276,781	461,448	33,397	483,794	0	11,699
	Demand Primary 23/34.5 KV	DPRITGSSS	199.152.090	35.659.182	1,775,409	40.236.633	14,544,951	1,042,921	403,794	0	368.429
16 17	Demand Primary Remainder	DEMSECS	40,972,997	7,289,358	1,775,409	8,220,516	14,544,951	210,753	0	0	75,211
18	Secondary Total Acct 3640	DEIVISEUS	246,407,282	44,079,543	1,831,604	49,733,930	15,006,399	1,287,071	483,794	0	455,338
19	3650 Overhead Conductors and Devices		240,407,202	44,079,343	1,031,004	49,733,930	13,000,333	1,207,071	403,734	U	455,550
20	Demand Primary 23/34.5 KV	DEMPRIS	6,192,897	1,114,927	55,397	1,258,632	454,889	32,922	476,918	0	11,533
21	Demand Primary Remainder	DPRITGSSS	341,393,598	61,128,238	3,043,469	68,975,068	24,933,472	1,787,813	0	0	631,574
22	Secondary	DEMSECS	69,276,747	12,324,775	0,043,403	13,899,168	24,333,472	356,339	0	0	127,165
23	Total Acct 3650	526266	416,863,242	74,567,940	3,098,866	84,132,869	25,388,361	2,177,074	476,918	0	770,272
24	3660 Underground Conduit		,,	,,-	-,,	,,		_,,	,	•	,
25	Demand Primary 23/34.5 KV	DEMPRIS	5,383,319	969,176	48,155	1,094,095	395,423	28,618	414,572	0	10,025
26	Demand Primary Remainder	DPRITGSSS	14,009,304	2,508,436	124,891	2,830,436	1,023,161	73,364	0	Ō	25,917
27	Secondary	DEMSECS	9,771,619	1,738,433	0	1,960,505	0	50,262	0	0	17,937
28	Total Acct 3660		29,164,242	5,216,046	173,046	5,885,036	1,418,584	152,245	414,572	0	53,879
30	3670 Underground Conductors and Devices										
31	Demand Primary 23/34.5 KV	DEMPRIS	30,201,674	5,437,304	270,161	6,138,130	2,218,415	160,555	2,325,844	0	56,242
32	Demand Primary Remainder	DPRITGSSS	57,749,089	10,340,264	514,824	11,667,610	4,217,669	302,421	0	0	106,835
33	Secondary	DEMSECS	44,472,711	7,911,979	0	8,922,672	0	228,755	0	0	81,635
34	Total Acct 3670		132,423,475	23,689,547	784,985	26,728,412	6,436,084	691,730	2,325,844	0	244,712
35	3680 Line Transformers	DEMTRNSFS	462,902,840	82,353,369	0	92,873,363	0	2,381,037	0	0	849,711
36	3691 Services	CUST369S	164,242,356	29,291,806	0	33,040,617	0	0	0	0	302,387
37	3700 Meters	CUST370	37,296,595	17,551,138	1,296,514	2,639,963	1,984,657	0	1,368,153	1,169,501	0
37	3701 AMI Meters	CUST371	20,335,043	5,512,650	29,047	642,921	0	0	0	0	0
38	3711 Installations on Customer Premises	CUST3711P	378,960	70,234	2,141	74,730	15,791	31,488	1,847	256 0	678
39	3712 Installations on Customer Premises	CUST373	0	0	0	0	13.606	31,756,449 0	6 003	•	0
40 41	372 Leased Property on Customer Premises	CUST372 CUST373	0	0	0	0	13,606 0	•	6,903	121,139 0	0
41	3730 Street Lighting and Signal Systems 3740 Asset retirement costs for Dist Plant	PLT362	2,948,929	528.455	26,303	596,333	215,559	118,371,145 15,478	34,219	0	5,461
42	Total Distribution - ACE	_1. [1302	1,913,167,243	354,572,631	10,810,479	377,270,655	79,718,785	158,963,832	9,324,635	1,290,896	3,423,480

		ALLOC	TOTAL ACE DISTRIBUTION (1)	TOTAL RESIDENTIAL SERVICE (2)	MONTHLY GENERAL SERVICE (3)	ANNUAL GENERAL SERVICE (4)	TRANSM GENERAL SERVICE (5)	STREET LIGHTING SERVICE (6)	DIRECT DISTRIBUTION CONNECTION (7)
	DEVELOP OF RATE BASE CON'T-3								
	ELECTRIC PLANT IN SERVICE General Plant								
1	3891 Land and Land Rights	LABOR	341,986	229,079	49,880	48,900	4,304	9,506	317
2	3903 Structures and Improvements	LABOR	28,274,742	18,939,821	4,123,957	4,042,940	355,875	785,955	26,194
3	3911 Office Furniture and Equipment	LABOR	3,873,572	2,594,710	564,972	553,873	48,754	107,674	3,588
4	3912 Office Furniture and Equipment	LABOR	0	0	0	0	0	0	0
5	3913 Office Furniture and Equipment	LABOR	18,410,146	12,332,027	2,685,176	2,632,424	231,716	511,748	17,055
6	3915 Office Furniture and Equipment	LABOR	0	0	0	0	0	0	0
7	3920 Transportation Equipment	LABOR	22,117,847	14,815,628	3,225,955	3,162,580	278,382	614,811	20,490
8	3931 Stores Equipment	LABOR	86,189	57,734	12,571	12,324	1,085	2,396	80
9	3932 Stores Equipment	LABOR	0	0	0	0	0	0	0
10	3941 Tools, Shop and Garage Equipment	LABOR	12,629,082	8,459,583	1,841,990	1,805,803	158,954	351,051	11,700
11	3942 Tools, Shop and Garage Equipment	LABOR	0	0	0	0	0	0	0
12	3951 Laboratory Equipment	LABOR	0	0	0	0	0	0	0
13	3952 Laboratory Equipment	LABOR	0	0	0	0	0	0	0
14	3960 Power Operated Equipment	LABOR	0	0	0	0	0	0	0
15	3970 Communication Equipment	LABOR	107,044,121	71,703,447	15,612,712	15,305,991	1,347,292	2,975,513	99,166
16	3982 Miscellaneous Equipment	LABOR	2,987,367	2,001,086	435,717	427,157	37,600	83,040	2,768
17	399 Other Tangible Property	LABOR	0	0	0	0	0	0	0
18	3991 Other Tangible Property	LABOR	35,806	23,985	5,222	5,120	451	995	33
19	Total General Plant		195,800,857	131,157,098	28,558,153	27,997,112	2,464,414	5,442,690	181,391
	Intangible Plant								
20	3020 000 Franchises and Consents	LABOR	0	0	0	0	0	0	0
21	3030 000 Miscellaneous Intangible Plant	LABOR	84,054,509	56,303,867	12,259,607	12,018,760	1,057,938	2,336,469	77,869
22	Total Intangible Plant		84,054,509	56,303,867	12,259,607	12,018,760	1,057,938	2,336,469	77,869
23	Total pre-Service Co Electric Plant In Service		3,188,398,001	2,100,628,208	406,200,868	497,005,312	14,137,882	166,742,992	3,682,739
24	Service Company Assets	SERVCO	69,526,572	46,572,337	10,140,663	9,941,444	875,084	1,932,635	64,410
25	Total System Electric Distribution		3,257,924,573	2,147,200,545	416,341,531	506,946,756	15,012,966	168,675,627	3,747,149

		ALLOC	RESIDENTIAL (8)-2	MONTHLY GENERAL SERV SECONDARY (9)	MONTHLY GENERAL SERV PRIMARY (10)	ANNUAL GENERAL SERV SECONDARY (11)	ANNUAL GENERAL SERV PRIMARY (12)	STREET AND PRIVATE LIGHTING (13)	GENERAL SERVICE SUBTRANSMSN (14)	GENERAL SERVICE TRANSMISSION (15)	DIRECT DISTRIBUTION CONNECTION (16)
	DEVELOP OF RATE BASE CON'T-3										
	ELECTRIC PLANT IN SERVICE General Plant										
1	3891 Land and Land Rights	LABOR	229,079	47,760	2,119	37,438	11,462	9,506	3,318	986	317
2	3903 Structures and Improvements	LABOR	18,939,821	3,948,728	175,229	3,095,260	947,680	785,955	274,316	81,559	26,194
3	3911 Office Furniture and Equipment	LABOR	2,594,710	540,966	24,006	424,043	129,830	107,674	37,581	11,173	3,588
4	3912 Office Furniture and Equipment	LABOR	0	0	0	0	0	0	0	0	0
5	3913 Office Furniture and Equipment	LABOR	12,332,027	2,571,081	114,095	2,015,374	617,050	511,748	178,612	53,104	17,055
6	3915 Office Furniture and Equipment	LABOR	0	0	0	0	0	0	0	0	0
7	3920 Transportation Equipment	LABOR	14,815,628	3,088,883	137,073	2,421,259	741,320	614,811	214,583	63,799	20,490
8	3931 Stores Equipment	LABOR	57,734	12,037	534	9,435	2,889	2,396	836	249	80
9	3932 Stores Equipment	LABOR	0	0	0	0	0	0	0	. 0	0
10	3941 Tools, Shop and Garage Equipment	LABOR	8,459,583	1,763,723	78,267	1,382,516	423,287	351,051	122,525	36,429	11,700
11	3942 Tools, Shop and Garage Equipment	LABOR	0	0	0	0	0	0	0	0	0
12	3951 Laboratory Equipment	LABOR	0	0	0	0	0	0	0	0	0
13	3952 Laboratory Equipment	LABOR	0	0	0	0	0	0	0	0	0
14	3960 Power Operated Equipment	LABOR	0	0	0	0	0	0	0	0	U
15	3970 Communication Equipment	LABOR	71,703,447	14,949,319	663,393	11,718,210	3,587,781	2,975,513	1,038,522	308,770	99,166
16	3982 Miscellaneous Equipment	LABOR	2,001,086	417,203	18,514	327,030	100,127	83,040	28,983	8,617	2,768
17	399 Other Tangible Property	LABOR	0	0	0	0	0	0	0	0	0
18 19	3991 Other Tangible Property Total General Plant	LABOR	23,985 131,157,098	5,001 27,344,700	222 1,213,453	3,920 21,434,485	1,200 6,562,626	995 5,442,690	347 1,899,623	103 564,791	33 181,391
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	Intangible Plant		_	_	_	_	_	_	_	_	_
20	3020 000 Franchises and Consents	LABOR	0	0	0	0	0	0	0	0	0
21	3030 000 Miscellaneous Intangible Plant	LABOR	56,303,867	11,738,689	520,918	9,201,518	2,817,242	2,336,469	815,481	242,457	77,869
22	Total Intangible Plant		56,303,867	11,738,689	520,918	9,201,518	2,817,242	2,336,469	815,481	242,457	77,869
23	Total pre-Service Co Electric Plant In Service		2,100,628,208	393,656,019	12,544,849	407,906,659	89,098,653	166,742,992	12,039,739	2,098,143	3,682,739
24	Service Company Assets	SERVCO	46,572,337	9,709,780	430,883	7,611,133	2,330,311	1,932,635	674,534	200,551	64,410
25	Total System Electric Distribution		2,147,200,545	403,365,799	12,975,732	415,517,792	91,428,964	168,675,627	12,714,272	2,298,694	3,747,149

	ALLOC	TOTAL ACE DISTRIBUTION (1)	TOTAL RESIDENTIAL SERVICE (2)	MONTHLY GENERAL SERVICE (3)	ANNUAL GENERAL SERVICE (4)	TRANSM GENERAL SERVICE (5)	STREET LIGHTING SERVICE (6)	DIRECT DISTRIBUTION CONNECTION (7)
DEVELOP OF RATE BASE CON'T	-4							
DEPRECIATION RESERVE								
1 Distribution	DISTPLT	682,540,242	448,958,051	85,743,517	107,240,540	2,491,119	37,303,635	803,379
2 General	GENPLT	62,777,667	42,051,586	9,156,314	8,976,433	790,140	1,745,035	58,158
3 Intangible	INTPLT	43,204,863	28,940,754	6,301,561	6,177,763	543,791	1,200,969	40,025
4 Other	PLANT	0	0	0	0	0	0	0
5 Service Company Assets Reserve	SERVCO	53,406,493	35,774,311	7,789,500	7,636,471	672,192	1,484,544	49,476
6 Total Depreciation Reserve		841,929,265	555,724,702	108,990,893	130,031,208	4,497,242	41,734,183	951,038
7 Total Net Plant		2,415,995,308	1,591,475,843	307,350,638	376,915,548	10,515,724	126,941,444	2,796,111

	ALLOC	RESIDENTIAL (8)-2	MONTHLY GENERAL SERV SECONDARY (9)	MONTHLY GENERAL SERV PRIMARY (10)	ANNUAL GENERAL SERV SECONDARY (11)	ANNUAL GENERAL SERV PRIMARY (12)	STREET AND PRIVATE LIGHTING (13)	GENERAL SERVICE SUBTRANSMSN (14)	GENERAL SERVICE TRANSMISSION (15)	DIRECT DISTRIBUTION CONNECTION (16)
DEVELOP OF RATE BASE CON'T-4										
DEPRECIATION RESERVE										
1 Distribution	DISTPLT	448,958,051	83,206,650	2,536,867	88,533,137	18,707,403	37,303,635	2,188,188	302,931	803,379
2 General	GENPLT	42,051,586	8,767,257	389,057	6,872,324	2,104,109	1,745,035	609,057	181,083	58,158
3 Intangible	INTPLT	28,940,754	6,033,804	267,757	4,729,673	1,448,091	1,200,969	419,165	124,625	40,025
4 Other	PLANT	0	0	0	0	0	0	0	0	0
5 Service Company Assets Reserve	SERVCO	35,774,311	7,458,520	330,980	5,846,454	1,790,017	1,484,544	518,140	154,052	49,476
6 Total Depreciation Reserve		555,724,702	105,466,231	3,524,662	105,981,588	24,049,619	41,734,183	3,734,550	762,691	951,038
7 Total Net Plant		1,591,475,843	297,899,569	9,451,070	309,536,203	67,379,345	126,941,444	8,979,722	1,536,002	2,796,111

		ALLOC	TOTAL ACE DISTRIBUTION (1)	TOTAL RESIDENTIAL SERVICE (2)	MONTHLY GENERAL SERVICE (3)	ANNUAL GENERAL SERVICE (4)	TRANSM GENERAL SERVICE (5)	STREET LIGHTING SERVICE (6)	DIRECT DISTRIBUTION CONNECTION (7)
	DEVELOP OF RATE BASE CON'T-5								
	ADDITIONS AND DEDUCTIONS TO RATE	BASE							
	ADDITIONS TO RATE BASE								
8 9 10	General	DISTPLT GENPLT	3,630,877 2,759,880 6,390,756	2,388,301 1,848,704 4,237,004	456,126 402,537 858,663	570,482 394,629 965,111	13,252 34,737 47,989	198,442 76,717 275,159	4,274 2,557 6,830
11 12 13	Labor Stock	DISTPLT LABOR	31,908,733 0 31,908,733	20,988,773 0 20,988,773	4,008,506 0 4,008,506	5,013,492 0 5,013,492	116,460 0 116,460	1,743,944 0 1,743,944	37,558 0 37,558
14 15 16 17 18 19 20 21	Cash Working Capital O&M - Distribution Depreciation Deferred Tax Distribution Other Taxes Tax on Sales Revenue Net ITC Adjustment FIT & SIT Cost of Electric Supply Invested Capital Distribution IOCD	DISTOMEXP DISTPLT PLANT OTHTAX CLAIMREV PLANT CLAIMREV BGSNUGRV NETINC CUSTDEP	19,721,119 18,236,949 0 911,317 23,275,125 7,907 0 34,854,402 16,760,102 (34,564)	14,120,304 11,995,813 0 641,518 15,970,523 5,211 0 23,001,991 7,690,528 (15,471)	2,600,091 2,291,001 0 177,664 3,063,282 1,010 0 5,701,568 4,567,852 (8,483)	2,328,176 2,865,385 0 67,181 3,149,419 1,230 0 3,594,282 3,219,975 (10,610)	186,404 66,561 0 5,471 175,384 36 0 2,409,997 239,019	464,680 996,724 0 18,915 890,490 409 0 128,902 1,017,152 0	21,463 21,466 0 569 26,028 9 0 17,663 25,577
	Total Cash Working Capital		113,732,356	73,410,416	18,393,985	15,215,037	3,082,871	3,517,272	112,775

		ALLOC	RESIDENTIAL (8)-2	MONTHLY GENERAL SERV SECONDARY (9)	MONTHLY GENERAL SERV PRIMARY (10)	ANNUAL GENERAL SERV SECONDARY (11)	ANNUAL GENERAL SERV PRIMARY (12)	STREET AND PRIVATE LIGHTING (13)	GENERAL SERVICE SUBTRANSMSN (14)	GENERAL SERVICE TRANSMISSION (15)	DIRECT DISTRIBUTION CONNECTION (16)
	DEVELOP OF RATE BASE CON'T-5										
	ADDITIONS AND DEDUCTIONS TO RATE	BASE									
	ADDITIONS TO RATE BASE										
8 9 10 11 12	General Total Plant Held for Future Use MATERIALS & SUPPLIES Distribution	DISTPLT GENPLT DISTPLT LABOR	2,388,301 1,848,704 4,237,004 20,988,773	442,630 385,433 828,063 3,889,908	13,495 17,104 30,599 118,598	470,965 302,126 773,092 4,138,921	99,517 92,502 192,019 874,570	198,442 76,717 275,159 1,743,944	11,640 26,776 38,416 102,298	1,611 7,961 9,572 14,162	4,274 2,557 6,830 37,558
13	Total Materials & Supplies		20,988,773	3,889,908	118,598	4,138,921	874,570	1,743,944	102,298	14,162	37,558
14 15 16 17 18 19 20 21	Cash Working Capital O&M - Distribution Depreciation Deferred Tax Distribution Other Taxes Tax on Sales Revenue Net TC Adjustment FIT & SIT Cost of Electric Supply Invested Capital Distribution	DISTOMEXP DISTPLT PLANT OTHTAX CLAIMREV PLANT CLAIMREV BGSNUGRV NETINC CUSTDEP	14,120,304 11,995,813 0 641,518 15,970,523 5,211 0 23,001,991 7,690,528 (15,471)	2,503,677 2,223,218 0 174,597 2,960,668 979 0 5,252,664 4,537,367 (8,232)	96,415 67,783 0 3,067 102,614 31 0 448,903 30,486 (251)	1,785,156 2,365,537 0 49,182 2,513,222 1,008 0 2,579,537 2,809,436 (8,759)	543,020 499,847 0 17,999 636,197 222 0 1,014,745 410,539 (1,851)	464,680 996,724 0 18,915 890,490 0 128,902 1,017,152	125,857 58,467 0 4,327 127,040 31 0 1,717,591 111,793	60,547 8,094 0 1,144 48,343 6 0 692,405 127,225 0	21,463 21,466 0 569 26,028 9 0 17,663 25,577 0
	Total Cash Working Capital		73,410,416	17,644,937	749,048	12,094,319	3,120,718	3,517,272	2,145,106	937,765	112,775

		ALLOC	TOTAL ACE DISTRIBUTION (1)	TOTAL RESIDENTIAL SERVICE (2)	MONTHLY GENERAL SERVICE (3)	ANNUAL GENERAL SERVICE (4)	TRANSM GENERAL SERVICE (5)	STREET LIGHTING SERVICE (6)	DIRECT DISTRIBUTION CONNECTION (7)
	DEVELOP OF RATE BASE CON'T-6								
	DEDUCTIONS TO RATE BASE								
1 2	CUSTOMER ADVANCES ACE Total Customer Advances	DISTPLT	9,971,369 9,971,369	6,558,919 6,558,919	1,252,644 1,252,644	1,566,699 1,566,699	36,393 36,393	544,976 544,976	11,737 11,737
3 4	CUSTOMER DEPOSITS ACE Total Customer Deposits	CUSPDEP	18,982,828 18,982,828	8,496,886 8,496,886	4,658,942 4,658,942	5,827,000 5,827,000	0 0	0	0
5 6 7	DEFERRED FIT Labor Plant TCJA EDIT Total Deferred FIT	LABOR PLANT LABOR	(3,028,429) 346,451,766 106,685,785 450,109,122	(2,028,592) 228,335,986 71,463,415 297,770,810	(441,706) 44,274,278 15,560,447 59,393,020	(433,028) 53,909,351 15,254,754 68,731,076	(38,117) 1,596,498 1,342,782 2,901,163	(84,181) 17,937,177 2,965,552 20,818,548	(2,806) 398,476 98,834 494,505
8 9 10		LABOR PLANT	(1,426,262) 138,144,815 136,718,553	(955,381) 91,047,112 90,091,731	(208,025) 17,654,007 17,445,983	(203,938) 21,495,914 21,291,976	(17,951) 636,590 618,639	(39,646) 7,152,303 7,112,657	(1,321) 158,889 157,568
11	Total Rate Base		1,952,245,281	1,287,193,690	247,861,203	300,692,437	10,206,849	104,001,638	2,289,464

	ALLOC	RESIDENTIAL (8)-2	MONTHLY GENERAL SERV SECONDARY (9)	MONTHLY GENERAL SERV PRIMARY (10)	ANNUAL GENERAL SERV SECONDARY (11)	ANNUAL GENERAL SERV PRIMARY (12)	STREET AND PRIVATE LIGHTING (13)	GENERAL SERVICE SUBTRANSMSN (14)	GENERAL SERVICE TRANSMISSION (15)	DIRECT DISTRIBUTION CONNECTION (16)
DEVELOP OF RATE BASE CON'T-6										
EDUCTIONS TO RATE BASE										
ISTOMER ADVANCES ACE Total Customer Advances	DISTPLT	6,558,919 6,558,919	1,215,583 1,215,583	37,062 37,062	1,293,399 1,293,399	273,300 273,300	544,976 544,976	31,968 31,968	4,426 4,426	11,737 11,737
ISTOMER DEPOSITS ACE Total Customer Deposits	CUSPDEP	8,496,886 8,496,886	4,521,099 4,521,099	137,843 137,843	4,810,518 4,810,518	1,016,482 1,016,482	0	0	0 0	0 0
FERRED FIT Labor Plant JA EDIT Total Deferred FIT	LABOR PLANT LABOR	(2,028,592) 228,335,986 71,463,415 297,770,810	(422,937) 42,894,423 14,899,275 57,370,760	(18,768) 1,379,855 661,172 2,022,260	(331,525) 44,186,681 11,678,983 55,534,139	(101,503) 9,722,670 3,575,770 13,196,937	(84,181) 17,937,177 2,965,552 20,818,548	(29,381) 1,352,052 1,035,045 2,357,716	(8,736) 244,446 307,737 543,447	(2,806) 398,476 98,834 494,505
EFERRED SIT Labor Plant Total Deferred SIT	LABOR PLANT	(955,381) 91,047,112 90,091,731	(199,186) 17,103,801 16,904,616	(8,839) 550,206 541,367	(156,134) 17,619,078 17,462,944	(47,804) 3,876,835 3,829,032	(39,646) 7,152,303 7,112,657	(13,837) 539,120 525,282	(4,114) 97,471 93,357	(1,321) 158,889 157,568 2,289,464
	EDUCTIONS TO RATE BASE ISTOMER ADVANCES ACE Total Customer Advances STOMER DEPOSITS ACE Total Customer Deposits FERRED FIT Labor Plant JA EDIT Total Deferred FIT FERRED SIT Labor Plant	DEVELOP OF RATE BASE CON'T-6 EDUCTIONS TO RATE BASE STOMER ADVANCES ACE DISTPLT Total Customer Advances STOMER DEPOSITS ACE CUSPDEP Total Customer Deposits FERRED FIT Labor LABOR Plant PLANT JA EDIT LABOR Total Deferred FIT FERRED SIT Labor LABOR Plant LABOR Plant PLANT Total Deferred SIT	DEVELOP OF RATE BASE CON'T-6 EDUCTIONS TO RATE BASE STOMER ADVANCES ACE DISTPLT 6,558,919 Total Customer Advances 6,558,919 STOMER DEPOSITS ACE CUSPDEP 8,496,886 Total Customer Deposits 8,496,886 FERRED FIT Labor LABOR (2,028,592) Plant PLANT 228,335,986 Total Deferred FIT LABOR 71,463,415 Total Deferred FIT LABOR (955,381) FERRED SIT LABOR (955,381) Plant PLANT 91,047,112 Total Deferred SIT 90,091,731	RESIDENTIAL GENERAL SERV SECONDARY	ALLOC (8)-2 SECONDARY SECONDARY PRIMARY ALLOC (8)-2 (9) SECONDARY PRIMARY (10) DEVELOP OF RATE BASE CON'T-6 EDUCTIONS TO RATE BASE STOMER ADVANCES ACE DISTPLT 6,558,919 1,215,583 37,062 Total Customer Advances 6,558,919 1,215,583 37,062 STOMER DEPOSITS ACE CUSPDEP 8,496,886 4,521,099 137,843 Total Customer Deposits 8,496,886 4,521,099 137,843 FERRED FIT Labor LABOR (2,028,592) (422,937) (18,768) Plant PLANT 228,335,986 42,894,423 1,379,855 ZIA EDIT LABOR 71,463,415 14,899,275 661,172 Total Deferred FIT 297,770,810 57,370,760 2,022,260 FERRED SIT LABOR (955,381) (199,186) (8,839) Plant PLANT 91,047,112 17,103,801 550,206 Total Deferred SIT 90,091,731 16,904,616 541,367	RESIDENTIAL GENERAL SERV SECONDARY SECONDARY	RESIDENTIAL RESIDENTIAL	RESIDENTIAL GENERAL SERV SECONDARY PRIMARY SECONDARY SECON	RESIDENTIAL (8)-2 SECONDARY PRIMARY SECONDARY PRIMARY (10) SECONDARY PRIMARY (11) SERVICE SUBTRANSMSN (14) DEVELOP OF RATE BASE CONT-6 EDUCTIONS TO RATE BASE STOMER ADVANCES (1,293,399) 1,215,583 (1,293,399) 273,300 544,976 31,968 (1,293,399) 273,300 544,976 31,968 (1,293,399) 273,300 544,976 (1,293,398) 273,300 544,976 (1,293,398) 273,300 (RESIDENTIAL (8)-2 SERVICE SECONDARY PRIMARY SECONDARY PRIMARY (12) SERVICE USERNASSION (13) SERVICE SERVICE SERVICE SECONDARY PRIMARY (12) SERVICE USERNASSION (14) SERVICE SERVICE SECONDARY PRIMARY (12) SERVICE SERVICE SERVICE (13) SERVICE SERVICE (14) SERVICE (15)

		ALLOC	TOTAL ACE DISTRIBUTION (1)	TOTAL RESIDENTIAL SERVICE (2)	MONTHLY GENERAL SERVICE (3)	ANNUAL GENERAL SERVICE (4)	TRANSM GENERAL SERVICE (5)	STREET LIGHTING SERVICE (6)	DIRECT DISTRIBUTION CONNECTION (7)
	OPERATING REVENUES-7								
	ELECTRIC SALES REVENUES								
1	Revenue - Retail Sales ACE		476,723,799	296,020,547	86,151,215	69,944,842	5,114,341	18,905,207	587,648
2	Total Revenue - Retail Sales ACE		476,723,799	296,020,547	86,151,215	69,944,842	5,114,341	18,905,207	587,648
	REVENUE - OTHER								
3	Other Revenues	CUST	0	0	0	0	0	0	0
4	Late Payment Revenue ACE	LPAY	117,067	0	57,438	46,633	0	12,604	392
5	Miscellaneous Service Revenue ACE	CUST	36,858	32,520	3,680	196	3	389	69
5	Miscellaneous Service Revenue ACE - I/C	LABOR	1,313,995	880,179	191,650	187,885	16,538	36,525	1,217
6	Rent from Electric Property ACE Poll Attach	PLT364	6,482,057	4,445,569	828,308	1,168,016	8,728	23,221	8,215
7	Rent from Electric Property ACE Other	DISTPLT	730,921	480,781	91,821	114,842	2,668	39,948	860
8	Total Other Revenue		8,680,898	5,839,049	1,172,898	1,517,572	27,938	112,687	10,753
9	Total Revenue		485,404,697	301,859,596	87,324,113	71,462,414	5,142,279	19,017,894	598,402

		ALLOC	RESIDENTIAL (8)-2	MONTHLY GENERAL SERV SECONDARY (9)	MONTHLY GENERAL SERV PRIMARY (10)	ANNUAL GENERAL SERV SECONDARY (11)	ANNUAL GENERAL SERV PRIMARY (12)	STREET AND PRIVATE LIGHTING (13)	GENERAL SERVICE SUBTRANSMSN (14)	GENERAL SERVICE TRANSMISSION (15)	DIRECT DISTRIBUTION CONNECTION (16)
	OPERATING REVENUES-7										
	ELECTRIC SALES REVENUES										
1	Revenue - Retail Sales ACE		296,020,547	84,363,933	1,787,281	57,356,426	12,588,416	18,905,207	3,024,915	2,089,427	587,648
2	Total Revenue - Retail Sales ACE		296,020,547	84,363,933	1,787,281	57,356,426	12,588,416	18,905,207	3,024,915	2,089,427	587,648
	REVENUE - OTHER										
3	Other Revenues	CUST	0	0	0	0	0	0	0	0	0
4	Late Payment Revenue ACE	LPAY	0	56,246	1,192	38,240	8,393	12,604	0	0	392
5	Miscellaneous Service Revenue ACE	CUST	32,520	3,671	10	188	8	389	2	1	69
5	Miscellaneous Service Revenue ACE - I/C	LABOR	880,179	183,507	8,143	143,844	44,041	36,525	12,748	3,790	1,217
6	Rent from Electric Property ACE Poll Attach	PLT364	4,445,569	795,263	33,045	897,277	270,739	23,221	8,728	0	8,215
7	Rent from Electric Property ACE Other	DISTPLT	480,781	89,105	2,717	94,809	20,033	39,948	2,343	324	860
8	Total Other Revenue		5,839,049	1,127,791	45,107	1,174,358	343,214	112,687	23,822	4,116	10,753
9	Total Revenue		301,859,596	85,491,725	1,832,388	58,530,784	12,931,629	19,017,894	3,048,737	2,093,542	598,402

		ALLOC	TOTAL ACE DISTRIBUTION	TOTAL RESIDENTIAL SERVICE	MONTHLY GENERAL SERVICE	ANNUAL GENERAL SERVICE	TRANSM GENERAL SERVICE	STREET LIGHTING SERVICE	DIRECT DISTRIBUTION CONNECTION
		ALLOC	(1)	(2)	(3)	(4)	(5)	(6)	(7)
	OPERATION & MAINTENANCE EXP-8								
	Distribution Expenses - ACE								
	Operation								
1	958000 Operation Supervision & Engineering	TLABDO	922,818	609,072	163,959	115,619	19,324	14,269	575
2	958100 Load dispatching	SALESWOT	3,194,359	2,158,896	384,409	513,855	113,474	21,472	2,252
3	958200 Station expenses	_PLT362 PLTDOHLN	22,205	14,982	2,818	4,125	174	79	28
4 5	958300 Overhead line expenses 958400 Underground line expenses	PLTDUHLN	4,189,793 0	2,874,514 0	535,568 0	755,223 0	4,164 0	15,013 0	5,312 0
6	958500 Street lighting	PLT373	431,115	0	0	0	0	431,115	0
7	958600 Meter expenses	PLT370	5,611,640	3,600,376	1,523,657	329,075	158,533	431,119	0
8	958700 Customer installations expenses	PLT369	812,500	588,190	104,901	118,326	130,333	0	1,083
9	958800 Miscellaneous distribution expenses	EXPDISTO	17,174,240	11,123,407	3,072,412	2,072,000	332,782	563,192	10,446
10	958900 Rents	EXPDISTO	3,536,842	2,290,741	632,729	426,705	68,533	115,983	2,151
11	Total Operation	_	35,895,512	23,260,178	6,420,452	4,334,928	696,984	1,161,124	21,846
	Maintenance						·		
12	959000 Maintenance Supervision & Engineering	TLABDM	2,310	1,520	283	398	9	97	3
13	959200 Maintain equipment	_PLT362	4,453,246	3,004,597	565,230	827,219	34,865	15,770	5,564
14	959300 Maintain overhead lines	PLTDOHLN	63,403,712	43,499,722	8,104,697	11,428,714	63,007	227,191	80,380
15	959400 Maintain underground line	PLTDUGLN	4,469,129	3,062,548	566,001	766,986	51,939	15,996	5,659
16	959500 Maintain line transformers	_PLT368	561,982	405,612	72,161	81,379	0	2,086	745
17	959600 Maintain street lighting & signal systems	_PLT373	1,823,429	0	0	0	0	1,823,429	0
18	959700 Maintain meters	_PLT370	7,608	4,881	2,066	446	215	0	0
19 20	959800 Maintain distribution plant	_EXPDISTM	1,344,511 76,065,926	899,303 50,878,183	167,529 9,477,967	235,809 13,340,952	2,700 152,734	37,508 2,122,078	1,662 94,012
21	Total Maintenance				15,898,419	17,675,880	849,718	3,283,202	115,859
21	Total Distribution Expenses - ACE		111,961,438	74,138,360	15,696,419	17,075,000	049,710	3,203,202	115,659
	Customer Accounts Expenses								
22	990200 Meter reading expenses	CUST902	7,570,059	6,615,626	785,245	129,795	39,392	0	0
23	990300 Cust records and collection exp	CUST903	50,157,398	44,499,573	4,624,990	288,541	215,834	451,219	77,241
24	990500 Miscellaneous cust accounts exp	_EXP9023	0	0	0	0	0	0	0
25	Total Customer Accounts Expenses		57,727,457	51,115,200	5,410,234	418,337	255,227	451,219	77,241
	Customer Service Expenses								
26	990700 Supervision	CSERV	0	0	0	0	0	0	0
27	990800 Customer assistance expenses	CSERV	5,029,692	3,374,136	673,947	626,992	299,377	46,251	8,989
28	990900 Informational & instructional adv	CSERV	292,300	196,088	39,166	36,438	17,398	2,688	522
29	991000 Miscellaneous customer service & informat	tic CSERV	0	0	0	0	0	0	0
30	Total Customer Service Expenses		5,321,992	3,570,224	713,114	663,430	316,775	48,939	9,511
	Sales Expense								
31	991200 Demonstrating & selling expenses	CSALES	0	0	0	0	0	0	0
32	991300 Advertising expense	CSALES	0	0	0	0	0	0	0
33	Total Sales Expense		0	0	0	0	0	0	0

		ALLOC	RESIDENTIAL (8)-2	MONTHLY GENERAL SERV SECONDARY (9)	MONTHLY GENERAL SERV PRIMARY (10)	ANNUAL GENERAL SERV SECONDARY (11)	ANNUAL GENERAL SERV PRIMARY (12)	STREET AND PRIVATE LIGHTING (13)	GENERAL SERVICE SUBTRANSMSN (14)	GENERAL SERVICE TRANSMISSION (15)	DIRECT DISTRIBUTION CONNECTION (16)
	OPERATION & MAINTENANCE EXP-8										
	Distribution Expenses - ACE										
4	Operation	TI ARDO	600.072	156 450	7 500	07 00E	27 944	14.260	14.940	A A7E	E7E
2	958000 Operation Supervision & Engineering 958100 Load dispatching	TLABDO SALESWOT	609,072 2,158,896	156,450 370,588	7,508 13,821	87,805 397,483	27,814 116,372	14,269 21,472	14,849 113,474	4,475 0	575 2,252
3	958200 Station expenses	PLT362	14,982	2,685	134	3,030	1,095	79	174	0	28
4	958300 Overhead line expenses	PLTDOHLN	2,874,514	514,200	21,368	580,158	175,065	15,013	4,164	0	5,312
5	958400 Underground line expenses	PLTDUGLN	0	0	0	0	0	0	0	0	0
6	958500 Street lighting	_PLT373	0	0	0	0	0	431,115	0	0	0
7	958600 Meter expenses	_PLT370	3,600,376	1,440,846	82,811	205,089	123,986	0	85,472	73,061	0
8 9	958700 Customer installations expenses 958800 Miscellaneous distribution expenses	_PLT369 EXPDISTO	588,190 11,123,407	104,901 2,930,152	0 142,260	118,326 1,570,417	0 501,583	563,192	0 244,800	0 87,983	1,083 10,446
10	958900 Rents	EXPDISTO	2,290,741	603,432	29,297	323,410	103,295	115,983	50,414	18,119	2,151
11	Total Operation		23,260,178	6,123,254	297,198	3,285,718	1,049,210	1,161,124	513,346	183,638	21,846
	Maintenance		.,,	., .,	, , , ,			, . ,			
12	959000 Maintenance Supervision & Engineering	TLABDM	1,520	272	11	307	91	97	9	0	3
13	959200 Maintain equipment	_PLT362	3,004,597	538,431	26,799	607,590	219,629	15,770	34,865	0	5,564
14	959300 Maintain overhead lines	PLTDOHLN	43,499,722	7,781,339	323,358	8,779,477	2,649,237	227,191	63,007	0	80,380
15 16	959400 Maintain underground line 959500 Maintain line transformers	PLTDUGLN PLT368	3,062,548 405,612	547,843 72,161	18,157 0	618,118 81,379	148,868 0	15,996 2,086	51,939 0	0	5,659 745
17	959600 Maintain line transformers 959600 Maintain street lighting & signal systems	PLT373	103,012	72,101	0	01,579	0	1,823,429	0	0	0
18	959700 Maintain meters	PLT370	4,881	1,953	112	278	168	0	116	99	0
19	959800 Maintain distribution plant	_ EXPDISTM	899,303	160,899	6,630	181,505	54,305	37,508	2,698	2	1,662
20	Total Maintenance		50,878,183	9,102,899	375,068	10,268,654	3,072,298	2,122,078	152,633	101	94,012
21	Total Distribution Expenses - ACE		74,138,360	15,226,152	672,266	13,554,372	4,121,508	3,283,202	665,979	183,739	115,859
			10,326,710								
	Customer Accounts Expenses	01107000	0.045.000	==		70.400	54.000		00.470	45.040	
22 23	990200 Meter reading expenses	CUST902 CUST903	6,615,626	751,821	33,424	78,466 259,915	51,329 28,627	0 451 210	23,476 11,553	15,916	77 244
24	990300 Cust records and collection exp 990500 Miscellaneous cust accounts exp	EXP9023	44,499,573 0	4,597,083 0	27,907 0	239,913	20,027	451,219 0	11,555	204,281	77,241 0
25	Total Customer Accounts Expenses	_LXI 3023	51,115,200	5,348,904	61,331	338,381	79,956	451,219	35,029	220,197	77,241
26	Customer Service Expenses 990700 Supervision	CSERV	0	0	0	0	0	0	0	0	0
27	990800 Customer assistance expenses	CSERV	3,374,136	651,007	22,940	468,874	158,118	46,251	158,549	140,828	8,989
28	990900 Informational & instructional adv	CSERV	196,088	37,833	1,333	27,249	9,189	2,688	9,214	8,184	522
29	991000 Miscellaneous customer service & informati	c CSERV	0	0	0	0	0	0	0	0	0
30	Total Customer Service Expenses		3,570,224	688,841	24,273	496,122	167,307	48,939	167,763	149,012	9,511
	Sales Expense										
31	991200 Demonstrating & selling expenses	CSALES	0	0	0	0	0	0	0	0	0
32	991300 Advertising expense	CSALES	0	0	0	0	0	0	0	0	0
33	Total Sales Expense		0	0	0	0	0	0	0	0	0

		ALLOC	TOTAL ACE DISTRIBUTION (1)	TOTAL RESIDENTIAL SERVICE (2)	MONTHLY GENERAL SERVICE (3)	ANNUAL GENERAL SERVICE (4)	TRANSM GENERAL SERVICE (5)	STREET LIGHTING SERVICE (6)	DIRECT DISTRIBUTION CONNECTION (7)
	OPERATION & MAINT EXP CON'T-9								
	Administrative & General Expense								
	Operation								
1	992000 Administrative & General salaries	LABOR	3,046,550	2,040,730	444,349	435,619	38,345	84,685	2,822
2	992100 Office supplies & expenses	LABOR	2,091,745	1,401,154	305,087	299,094	26,327	58,144	1,938
3	992300 Outside services employed	LABOR	59,647,957	39,955,152	8,699,837	8,528,923	750,749	1,658,038	55,258
4	992400 Property insurance	PLANT	422,894	278,717	54,043	65,804	1,949	21,895	486
5	992500 Injuries & damages	LABOR	322,122	215,773	46,983	46,060	4,054	8,954	298
6	992600 Employee pensions & benefits	LABOR	8,391,567	5,621,086	1,223,936	1,199,891	105,619	233,261	7,774
	992800 Regulatory commission expenses								
7	Regulatory commission exp - NJ Retail	CLAIMREV	668,768	458,883	88,018	90,493	5,039	25,587	748
8	Total Acct 992800 Regulatory comm Exp		668,768	458,883	88,018	90,493	5,039	25,587	748
9	992900 Duplicate charges-Credit	LABOR	0	0	0	0	0	0	0
10	993010 General ad expenses	LABOR	585,376	392,114	85,379	83,702	7,368	16,272	542
11	993020 Miscellaneous general expenses	LABOR	736,055	493,046	107,356	105,247	9,264	20,460	682
12	993100 Rents	LABOR	0	0	0	0	0	0	0
13	Total Operation		75,913,034	50,856,656	11,054,986	10,854,832	948,714	2,127,296	70,549
	Maintenance								
14	993500 Maintenance of general plant	GENPLT	414,526	277,670	60,460	59,272	5,217	11,523	384
15	Total Maintenance		414,526	277,670	60,460	59,272	5,217	11,523	384
16	Total Administrative & General Exp		76,327,560	51,134,326	11,115,446	10,914,104	953,932	2,138,819	70,933
17	Total Operation & Maintenance Expense		251,338,447	179,958,110	33,137,213	29,671,750	2,375,651	5,922,178	273,543

		ALLOC	RESIDENTIAL (8)-2	MONTHLY GENERAL SERV SECONDARY (9)	MONTHLY GENERAL SERV PRIMARY (10)	ANNUAL GENERAL SERV SECONDARY (11)	ANNUAL GENERAL SERV PRIMARY (12)	STREET AND PRIVATE LIGHTING (13)	GENERAL SERVICE SUBTRANSMSN (14)	GENERAL SERVICE TRANSMISSION (15)	DIRECT DISTRIBUTION CONNECTION (16)
	OPERATION & MAINT EXP CON'T-9										
	Administrative & General Expense										
	Operation										
1	992000 Administrative & General salaries	LABOR	2,040,730	425,468	18,881	333,508	102,111	84,685	29,557	8,788	2,822
2	992100 Office supplies & expenses	LABOR	1,401,154	292,124	12,963	228,985	70,109	58,144	20,294	6,034	1,938
3	992300 Outside services employed	LABOR	39,955,152	8,330,175	369,661	6,529,712	1,999,211	1,658,038	578,693	172,055	55,258
4	992400 Property insurance	PLANT	278,717	52,359	1,684	53,936	11,868	21,895	1,650	298	486
5	992500 Injuries & damages	LABOR	215,773	44,986	1,996	35,263	10,797	8,954	3,125	929	298
6	992600 Employee pensions & benefits	LABOR	5,621,086	1,171,930	52,006	918,632	281,259	233,261	81,413	24,206	7,774
	992800 Regulatory commission expenses										
7	Regulatory commission exp - NJ Retail	CLAIMREV	458,883	85,069	2,948	72,213	18,280	25,587	3,650	1,389	748
8	Total Acct 992800 Regulatory comm Exp		458,883	85,069	2,948	72,213	18,280	25,587	3,650	1,389	748
9	992900 Duplicate charges-Credit	LABOR	0	0	0	0	0	0	0	0	0
10	993010 General ad expenses	LABOR	392,114	81,751	3,628	64,082	19,620	16,272	5,679	1,689	542
11	993020 Miscellaneous general expenses	LABOR	493,046	102,794	4,562	80,577	24,670	20,460	7,141	2,123	682
12	993100 Rents	LABOR	0	0	0	0	0	0	0	0	0
13	Total Operation		50,856,656	10,586,657	468,329	8,316,908	2,537,924	2,127,296	731,203	217,511	70,549
	Maintenance										
14	993500 Maintenance of general plant	GENPLT	277,670	57,891	2,569	45,379	13,894	11,523	4,022	1,196	384
15	Total Maintenance		277,670	57,891	2,569	45,379	13,894	11,523	4,022	1,196	384
16	Total Administrative & General Exp		51,134,326	10,644,548	470,898	8,362,286	2,551,818	2,138,819	735,225	218,707	70,933
17	Total Operation & Maintenance Expense		179,958,110	31,908,445	1,228,769	22,751,162	6,920,588	5,922,178	1,603,996	771,655	273,543

		ALLOC	TOTAL ACE DISTRIBUTION (1)	TOTAL RESIDENTIAL SERVICE (2)	MONTHLY GENERAL SERVICE (3)	ANNUAL GENERAL SERVICE (4)	TRANSM GENERAL SERVICE (5)	STREET LIGHTING SERVICE (6)	DIRECT DISTRIBUTION CONNECTION (7)
	DEPRECIATION & AMORT EXP-10								
	Depreciation & Amortization Acct 403 Depreciation Distribution								
1	ACE	DISTPLT	91,653,327	60,287,286	11,513,869	14,400,546	334,514	5,009,232	107,880
2	General	GENPLT	10,237,634	6,857,674	1,493,190	1,463,856	128,854	284,576	9,484
3	A/C 403 Total		101,890,961	67,144,960	13,007,059	15,864,402	463,368	5,293,808	117,364
	Acct 404 Amortization								
4	Amort of Limited Term Plant	LABOR	0	0	0	0	0	0	0
5	Amort of Software - Elec	LABOR	13,408,659	8,981,783	1,955,694	1,917,273	168,766	372,721	12,422
	A/C 404 Total		13,408,659	8,981,783	1,955,694	1,917,273	168,766	372,721	12,422
	Acct 405 Amortization of Intangible Electric								
6	Intangible - Software	LABOR	0	0	0	0	0	0	0
7	Misc. Amortization	PLANT	0	0	0	0	0	0	0
8	General	PLANT	0	0	0	0	0	0	0
9	A/C 405 Total		0	0	0	0	0	0	0
	Acct 407 Amortization - Other								
10	Misc. Amortization	PLANT	709,100	467,346	90,618	110,339	3,268	36,713	816
11	A/C 407 Total		709,100	467,346	90,618	110,339	3,268	36,713	816
12	Total Depreciation and Amortization		116,008,720	76,594,089	15,053,371	17,892,014	635,402	5,703,242	130,602

		ALLOC	RESIDENTIAL (8)-2	MONTHLY GENERAL SERV SECONDARY (9)	MONTHLY GENERAL SERV PRIMARY (10)	ANNUAL GENERAL SERV SECONDARY (11)	ANNUAL GENERAL SERV PRIMARY (12)	STREET AND PRIVATE LIGHTING (13)	GENERAL SERVICE SUBTRANSMSN (14)	GENERAL SERVICE TRANSMISSION (15)	DIRECT DISTRIBUTION CONNECTION (16)
	DEPRECIATION & AMORT EXP-10										
	Depreciation & Amortization Acct 403 Depreciation Distribution										
1	ACE	DISTPLT	60,287,286	11,173,211	340,657	11,888,466	2,512,080	5,009,232	293,836	40,678	107,880
2	General	GENPLT	6,857,674	1,429,744	63,447	1,120,722	343,133	284,576	99,324 393,159	29,531 70,209	9,484 117,364
3	A/C 403 Total		67,144,960	12,602,955	404,104	13,009,189	2,855,213	5,293,808	393,139	70,209	117,304
	Acct 404 Amortization										
	Amort of Limited Term Plant	LABOR	0	0	0	0	0	. 0	0	0	0
5	Amort of Software - Elec	LABOR	8,981,783	1,872,595	83,099	1,467,857	449,416	372,721	130,088	38,677	12,422
	A/C 404 Total		8,981,783	1,872,595	83,099	1,467,857	449,416	372,721	130,088	38,677	12,422
	Acct 405 Amortization of Intangible Electric										
6	Intangible - Software	LABOR	0	0	0	0	0	0	0	0	0
7	Misc. Amortization	PLANT	0	0	0	0	0	0	0	0	0
8	General	PLANT	0	0	0	0	0	0	0	0	0
9	A/C 405 Total		0	0	0	0	0	0	0	0	0
	Acct 407 Amortization - Other										
10	Misc. Amortization	PLANT	467,346	87,794	2,824	90,439	19,900	36,713	2,767	500	816
11	A/C 407 Total		467,346	87,794	2,824	90,439	19,900	36,713	2,767	500	816
12	Total Depreciation and Amortization		76,594,089	14,563,344	490,027	14,567,485	3,324,529	5,703,242	526,015	109,387	130,602

		ALLOC	TOTAL ACE DISTRIBUTION (1)	TOTAL RESIDENTIAL SERVICE (2)	MONTHLY GENERAL SERVICE (3)	ANNUAL GENERAL SERVICE (4)	TRANSM GENERAL SERVICE (5)	STREET LIGHTING SERVICE (6)	DIRECT DISTRIBUTION CONNECTION (7)
	OTHER TAXES & EXPENSES-11								
	Other Taxes								
1	Payroll Taxes - FICA	LABOR	2,284,834	1,530,495	333,250	326,703	28,758	63,512	2,117
2	Payroll Taxes - FUTA/SUTA	LABOR	0	0	0	0	0	0	0
3	Property Taxes - New Jersey	PLANT	1,338,533	882,187	171,056	208,281	6,168	69,301	1,540
4	Franchise Tax	PLANT	0	0	0	0	0	0	0
5	Misc. Amortization	PLTDOHLN	0	0	0	0	0	0	0
6	Misc. Tax	TEFAREV	2,072,644	1,599,551	592,799	(105,708)	0	(13,997)	0
7	Sales & Use Taxes	DISTOMEXP	(211,512)	(151,443)	(27,886)	(24,970)	(1,999)	(4,984)	(230)
8	Total Other Taxes		5,484,499	3,860,790	1,069,218	404,307	32,927	113,832	3,426
	Net ITC Adjustment								
9	Distribution - ACE	DISTPLT	(157,134)	(103,359)	(19,740)	(24,689)	(574)	(8,588)	(185)
10	General	GENPLT	2,461	1,648	359	352	31	68	2
11	Total Net ITC Adjustment		(154,673)	(101,710)	(19,381)	(24,337)	(543)	(8,520)	(183)
	IOCD								
12	ACE	CUSTDEP	41,011	18,357	10,065	12,589	0	0	0
13	Total Interest on Customer Deposits		41,011	18,357	10,065	12,589	0	0	0

		ALLOC	RESIDENTIAL (8)-2	MONTHLY GENERAL SERV SECONDARY (9)	MONTHLY GENERAL SERV PRIMARY (10)	ANNUAL GENERAL SERV SECONDARY (11)	ANNUAL GENERAL SERV PRIMARY (12)	STREET AND PRIVATE LIGHTING (13)	GENERAL SERVICE SUBTRANSMSN (14)	GENERAL SERVICE TRANSMISSION (15)	DIRECT DISTRIBUTION CONNECTION (16)
	OTHER TAXES & EXPENSES-11										
	Other Taxes										
1	Payroll Taxes - FICA	LABOR	1,530,495	319,090	14,160	250,123	76,580	63,512	22,167	6,591	2,117
2	Payroll Taxes - FUTA/SUTA	LABOR	0	0	0	0	0	0	0	0	0
3	Property Taxes - New Jersey	PLANT	882,187	165,725	5,331	170,717	37,564	69,301	5,224	944	1,540
4	Franchise Tax	PLANT	0	0	0	0	0	0	0	0	0
5	Misc. Amortization	PLTDOHLN	0	0	0	0	0	0	0	0	0
6	Misc. Tax	TEFAREV	1,599,551	592,799	0	(105,708)	0	(13,997)	0	0	0
7	Sales & Use Taxes	DISTOMEXP	(151,443)	(26,852)	(1,034)	(19,146)	(5,824)	(4,984)	(1,350)	(649)	(230)
8	Total Other Taxes		3,860,790	1,050,761	18,457	295,986	108,320	113,832	26,041	6,886	3,426
	Net ITC Adjustment										
9	Distribution - ACE	DISTPLT	(103,359)	(19,156)	(584)	(20,382)	(4,307)	(8,588)	(504)	(70)	(185)
10	General	GENPLT	1,648	344	15	269	82	68	24	7	2
11	Total Net ITC Adjustment		(101,710)	(18,812)	(569)	(20,113)	(4,224)	(8,520)	(480)	(63)	(183)
	IOCD										
12	ACE	CUSTDEP	18,357	9,768	298	10,393	2,196	0	0	0	0
13	Total Interest on Customer Deposits		18,357	9,768	298	10,393	2,196	0	0	0	0

		ALLOC	TOTAL ACE DISTRIBUTION (1)	TOTAL RESIDENTIAL SERVICE (2)	MONTHLY GENERAL SERVICE (3)	ANNUAL GENERAL SERVICE (4)	TRANSM GENERAL SERVICE (5)	STREET LIGHTING SERVICE (6)	DIRECT DISTRIBUTION CONNECTION (7)
	DEVELOPMENT OF INCOME TAXES-12								
1	FEDERAL & STATE TAX CALCULATION OPERATING REVENUES		485,404,697	301.859.596	07 204 442	71.462.414	E 440 070	10.017.004	598.402
'	OPERATING REVENUES OPERATING EXPENSES		485,404,697	301,859,596	87,324,113	71,402,414	5,142,279	19,017,894	598,402
2			251,338,447	179,958,110	33,137,213	29,671,750	2,375,651	5,922,178	273,543
3	Depreciation and Amortization		116,008,720	76,594,089	15,053,371	17,892,014	635,402	5,703,242	130,602
4	Taxes Other than Income Tax		5,484,499	3,860,790	1,069,218	404,307	32,927	113,832	3,426
5	OPERATING INC BEFORE FED TAX		112,573,032	41,446,607	38,064,311	23,494,343	2,098,299	7,278,642	190,831
6	Less: Interest Expense	PLANT	35,225,686	23,216,195	4,501,613	5,481,265	162,325	1,823,773	40,515
-	Schedule M	LABOR	42.052	0.744	4.004	4.000	404	202	40
7 8	Labor	LABOR PLANT	13,053 1,617,508	8,744 1,066,051	1,904 206.707	1,866 251.691	164 7,454	363 83.745	12 1,860
9	Plant (Flow Through) Timing Labor	LABOR	5,396,695	3,614,973	787,124	771,661	7,454 67,925	150,012	5,000
10	Timing Labor	PLANT	(110,912,272)	(73,098,958)	(14,173,866)	(17,258,416)	(511,099)	(5,742,367)	(127,567)
11	Total Schedule M	LAN	(103,885,016)	(68,409,190)	(13,178,130)	(16,233,197)	(435,557)	(5,508,247)	(120,695)
	TAXABLE INCOME		(26,537,670)	(50,178,778)	20,384,567	1,779,881	1,500,418	(53,378)	29,620
	State Income Taxes		(2,388,390)	(4,516,090)	1,834,611	160,189	135,038	(4,804)	2,666
	NJ Depreciation Amortization	PLANT	(4,345,502)	(2,863,990)	(555,327)	(676,178)	(20,025)	(224,984)	(4,998)
	NJSA Amortization	PLANT	0	0	0	0	0	0	0
13	State Income Taxes Sub Total		(6,733,892)	(7,380,080)	1,279,284	(515,989)	115,013	(229,788)	(2,332)
14	New Jersey NOL		6,733,892	7,380,080	(1,279,284)	515,989	(115,013)	229,788	2,332
15	Total State Income Taxes		0	0	0	0	0	0	0
16	Federal Income Taxes		(5,572,911)	(10,537,543)	4,280,759	373,775	315,088	(11,209)	6,220
17 18	Federal NOL Total Federal Income Taxes		5,572,911 0	10,537,543 0	(4,280,759) 0	(373,775) 0	(315,088) 0	11,209 0	(6,220)
10	Deferred State Income Taxes		U	Ü	U	U	U	U	U
19	State NOL		(6,733,892)	(7,380,080)	1,279,284	(515,989)	115,013	(229,788)	(2,332)
20	Timing Labor	LABOR	(485,703)	(325,348)	(70,841)	(69,449)	(6,113)	(13,501)	(450)
21	Timing Eabor	PLANT	9,982,104	6,578,906	1,275,648	1,553,257	45,999	516,813	11,481
22	Timing State Only	PLANT	4,345,502	2,863,990	555,327	676,178	20,025	224,984	4,998
23	Total Deferred State Income Taxes-Current Year		7,108,012	1,737,469	3,039,418	1,643,997	174,923	498,508	13,697
24	State Deferred Income Taxes-Prior Year	PLANT	0	0	0	0	0	0	0
25	Total State Deferred Income Tax		7,108,012	1,737,469	3,039,418	1,643,997	174,923	498,508	13,697
	Deferred Federal Income Taxes		(5.550.044)	(40 507 540)	4 000 750		0.45.000	(44.000)	
26	FED NOL	LABOR	(5,572,911)	(10,537,543)	4,280,759	373,775	315,088	(11,209)	6,220
27	Timing Labor	PLANT	(1,031,308)	(690,821)	(150,419)	(147,464)	(12,980)	(28,667) 1,097,366	(955) 24,378
28 29	Timing Plant Timing State Only	PLANT	21,195,335 (912,555)	13,969,211 (601,438)	2,708,626 (116,619)	3,298,083 (141,997)	97,671 (4,205)	(47,247)	(1,050)
30	NOL Payable Netting Entry - FBOS	PLANT	(22,556,903)	(14,866,580)	(2,882,625)	(3,509,949)	(103,945)	(1,167,860)	(25,944)
31	Total Deferred Federal Income Taxes-Current Year		(8,878,343)	(12,727,171)	3,839,721	(127,553)	291,628	(157,617)	2,649
32	Federal Deferred Income Taxes-Prior Year	PLANT	0	(1=,1=1,111)	0	0	0	0	0
33	Total Federal Deferred Income Tax		(8,878,343)	(12,727,171)	3,839,721	(127,553)	291,628	(157,617)	2,649
34	Total Income Taxes		(1,770,331)	(10,989,703)	6,879,139	1,516,445	466,551	340,891	16,346
35	Total Expenses		370,947,672	249,339,933	56,129,626	49,472,767	3,509,988	12,071,624	423,734
36	Net Operating Income		114,457,025	52,519,663	31,194,487	21,989,646	1,632,291	6,946,271	174,667

		ALLOC	RESIDENTIAL (8)-2	MONTHLY GENERAL SERV SECONDARY (9)	MONTHLY GENERAL SERV PRIMARY (10)	ANNUAL GENERAL SERV SECONDARY (11)	ANNUAL GENERAL SERV PRIMARY (12)	STREET AND PRIVATE LIGHTING (13)	GENERAL SERVICE SUBTRANSMSN (14)	GENERAL SERVICE TRANSMISSION (15)	DIRECT DISTRIBUTION CONNECTION (16)
	DEVELOPMENT OF INCOME TAXES-12										
	FEDERAL & STATE TAX CALCULATION										
1	OPERATING REVENUES OPERATING EXPENSES		301,859,596	85,491,725	1,832,388	58,530,784	12,931,629	19,017,894	3,048,737	2,093,542	598,402
2	Operation & Maintenance Expense		179,958,110	31,908,445	1,228,769	22,751,162	6,920,588	5,922,178	1,603,996	771,655	273,543
3	Depreciation and Amortization		76,594,089	14,563,344	490,027	14,567,485	3,324,529	5,703,242	526,015	109,387	130,602
4			3,860,790	1,050,761	18,457	295,986	108,320	113,832	26,041	6,886	3,426
5		D. 41.17	41,446,607	37,969,175	95,136	20,916,151	2,578,192	7,278,642	892,684	1,205,615	190,831
6	•	PLANT	23,216,195	4,361,316	140,298	4,492,707	988,558	1,823,773	137,471	24,854	40,515
7	Schedule M Labor	LABOR	8,744	1,823	81	1,429	438	363	127	38	12
8	Plant (Flow Through)	PLANT	1,066,051	200,265	6,442	206,298	45,393	83,745	6,312	1,141	1.860
9		LABOR	3,614,973	753,679	33,445	590,781	180,880	150,012	52,358	15,567	5,000
10	Timing Plant	PLANT	(73,098,958)	(13,732,122)	(441,744)	(14,145,822)	(3,112,593)	(5,742,367)	(432,843)	(78,256)	(127,567)
11	Total Schedule M		(68,409,190)	(12,776,355)	(401,775)	(13,347,315)	(2,885,883)	(5,508,247)	(374,046)	(61,511)	(120,695)
12	TAXABLE INCOME		(50,178,778)	20,831,504	(446,937)	3,076,130	(1,296,249)	(53,378)	381,168	1,119,250	29,620
	State Income Taxes		(4,516,090)	1,874,835	(40,224)	276,852	(116,662)	(4,804)	34,305	100,733	2,666
	NJ Depreciation Amortization	PLANT	(2,863,990)	(538,020)	(17,307)	(554,228)	(121,950)	(224,984)	(16,959)	(3,066)	(4,998)
	NJSA Amortization	PLANT	0	0	0	0	0	0	0	0	0
13	State Income Taxes Sub Total		(7,380,080)	1,336,816	(57,532)	(277,376)	(238,613)	(229,788)	17,346	97,666	(2,332)
14			7,380,080	(1,336,816)	57,532	277,376	238,613	229,788	(17,346)	(97,666)	2,332
15	Total State Income Taxes		0	0	0	0	0	0	0	. 0	0
16			(10,537,543)	4,374,616	(93,857)	645,987	(272,212)	(11,209)	80,045	235,043	6,220
17 18	Federal NOL Total Federal Income Taxes		10,537,543	(4,374,616) 0	93,857 0	(645,987) 0	272,212 0	11,209 0	(80,045)	(235,043)	(6,220)
10	Deferred State Income Taxes		U	U	U	U	U	U	U	U	U
19	State NOL		(7,380,080)	1,336,816	(57,532)	(277,376)	(238,613)	(229,788)	17,346	97,666	(2,332)
20	Timing Labor	LABOR	(325,348)	(67,831)	(3,010)	(53,170)	(16,279)	(13,501)	(4,712)	(1,401)	(450)
21	Timing Plant	PLANT	6,578,906	1,235,891	39,757	1,273,124	280,133	516,813	38,956	7,043	11,481
22	Timing State Only	PLANT	2.863.990	538.020	17,307	554,228	121,950	224,984	16,959	3,066	4,998
23	Total Deferred State Income Taxes-Current Year		1,737,469	3,042,895	(3,477)	1,496,805	147,192	498,508	68,549	106,375	13,697
24	State Deferred Income Taxes-Prior Year	PLANT	0	0	0	0	0	0	0	0	0
25	Total State Deferred Income Tax		1,737,469	3,042,895	(3,477)	1,496,805	147,192	498,508	68,549	106,375	13,697
	Deferred Federal Income Taxes										
26	FED NOL	1.4505	(10,537,543)	4,374,616	(93,857)	645,987	(272,212)	(11,209)	80,045	235,043	6,220
27	Timing Labor	LABOR	(690,821)	(144,028)	(6,391)	(112,898)	(34,566)	(28,667)	(10,006)	(2,975)	(955)
28 29	Timing Plant Timing State Only	PLANT PLANT	13,969,211 (601,438)	2,624,208 (112,984)	84,417 (3,635)	2,703,267 (116,388)	594,817 (25,610)	1,097,366 (47,247)	82,716 (3,561)	14,955 (644)	24,378 (1,050)
30	NOL Payable Netting Entry - FBOS	PLANT	(14,866,580)	(2,792,785)	(89,840)	(2,876,922)	(633,027)	(1,167,860)	(88,030)	(15,915)	(25,944)
31	Total Deferred Federal Income Taxes-Current Year		(12,727,171)	3,949,027	(109,306)	243,046	(370,599)	(1,167,660)	61,165	230,463	2,649
32		PLANT	(12,727,171)	0,040,027	(100,000)	240,040	(0,0,000)	(107,017)	01,100	0	2,040
33	Total Federal Deferred Income Tax	,	(12,727,171)	3,949,027	(109,306)	243,046	(370,599)	(157,617)	61,165	230,463	2,649
34	Total Income Taxes		(10,989,703)	6,991,922	(112,783)	1,739,851	(223,407)	340,891	129,714	336,838	16,346
35			249,339,933	54,505,428	1,624,198	39,344,765	10,128,003	12,071,624	2,285,286	1,224,703	423,734
36	Net Operating Income		52,519,663	30,986,297	208,190	19,186,020	2,803,627	6,946,271	763,451	868,840	174,667

			TOTAL ACE DISTRIBUTION	TOTAL RESIDENTIAL SERVICE	MONTHLY GENERAL SERVICE	ANNUAL GENERAL SERVICE	TRANSM GENERAL SERVICE	STREET LIGHTING SERVICE	DIRECT DISTRIBUTION CONNECTION
		ALLOC	(1)	(2)	(3)	(4)	(5)	(6)	(7)
	DEVELOPMENT OF LABOR ALLOCATOR-13	3							
	Distribution Labor - ACE Operation Labor								
1	958000 Operation Supervision & Engineering	LABDO	142,071	93,769	25,242	17,800	2,975	2,197	88
2	958100 Load dispatching	_EXP581	2,314,814	1,564,459	278,565	372,369	82,230	15,560	1,632
3	958200 Station expenses	_EXP582	2,436	1,644	309	453	19	9	3
4	958300 Overhead line expenses	_EXP583	1,835,174	1,259,068	234,585	330,796	1,824	6,576	2,327
5	958400 Underground line expenses	_EXP584	0	0	0	0	0	0	0
6	958500 Street lighting	_EXP585	0	0	0	0	0	0	0
7	958600 Meter expenses	_EXP586	2,515,060	1,613,639	682,882	147,487	71,052	0	0
8 9	958700 Customer installations expenses	_EXP587 EXP588	367,307	265,903 3,237,777	47,422 894.311	53,492	0	163,933	490
10	958800 Miscellaneous distribution expenses 958900 Rents	EXP588	4,999,040 0	3,237,777	094,311	603,113 0	96,866 0	103,933	3,041 0
11	Total Operation Labor	_EXE309	12,175,904	8,036,259	2,163,316	1,525,509	254,966	188,274	7,580
• • •	Maintenance Labor		12,170,004	0,000,200	2,100,010	1,020,000	204,000	100,214	7,000
12	959000 Maintenance Supervision & Engineering	LABDM	1.522	1.002	187	262	6	64	2
13	959200 Maintain equipment	EXP592	2.114.073	1.426.361	268.330	392,703	16.552	7.487	2.641
14	959300 Maintain overhead lines	EXP593	8,263,506	5,669,387	1,056,298	1,489,522	8,212	29,610	10,476
15	959400 Maintain underground line	EXP594	2,192,500	1,502,449	277,673	376,274	25,480	7,847	2,776
16	959500 Maintain line transformers	_EXP595	191,059	137,897	24,533	27,667	0	709	253
17	959600 Maintain street lighting & signal systems	_EXP596	521,038	0	0	0	0	521,038	0
18	959700 Maintain meters	_EXP597	5,239	3,361	1,422	307	148	0	0
19	959800 Maintain distribution plant	_EXP598	453,494	303,328	56,506	79,537	911	12,651	560
20	Total Maintenance Labor		13,742,430	9,043,786	1,684,949	2,366,272	51,308	579,406	16,709
21	Total Distribution Labor - ACE		25,918,334	17,080,045	3,848,265	3,891,781	306,274	767,681	24,289
	Customer Accounts Labor								
22	990200 Meter reading expenses	_EXP902	1,081,552	945,190	112,190	18,544	5,628	0	0
23	990300 Customer records and collection expenses	_EXP903	275,982	244,851	25,448	1,588	1,188	2,483	425
24	990500 Miscellaneous customer accounts expenses	_EXP905	0	0	0	0	0	0	0
25	Total Customer Accounts Labor		1,357,533	1,190,040	137,638	20,132	6,816	2,483	425
	Customer Service Labor								
26	990700 Supervision	_EXP907	0	0	0	0	0	0	0
27	990800 Customer assistance expenses	_EXP908	643,727	431,840	86,255	80,246	38,316	5,919	1,150
28	991000 Miscellaneous customer service & information	:_EXP910	0	0	0	0	0	0	0
29	Total Customer Service Labor		643,727	431,840	86,255	80,246	38,316	5,919	1,150
	Sales Labor								
30	991200 Demonstrating & selling expenses	EXP912	0	0	0	0	0	0	0
31	991300 Advertising expense	_ EXP913	0	0	0	0	0	0	0
32	Total Sales Labor	_	0	0	0	0	0	0	0

		ALLOC	RESIDENTIAL (8)-2	MONTHLY GENERAL SERV SECONDARY (9)	MONTHLY GENERAL SERV PRIMARY (10)	ANNUAL GENERAL SERV SECONDARY (11)	ANNUAL GENERAL SERV PRIMARY (12)	STREET AND PRIVATE LIGHTING (13)	GENERAL SERVICE SUBTRANSMSN (14)	GENERAL SERVICE TRANSMISSION (15)	DIRECT DISTRIBUTION CONNECTION (16)
	DEVELOPMENT OF LABOR ALLOCATOR-13	3									
	Distribution Labor - ACE										
1	Operation Labor 958000 Operation Supervision & Engineering	LABDO	93.769	24.086	1.156	13.518	4.282	2.197	2,286	689	88
2	958100 Load dispatching	_EXP581	1,564,459	268,549	10,016	288,039	84,330	15,560	82,230	0	1,632
3	958200 Station expenses	_EXP582	1,644	295	15	332	120	9	19	0	3
4 5	958300 Overhead line expenses	_EXP583 EXP584	1,259,068 0	225,225 0	9,359 0	254,116 0	76,680 0	6,576 0	1,824 0	0	2,327 0
6	958400 Underground line expenses 958500 Street lighting	EXP585	0	0	0	0	0	0	0	0	0
7	958600 Meter expenses	EXP586	1,613,639	645,767	37,115	91,918	55,569	0	38,307	32,745	0
8	958700 Customer installations expenses	_EXP587	265,903	47,422	0	53,492	0	0	0	0	490
9	958800 Miscellaneous distribution expenses	_EXP588	3,237,777	852,902	41,409	457,114	146,000	163,933	71,256	25,610	3,041
10 11	958900 Rents Total Operation Labor	_EXP589	0 8,036,259	0 2,064,247	0 99,069	0 1,158,528	0 366,981	0 188,274	0 195,922	0 59,044	0 7,580
	Maintenance Labor		0,030,239	2,004,247	99,009	1,130,320	300,961	100,274	195,922	35,044	7,300
12		LABDM	1,002	179	7	202	60	64	6	0	2
13	959200 Maintain equipment	_EXP592	1,426,361	255,607	12,722	288,439	104,263	7,487	16,552	0	2,641
14	959300 Maintain overhead lines	_EXP593	5,669,387	1,014,154	42,144	1,144,243	345,279	29,610	8,212	0	10,476
15	959400 Maintain underground line	_EXP594	1,502,449	268,765	8,908	303,241	73,033	7,847	25,480	0	2,776
16 17	959500 Maintain line transformers	_EXP595 EXP596	137,897 0	24,533	0	27,667 0	0	709 521,038	0	0	253 0
18	959600 Maintain street lighting & signal systems 959700 Maintain meters	EXP597	3,361	1,345	77	191	116	321,036 N	80	68	0
19	959800 Maintain distribution plant	EXP598	303,328	54,270	2,236	61,220	18,317	12,651	910	1	560
20	Total Maintenance Labor	_	9,043,786	1,618,854	66,095	1,825,204	541,068	579,406	51,239	69	16,709
21	Total Distribution Labor - ACE		17,080,045	3,683,101	165,164	2,983,732	908,049	767,681	247,161	59,113	24,289
	Customer Accounts Labor										
22	990200 Meter reading expenses	_EXP902	945,190	107,414	4,775	11,211	7,334	0	3,354	2,274	0
23		_EXP903	244,851	25,295	154	1,430	158	2,483	64	1,124	425
24	990500 Miscellaneous customer accounts expenses	_EXP905	0	0	0	0	0	0	0	0	0
25	Total Customer Accounts Labor		1,190,040	132,709	4,929	12,641	7,491	2,483	3,418	3,398	425
	Customer Service Labor										
26	990700 Supervision	_EXP907	0	0	0	0	0	0	0	0	0
27	990800 Customer assistance expenses	_EXP908	431,840	83,319	2,936	60,009	20,237	5,919	20,292	18,024	1,150
28 29	991000 Miscellaneous customer service & informatic Total Customer Service Labor	_EXP910	0 431,840	0 83,319	2,936	0 60,009	0 20,237	0 5,919	0 20,292	0 18,024	0 1,150
	Sales Labor										
30	991200 Demonstrating & selling expenses	_EXP912	0	0	0	0	0	0	0	0	0
31	991300 Advertising expense	_EXP913	0	0	0	0	0	0	0	0	0
32	Total Sales Labor		0	0	0	0	0	0	0	0	0

		ALLOC	TOTAL ACE DISTRIBUTION (1)	TOTAL RESIDENTIAL SERVICE (2)	MONTHLY GENERAL SERVICE (3)	ANNUAL GENERAL SERVICE (4)	TRANSM GENERAL SERVICE (5)	STREET LIGHTING SERVICE (6)	DIRECT DISTRIBUTION CONNECTION (7)
	DEVEL OF LABOR ALLOC CON'T-14								
	Administrative & General Labor								
	Operation Labor								
1	992000 Administrative & General salaries	_EXP920	3,092,042	2,071,202	450,984	442,124	38,917	85,950	2,864
2	992100 Office supplies & expenses	_EXP921	0	0	0	0	0	0	0
3	992300 Outside services employed	_EXP923	0	0	0	0	0	0	0
4	992800 Regulatory commission expenses	_EXP923	0	0	0	0	0	0	0
5	992900 Duplicate charges-Credit	_EXP923	0	0	0	0	0	0	0
6	993020 Miscellaneous general expenses	EXP9302	0	0	0	0	0	0	0
7	Total Operation Labor		3,092,042	2,071,202	450,984	442,124	38,917	85,950	2,864
	Maintenance Labor								
8	993500 Maintenance of general plant	EXP935	0	0	0	0	0	0	0
9	Total Maintenance Labor	_	0	0	0	0	0	0	0
10	Total Administrative & General Labor		3,092,042	2,071,202	450,984	442,124	38,917	85,950	2,864
11	Total Operation & Maintenance Labor		31,011,635	20,773,127	4,523,142	4,434,282	390,323	862,033	28,729

		ALLOC	RESIDENTIAL (8)-2	MONTHLY GENERAL SERV SECONDARY (9)	MONTHLY GENERAL SERV PRIMARY (10)	ANNUAL GENERAL SERV SECONDARY (11)	ANNUAL GENERAL SERV PRIMARY (12)	STREET AND PRIVATE LIGHTING (13)	GENERAL SERVICE SUBTRANSMSN (14)	GENERAL SERVICE TRANSMISSION (15)	DIRECT DISTRIBUTION CONNECTION (16)
	DEVEL OF LABOR ALLOC CON'T-14										
	Administrative & General Labor										
	Operation Labor										
1	992000 Administrative & General salaries	_EXP920	2,071,202	431,821	19,163	338,488	103,635	85,950	29,998	8,919	2,864
2	992100 Office supplies & expenses	_EXP921	0	0	0	0	0	0	0	0	0
3	992300 Outside services employed	_EXP923	0	0	0	0	0	0	0	0	0
4	992800 Regulatory commission expenses	_EXP923	0	0	0	0	0	0	0	0	0
5	992900 Duplicate charges-Credit	_EXP923	0	0	0	0	0	0	0	0	0
6	993020 Miscellaneous general expenses	_EXP9302	0	0	0	0	0	0	0	0	0
7	Total Operation Labor		2,071,202	431,821	19,163	338,488	103,635	85,950	29,998	8,919	2,864
	Maintenance Labor										
8	993500 Maintenance of general plant	EXP935	0	0	0	0	0	0	0	0	0
9	Total Maintenance Labor	_	0	0	0	0	0	0	0	0	0
10	Total Administrative & General Labor		2,071,202	431,821	19,163	338,488	103,635	85,950	29,998	8,919	2,864
11	Total Operation & Maintenance Labor		20,773,127	4,330,951	192,191	3,394,870	1,039,412	862,033	300,869	89,454	28,729

		TOTAL ACE DISTRIBUTION	TOTAL RESIDENTIAL SERVICE	MONTHLY GENERAL SERVICE	ANNUAL GENERAL SERVICE	TRANSM GENERAL SERVICE	STREET LIGHTING SERVICE	DIRECT DISTRIBUTION CONNECTION
	ALLOC	(1)	(2)	(3)	(4)	(5)	(6)	(7)
ALLOCATION FACTOR TA	BLE-15							
CAPACITY-DISTRIBUTION R Distribution Primary-Class ACED Distribution Secondry-Class ACE Dist Line Transformer Distr Pri-Class ACED - NONTGS	DEMPRI D DEMSEC DEMTRNSF S DPRITGSS	2,602,652 1.00000 1.00000 2,510,197	1,758,993 0.73166 0.73166 1,758,993	313,203 0.12559 0.12559 313,203	418,671 0.13471 0.13471 418,671	92,455 0.00000 0.00000 0	17,495 0.00728 0.00728 17,495	1835 0.00076 0.00076 1,835
6 Class Maximum Diversified Dema7 Class Maximum Diversified Dema		2,404,120 2,602,652	1,758,993 1,758,993	301,942 313,203	323,855 418,671	0 92,455	17,495 17,495	1,835 1,835
8 9 Class Maximum Diversified Dem 10 Class Maximum Diversified Dem 11 Dist Line Transformer NJ 12 Distr Pri-Class ACED - NONTGS	NJ Sec DEMSECS DEMTRNSFS	1.00000 1.00000 1.00000 1.00000	0.64522 0.72175 0.72175 0.68021	0.12193 0.12840 0.12840 0.12786	0.17853 0.14481 0.14481 0.18711	0.04969 0.00000 0.00000 0.00000	0.00343 0.00371 0.00371 0.00356	0.00120 0.00132 0.00132 0.00126
13 14 15 16 17 18 19 20 21 22 23 24 25 26 27 28 29 30 31 32 23 33 34 35 36 37 38 39 40 41 42 43 44	CUST369S	1.00000	0.72393	0.12911	0.14563	0.00000	0.00000	0.00133

	ALLOC	RESIDENTIAL (8)-2	MONTHLY GENERAL SERV SECONDARY (9)	MONTHLY GENERAL SERV PRIMARY (10)	ANNUAL GENERAL SERV SECONDARY (11)	ANNUAL GENERAL SERV PRIMARY (12)	STREET AND PRIVATE LIGHTING (13)	GENERAL SERVICE SUBTRANSMSN (14)	GENERAL SERVICE TRANSMISSION (15)	DIRECT DISTRIBUTION CONNECTION (16)
ALLOCATION FACTOR TABLE-15										
CAPACITY-DISTRIBUTION RELATED 1 Distribution Primary-Class ACED 2 Distribution Secondry-Class ACED 3 Dist Line Transformer 4 Distr Pri-Class ACED - NONTGSS	DEMPRI DEMSEC DEMTRNSF DPRITGSS	1,758,993 0.73166 0.73166 1,758,993	301,942 0.12559 0.12559 301,942	11,261 0.00000 0.00000 11,261	323,855 0.13471 0.13471 323,855	94,816 0.00000 0.00000 94,816	17,495 0.00728 0.00728 17,495		0.00000 0.00000 0.00000	1,835 0.00076 0.00076 1,835
5 6 Class Maximum Diversified Demands SEC 7 Class Maximum Diversified Demands PRI		1,758,993 1,758,993	301,942 301,942	0 11,261	323,855 323,855	0 94,816	17,495 17,495	0 92,455	0 0	1,835 1,835
9 Class Maximum Diversified Dem NJ Pri 10 Class Maximum Diversified Dem NJ Sec 11 Dist Line Transformer NJ 12 Distr Pri-Class ACED - NONTGSS NJ	DEMPRIS DEMSECS DEMTRNSFS DPRITGSSS	0.64522 0.72175 0.72175 0.68021	0.11616 0.12840 0.12840 0.12180	0.00577 0.00000 0.00000 0.00606	0.13113 0.14481 0.14481 0.13743	0.04739 0.00000 0.00000 0.04968	0.00343 0.00371 0.00371 0.00356	0.04969 0.00000 0.00000 0.00000	0.00000 0.00000 0.00000 0.00000	0.00120 0.00132 0.00132 0.00126
13 14 15 16 17 18 19 20 21 22 23 24 25 26 27 28 29 30 31 32 33 34 35 36 37 38 39 40 41 42 43 44	CUST369S	0.72393	0.12911	0.00000	0.14563	0.00000	0.00000	0.00000	0.00000	0.00133

	ELEC							
45	ALLOC	TOTAL ACE DISTRIBUTION (1)	TOTAL RESIDENTIAL SERVICE (2)	MONTHLY GENERAL SERVICE (3)	ANNUAL GENERAL SERVICE (4)	TRANSM GENERAL SERVICE (5)	STREET LIGHTING SERVICE (6)	DIRECT DISTRIBUTION CONNECTION (7)
ALLOCATION FACTOR TABLE								
CUSTOMER RELATED-16 1 Number of Meters 2 Number of Customers 3 Customer Service Expenses Allocator 4 Sales Expenses Allocator 5 Acut 369-Services-Class MDD 6 Acct 370-Meters Direct Assignment 6 Acct 370-Meters Direct Assignment 7 Acut 3703 Street Light & Signal Sys Dir Assign 8 Acct 990200 Meter reading expenses 9 Acct 990200 Cust records and collection exp 10 D.A. 372-Leased Prop Cust Prem 11 D.A. Customer Deposits 12 Acct 371.1 Based on Dist PIt 13 14 15 16 17 18 19 20 21 22 23 24 25 26 27 28 29 30 31 31 32 33 34 43 35 36 37 38 39 40 41 41 42 43 44	CUST CSERV CSALES CUST369 CUST370 CUST371 CUST373 CUST902 CUST903 CUST972 CUSPDEP CUST3711P	560,076 568,813 1,0000 1,0000 2,385,708 63,274,614 26,492,974 1 7,570,084 50,150,408 141,649 (20,534,018) 2,908,542,635	500,038 501,866 0.6708 0.6708 1,758,993 37,277,797 20,314,580 0 6,615,649 44,493,371 0 (9,191,213) 1,913,167,243	56,852 56,799 0.1340 0.1340 301,942 18,838,153 5,536,121 0 785,247 4,624,345 0 (5,039,649) 365,383,109	3,087 3,026 0.1247 0.1247 323,855 4,622,288 642,274 0 129,796 288,501 13,606 (6,303,156) 456,989,441	99 52 0.0595 0.0595 0 2,536,376 0 39,392 215,804 128,042 0 10,615,531	0 6,006 0.92% 0.92% 0 0 451,156 0 0 158,963,832	0 1,064 0 918 0 0 0 77,230 0 0 3,423,480

45	ALLOC	RESIDENTIAL (8)-2	MONTHLY GENERAL SERV SECONDARY (9)	MONTHLY GENERAL SERV PRIMARY (10)	ANNUAL GENERAL SERV SECONDARY (11)	ANNUAL GENERAL SERV PRIMARY (12)	STREET AND PRIVATE LIGHTING (13)	GENERAL SERVICE SUBTRANSMSN (14)	GENERAL SERVICE TRANSMISSION (15)	DIRECT DISTRIBUTION CONNECTION (16)
ALLOCATION FACTOR TABLE CUSTOMER RELATED-16 Number of Meters Number of Customers Sustomer Service Expenses Allocator Sales Expense Allocator Act 369-Services-Class MDD Act 370-Meters Direct Assignment Acct 3701-AMI Meters Direct Assignment Acct 3701-AMI Meters Direct Assignment Acct 3701-AMI Meters Direct Assignment Acct 3730 Street Light & Signal Sys Dir Assign Acct 990200 Meter reading expenses Acct 990200 Meter reading expenses Acct 3701-1 Based on Dist Ptt Acct 371.1 Based on Dist Ptt	CUST CSERV CSALES CUST369 CUST370 CUST371 CUST373 CUST902 CUST903 CUST907 CUST3712 CUSPDEP CUST3711P	500,038 501,866 0.6708 0.6708 1,758,993 37,277,797 20,314,580 0,6,615,649 44,493,371 0,9,191,213 1,913,167,243	56,684 56,645 0.1294 0.1294 301,942 17,542,292 5,507,103 0 751,823 4,596,442 0 (4,890,543) 354,572,631	168 154 0.0046 0.0046 0 1,295,861 29,018 0 33,424 27,903 0 (149,107) 10,810,479	2,958 2,908 0,0932 323,855 2,638,632 642,274 0 78,466 259,879 0 (5,203,612) 377,270,655	129 118 0.0314 0.0314 0 1.983,656 0 0 51,329 28,623 13,606 (1,099,544) 79,718,785	0 6,006 0.0092 0.0092 0 0 1 1 0 451,156 0 0 158,963,832	59 36 0.0315 0.0315 0 1,367,464 0 0 23,476 11,551 6,903 0 9,324,635	40 16 0.0280 0.0280 0 1,168,912 0 15,916 204,253 121,139 0 1,290,896	0 1,064 0.0018 0.0018 918 0 0 0 77,230 0 0 3,423,480

	ALLOC	TOTAL ACE DISTRIBUTION (1)	TOTAL RESIDENTIAL SERVICE (2)	MONTHLY GENERAL SERVICE (3)	ANNUAL GENERAL SERVICE (4)	TRANSM GENERAL SERVICE (5)	STREET LIGHTING SERVICE (6)	DIRECT DISTRIBUTION CONNECTION (7)
ALLOCATION FACTOR TABLE								
INTERNALLY DEVELOPED-17								
1 Acct 3620 Station Equipment	PLT362	507,055,474	342,109,399	64,358,246	94,188,811	3,969,841	1,795,648	633,529
2 Accts 364 - 367 Distribution Plant	PLT3647	1,202,562,942	824,858,241	153,441,576	214,729,675	3,701,128	4,308,120	1,524,202
3 Accts 364 & 365 Overhead Lines	PLTDOHLN	966,760,504	663,270,524	123,577,953	174,261,559	960,712	3,464,145	1,225,611
4 Accts 366 & 367 Underground Lines	PLTDUGLN	235,802,438	161,587,717	29,863,623	40,468,116	2,740,416	843,975	298,591
5 Acct 3730 Street Lighting and Signal Systems	PLT373	118,371,145	0 57 624 629	0	0	0	118,371,145 0	0
6 Acct 3700 Meters 7 Acct 369 Services	PLT370 PLT369	89,826,182 226,877,166	57,631,638	24,389,350 29,291,806	5,267,540 33,040,617	2,537,655 0	0	-
7 Acct 369 Services 8 Acct 3680 Line Transformers	PLT368	641,360,322	164,242,356 462,902,840	82,353,369	92,873,363	0	2,381,037	302,387 849,711
9 Acct 958100 Load dispatching	EXP581	3,194,359	2,158,896	384,409	513,855	113,474	2,361,037	2,252
10 Acct 958200 Station expenses	EXP582	22,205	14,982	2.818	4,125	174	79	28
11 Acct 958300 Overhead line expenses	EXP583	4,189,793	2,874,514	535,568	755,223	4,164	15,013	5,312
12 Acct 958400 Underground line expenses	EXP584	0	2,01.1,011	0	0	0	0	0,0.12
13 Acct 958500 Street lighting	EXP585	431,115	0	0	0	0	431,115	0
14 Acct 958600 Meter expenses	EXP586	5,611,640	3,600,376	1,523,657	329,075	158,533	0	0
15 Acct 958700 Customer installations expenses	EXP587	812,500	588,190	104,901	118,326	0	0	1,083
16 Acct 958800 Miscellaneous distribution exp	EXP588	17,174,240	11,123,407	3,072,412	2,072,000	332,782	563,192	10,446
17 Acct 958900 Rents	EXP589	3,536,842	2,290,741	632,729	426,705	68,533	115,983	2,151
18 Acct 959200 Maintain equipment	EXP592	4,453,246	3,004,597	565,230	827,219	34,865	15,770	5,564
19 Acct 959300 Maintain overhead lines	EXP593	63,403,712	43,499,722	8,104,697	11,428,714	63,007	227,191	80,380
20 Acct 959400 Maintain underground line	EXP594	4,469,129	3,062,548	566,001	766,986	51,939	15,996	5,659
21 Acct 959500 Maintain line transformers	EXP595	561,982	405,612	72,161	81,379	0	2,086	745
22 Acct 959600 Maint street lighting & signal sys	EXP596	1,823,429	0	0	0	0	1,823,429	0
23 Acct 959700 Maintain meters	EXP597	7,608	4,881	2,066	446	215	0	0
24 Acct 959800 Maintain distribution plant 25 Total Distribution Plant	EXP598 DISTPLT	1,344,511 2,908,542,635	899,303 1,913,167,243	167,529 365,383,109	235,809 456,989,441	2,700 10,615,531	37,508 158,963,832	1,662 3,423,480
26 Total Operation & Maintenance Labor	LABOR	31,011,635	20,773,127	4.523.142	4.434.282	390.323	862,033	28,729
27 Total General Plant	GENPLT	195,800,857	131,157,098	28,558,153	27,997,112	2,464,414	5,442,690	181,391
28 Dist O&M Expense	DISTOMEXP	251,338,447	179,958,110	33,137,213	29,671,750	2,375,651	5,922,178	273,543
29 Taxable Income	TAXINC	(26,537,670)	(50,178,778)	20,384,567	1,779,881	1,500,418	(53,378)	29,620
30 Acct 364 Poles	PLT364	359,284,962	246,407,282	45.911.147	64,740,329	483,794	1.287.071	455,338
31 Depreciation Reserve	DEPRERES	841,929,265	555,724,702	108,990,893	130,031,208	4,497,242	41,734,183	951,038
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2 Accts 364 - 367 Distribution Plant PLT3647	DIRECT DISTRIBUTION CONNECTION (16)	GENERAL SERVICE TRANSMISSION (15)	GENERAL SERVICE SUBTRANSMSN (14)	STREET AND PRIVATE LIGHTING (13)	ANNUAL GENERAL SERV PRIMARY (12)	ANNUAL GENERAL SERV SECONDARY (11)	MONTHLY GENERAL SERV PRIMARY (10)	MONTHLY GENERAL SERV SECONDARY (9)	RESIDENTIAL (8)-2	ALLOC	
1 Act 320 Station Equipment PLT362 342,109.399 61,306.829 3,051,417 69,181,462 25,007,349 1,795,648 3,969,841 0 2 Acts 364 - 367 Distribution Plant PLT3647 824,858,241 147,553,076 5,888,501 166,480,247 48,249,428 4,308,120 3,701,128 0 0 3 Accts 364 a 365 Overhead Lines PLTDOHLN 663,270,524 118,647,463 4,930,470 133,866,799 40,394,760 3,464,145 960,712 0 0 4 Accts 366 a 367 Underground Lines PLTDUGLN 161,587,717 26,905,593 958,030 32,613,448 7,854,668 843,975 2,740,416 0 0 6 Acct 3700 Meters PLT373 0 5,631,638 23,063,788 1,325,561 3,242,883 1,984,657 0 1,368,153 1,169,501 Acct 3700 Meters PLT369 164,242,356 29,291,806 0 33,040,617 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0											ALLOCATION FACTOR TABLE
27 Total General Plant GENPLT 131,157,098 27,344,700 1,213,453 21,434,485 6,562,626 5,442,690 1,899,623 564,791 28 Dist O&M Expense DISTOMEXP 179,958,110 31,908,445 1,228,769 22,751,162 6,920,588 5,922,178 1,603,996 771,655 29 Taxable Income TAXINC (50,178,778) 20,831,504 (446,937) 3,076,130 (1,296,249) (53,378) 381,168 1,119,250 30 Acct 364 Poles PLT364 246,407,282 44,079,543 1,831,604 49,733,930 15,006,399 1,287,071 483,794 0 31 Depreciation Reserve DEPRERS 555,724,702 105,466,231 3,524,662 105,981,588 24,049,619 41,734,183 3,734,550 762,691 33 3 3 3 4 4 3 3 5 5 5 5 5 5 5 5 5 5 5	633,529 1,524,202 1,225,611 298,591 0 302,387 849,711 2,252 28 5,312 0 0 1,083 10,446 2,151 5,564 80,380 5,659 745 0 0 1,662 3,423,480 28,729 181,391 273,543 29,620 455,338 951,038	0 0 1,169,501 0 0 0 0 0 0 73,061 0 87,983 18,119 0 0 0 0 99 2 1,290,896 89,454 564,791 771,655 1,119,250	3,701,128 960,712 2,740,416 0 1,368,153 0 0 113,474 174 4,164 0 0 85,472 0 244,800 50,414 34,865 63,007 51,939 0 116 2,698 9,324,635 300,869 1,899,623 1,603,996 381,168 483,794	4,308,120 3,464,145 843,975 118,371,145 0 2,381,037 21,472 79 15,013 0 431,115 0 0 563,192 115,983 15,770 227,191 15,996 2,086 1,823,429 0 37,508 158,963,832 62,033 5,442,690 5,922,178 (53,378) (53,378)	48,249,428 40,394,760 7,854,668 0 1,984,657 0 0 116,372 1,095 175,065 0 0 501,583 103,295 219,629 2,649,237 148,868 0 0 188 54,305 79,718,785 1,039,412 6,562,626 6,920,588 (1,296,249) 15,006,399	166,480,247 133,866,799 32,613,448 0 3,282,833 33,040,637 92,873,363 397,483 3,030 580,158 0 0 205,089 118,326 1,570,417 323,410 607,590 8,779,477 618,118 81,379 0 278 181,505 377,270,655 3,394,870 21,434,485 22,751,162 3,076,130 49,733,930	5,888,501 4,930,470 958,030 0 1,325,561 0 0 13,821 134 21,368 0 82,811 0 142,260 29,297 26,799 323,358 18,157 0 0 112 6,630 10,810,479 192,191 1,213,453 1,228,769 (446,937) 1,831,604	147,553,076 118,647,483 28,905,593 0 23,063,788 29,291,806 82,353,369 370,588 2,685 514,200 0 1,440,846 104,901 2,930,152 603,432 538,431 7,781,339 547,843 72,161 0 1,953 160,899 354,572,631 4,330,951 27,344,700 31,908,445 20,831,504 44,079,543	824,858,241 663,270,524 161,587,717 0 57,631,638 164,242,356 462,902,840 2,158,896 14,982 2,874,514 0 3,600,376 588,190 11,123,407 2,290,741 3,004,597 43,499,722 3,062,548 495,612 0 4,881 899,303 1,913,167,243 20,773,127 131,157,098 179,958,110 (50,178,778) 246,407,282	PLT3647 PLTDOHLN PLTDUGLN PLT373 PLT370 PLT369 PLT368 EXP581 EXP582 EXP583 EXP584 EXP585 EXP586 EXP587 EXP588 EXP589 EXP592 EXP593 EXP594 EXP595 EXP596 EXP597 EXP596 EXP597 EXP597 EXP597 EXP598 DISTPLT LABOR GENPLT DISTOMEXP TAXINC PLT364	1 Acct 3620 Station Equipment 2 Accts 364 - 367 Distribution Plant 3 Accts 364 - 365 Overhead Lines 4 Accts 366 & 367 Underground Lines 5 Acct 3730 Street Lighting and Signal Systems 6 Acct 3730 Street Lighting and Signal Systems 7 Acct 369 Services 8 Acct 3680 Line Transformers 9 Acct 958100 Load dispatching 10 Acct 958200 Station expenses 11 Acct 958300 Overhead line expenses 12 Acct 958500 Street lighting 14 Acct 958500 Street lighting 15 Acct 958500 Street lighting 16 Acct 958600 Meler expenses 17 Acct 958600 Meler expenses 18 Acct 958600 Meler approach in the expenses 19 Acct 958600 Meler approach in the expenses 10 Acct 958600 Meler approach in the expenses 11 Acct 958900 Meler approach in the expenses 12 Acct 958900 Meler approach in the expenses 13 Acct 958900 Meler approach in the expenses 14 Acct 958900 Meler approach in the expenses 15 Acct 958900 Meler approach in the expenses 16 Acct 958900 Meler approach in the expenses 17 Acct 959900 Meler approach in the expenses 18 Acct 958900 Meler approach in the expenses 19 Acct 958900 Meler approach in the expenses 20 Acct 958900 Meler approach in the expenses 21 Acct 958900 Meler approach in the expenses 22 Acct 958900 Meler approach in the expenses 23 Acct 958900 Meler approach in the expenses 24 Acct 958900 Meler approach in the expenses 25 Acct 958900 Meler approach in the expenses 26 Total Operation & Maintenance Labor 27 Total General Plant 28 Dist O&M Expense 29 Taxable Income 30 Acct 364 Poles 31 Depreciation Reserve 32 33 34 34 35 36 37 38 39 40 40 41 42 43

	ALLOC	TOTAL ACE DISTRIBUTION (1)	TOTAL RESIDENTIAL SERVICE (2)	MONTHLY GENERAL SERVICE (3)	ANNUAL GENERAL SERVICE (4)	TRANSM GENERAL SERVICE (5)	STREET LIGHTING SERVICE (6)	DIRECT DISTRIBUTION CONNECTION (7)
ALLOCATION FACTOR TABLE								
INTERNALLY DEVELOPED CON'T-18								
1 Distribution Operating Exp Acct 581 - 587	EXPDISTO	14,261,613	9,236,958	2,551,353	1,720,604	276,345	467,679	8,674
2 Distribution Maintenance Exp Acct 592 - 597	EXPDISTM	74,719,105	49,977,360	9,310,155	13,104,745	150,026	2,084,472	92,348
3 Distribution Operating Labor Acct 581 - 589 4 Distribution Maintenance Labor Acct 592 - 598	LABDO LABDM	12,033,832 13.740.908	7,942,490 9.042,784	2,138,074 1.684,762	1,507,709 2.366.010	251,991 51.302	186,077 579.342	7,492 16.707
5 Total Distribution Operating Labor	TLABDM	12,175,904	9,042,784 8,036,259	2,163,316	1,525,509	254,966	188,274	7,580
6 Total Distribution Maintenance Labor	TLABDM	13,742,430	9,043,786	1,684,949	2,366,272	51,308	579,406	16,709
7 Acct 990200 Meter reading expenses	EXP902	7,570,059	6,615,626	785,245	129,795	39,392	0	0
8 Acct 990300 Cust records and collection exp	EXP903	50,157,398	44,499,573	4,624,990	288,541	215,834	451,219	77,241
9 Acct 990500 Miscellaneous cust accounts exp	EXP905	0	0	0	0	0	0	0
10 Acct 990700 Supervision	EXP907	0	0	0	0	0	0	0
11 Acct 990800 Customer assistance expenses	EXP908	5,029,692	3,374,136	673,947	626,992	299,377	46,251	8,989
12 Acct 991000 Misc cust service & informat exp	EXP910	0	0	0	0	0	0	0
13 Acct 991200 Demonstrating & selling expenses	EXP912	0	0	0	0	0	0	0
14 Acct 991300 Advertising expense 15 Acct 992000 Administrative & General salaries	EXP913 EXP920	3,046,550	2.040.730	444,349	435.619	38.345	84,685	2,822
16 Acct 992100 Office supplies & expenses	EXP921	2.091.745	1.401.154	305.087	299.094	26.327	58,144	1.938
17 Acct 992300 Outside services employed	EXP923	59,647,957	39,955,152	8,699,837	8,528,923	750,749	1,658,038	55,258
18 Acct 993020 Miscellaneous general expenses	EXP9302	736,055	493,046	107,356	105,247	9,264	20,460	682
19 Acct 993500 Maintenance of general plant	EXP935	414,526	277,670	60,460	59,272	5,217	11,523	384
20 Total Intangible Plant	INTPLT	84,054,509	56,303,867	12,259,607	12,018,760	1,057,938	2,336,469	77,869
21 Service Company Assets Reserve	SERVCO	31,011,635	20,773,127	4,523,142	4,434,282	390,323	862,033	28,729
22 Total System Electric Distribution	PLANT	3,257,924,573	2,147,200,545	416,341,531	506,946,756	15,012,966	168,675,627	3,747,149
23 Accts 902 & 903 Mtr Read & Cust Rec	EXP9023	57,727,457	51,115,200	5,410,234	418,337	255,227 0	451,219 0	77,241 0
 Total Customer Deposits Sales Revenue Required Claimed ROR 	CUSTDEP CLAIMREV	18,982,828 511,238,818	8,496,886 350,793,007	4,658,942 67,285,085	5,827,000 69,177,087	3,852,307	19,559,629	571,703
26 Residential Distribution Plant	RESDIST	1,913,167,243	1,913,167,243	07,265,065	09,177,067	3,032,307	19,559,629	371,703
27 Non-Residential Distribution Plant	NRESDIST	995,375,392	1,313,107,243	365,383,109	456,989,441	10,615,531	158,963,832	3,423,480
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	ALLOC	RESIDENTIAL (8)-2	MONTHLY GENERAL SERV SECONDARY (9)	MONTHLY GENERAL SERV PRIMARY (10)	ANNUAL GENERAL SERV SECONDARY (11)	ANNUAL GENERAL SERV PRIMARY (12)	STREET AND PRIVATE LIGHTING (13)	GENERAL SERVICE SUBTRANSMSN (14)	GENERAL SERVICE TRANSMISSION (15)	DIRECT DISTRIBUTION CONNECTION (16)
ALLOCATION FACTOR TABLE										
INTERNALLY DEVELOPED CON'T-18 1 Distribution Operating Exp Acct 591 - 587 2 Distribution Maintenance Exp Acct 592 - 597 3 Distribution Maintenance Exp Acct 592 - 597 3 Distribution Operating Labor Acct 581 - 589 4 Distribution Operating Labor Acct 592 - 598 5 Total Distribution Operating Labor 6 Total Distribution Operating Labor 7 Acct 990200 Meter reading expenses 8 Acct 990300 Cust records and collection exp 9 Acct 990500 Miscellaneous cust accounts exp 10 Acct 990700 Supervision 11 Acct 990800 Customer assistance expenses 12 Acct 991000 Disco cust service & informat exp 13 Acct 991200 Demonstrating & selling expenses 14 Acct 991300 Advertising expense 15 Acct 992300 Advertising expense 16 Acct 992300 Outside services employed 18 Acct 993200 Miscellaneous general expenses 19 Acct 993300 Miscellaneous general expenses 10 Acct 993300 Miscellaneous general expenses 11 Acct 993300 Miscellaneous general expenses 12 Acct 993500 Miscellaneous general expenses 13 Acct 993500 Miscellaneous general expenses 14 Acct 993300 Miscellaneous general expenses 15 Acct 993300 Miscellaneous general expenses 16 Acct 993300 Miscellaneous general expenses 17 Acct 993300 Miscellaneous general expenses 18 Acct 993300 Miscellaneous general expenses 19 Acct 993300 Miscellaneous general expenses 20 Total Intangible Plant 21 Service Company Assets Reserve 22 Total System Electric Distribution 23 Accts 902 & 903 Mtr Read & Cust Rec 24 Total Customer Deposits 25 Sales Revenue Required Claimed ROR 26 Residential Distribution Plant 27 Non-Residential Distribution Plant 28 Distribution Plant 29 30 31 31 32 33 34	EXPDISTO EXPDISTO EXPDISTM LABDO LABDM TLABDO TLABDM EXP902 EXP903 EXP905 EXP907 EXP908 EXP910 EXP912 EXP913 EXP920 EXP921 EXP923 EXP920 EXP921 EXP923 CXP925 INTPLT SERVCO PLANT EXP9023 CUSTDEP CLAIMREV RESDIST NRESDIST	(8)-2 9,236,958 49,977,360 7,942,490 9,042,784 8,036,259 9,043,786 6,615,626 44,499,573 0 0 3,374,136 0 0 2,040,730 1,401,154 39,955,152 493,046 277,670 56,303,867 20,773,127 2,147,200,545 51,115,200 8,496,886 350,793,007 1,913,167,243	(9) 2,433,219 8,941,727 2,040,161 1,618,675 2,064,247 1,618,854 751,821 4,597,083 0 0 651,007 0 0 425,468 292,124 8,330,175 102,794 57,891 11,738,689 4,330,951 403,365,799 5,348,904 4,521,099 65,031,160 0 354,572,631	(10) 118,133 368,427 97,913 66,087 99,069 66,095 33,424 27,907 0 0 22,940 0 0 18,881 12,963 369,661 4,562 2,569 520,918 192,191 12,975,732 61,331 137,843 2,253,925 0 10,810,479	1,304,086 10,086,843 1,145,010 1,825,002 1,158,528 1,825,204 78,466 259,915 0 0 468,874 0 0 333,508 228,985 6,529,712 80,577 45,379 9,201,518 3,394,870 415,517,792 338,381 4,810,518 55,202,991 0 377,270,655	416,518 3,017,902 362,699 541,008 366,981 541,068 51,329 28,627 0 0 158,118 0 0 102,111 70,109 1,999,211 24,670 13,894 2,817,242 1,039,412 91,428,964 79,956 1,016,482 13,974,095 0 79,718,785	(13) 467,679 2,084,472 186,077 579,342 188,274 579,406 0 451,219 0 0 46,251 0 0 84,685 58,144 1,658,038 20,460 11,523 2,336,469 862,033 168,675,627 451,219 0 19,559,629 0 158,963,832	203,283 149,927 193,636 51,234 195,922 51,239 23,476 11,553 0 0 158,549 0 0 0 29,557 20,294 578,693 7,141 4,022 815,481 300,869 12,714,272 35,029 0 2,790,441 0 9,324,635	73,061 99 58,355 69 59,044 69 15,916 204,281 0 0 140,828 6,034 172,055 2,123 1,196 242,457 89,454 2,298,694 220,197 0 1,061,865 0	8,674 92,348 7,492 16,707 7,580 16,709 0 77,241 0 0 8,989 0 0 0 2,822 1,938 55,258 682 384 77,869 28,729 3,747,149 77,241 0 571,703 0 3,423,480
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	ALLOC	TOTAL ACE DISTRIBUTION (1)	RESID SEF	OTAL DENTIAL RVICE (2)	MONTHLY GENERAL SERVICE (3)	ANNUAL GENERAL SERVICE (4)	TRANSM GENERAL SERVICE (5)	STREET LIGHTING SERVICE (6)	DIRECT DISTRIBUTION CONNECTION (7)
ALLOCATION FACTOR TABLE									
INTERNALLY DEVELOPED CON'T-19 1	CREVRES CREVGSS CREVCOM CREVGSSL CREVGSP CREVLTG CREVGST CREVGST CREVDDC	350,793,007 65,031,160 2,253,925 55,202,991 13,974,095 19,559,629 2,790,441 1,061,865 571,703 511,238,818		0,793,007 0 0 0 0 0 0 0 0 0 0 0,793,007	0 65,031,160 2,253,925 0 0 0 0 0 0 67,285,085	0 0 0 55,202,991 13,974,095 0 0 0 0 69,177,087	0 0 0 0 0 0 0 2,790,441 1,061,865 0 3,852,307	0 0 0 0 19,559,629 0 0 19,559,629	0 0 0 0 0 0 0 571,703 571,703
27 REVENUE REQUIREMENTS INPUTS 28									
29 Current Revenue - Retail Sales ACE 30		476,723,799	296	5,020,547	86,151,215	69,944,842	5,114,341	18,905,207	587,648
31 Claimed Rate of Return 32		7.13%		7.13%	7.13%	7.13%	7.13%	7.13%	7.13%
32 BILLING DETERMINANTS 34 Average Number of Customers (12 Months 35 Total KWH Sales @ Meter 36 Total MWH Sales @ Meter 37 38 39 40 41 42 43 44)	568,813 8,778,187,173 8,778,187		501,866 2,550,392 4,032,550	56,799 1,475,895,885 1,475,896	3,026 2,141,846,944 2,141,847	52 1,044,186,603 1,044,187	6,006 68,752,713 68,753	1,064 14,954,636 14,955

		ALLOC	RESIDENTIAL (8)-2	MONTHLY GENERAL SERV SECONDARY (9)	MONTHLY GENERAL SERV PRIMARY (10)	ANNUAL GENERAL SERV SECONDARY (11)	ANNUAL GENERAL SERV PRIMARY (12)	STREET AND PRIVATE LIGHTING (13)	GENERAL SERVICE SUBTRANSMSN (14)	GENERAL SERVICE TRANSMISSION (15)	DIRECT DISTRIBUTION CONNECTION (16)
	ALLOCATION FACTOR TABLE										
1	NTERNALLY DEVELOPED CON'T-19 <u>Claimed Revenues</u>										
	ned Revenues Residential ned Revenues MGSS	CREVRES CREVGSS	350,793,007 0	0 65,031,160	0	0	0 0	0	0	0	0
	ned Revenues MGSP	CREVCOM	0	0	2,253,925	0	0	0	0	0	0
	ned Revenues AGSS ned Revenues AGSP	CREVGSSL CREVGSP	0	0	0	55,202,991 0	0 13,974,095	0	0	0	0
	ned Revenues Lighting	CREVLTG	0	0	0	0	0	19,559,629	0	0	0
	ned Revenues GSST ned Revenues GST	CREVGSST CREVGST	0	0	0	0	0	0	2,790,441 0	0 1,061,865	0
	ned Revenues GST	CREVDDC	0	0	0	0	0	0	0	0,001,005	571,703
	Claimed Revenue		350,793,007	65,031,160	2,253,925	55,202,991	13,974,095	19,559,629	2,790,441	1,061,865	571,703
12 13											
14											
15 16											
17											
18 19											
20											
21											
22 23											
24											
25 26											
	REVENUE REQUIREMENTS INPUTS										
28			000 000 547	04.000.000	4 707 004	57.050.400	10.500.110	40.005.007	0.004.045	0.000.407	507.040
29 Curre 30	ent Revenue - Retail Sales ACE		296,020,547	84,363,933	1,787,281	57,356,426	12,588,416	18,905,207	3,024,915	2,089,427	587,648
31 Clair	med Rate of Return		7.13%	7.13%	7.13%	7.13%	7.13%	7.13%	7.13%	7.13%	7.13%
32 33	BILLING DETERMINANTS										
34 Aver	rage Number of Customers (12 Months)		501,866	56,645	154	2,908	118	6,006	36	16	1,064
	KWH Sales @ Meter MWH Sales @ Meter		4,032,550,392 4,032,550	1,398,199,951 1,398,200	77,695,934 77,696	1,591,748,317 1,591,748	550,098,627 550,099	68,752,713 68,753	552,866,415 552,866	491,320,188 491,320	14,954,636 14,955
37	WWW Calcs & Well		4,002,000	1,000,200	77,000	1,001,140	000,000	00,700	002,000	401,020	14,000
38 39											
39 40											
41											
42 43											
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45											

				LLL	TINO DIOTNIDOTI	JIV			
		ALLOC	TOTAL ACE DISTRIBUTION (1)	TOTAL RESIDENTIAL SERVICE (2)	MONTHLY GENERAL SERVICE (3)	ANNUAL GENERAL SERVICE (4)	TRANSM GENERAL SERVICE (5)	STREET LIGHTING SERVICE (6)	DIRECT DISTRIBUTION CONNECTION (7)
	RATIO TABLE								
1 Distribu 2 Distribu 3 Dist Lir 4 Distr P 5 6 Class N 7 Class N 8 Dist Lir	ACITY-DISTRIBUTION RELATED-20 ution Primary-Class ACED ution Secondry-Class ACED ne Transformer ri-Class ACED - NONTGSS Maximum Diversified Dem NJ Pri Maximum Diversified Dem NJ Sec ne Transformer NJ ri-Class ACED - NONTGSS NJ	DEMPRI DEMSEC DEMTRNSF DPRITGSS DEMPRIS DEMSECS DEMTRNSFS DPRITGSSS	1.00000 1.00000 1.00000 1.00000 1.00000 1.00000 1.00000 1.00000	0.675846 0.731658 0.731658 0.700739 0.645220 0.721752 0.721752 0.680212	0.120340 0.125594 0.125594 0.124772 0.121933 0.128404 0.128404 0.127859	0.160863 0.134708 0.134708 0.166788 0.178527 0.144807 0.144807 0.187109	0.035523 0.000000 0.000000 0.000000 0.049689 0.000000 0.000000 0.000000	0.006722 0.007277 0.007277 0.006970 0.003430 0.003712 0.003762	0.000705 0.000763 0.000763 0.000731 0.001202 0.001325 0.001325 0.001258

	ALLOC	RESIDENTIAL (8)-2	MONTHLY GENERAL SERV SECONDARY (9)	MONTHLY GENERAL SERV PRIMARY (10)	ANNUAL GENERAL SERV SECONDARY (11)	ANNUAL GENERAL SERV PRIMARY (12)	STREET AND PRIVATE LIGHTING (13)	GENERAL SERVICE SUBTRANSMSN (14)	GENERAL SERVICE TRANSMISSION (15)	DIRECT DISTRIBUTION CONNECTION (16)
2 Distribution Secondry-Class ACED 3 Dist Line Transformer 4 Distr Pri-Class ACED - NONTGSS 5 6 Class Maximum Diversified Dem NJ Pri 7 Class Maximum Diversified Dem NJ Sec 8 Dist Line Transformer NJ 9 Distr Pri-Class ACED - NONTGSS NJ 10 11 12 13 14 15 16 17 18 19 20 21 12 22 23 24 25 26 27 28 29 30 31 32 33 34 35 36 37 38 39 40 41 41 42 43	DEMPRI DEMSEC DEMTRINSF DPRITGSS DEMPRIS DEMSECS DEMTRINSFS DPRITGSSS	0.675846 0.675846 0.731658 0.731658 0.700739 0.645220 0.721752 0.680212								
44 45										

		ELECTRIC DISTRIBUTION										
		ALLOC	TOTAL ACE DISTRIBUTION (1)	TOTAL RESIDENTIAL SERVICE (2)	MONTHLY GENERAL SERVICE (3)	ANNUAL GENERAL SERVICE (4)	TRANSM GENERAL SERVICE (5)	STREET LIGHTING SERVICE (6)	DIRECT DISTRIBUTION CONNECTION (7)			
	RATIO TABLE											
	CUSTOMER RELATED-21											
1	Number of Meters		1.000000	0.892804	0.101508	0.005512	0.000177	0.000000	0.000000			
2	Number of Customers	CUST	1.000000	0.882304	0.099855	0.005320	0.000091	0.010559	0.001871			
3	Customer Service Expenses Allocator	CSERV	1.000000	0.670844	0.133994	0.124658	0.059522	0.009196	0.001787			
4	Sales Expense Allocator	CSALES	1.000000	0.670844	0.133994	0.124658	0.059522	0.009196	0.001787			
5	Acct 369-Services-Class Max NCD	CUST369	1.000000	0.737305	0.126563	0.135748	0.000000	0.000000	0.000385			
6	Acct 370-Meters Direct Assignment	CUST370	1.000000	0.589143	0.297721	0.073051	0.040085	0.000000	0.000000			
6	Acct 3701-Meters Direct Assignment	CUST371	1.000000	0.766791	0.208966	0.024243	0.000000	0.000000	0.000000			
7	Acct 3730 Street Light & Signal Sys Dir Assign	CUST373	1.000000	0.000000	0.000000	0.000000	0.000000	1.000000	0.000000			
8	Acct 990200 Meter reading expenses	CUST902	1.000000	0.873920	0.103730	0.017146	0.005204	0.000000	0.000000			
9	Acct 990300 Cust records and collection exp	CUST903	1.000000	0.887199	0.092210	0.005753	0.004303	0.008996	0.001540			
10	D.A. 372-Leased Prop Cust Prem	CUST372	1.000000	0.000000	0.000000	0.096057	0.903943	0.000000	0.000000			
11	D.A. Customer Deposits	CUSPDEP	1.000000	0.447609	0.245429	0.306962	0.000000	0.000000	0.000000			
	Acct 3711 Based on Dist Plt	CUST3711P	1.000000	0.657775	0.125624	0.157120	0.003650	0.054654	0.001177			
13												
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	ALLOC	TOTAL ACE DISTRIBUTION (1)	TOTAL RESIDENTIAL SERVICE (2)	MONTHLY GENERAL SERVICE (3)	ANNUAL GENERAL SERVICE (4)	TRANSM GENERAL SERVICE (5)	STREET LIGHTING SERVICE (6)	DIRECT DISTRIBUTION CONNECTION (7)
RATIO TABLE								
INTERNALLY DEVELOPED-22 1 Acct 3620 Station Equipment 2 Accts 364 - 367 Distribution Plant 3 Accts 364 - 367 Distribution Plant 4 Accts 364 - 365 Overhead Lines 4 Accts 366 & 367 Underground Lines 5 Acct 3730 Street Lighting and Signal Systems 6 Acct 3730 Street Lighting and Signal Systems 6 Acct 3730 Meters 7 Acct 369 Services 8 Acct 3680 Line Transformers 9 Acct 958100 Load dispatching 10 Acct 958200 Station expenses 11 Acct 958300 Overhead line expenses 12 Acct 958300 Overhead line expenses 13 Acct 958600 Meter expenses 14 Acct 958600 Meter expenses 15 Acct 958600 Meter expenses 16 Acct 958600 Meter expenses 17 Acct 958600 Meter expenses 18 Acct 959800 Maintain equipment 19 Acct 959900 Maintain equipment 19 Acct 959300 Maintain in underground line 21 Acct 959900 Maintain in trentsformers 22 Acct 959900 Maintain street lighting & signal sys 23 Acct 959700 Maintain meters 24 Acct 959900 Maintain distribution plant 25 Total Distribution Plant 26 Total Operation & Maintenance Labor 27 Total General Plant 28 Dist O&M Expense 29 Taxable Income 30 Acct 364 Poles 31 Other Taxes 32 Depreciation Reserve	PLT362 PLT3647 PLTDOHLN PLTDUGLN PLT373 PLT370 PLT369 PLT368 EXP581 EXP582 EXP583 EXP584 EXP585 EXP586 EXP587 EXP588 EXP589 EXP599 EXP599 EXP591 EXP591 EXP591 EXP596 EXP597 EXP598 DISTPLT LABOR GENPLT DISTOMEXP TAXINC PLT364 OTHTAX DEPRERES	1.000000 1.000000	0.674698 0.685917 0.688075 0.685267 0.000000 0.641591 0.723926 0.721752 0.675846 0.674698 0.686075 0.000000 0.641591 0.723926 0.647680 0.647680 0.674698 0.686075 0.685267 0.721752 0.000000 0.641591 0.668870 0.659849 0.669849 0.715999 1.890851 0.685827 0.703946 0.660061	0.126925 0.127595 0.127827 0.126647 0.000000 0.271517 0.129109 0.128404 0.120340 0.126925 0.127827 0.000000 0.271517 0.129109 0.178897 0.178897 0.178897 0.126647 0.126647 0.126640 0.00000 0.271517 0.1246040 0.000000 0.271517 0.126624 0.145853 0.131843 0.768137 0.127785 0.194953 0.129454	0.185756 0.178560 0.180253 0.171619 0.000000 0.058641 0.145632 0.144807 0.160863 0.185756 0.180253 0.000000 0.058641 0.145632 0.120646 0.120646 0.120646 0.185756 0.180253 0.171619 0.144807 0.000000 0.058641 0.175387 0.157120 0.142988 0.142988 0.118055 -0.067070 0.180192 0.073718 0.154444	0.007829 0.003078 0.000994 0.011622 0.000000 0.028251 0.000000 0.035523 0.007829 0.000994 0.000000 0.028251 0.000000 0.019377 0.019377 0.019377 0.019377 0.007829 0.000994 0.011622 0.000000 0.028251 0.000000 0.028251 0.000000 0.019377 0.019377 0.019377 0.019377 0.019377 0.019377 0.019377 0.019377 0.019377 0.019377 0.019377 0.000094 0.011622 0.000000 0.000000 0.028251 0.002008 0.003650 0.012586 0.012586 0.012586 0.009452 -0.056539 0.001347 0.006004	0.003541 0.003582 0.003583 0.0035879 1.000000 0.000000 0.003712 0.006722 0.003583 0.000000 0.000000 0.000000 0.000000 0.000000	0.001249 0.001267 0.001268 0.001266 0.000000 0.000000 0.001333 0.001325 0.000705 0.001249 0.001268 0.000000 0.000000 0.001333 0.00168 0.001249 0.001268 0.001266 0.001325 0.000000 0.001266
35 36 37 38 39 40 41 42 43								
41 42								

	ALLOC	RESIDENTIAL (8)-2	MONTHLY GENERAL SERV SECONDARY (9)	MONTHLY GENERAL SERV PRIMARY (10)	ANNUAL GENERAL SERV SECONDARY (11)	ANNUAL GENERAL SERV PRIMARY (12)	STREET AND PRIVATE LIGHTING (13)	GENERAL SERVICE SUBTRANSMSN (14)	GENERAL SERVICE TRANSMISSION (15)	DIRECT DISTRIBUTION CONNECTION (16)
RATIO TABLE										
INTERNALLY DEVELOPED-22 1 Acct 3620 Station Equipment 2 Accts 364 - 365 Overhead Lines 3 Accts 364 & 365 Overhead Lines 4 Accts 366 & 367 Underground Lines 5 Acct 3730 Street Lighting and Signal Systems 6 Acct 3760 Meters 7 Acct 369 Services 8 Acct 3680 Line Transformers 9 Acct 958100 Load dispatching 10 Acct 958200 Station expenses 11 Acct 958200 Station expenses 12 Acct 958400 Underground line expenses 13 Acct 958500 Street lighting 14 Acct 958800 Meter expenses 15 Acct 958800 Miscellaneous distribution exp 16 Acct 958800 Miscellaneous distribution exp 17 Acct 95800 Miscellaneous distribution exp 18 Acct 958900 Maintain equipment 19 Acct 959300 Maintain overhead lines 20 Acct 959400 Maintain underground line 21 Acct 959500 Maintain line transformers 22 Acct 959600 Maint street lighting & signal sys 23 Acct 959700 Maintain meters 24 Acct 959800 Maintain distribution plant 25 Total Distribution Plant 26 Total Operation & Maintenance Labor 27 Total General Plant 28 Dist O&M Expense 29 Taxable Income 30 Acct 364 Poles 31 Other Taxes 32 Depreciation Reserve 33 34 34 35 36 36 37 38 39 40 41	PLT362 PLT3647 PLTDOHLN PLT373 PLT370 PLT369 PLT368 EXP581 EXP582 EXP583 EXP584 EXP585 EXP586 EXP587 EXP588 EXP589 EXP599 EXP590 EXP590 EXP591 EXP591 EXP596 EXP597 EXP598 EXP597 EXP598 EXP597 EXP598 DISTPLT LABOR GENPLT DISTOMEXP TAXINC PLT364 OTHTAX DEPRERES	0.674698 0.685917 0.686075 0.685267 0.000000 0.641591 0.723926 0.721752 0.675846 0.674698 0.686075 0.000000 0.641591 0.723926 0.647680 0.647680 0.647680 0.647680 0.647680 0.647680 0.647680 0.647680 0.721752 0.000000 0.641591 0.6685267 0.721752 0.000000 0.641591 0.668849 0.715999 1.890851 0.685827 0.703946 0.660061	0.120908 0.122699 0.122727 0.122584 0.000000 0.256760 0.129109 0.128404 0.116013 0.120908 0.122727 0.000000 0.256760 0.129109 0.170613 0.170613 0.170613 0.120908 0.122727 0.122584 0.128404 0.000000 0.256760 0.119671 0.121907 0.139656 0.139656 0.139656 0.139656 0.139656 0.126954 -0.784979 0.122687 0.122587	0.006018 0.004897 0.005100 0.004063 0.000000 0.014757 0.000000 0.004063 0.000000 0.004063 0.000000 0.004000 0.000000 0.0014757 0.000000 0.00283 0.006283 0.006283 0.006283 0.006018 0.005100 0.004063 0.000000 0.014757 0.004931 0.003717 0.006197 0.006197 0.006197 0.00619842 0.005098 0.003365 0.0004186	0.136438 0.138438 0.138438 0.000000 0.036547 0.145632 0.144807 0.124433 0.138469 0.000000 0.036547 0.145632 0.091440 0.091440 0.138438 0.138469 0.138438 0.138469 0.138438 0.138469 0.138508 0.14807 0.109471 0.109471 0.109471 0.109471 0.109471 0.109479 0.138425 0.138425 0.138425 0.138425	0.049319 0.040122 0.041784 0.033310 0.000000 0.022094 0.000000 0.036431 0.041784 0.000000 0.022094 0.000000 0.022094 0.000000 0.022946 0.029206 0.049319 0.041784 0.033310 0.00000 0.022094 0.000000 0.022094 0.033517 0.033517 0.033517 0.03565 0.048846 0.041767 0.019750 0.028565	0.003541 0.003582 0.003583 0.003579 1.000000 0.000000 0.000001 0.003712 0.006722 0.003541 0.003583 0.000000 0.000000 0.000000 0.000000 0.000000	0.007829 0.00378 0.000978 0.000994 0.011622 0.000000 0.015231 0.000000 0.035523 0.007829 0.000994 0.000000 0.015231 0.000000 0.014254 0.014254 0.014254 0.007829 0.000994 0.011622 0.000000 0.014254 0.014254 0.014254 0.014254 0.014254 0.014254 0.014254 0.009702 0.009702 0.009702 0.009702 0.009702 0.009702 0.009702 0.009703	0.000000 0.000000 0.000000 0.000000 0.000000	0.001249 0.001267 0.001268 0.000000 0.000000 0.000333 0.001325 0.000705 0.001249 0.001268 0.000000 0.0000000 0.0000000 0.001333 0.001333 0.00168 0.000608 0.001266 0.001266 0.001266 0.001266 0.001266 0.001266 0.001266 0.001325 0.000000 0.0000000 0.0000000000000000

	ALLOC	TOTAL ACE DISTRIBUTION (1)	TOTAL RESIDENTIAL SERVICE (2)	MONTHLY GENERAL SERVICE (3)	ANNUAL GENERAL SERVICE (4)	TRANSM GENERAL SERVICE (5)	STREET LIGHTING SERVICE (6)	DIRECT DISTRIBUTION CONNECTION (7)
RATIO TABLE								
RATIO TABLE INTERNALLY DEVELOPED CON'T-23 Distribution Operating Exp Acct 581 - 587 Distribution Maintenance Exp Acct 592 - 597 Distribution Maintenance Exp Acct 592 - 598 Distribution Maintenance Labor Acct 581 - 589 Distribution Maintenance Labor Acct 582 - 598 Total Distribution Operating Labor Total Distribution Maintenance Labor Acct 990:200 Meter reading expenses Acct 990:200 Miscellaneous cust accounts exp Acct 990:500 Miscellaneous cust accounts exp Acct 990:500 Miscellaneous cust accounts exp Acct 991:000 Customer assistance expenses Acct 991:000 Misc cust service & informat exp Acct 991:000 Misc cust service & informat exp Acct 991:000 Administrative & General salaries Acct 991:200 Demonstrating & selling expenses Acct 992:000 Administrative & General salaries Acct 992:000 Miscellaneous general expenses Acct 992:000 Miscellaneous general expenses Acct 993:000 Miscellaneous general expenses Total Intangible Plant Service Company Assets Reserve Total System Electric Distribution Accts 902 & 903 Mtr Read & Cust Rec Total Customer Deposits Sales Revenue Required Claimed ROR	EXPDISTO EXPDISTM LABDO LABDM TLABDO TLABDM EXP902 EXP903 EXP905 EXP907 EXP908 EXP910 EXP912 EXP913 EXP920 EXP921 EXP923 EXP923 EXP9302 EXP9302 EXP9302 EXP9302 EXP9302 EXP9303 INTPLT SERVCO PLANT EXP9023 CUSTDEP CLAIMREV	1.000000 1.000000 1.000000 1.000000 1.000000 1.000000 1.000000 0.000000 0.000000 0.000000 0.000000	0.647680 0.668870 0.660813 0.658092 0.660013 0.658092 0.873920 0.887199 0.000000 0.000000 0.070844 0.000000 0.000000 0.000000 0.669849 0.669849 0.669849 0.669849 0.669849 0.669849 0.669849 0.669849 0.669849 0.659070 0.885457 0.447609	0.178897 0.124602 0.177672 0.122609 0.177672 0.122609 0.103730 0.092210 0.000000 0.000000 0.000000 0.000000 0.145853	0.120646 0.175387 0.125289 0.172187 0.125289 0.172187 0.0077146 0.005753 0.000000 0.000000 0.124658 0.000000 0.000000 0.142988 0.142988 0.142988 0.142988 0.142988 0.142988 0.142988 0.142988 0.142988 0.142988 0.142988 0.142988 0.142988 0.14388	0.019377 0.002008 0.020940 0.003734 0.020940 0.003734 0.005204 0.004303 0.000000 0.059522 0.000000 0.000000 0.012586	0.032793 0.027897 0.015463 0.042162 0.015463 0.042162 0.000000 0.008996 0.000000 0.009196 0.000000 0.000000 0.0027797 0.027816	0.000608 0.001236 0.000623 0.001216 0.000623 0.001216 0.000000 0.001540 0.000000 0.001787 0.000000 0.000000 0.000000 0.000000 0.000000
26 Residential Distribution Plant 27 Non-Residential Distribution Plant 28 29 30 31 31 32 33 34 35 36 37 38 39 40 41 42 43 44	RESDIST NRESDIST	1.00000 1.00000	1.00000 0.000000	0.00000 0.367081	0.00000 0.459113	0.00000 0.010665	0.00000 0.159702	0.00000 0.003439

	ALLOC	RESIDENTIAL (8)-2	MONTHLY GENERAL SERV SECONDARY (9)	MONTHLY GENERAL SERV PRIMARY (10)	ANNUAL GENERAL SERV SECONDARY (11)	ANNUAL GENERAL SERV PRIMARY (12)	STREET AND PRIVATE LIGHTING (13)	GENERAL SERVICE SUBTRANSMSN (14)	GENERAL SERVICE TRANSMISSION (15)	DIRECT DISTRIBUTION CONNECTION (16)
RATIO TABLE										
INTERNALLY DEVELOPED CON'T-23 1 Distribution Operating Exp Acct 581 - 587 2 Distribution Maintenance Exp Acct 592 - 597 3 Distribution Maintenance Exp Acct 592 - 598 4 Distribution Maintenance Labor Acct 592 - 598 5 Total Distribution Maintenance Labor Acct 592 - 598 5 Total Distribution Maintenance Labor 7 Acct 990200 Meter reading expenses 8 Acct 990300 Cust records and collection exp 9 Acct 990500 Miscellaneous cust accounts exp 10 Acct 990700 Supervision 11 Acct 991000 Misc cust service & informat exp 13 Acct 991200 Demonstrating & selling expenses 14 Acct 991200 Advertising expense 15 Acct 992000 Administrative & General salaries 16 Acct 992000 Administrative & General salaries 16 Acct 992000 Miscellaneous general expenses 17 Acct 992300 Miscellaneous general expenses 18 Acct 993020 Miscellaneous general expenses 19 Acct 993020 Miscellaneous general expenses 10 Acct 993020 Miscellaneous general expenses 11 Acct 993020 Miscellaneous General plant 12 Total Intangible Plant 13 Service Company Assets Reserve 14 Total Customer Deposits 15 Sales Revenue Required Claimed ROR 16 Residential Distribution Plant 17 Non-Residential Distribution Plant 18 Non-Residential Distribution Plant 19 Acct 99304 10 Acct 9930504 11 Acct 9930504 12 Acct 9930504 13 Acct 9930504 14 Acct 9930504 15 Acct 9930506 16 Acct 9930506 17 Acct 9930506 18 Acct 99306 18 Acct 99306 18 Acct 99306 18 Acct 9	EXPDISTO EXPDISTM LABDO LABDM TLABDO TLABDM EXP902 EXP903 EXP907 EXP908 EXP910 EXP912 EXP913 EXP920 EXP921 EXP923 EXP923 EXP933 CXP923 CXP923 CXP935 INTPLT SERVCO PLANT EXP9023 CUSTDEP CLAIMREV RESDIST NRESDIST	0.647680 0.668870 0.660013 0.658092 0.660013 0.658092 0.873920 0.887199 0.000000 0.000000 0.000000 0.670844 0.669849 0.669849 0.669849 0.669849 0.669849 0.669841 0.669849 0.669849 0.669840	0.170613 0.119671 0.169535 0.117800 0.169535 0.117800 0.099315 0.090000 0.000000 0.129433 0.000000 0.129433 0.000000 0.139656	0.008283 0.004931 0.008136 0.004810 0.008136 0.004815 0.000556 0.000000 0.004561 0.000000 0.004561 0.000000 0.006197	0.091440 0.134997 0.095149 0.132815 0.095149 0.132815 0.010365 0.005182 0.000000 0.000000 0.000000 0.109321 0.109471	0.029206 0.040390 0.030140 0.039372 0.030140 0.039372 0.006781 0.000571 0.000000 0.000000 0.031437 0.000000 0.033517 0.033517 0.033517 0.033517 0.033517 0.033517 0.033517 0.033517 0.038517 0.038517 0.038517 0.038517 0.038517 0.038517 0.038517 0.038517 0.038517 0.038517 0.038517 0.038517 0.038517	0.032793 0.027897 0.015463 0.042162 0.015463 0.042162 0.000000 0.008996 0.000000 0.009196 0.000000 0.027797 0.027797 0.027797 0.027797 0.027797 0.027797 0.027797 0.027797 0.027797 0.027797 0.027797 0.151774 0.007816 0.000000 0.038259 0.000000 0.159702	0.014254 0.002007 0.016091 0.003729 0.003011 0.000230 0.000000 0.000000 0.000000 0.000000 0.000000	0.005123 0.00001 0.004849 0.000005 0.004849 0.000005 0.002102 0.004073 0.000000 0.000000 0.000000 0.000000 0.000000	0.000608 0.001236 0.000623 0.001216 0.000623 0.001216 0.000000 0.001540 0.000000 0.001787 0.000000 0.000000 0.000000 0.000000 0.000926 0.000926 0.000926 0.000926 0.000926 0.000938 0.000926 0.000938

		ALLOC	TOTAL ACE DISTRIBUTION (1)	TOTAL RESIDENTIAL SERVICE (2)	MONTHLY GENERAL SERVICE (3)	ANNUAL GENERAL SERVICE (4)	TRANSM GENERAL SERVICE (5)	STREET LIGHTING SERVICE (6)	DIRECT DISTRIBUTION CONNECTION (7)
	ALLOCATION FACTOR TABLE								
1 2 2 3 3 4 4 5 5 6 6 7 7 8 8 9 10 11 11 12 13 13 14 15 16 6 17 18 19 20 0 21 22 23 24 25	Claimed Revenues MGSS Claimed Revenues MGSP Claimed Revenues AGSS Claimed Revenues AGSP Claimed Revenues Lighting Claimed Revenues GSST Claimed Revenues GST Claimed Revenues GDC	CREVRES CREVGSS CREVCOM CREVGSSL CREVGSP CREVLTG CREVGST CREVGST CREVDDC	1.00000 1.00000 1.00000 1.00000 1.00000 1.00000 1.00000 1.00000 1.00000	1.000000 0.000000 0.000000 0.000000 0.000000	0.000000 1.000000 1.000000 0.000000 0.000000 0.000000 0.000000	0.000000 0.000000 1.000000 0.000000 0.000000 0.000000 0.000000	0.000000 0.000000 0.000000 0.000000 0.000000	0.000000 0.000000 0.000000 0.000000 1.000000 0.000000 0.000000 0.000000 0.000000	0.000000 0.000000 0.000000 0.000000 0.000000
26 27 28	REVENUE REQUIREMENTS INPUTS								
29 30			1.000000	0.620948	0.180715	0.146720	0.010728	0.039657	0.001233
31 32 33 34 35 36 37 38 39 40 41 42 43 44 45	BILLING DETERMINANTS Average Number of Customers (12 Months) Total KWH Sales @ Meter)	1.000000 1.000000 1.000000	0.882304 0.459383 0.459383	0.099855 0.168132 0.168132	0.005320 0.243996 0.243996	0.000091 0.118952 0.118952	0.010559 0.007832 0.007832	0.001871 0.001704 0.001704

	ALLOC	RESIDENTIAL (8)-2	MONTHLY GENERAL SERV SECONDARY (9)	MONTHLY GENERAL SERV PRIMARY (10)	ANNUAL GENERAL SERV SECONDARY (11)	ANNUAL GENERAL SERV PRIMARY (12)	STREET AND PRIVATE LIGHTING (13)	GENERAL SERVICE SUBTRANSMSN (14)	GENERAL SERVICE TRANSMISSION (15)	DIRECT DISTRIBUTION CONNECTION (16)
ALLOCATION FACTOR TABLE										
INTERNALLY DEVELOPED CON'T-24 1	CREVRES CREVGSS CREVCOM CREVGSSL CREVGSP CREVLTG CREVGSST CREVGST CREVDDC	1.00000 0.00000 0.000000 0.000000 0.000000	0.000000 1.000000 0.000000 0.000000 0.000000 0.000000	0.000000 0.000000 1.000000 0.000000 0.000000 0.000000 0.000000	0.00000 0.00000 1.00000 1.00000 0.00000 0.00000 0.00000 0.00000	0.00000 0.00000 0.00000 0.00000 1.00000 0.00000 0.00000 0.00000	0.000000 0.000000 0.000000 0.000000 1.000000 0.000000 0.000000 0.000000	0.000000 0.000000 0.000000 0.000000 0.000000	0.000000 0.000000 0.000000 0.000000 0.000000	0.000000 0.000000 0.000000 0.000000 0.000000
25 26 27 REVENUE REQUIREMENTS INPUTS										
28 29 Current Revenue - Retail Sales ACE 30 31 Claimed Rate of Return		0.620948	0.176966	0.003749	0.120314	0.026406	0.039657	0.006345	0.004383	0.001233
32 33 BILLING DETERMINANTS 34 Average Number of Customers (12 Months 35 Total KWH Sales @ Meter 36 Total MWH Sales @ Meter 37 38 39 40 41 42 43 44 45	s)	0.882304 0.459383 0.459383	0.099585 0.159281 0.159281	0.000271 0.008851 0.008851	0.005112 0.181330 0.181330	0.000207 0.062667 0.062667	0.010559 0.007832 0.007832	0.000063 0.062982 0.062982	0.000028 0.055971 0.055971	0.001871 0.001704 0.001704

		ALLOC	TOTAL ACE DISTRIBUTION (1)	TOTAL RESIDENTIAL SERVICE (2)	MONTHLY GENERAL SERVICE (3)	ANNUAL GENERAL SERVICE (4)	TRANSM GENERAL SERVICE (5)	STREET LIGHTING SERVICE (6)	DIRECT DISTRIBUTION CONNECTION (7)
	ALLOCATED DIRECT ASSIGNMENT								
	BASED ON CLAIMED REV-25 Revenues Residential	CREVRES	200 020 547	200 020 547	0	0	0	0	0
1	Revenues MGSS	CREVGES	296,020,547 84,363,933	296,020,547 0	0 84,363,933	0	0	0	0
	Revenues MGSP	CREVCOM	1,787,281	0	1,787,281	0	0	0	0
4		CREVGSSL	57,356,426	0	1,767,261	57,356,426	0	0	0
	Revenues AGSP	CREVGSP	12,588,416	0	0	12,588,416	0	0	0
	Revenues Lighting	CREVLTG	18,905,207	0	0	0	0	18,905,207	ő
7	Revenues GSST	CREVGSST	3,024,915	0	0	0	3,024,915	0	0
8	Revenues GST	CREVGST	2,089,427	0	0	0	2,089,427	0	0
	Revenues DDC	CREVDDC	587,648	0	0	0	0	0	587,648
10	Revenue		476,723,799	296,020,547	86,151,215	69,944,842	5,114,341	18,905,207	587,648
11	Revenue	REVENUES	1.000000	0.620948	0.180715	0.146720	0.010728	0.039657	0.001233
12									
13									
14									
15									
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17									
18									
19									
20									
21									

	ALLOC	RESIDENTIAL (8)-2	MONTHLY GENERAL SERV SECONDARY (9)	MONTHLY GENERAL SERV PRIMARY (10)	ANNUAL GENERAL SERV SECONDARY (11)	ANNUAL GENERAL SERV PRIMARY (12)	STREET AND PRIVATE LIGHTING (13)	GENERAL SERVICE SUBTRANSMSN (14)	GENERAL SERVICE TRANSMISSION (15)	DIRECT DISTRIBUTION CONNECTION (16)
ALLOCATED DIRECT ASSIGNMENT										
BASED ON CLAIMED REV-25 1 Revenues Residential	CREVRES	200 020 547	0	0	0	0	0	0	0	0
2 Revenues MGSS	CREVRES	296,020,547	84,363,933	0	0	0	0	0	0	0
3 Revenues MGSP	CREVCOM	0	04,505,555	1,787,281	0	0	0	0	0	0
4 Revenues AGSS	CREVGSSL	0	0	0	57,356,426	Ö	0	Ö	Ö	Ö
5 Revenues AGSP	CREVGSP	0	0	0	0	12,588,416	0	0	0	0
6 Revenues Lighting	CREVLTG	0	0	0	0	0	18,905,207	0	0	0
7 Revenues GSST	CREVGSST	0	0	0	0	0	0	3,024,915	0	0
8 Revenues GST	CREVGST	0	0	0	0	0	0	0	2,089,427	0
9 Revenues DDC	CREVDDC	0	0	0	0	0	0	0	0	587,648
10 Revenue		296,020,547	84,363,933	1,787,281	57,356,426	12,588,416	18,905,207	3,024,915	2,089,427	587,648
11 Revenue	REVENUES	0.620948	0.176966	0.003749	0.120314	0.026406	0.039657	0.006345	0.004383	0.001233
12										
13 14										
15										
16										
17										
18										
19										
20										
21										

		ALLOC	TOTAL ACE DISTRIBUTION (1)	TOTAL RESIDENTIAL SERVICE (2)	MONTHLY GENERAL SERVICE (3)	ANNUAL GENERAL SERVICE (4)	TRANSM GENERAL SERVICE (5)	STREET LIGHTING SERVICE (6)	DIRECT DISTRIBUTION CONNECTION (7)
	ALLOCATED DIRECT ASSIGNMENT								
	BASED ON CLAIMED REV-26								
1	Revenues Residential	CREVRES	0	0	0	0	0	0	0
2		CREVGSS	84,363,933	0	84,363,933	0	0	0	0
	Revenues MGSP	CREVCOM	1,787,281	0	1,787,281	0	0	0	0
4		CREVGSSL	57,356,426	0	0	57,356,426	0	0	0
5		CREVGSP	12,588,416	0	0	12,588,416	0	0	0
6		CREVLTG	18,905,207	0	0	0	Ō	18,905,207	Ō
7	Revenues GSST	CREVGSST	0	0	0	0	0	0	0
8	Revenues GST	CREVGST	0	0	0	0	0	0	0
9	Revenues DDC	CREVDDC	587,648	0	0	0	0	0	587,648
10	Late Pay Assign Rev W/O Res		175,588,912	0	86,151,215	69,944,842	0	18,905,207	587,648
11	Late Pay Assign Rev W/O Res	LPAY	1.000000	0.000000	0.490642	0.398344	0.000000	0.107667	0.003347
12									
13									
14	Revenues Residential	CREVRES	310,873,893	310,873,893	0	0	0	0	0
15		CREVGSS	70,990,209	0	70,990,209	0	0	0	0
16	Revenues MGSP	CREVCOM	6,066,967	0	6,066,967	0	0	0	0
17		CREVGSSL	34,862,669	0	0	34,862,669	0	0	0
18	Revenues AGSP	CREVGSP	13,714,362	0	0	13,714,362	0	0	0
19		CREVLTG	1,742,122	0	0	0	0	1,742,122	0
20		CREVGSST	23,213,393	0	0	0	23,213,393	0	0
21		CREVGST	9,357,917	0	0	0	9,357,917	0	0
	Revenues DDC	CREVDDC	238,711	0	0	0	0	0	238,711
23			471,060,244	310,873,893	77,057,176	48,577,031	32,571,311	1,742,122	238,711
24	Revenue BGS & NUGS	BGSNUGRV	1.000000	0.659945	0.163582	0.103123	0.069145	0.003698	0.000507
25									
26	D	ODEV/DEO	50 540 000	50 540 000			•		
27		CREVRES	52,519,663	52,519,663	0	0	0	0	0
28		CREVGSS CREVCOM	30,986,297	0	30,986,297	0	0	0	0
29 30		CREVGON	208,190	0	208,190 0	19.186.020	0	0	0
	Revenues AGSP	CREVGSSL	19,186,020 2,803,627	0	0	2,803,627	0	0	0
32		CREVLTG	6,946,271	0	0	2,003,027	0	6,946,271	0
				0	0	0	-	0,940,271	0
33 34		CREVGSST CREVGST	763,451 868,840	0	0	0	763,451 868,840	0	0
	Revenues GST Revenues DDC	CREVDDC	174,667	0	0	0	000,040	0	174,667
36		CKEADDC	114,457,025	52,519,663	31,194,487	21,989,646	1,632,291	6,946,271	174,667
37		NETINC	1.000000	0.458859	0.272543	0.192121	0.014261	0.060689	0.001526
38	THE INCOME	14211140	1.00000	0.430035	0.212040	0.102121	0.014201	0.000009	0.001020

		ALLOC	RESIDENTIAL (8)-2	MONTHLY GENERAL SERV SECONDARY (9)	MONTHLY GENERAL SERV PRIMARY (10)	ANNUAL GENERAL SERV SECONDARY (11)	ANNUAL GENERAL SERV PRIMARY (12)	STREET AND PRIVATE LIGHTING (13)	GENERAL SERVICE SUBTRANSMSN (14)	GENERAL SERVICE TRANSMISSION (15)	DIRECT DISTRIBUTION CONNECTION (16)
	ALLOCATED DIRECT ASSIGNMENT										
	BASED ON CLAIMED REV-26										
1	Revenues Residential	CREVRES	0	0	0	0	0	0	0	0	0
	Revenues MGSS	CREVGSS	0	84,363,933	0	0	0	0	0	0	0
	Revenues MGSP	CREVCOM	0	0	1,787,281	0	0	0	0	0	0
4	Revenues AGSS	CREVGSSL	0	0	0	57,356,426	0	0	0	0	0
	Revenues AGSP Revenues Lighting	CREVGSP CREVLTG	0	0	0	0	12,588,416 0	0 18,905,207	0	0	0
7	Revenues Lignling Revenues GSST	CREVEIG	0	0	0	0	0	10,903,207	0	0	0
	Revenues GST	CREVGST	0	0	0	0	0	0	0	0	0
	Revenues DDC	CREVDDC	0	0	0	0	0	0	0	0	587,648
	Late Pay Assign Rev W/O Res		0	84,363,933	1,787,281	57,356,426	12,588,416	18,905,207	0	0	587,648
	Late Pay Assign Rev W/O Res	LPAY	0.000000	0.480463	0.010179	0.326652	0.071693	0.107667	0.000000	0.000000	0.003347
12											
13											
14	Revenues Residential	CREVRES	310,873,893	0	0	0	0	0	0	0	0
15		CREVGSS	0	70,990,209	0	0	0	0	0	0	0
16 17		CREVCOM CREVGSSL	0	0	6,066,967	0	0	0	0	0	0
18	Revenues AGSP	CREVGSSL	0	0	0	34,862,669 0	13,714,362	0	0	0	0
19		CREVLTG	0	0	0	0	13,7 14,302	1,742,122	0	0	0
	Revenues GSST	CREVGSST	0	0	0	0	0	1,742,122	23,213,393	0	0
	Revenues GST	CREVGST	0	0	0	0	0	0	0	9,357,917	0
22	Revenues DDC	CREVDDC	0	0	0	0	0	0	0	0	238,711
23	BGS & NUGS Revenue		310,873,893	70,990,209	6,066,967	34,862,669	13,714,362	1,742,122	23,213,393	9,357,917	238,711
24	Revenue BGS & NUGS	BGSNUGRV	0.659945	0.150703	0.012879	0.074009	0.029114	0.003698	0.049279	0.019866	0.000507
25											
26	Barrell Barrell	005/050	50 540 000		•				•		
28	Revenues Residential Revenues MGSS	CREVRES CREVGSS	52,519,663 0	0 30,986,297	0	0	0	0	0	0	0
	Revenues MGSP	CREVCOM	0	30,986,297	208,190	0	0	0	0	0	0
	Revenues AGSS	CREVGSSL	0	0	200,130	19,186,020	0	0	0	0	0
31	Revenues AGSP	CREVGSP	0	ő	0	0	2,803,627	0	0	ő	Ö
32		CREVLTG	0	0	0	0	0	6,946,271	0	0	0
33	Revenues GSST	CREVGSST	0	0	0	0	0	0	763,451	0	0
34	Revenues GST	CREVGST	0	0	0	0	0	0	0	868,840	0
35		CREVDDC	0	0	0	0	0	0	0	0	174,667
	Net Income		52,519,663	30,986,297	208,190	19,186,020	2,803,627	6,946,271	763,451	868,840	174,667
37	Net Income	NETINC	0.458859	0.270724	0.001819	0.167626	0.024495	0.060689	0.006670	0.007591	0.001526
38 39											
40											
41											
42											
43											
44											
45											

	ALLOC	TOTAL ACE DISTRIBUTION (1)	TOTAL RESIDENTIAL SERVICE (2)	MONTHLY GENERAL SERVICE (3)	ANNUAL GENERAL SERVICE (4)	TRANSM GENERAL SERVICE (5)	STREET LIGHTING SERVICE (6)	DIRECT DISTRIBUTION CONNECTION (7)
ALLOCATED DIRECT ASSIGNMENT								
BASED ON PRIMARY DEMAND-27 1 MWH Sales @ Meter Residential 2 MWH Sales @ Meter MGSS 3 MWH Sales @ Meter AGSP 4 MWH Sales @ Meter AGSP 6 MWH Sales @ Meter Lighting 7 MWH Sales @ Meter GST 8 MWH Sales @ Meter GST 9 MWH Sales @ Meter DDC 10 ACE MWH 11 ACE Allocator 12 Sales without Trans 13 14 15 16 17 18 19 20 21 22 23 24 25 26 27 28 29 30 31 32 33 34 35 36 37 38 39 40 41 42 43 44 45	DEMPRI DEMPRI DEMPRI DEMPRI DEMPRI DEMPRI DEMPRI DEMPRI SALES SALESWOT	4,032,550 1,398,200 77,696 1,591,748 550,099 68,753 552,866 491,320 14,955 8,778,187 1,000000 8,778,187 1,000000	2,725,385 944,968 52,511 1,075,777 371,782 46,466 373,653 332,057 10,107 5,932,706 0.675846 5,932,706 0.675846	485,277 168,259 9,350 191,551 66,199 8,274 66,532 59,125 1,800 1,056,367 0,120340 1,056,367 0,120340	648,689 224,919 12,498 256,054 88,491 11,060 88,936 79,035 2,406 1,412,088 0.160863 1,412,088 0.160863	143,250 49,669 2,760 56,544 19,541 2,442 19,640 17,453 531 311,831 0.035523 311,831 0.035523	27,107 9,399 522 10,700 3,698 462 3,716 3,303 101 59,007 0.006722 59,007 0.006722	2,843 986 55 1,122 388 48 390 346 11 6,189 0.000705 6,189 0.000705

				MONTHLY	MONTHLY	ANNUAL	ANNUAL	STREET AND	GENERAL	GENERAL	DIRECT
			RESIDENTIAL	GENERAL SERV	GENERAL SERV	GENERAL SERV	GENERAL SERV	PRIVATE	SERVICE	SERVICE	DISTRIBUTION
				SECONDARY	PRIMARY	SECONDARY	PRIMARY	LIGHTING	SUBTRANSMSN	TRANSMISSION	CONNECTION
		ALLOC	(8)-2	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
	ALLOCATED DIRECT ASSIGNMENT										
	BASED ON PRIMARY DEMAND-27										
	MWH Sales @ Meter Residential	DEMPRI	2,725,385	467,829	17,448	501,781	146,908	27,107	143,250	0	2,843
2	MWH Sales @ Meter MGSS	DEMPRI	944,968	162,210	6,050	173,982	50,937	9,399	49,669	0	986
3	MWH Sales @ Meter MGSP	DEMPRI	52,511	9,014	336	9,668	2,831	522	2,760	0	55
4	MWH Sales @ Meter AGSS	DEMPRI	1,075,777	184,664	6,887	198,066	57,988	10,700	56,544	0	1,122
5	MWH Sales @ Meter AGSP	DEMPRI	371,782	63,819	2,380	68,450	20,040	3,698	19,541	0	388
6	MWH Sales @ Meter Lighting	DEMPRI	46,466	7,976	297	8,555	2,505	462	2,442	0	48
7	MWH Sales @ Meter GSST	DEMPRI	373,653	64,140	2,392	68,795	20,141	3,716	19,640	0	390
8	MWH Sales @ Meter GST	DEMPRI	332,057	57,000	2,126	61,136	17,899	3,303	17,453	0	346
	MWH Sales @ Meter DDC	DEMPRI	10,107	1,735	65	1,861	545	101	531	0	11
10	ACE MWH		5,932,706	1,018,386	37,981	1,092,294	319,794	59,007	311,831	0	6,189
11	ACE Allocator	SALES	0.675846	0.116013	0.004327	0.124433	0.036431	0.006722	0.035523	0.000000	0.000705
12	Sales without Trans		5,932,706	1,018,386	37,981	1,092,294	319,794	59,007	311,831	0	6,189
13		SALESWOT	0.675846	0.116013	0.004327	0.124433	0.036431	0.006722	0.035523	0.000000	0.000705
14											

ATLANTIC CITY ELECTRIC ACE RETAIL COST OF SERVICE STUDY 12 MONTHS ENDED SEPTEMBER 30, 2022 ELECTRIC DISTRIBUTION

			TOTAL ACE	TOTAL RESIDENTIAL	MONTHLY GENERAL	ANNUAL GENERAL	TRANSM GENERAL	STREET LIGHTING	DIRECT DISTRIBUTION
		ALLOC	DISTRIBUTION (1)	SERVICE (2)	SERVICE (3)	SERVICE (4)	SERVICE (5)	SERVICE (6)	CONNECTION (7)
	REVENUE REQUIREMENTS-28								
	Present Rates								
1	Rate Base		1,952,245,281	1,287,193,690	247,861,203	300,692,437	10,206,849	104,001,638	2,289,464
2	Net Operating Income (Present Rates)		114,457,025	52,519,663	31,194,487	21,989,646	1,632,291	6,946,271	174,667
3	Rate of Return (Present Rates)		5.86%	4.08%	12.59%	7.31%	15.99%	6.68%	7.63%
4	Relative Rate of Return		1.00	0.70	2.15	1.25	2.73	1.14	1.30
5	Sales Revenue (Present Rates)		476,723,799	296,020,547	86,151,215	69,944,842	5,114,341	18,905,207	587,648
6	Revenue Present Rates \$/KWH Revenue Required - \$/Mo/Customer		\$0.0543 \$69.84	\$0.0734 \$49.15	\$0.0584 \$126.40	\$0.0327 \$1,926.22	\$0.0049 \$8,196.06	\$0.2750 \$262.31	\$0.0393 \$46.03
,	Revenue Requireu - \$/MO/Customer		3 09.04	Ф49.13	φ120.40	\$1,920.22	ФО, 190.00	φ202.31	\$40.03
	Claimed Rate of Return								
8	Claimed Rate of Return		7.13%	7.13%	7.13%	7.13%	7.13%	7.13%	7.13%
9	Return Required Claimed Rate of Return		139,195,089	91,776,910	17,672,504	21,439,371	727,748	7,415,317	163,239
10	Sales Revenue Required Claimed ROR		511,238,818	350,793,007	67,285,085	69,177,087	3,852,307	19,559,629	571,703
11	Revenue Deficiency Sales Revenue		34,515,019	54,772,461	(18,866,129)	(767,755)	(1,262,035)	654,422	(15,945)
12	Percent Increase Required		7.24%	18.50%	-21.90%	-1.10%	-24.68%	3.46%	-2.71%
13	Annual Booked KWH Sales		8,778,187,173	4,032,550,392	1,475,895,885	2,141,846,944	1,044,186,603	68,752,713	14,954,636
14	Sales Revenue Required \$/KWH		\$0.0582	\$0.0870	\$0.0456	\$0.0323	\$0.0037	\$0.2845	\$0.0382
15	Revenue Deficiency \$/KWH		\$0.0039	\$0.0136	(\$0.0128)	(\$0.0004)	(\$0.0012)	\$0.0095	(\$0.0011)

ATLANTIC CITY ELECTRIC

BPU Assessment	0.2483%
Ratepayer Advocate Assessment	0.0531%
STATE TAX RATE	9.00%
FEDERAL TAX RATE - CURRENT	21.00%
EFFECTIVE STATE TAX RATE	8.9729%
1 - INCREMENTAL TAX RATE	0.7167
INCREMENTAL TAX RATE	0.2833
EFFECTIVE INCREMENTAL FEDERAL RATE	0.1905
FACTOR FOR TAXABLE BASIS	1.3952

ATLANTIC CITY ELECTRIC ACE RETAIL COST OF SERVICE STUDY 12 MONTHS ENDED SEPTEMBER 30, 2022 ELECTRIC DISTRIBUTION

		ALLOC	RESIDENTIAL (8)-2	MONTHLY GENERAL SERV SECONDARY (9)	MONTHLY GENERAL SERV PRIMARY (10)	ANNUAL GENERAL SERV SECONDARY (11)	ANNUAL GENERAL SERV PRIMARY (12)	STREET AND PRIVATE LIGHTING (13)	GENERAL SERVICE SUBTRANSMSN (14)	GENERAL SERVICE TRANSMISSION (15)	DIRECT DISTRIBUTION CONNECTION (16)
	REVENUE REQUIREMENTS-28										
	Present Rates										
1 2 3 4 5 6 7	Rate Base Net Operating Income (Present Rates) Rate of Return (Present Rates) Relative Rate of Return Sales Revenue (Present Rates) Revenue Present Rates \$\fomale KWH Revenue Required - \$\fomale Mo/Customer		1,287,193,690 52,519,663 4.08% 0.70 296,020,547 \$0.0734 \$49.15	240,250,419 30,986,297 12,90% 2.20 84,363,933 \$0,0603 \$124.11	7,610,785 208,190 2.74% 0.47 1,787,281 \$0.0230 \$967.14	247,441,535 19,186,020 7.75% 1.32 57,356,426 \$0.0360 \$1,643.64	53,250,902 2,803,627 5,26% 0,90 12,588,416 \$0,0229 \$8,890.12	104,001,638 6,946,271 6.68% 1.14 18,905,207 \$0.2750 \$262.31	8,350,576 763,451 9.14% 1.56 3,024,915 \$0.0055 \$7,002.12	1,856,273 868,840 46.81% 7.98 2,089,427 \$0.0043 \$10,882.43	2,289,464 174,667 7.63% 1.30 587,648 \$0.0393 \$46.03
	Claimed Rate of Return										
8 9 10 11 12 13 14 15	Claimed Rate of Return Return Required Claimed Rate of Return Sales Revenue Required Claimed ROR Revenue Deficiency Sales Revenue Percent Increase Required Annual Booked KWH Sales Sales Revenue Required \$/KWH Revenue Deficiency \$/KWH		7.13% 91,776,910 350,793,007 54,772,461 18.50% 4,032,550,392 \$0.0870 \$0.0136	7.13% 17,129,855 65,031,160 (19,332,773) -22.92% 1,398,199,951 \$0.0465 (\$0.0138)	26.11% 77,695,934 \$0.0290	7.13% 17,642,581 55,202,991 (2,153,435) -3.75% 1,591,748,317 \$0.0347 (\$0.0014)	7.13% 3,796,789 13,974,095 1,385,679 11.01% 550,098,627 \$0.0254	7.13% 7,415,317 19,559,629 654,422 3.46% 68,752,713 \$0.2845 \$0.0095	595,396 2,790,441 (234,473)	7.13% 132,352 1,061,865 (1,027,561) -49.18% 491,320,188 \$0.0022 (\$0.0021)	7.13% 163,239 571,703 (15,945) -2.71% 14,954,636 \$0.0382 (\$0.0011)

ATLANTIC CITY ELECTRIC

BPU Assessment
Ratepayer Advocate Assessment
STATE TAX RATE
FEDERAL TAX RATE - CURRENT
EFFECTIVE STATE TAX RATE
1 - INCREMENTAL TAX RATE
INCREMENTAL TAX RATE
EFFECTIVE INCREMENTAL FEDERAL RATE
FACTOR FOR TAXABLE BASIS

Schedule (JLM)-6

	TOTAL ACE DISTRIBUTION (1)	RESIDENTIAL (8)-2	MONTHLY GENERAL SERV SECONDARY (9)	MONTHLY GENERAL SERV PRIMARY (10)	ANNUAL GENERAL SERV SECONDARY (11)	ANNUAL GENERAL SERV PRIMARY (12)	STREET AND PRIVATE LIGHTING (13)	GENERAL SERVICE SUBTRANSMSN (14)	GENERAL SERVICE TRANSMISSION (15)	DIRECT DISTRIBUTION CONNECTION (16)
PRESENT RATE OF RETURN SUMMARY SCHEDULE										
RATE OF RETURN	5.86%	4.08%	12.90%	2.74%	7.75%	5.26%	6.68%	9.14%	46.81%	7.63%
REVENUES REQUIRED										
1 DEMAND DISTRIBUTION	350,820,351	212,477,297	66,464,830	1,177,247	55,343,407	11,508,487	1,309,607	2,046,162	0	493,315
2 DEMAND DISTRIBUTION PRIMARY	266,947,300	161,846,427	48,075,512	1,177,247	40,956,532	11,508,487	973,851	2,046,162	0	363,082
3 DEMAND DISTRIBUTION SECONDARY	58,136,291	36,707,505	11,576,141	0	9,618,774	0	146,610	0	0	87,260
4 DEMAND DISTRIBUTION TRANSFORMERS	66,311,744	38,130,386	16,031,919	0	11,853,206	0	189,146	0	0	107,087
5 CUSTOMER COMPONENTS	146,190,940	95,646,761	22,508,475	610,034	5,555,572	1,079,928	17,595,600	978,752	2,089,427	126,391
6 CUSTOMER METERS COMPONENT	59,077,468	34,747,691	16,103,282	500,822	4,958,509	802,550	0	658,774	1,273,783	32,057
7 CUSTOMER SERVICES COMPONENT	20,287,492	12,103,511	4,609,371	0	3,542,553	0	0	0	0	32,057
8 CUSTOMER 902-METER READING COMPONENT	31,906,584	22,179,593	5,821,755	50,569	3,663,424	78,295	0	39,347	41,544	32,057
9 CUSTOMER 903-CUST REC & COLLECT COMP	72,657,796	58,259,453	9,586,037	28,820	3,813,542	29,677	467,653	13,079	347,014	112,521
10 CUSTOMER SERVICE EXPENSE COMP	28,221,640	17,264,481	5,661,944	34,864	4,267,389	242,158	70,963	266,619	367,284	45,938
11 CUSTOMER OTHER COMPONENT	35,477,422	11,609,588	3,772,942	(5,041)	3,022,920	(72,751)	17,056,984	933	59,802	32,046
12 TOTAL ACE DISTRIBUTION	476,723,799	296,020,547	84,363,933	1,787,281	57,356,426	12,588,416	18,905,207	3,024,915	2,089,427	587,648
13 AVG. NUMBER OF CUSTOMER	568,813	501,866	56,645	154	2,908	118	6,006	36	16	1,064
14 CUSTOMER \$/MONTH/CUSTOMER	\$21.42	\$15.88	\$33.11	\$330.11	\$159.20	\$762.66	\$244.14	\$2,265.63	\$10,882.43	\$9.90

	TOTAL ACE DISTRIBUTION (1)	RESIDENTIAL (8)-2	MONTHLY GENERAL SERV SECONDARY (9)	MONTHLY GENERAL SERV PRIMARY (10)	ANNUAL GENERAL SERV SECONDARY (11)	ANNUAL GENERAL SERV PRIMARY (12)	STREET AND PRIVATE LIGHTING (13)	GENERAL SERVICE SUBTRANSMSN (14)	GENERAL SERVICE TRANSMISSION (15)	DIRECT DISTRIBUTION CONNECTION (16)
PRESENT RATE OF RETURN SUMMARY SCHEDULE										
RATE OF RETURN	5.86%	4.08%	12.90%	2.74%	7.75%	5.26%	6.68%	9.14%	46.81%	7.63%
\$/KWH										
1 DEMAND DISTRIBUTION	\$0.0400	\$0.0527	\$0.0475	\$0.0152	\$0.0348	\$0.0209	\$0.0190	\$0.0037	\$0.0000	\$0.0330
2 DEMAND DISTRIBUTION PRIMARY	\$0.0304	\$0.0401	\$0.0344	\$0.0152	\$0.0257	\$0.0209	\$0.0142	\$0.0037	\$0.0000	\$0.0243
3 DEMAND DISTRIBUTION SECONDARY	\$0.0066	\$0.0091	\$0.0083	\$0.0000	\$0.0060	\$0.0000	\$0.0021	\$0.0000	\$0.0000	\$0.0058
4 DEMAND DISTRIBUTION TRANSFORMERS	\$0.0076	\$0.0095	\$0.0115	\$0.0000	\$0.0074	\$0.0000	\$0.0028	\$0.0000	\$0.0000	\$0.0072
5 CUSTOMER COMPONENTS	\$0.0167	\$0.0237	\$0.0161	\$0.0079	\$0.0035	\$0.0020	\$0.2559	\$0.0018	\$0.0043	\$0.0085
6 CUSTOMER METERS COMPONENT	\$0.0067	\$0.0086	\$0.0115	\$0.0064	\$0.0031	\$0.0015	\$0.0000	\$0.0012	\$0.0026	\$0.0021
7 CUSTOMER SERVICES COMPONENT	\$0.0023	\$0.0030	\$0.0033	\$0.0000	\$0.0022	\$0.0000	\$0.0000	\$0.0000	\$0.0000	\$0.0021
8 ACCT 902 - METER READING COMP	\$0.0036	\$0.0055	\$0.0042	\$0.0007	\$0.0023	\$0.0001	\$0.0000	\$0.0001	\$0.0001	\$0.0021
9 ACCT 903 - CUST RECORDS & COLL COMP	\$0.0083	\$0.0144	\$0.0069	\$0.0004	\$0.0024	\$0.0001	\$0.0068	\$0.0000	\$0.0007	\$0.0075
10 CUSTOMER SERVICES EXP COMP	\$0.0032	\$0.0043	\$0.0040	\$0.0004	\$0.0027	\$0.0004	\$0.0010	\$0.0005	\$0.0007	\$0.0031
11 CUSTOMER OTHER COMPONENT	\$0.0040	\$0.0029	\$0.0027	-\$0.0001	\$0.0019	-\$0.0001	\$0.2481	\$0.0000	\$0.0001	\$0.0021
12 TOTAL ACE DISTRIBUTION	\$0.0543	\$0.0734	\$0.0603	\$0.0230	\$0.0360	\$0.0229	\$0.2750	\$0.0055	\$0.0043	\$0.0393

		TOTAL ACE DISTRIBUTION (1)	RESIDENTIAL (8)-2	MONTHLY GENERAL SERV SECONDARY (9)	MONTHLY GENERAL SERV PRIMARY (10)	ANNUAL GENERAL SERV SECONDARY (11)	ANNUAL GENERAL SERV PRIMARY (12)	STREET AND PRIVATE LIGHTING (13)	GENERAL SERVICE SUBTRANSMSN (14)	GENERAL SERVICE TRANSMISSION (15)	DIRECT DISTRIBUTION CONNECTION (16)
C	CLAIMED RATE OF RETURN SUMMARY SCHEDULE										
F	RATE OF RETURN	7.13%	7.13%	7.13%	7.13%	7.13%	7.13%	7.13%	7.13%	7.13%	7.13%
F	REVENUES REQUIRED										
1 [DEMAND DISTRIBUTION	384,811,450	265,047,220	48,447,872	1,581,528	53,174,353	12,877,160	1,346,002	1,859,792	0	477,523
2	DEMAND DISTRIBUTION PRIMARY	290.147.028	196,985,791	35,989,632	1,581,528	39,503,383	12,877,160	997,227	1,859,792	0	352,514
3	DEMAND DISTRIBUTION SECONDARY	63,878,411	46,009,815	8,397,902	0	9,236,074	0	150,151	0	0	84,470
4	DEMAND DISTRIBUTION TRANSFORMERS	76,979,037	55,354,567	10,178,480	0	11,145,447	0	198,624	0	0	101,920
5 (CUSTOMER COMPONENTS	149,523,882	102,403,096	19,643,361	672,435	5,384,987	1,097,249	18,205,056	930,956	1,061,865	124,876
6	CUSTOMER METERS COMPONENT	61,626,479	41,214,314	13,048,170	568,780	4,748,789	843,253	0	618,784	553,699	30,690
7	CUSTOMER SERVICES COMPONENT	23,096,513	16,651,477	3,059,071	0	3,355,275	0	0	0	0	30,690
8	CUSTOMER 902-METER READING COMPONENT	34,809,237	26,872,464	4,234,140	52,024	3,475,787	79,009	0	38,390	26,734	30,690
9	CUSTOMER 903-CUST REC & COLLECT COMP	75,673,159	63,237,905	7,926,077	29,435	3,625,731	29,857	468,200	12,799	232,116	111,039
10	CUSTOMER SERVICE EXPENSE COMP	30,935,352	21,883,681	4,080,288	35,838	4,078,036	244,284	71,092	260,220	237,373	44,542
11	CUSTOMER OTHER COMPONENT	38,865,707	15,800,640	2,590,970	(13,642)	2,877,746	(99,154)	17,665,764	763	11,944	30,676
12 7	OTAL ACE DISTRIBUTION	511,238,818	350,793,007	65,031,160	2,253,925	55,202,991	13,974,095	19,559,629	2,790,441	1,061,865	571,703
		511,238,818									
-	VG. NUMBER OF CUSTOMER	568,813	501,866	56,645	154	2,908	118	6,006	36	16	1,064
14 (CUSTOMER \$/MONTH/CUSTOMER	\$21.91	\$17.00	\$28.90	\$363.87	\$154.32	\$774.89	\$252.60	\$2,154.99	\$5,530.55	\$9.78

	TOTAL ACE DISTRIBUTION (1)	RESIDENTIAL (8)-2	MONTHLY GENERAL SERV SECONDARY (9)	MONTHLY GENERAL SERV PRIMARY (10)	ANNUAL GENERAL SERV SECONDARY (11)	ANNUAL GENERAL SERV PRIMARY (12)	STREET AND PRIVATE LIGHTING (13)	GENERAL SERVICE SUBTRANSMSN (14)	GENERAL SERVICE TRANSMISSION (15)	DIRECT DISTRIBUTION CONNECTION (16)
CLAIMED RATE OF RETURN SUMMARY SCHEDULE										
RATE OF RETURN	7.13%	7.13%	7.13%	7.13%	7.13%	7.13%	7.13%	7.13%	7.13%	7.13%
Average Number of Customers (12 Months) \$/MONTH/CUSTOMER	568,813 \$21.91	501,866 \$17.00	56,645 \$28.90	154 \$363.87	2,908 \$154.32	118 \$774.89	6,006 \$252.60	36 \$2,154.99	16 \$5,530.55	
\$/kwH										
1 DEMAND DISTRIBUTION 2 DEMAND DISTRIBUTION PRIMARY 3 DEMAND DISTRIBUTION PRIMARY 4 DEMAND DISTRIBUTION SECONDARY 5 CUSTOMER COMPONENTS 6 CUSTOMER METERS COMPONENT 7 CUSTOMER SERVICES COMPONENT 8 ACCT 902 - METER READING COMP 9 ACCT 903 - CUST RECORDS & COLL COMP 10 CUSTOMER SERVICES EXP COMP 11 CUSTOMER OTHER COMPONENT	0.0438 0.0331 0.0073 0.0088 0.0170 0.0070 0.0026 0.0040 0.0086 0.0035 0.0044	0.0657 0.0488 0.0114 0.0137 0.0254 0.0102 0.0041 0.0067 0.0157 0.0054 0.0039	0.0347 0.0257 0.0060 0.0073 0.0140 0.0093 0.0022 0.0030 0.0057 0.0029 0.0019	0.0204 0.0204 0.0000 0.0000 0.0087 0.0073 0.0000 0.0007 0.0004 0.0005 (0.0002)	0.0334 0.0248 0.0058 0.0070 0.0034 0.0030 0.0021 0.0022 0.0023 0.0026 0.0018	0.0234 0.0234 0.0000 0.0000 0.0020 0.0015 0.0000 0.0001 0.0001 0.0004 (0.0002)	0.0196 0.0145 0.0022 0.0029 0.2648 0.0000 0.0000 0.0000 0.0068 0.0010 0.2569	0.0034 0.0034 0.0000 0.0007 0.0017 0.0011 0.0000 0.0001 0.0000 0.0005 0.0000	0.0000 0.0000 0.0000 0.0000 0.0022 0.0011 0.0000 0.0001 0.0005 0.0005	0.0319 0.0236 0.0056 0.0068 0.0084 0.0021 0.0021 0.0021 0.0074 0.0030 0.0021
12 TOTAL ACE DISTRIBUTION	0.0582	0.0870	0.0465	0.0290	0.0347	0.0254	0.2845	0.0050	0.0022	0.0382

ATLANTIC CITY ELECTRIC COMPANY

BEFORE THE NEW JERSEY BOARD OF PUBLIC UTILITIES DIRECT TESTIMONY OF MICHAEL T. NORMAND BPU DOCKET NO. ER23020091

1	Q1.	Please state your name and position.
2	A1.	My name is Michael T. Normand. My title is Manager of Rate Administration
3		in the Regulatory Affairs Department of Pepco Holdings LLC ("PHI"). I am testifying
4		on behalf of Atlantic City Electric Company ("ACE" or the "Company").
5	Q2.	What are your responsibilities in your role as Manager of Rate Administration?
6	A2.	I am primarily responsible for the development of electric rates, including tariff
7		surcharges, for ACE and Delmarva Power & Light Company ("Delmarva"). I also
8		participate in the development of ACE's policies and practices with respect to rate
9		design and assist with regulatory compliance matters, including tariff administration
10		and periodic filings.
11	Q3.	Please state your educational background and professional experience.
12	A3.	In 2008, I graduated from West Virginia University with a Bachelor of Science
13		degree in Business Administration with a major in Finance. In 2016, I received a
14		Master of Science degree in Finance from Northeastern University. Beginning in 2008,
15		I was employed at Management Applications Consulting Inc. where I was involved in
16		
		various state regulatory proceedings. My responsibilities included load research,
17		various state regulatory proceedings. My responsibilities included load research, allocation factor development, marginal cost of service, embedded cost-of-service,
17 18		
		allocation factor development, marginal cost of service, embedded cost-of-service,

1		In 2012, I was promoted and was the Class Cost of Service study ("CCOSS") witness
2		for Delmarva's Delaware gas operations. Following this promotion, I have developed
3		and testified to several CCOSSs for the operating utilities of PHI. This includes
4		Delmarva's Maryland electric operations and Delaware gas operations, as well as
5		Potomac Electric Power Company's Maryland and District of Columbia operations. In
6		early 2017, I transferred to the Revenue Requirements team for ACE and Delmarva.
7		In early 2019, I was promoted to my current position as Manager of Rate
8		Administration for ACE and Delmarva.
9	Q4.	Have you previously submitted testimony before the New Jersey Board of Public
10		Utilities ("BPU" or the "Board") or other regulatory agencies?
1011	A4.	Utilities ("BPU" or the "Board") or other regulatory agencies? Yes. I have testified in previous regulatory proceedings, including but not
	A4.	
11	A4.	Yes. I have testified in previous regulatory proceedings, including but not
11 12	A4.	Yes. I have testified in previous regulatory proceedings, including but not limited to ACE's 2020 Base Rate Case for Class Cost of Service, BPU Docket No.
11 12 13	A4.	Yes. I have testified in previous regulatory proceedings, including but not limited to ACE's 2020 Base Rate Case for Class Cost of Service, BPU Docket No. ER20120746. On cost-recovery, rate design and tariffs I have testified in ACE's 2020
11 12 13 14	A4. Q5	Yes. I have testified in previous regulatory proceedings, including but not limited to ACE's 2020 Base Rate Case for Class Cost of Service, BPU Docket No. ER20120746. On cost-recovery, rate design and tariffs I have testified in ACE's 2020 Energy Efficiency Program Docket No. EO20090621 and ACE's 2019 Amended Plug-

17 A5. The purpose of my Direct Testimony is to:

> provide the revenue allocation and rate design supporting the Company's 1. proposed increase in distribution revenue in the amount of \$104.8 million (\$111.7 million with Sales and Use Tax ["SUT"]1), as recommended in the Direct Testimony of Company Witness Ziminsky. The proposed rate design incorporates the results from the CCOSS, as contained in the Direct Testimony

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19

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21

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¹ The Sales and Use Tax Rate is 6.625%

1		of Company Witness Masters. In addition, my recommended rate design also
2		considers the Unitized Rates of Return ("UROR") for each customer rate
3		schedule (or "rate class") in the allocation of overall revenue requirements
4		among rate classes. The proposed rate design incorporates two new light-
5		emitting diode ("LED") options;
6	2.	explain the proposed increase of \$1.27 (\$1.35 with SUT) to the Residential
7		customer charge;
8	3.	provide a summary of the Conservation Incentive Program ("CIP") and how it
9		has been applied as part of rate design;
10	4.	provide an electric distribution rate design based on the results of a CCOSS
11		using the BPU Staff's approach, pursuant to the Board's May 26, 2005 Final
12		Order in BPU Docket No. ER03020110;
13	5.	provide support for certain adjustments to revenues referenced in the Direct
14		Testimony of Company Witnesses Ziminsky and Witness Chen;
15	6.	provide a description of adjustments to revenues including the CIP Revenue
16		Annualization adjustment, Infrastructure Investment Program ("IIP"),
17		Veteran's Law, and Energy Discounts for Growing Enterprises ("EDGE");
18	7.	discuss the rate design considerations stemming from the Board's Electric
19		Vehicle ("EV") Order, BPU Docket No. EO18020190;
20	8.	provide a summary of the Gross Receipts Tax reserve proposed one-time
21		refund; and
22	9.	provide a summary matrix of tariff revisions.

1		This Direct Testimony and accompanying exhibits were prepared by me or
2		under my direct supervision and control. My testimony relies upon Company records,
3		public documents, and my personal knowledge and experience.
4	Q6.	Please describe your proposed Company Schedules.
5	A6.	The following is a list of the Schedules I am sponsoring:
6		• Schedule (MTN) – 1 – Proposed Company Rate Design and proposed
7		two new LED options;
8		• Schedule (MTN) – 2 – Revenue Proofs and CIP Revenue Per Customer
9		Targets;
10		• Schedule (MTN) – 3 – Proposed Company Rate Design Bill Impacts;
11		• Schedule (MTN) – 4 – Company Low-Income Analysis;
12		• Schedule (MTN) - 5 - Excess Deferred Income Tax ("EDIT") -
13		reconciliation of amounts under or over credited;
14		• Schedule (MTN) – 6 – Summary Matrix of Proposed Tariff Changes;
15		• Schedule (MTN) – 7 – Staff Rate Design; and
16		• Schedule (MTN) – 8– Staff Rate Design Bill Impacts.
17		Electric Distribution Rate Design
18	Q7.	What guided your proposed modifications to the Company's distribution rates?
19	A7.	The goal or objective of any proposed modifications to the distribution rate(s)
20		structure is to provide retail distribution rates that are reflective of the underlying costs
21		to provide delivery service. Rates that accurately reflect underlying costs provide a
22		greater degree of fairness with respect to the amount each customer pays for delivery
23		service.

Additionally, the principle of gradualism is applied in the revenue allocation to
each individual rate schedule. This is accomplished by limiting an under-contributing
rate schedule's increase to a certain percentage of the Company's overall requested
increase for the Company. This is described in more detail below regarding the four
step revenue allocation process. Moreover, gradualism is applied in the determination
the increase to specific components of each rate structure that impacts customers within
a particular rate schedule.

A8.

Finally, mindful that ACE is currently implementing advanced metering infrastructure ("AMI"), through its Smart Energy Network ("SEN"), it is anticipated that the CCOSS that is developed for the next base rate case will be using AMI load data for developing the CCOSS class demands as described in the Direct Testimony of Company Witness Masters. Since this data will become available in the near future and might impact the CCOSS class rate of return results, the Company is proposing a more gradual revenue allocation approach in this proceeding. This is discussed in more detail in the revenue allocation section of this testimony.

Q8. What are the overall principles that were employed in the design of the proposed distribution rates?

The distribution rates were designed using the following guiding principles:

1. In the allocation of revenues, minimize, to the greatest extent possible, the level that the rate of return for any individual rate class is more or less than the overall required rate of return. The measure of success at achieving this goal is the UROR, specifically, the extent to which the rate design results in a rate class specific UROR of unity. The UROR is a simple mathematical expression that relates the

relative return from each rate class to the overall return from the entire system, i.e., all
rate classes taken together. A UROR greater than 1.0 means that the rate class is
providing a greater than average return during the test year. A UROR less than 1.0
means that the rate class is providing less than the average return for the entire system
during the test year.

A9.

- 2. Provide customers within a given rate class with price signals that accurately reflect the cost of providing service. This is accomplished by establishing customer, energy, and, if applicable, demand rate components such that they recover the costs indicated by the CCOSS to the greatest extent practicable.
- 3. The objectives of designing rates that fully reflect underlying costs is balanced by the objective of moderating the changes to both the allocation of the revenue requirement among the rate classes as well as the components of the rate class distribution rate design components to the extent possible. This concept of gradualism discussed in A7 above is intended to reflect equity between rate schedules and avoid large bill impacts to any rate class as well as avoid wide variations in bill impacts among customers in a given rate class.

Allocation of Distribution Revenue Requirement

- Q9. Please describe the approach used to allocate the proposed revenue requirement among the Company's rate classes.
 - The proposed four step revenue allocation methodology is described below. The Company's proposed four step revenue allocation method is consistent with what ACE proposed in BPU Docket No. ER20120746. The method begins by summarizing the rate class-specific distribution revenue, net operating income, net rate base, rate of

return, and UROR results from the CCOSS. The UROR results from the CCOSS are
used as a benchmark to determine each class's appropriate movement towards cost of
service for use in the allocation of the proposed revenue increase on a rate class-specific
basis. The results of this analysis are provided on page 1 of Schedule (MTN)-1.

Q10. Please describe each step of the four step revenue allocation methodology.

A10.

In the first step, rate classes with URORs significantly above 1.0 are excluded from any allocation of the distribution revenue increase. In this proceeding, these are 2 rate classes with a UROR above 3.0. In the second step, rate classes that are reasonably close to the system rate of return as compared to all other rate classes are assigned the system average increase as expressed in percentage terms. Reasonably close is defined as a "band of reasonableness" equal to +/- 10% of the system average rate of return. This would be a UROR of 0.9 to 1.1. In this proceeding, these are 2 classes with a UROR between 0.9 and 1.1.

In the third step, rate classes with a UROR that are below the lower limit of the band of reasonableness, or 0.90, are allocated a delivery revenue increase calculated as each applicable rate class's current annualized distribution revenues multiplied by the system average increase of 20.84%, multiplied by a factor of 1.01 for rate classes with URORs that are less than 0.9.

In the fourth and final step, the remainder of the increase is allocated to all remaining rate classes in proportion to their current level of annualized distribution revenue. The results of the allocation of the proposed distribution revenue requirement are provided on page 1 of Schedule (MTN)-1.

1	Q11.	Please describe how gradualism is being applied to revenue allocation in this
2		proceeding.
3	A11.	Due to the Company implementing the SEN program, a careful consideration

A12.

of gradualism is being proposed in revenue allocation in this proceeding. In the future, the CCOSS results may be impacted by having additional detailed data from AMI meters that can be used in developing the demand allocation factors in the CCOSS. This may have a corresponding impact on class rates of return and URORs. In light of this, to prevent an over correction a more gradual revenue allocation approach is being proposed. Additionally, this approach is consistent with the Company's 2020 base rate case settlement that was approved by the Board by Order dated 7/14/2021 in Docket No. ER20120746.

Q12. Please describe the detailed revenue allocation results for each rate schedule.

The results of the CCOSS, provided on Table 1 on page 1 of Schedule (MTN-1. In view of the results of the CCOSS and the proposed constraints to provide for gradualism, I propose the following allocation of the proposed distribution revenue requirement pursuant to the four step methodology, the level of the allocation of the increase is selected in order to achieve the following objectives which are all indications of an equitable allocation of the revenue requirement:

 limit the maximum percentage increase to any one of these rate schedules to 1.01 times the proposed total system distribution revenues increase as expressed overall average percentage terms;

1	2. ensure that the final proposed UROR for a rate class with an existing
2	UROR above 1.1, or above the upper limit of the band of
3	reasonableness, does not increase nor move to a level below 1.00; and
4	3. ensure that the final proposed UROR for a rate class with an existing
5	UROR below 0.9, or below the lower limit of the band of
6	reasonableness, does not decrease nor move to a level above 1.00.
7	In the first step, Rate Schedules Transmission General Service ("TGS")
8	Transmission and Direct Distribution Connection ("DDC") have URORs of 7.98 and
9	3.20, respectively. Therefore, these classes are excluded from revenue allocation.
10	In the second step, MGS Primary ("MGS-P"), Street and Private Lighting
11	("SPL"), and Contributed Street Lighting ("CSL") have a UROR of 1.02. Typically,
12	these classes would receive the system average increase. However, these classes have
13	been included in step 4. There are three main considerations that determined this. First,
14	both of these classes had higher UROR and were included in the fourth step in the 2020
15	base rate case. As a result, the Company would like to monitor these classes UROR
16	movement to ensure the trend continues. Second, as discussed previously AMI data
17	will be available in the future to further ensure their UROR movement is consistent.
18	Last, the percentage increase in the fourth step, 20.89%, is immaterially different from
19	the system overall average increase of 20.84%.
20	In the third step is the Residential ("RS") class with a UROR of 0.65. This class
21	is the only under contributing class and is receiving a multiplier of 1.01 times the
22	proposed total system distribution revenue increase of 20.84%. While the Company
23	believes a higher multiplier is warranted, in light of the potential impact of future AMI

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1		load data and considerations of ensuring gradualism as discussed previously, this
2		increase is in line with previous rate cases. It also achieves the objective of moving this
3		class to a UROR closer to the band of reasonableness.
4		In the fourth step, the remaining rate schedules, MGS-P, SPL, CSL, Monthly
5		General Service ("MGS-S") Secondary, Annual General Service Secondary ("AGS-
6		S"), AGS Primary ("AGS-P"), and Transmission General Service ("TGS") Sub
7		Transmission are receiving the remainder of the revenue allocation.
8		The allocation calculation is provided in Tables 3 through 8 on page 1 of
9		Schedule (MTN)-1.
10	Q13.	How does the Company's proposed revenue allocation compare to the above-
11		mentioned objectives?
12	A13.	Favorably – insofar as the revenue allocation allows for movement towards a
13		unitized rate of return while adhering to the principle of gradualism in revenue
14		allocation. In particular, the proposed allocation achieved the following:
15		1. all rate schedules with an existing UROR greater than 1.1, or the upper
16		limit of the band of reasonableness, saw a decrease to their UROR under
17		the proposed revenue allocation while remaining above 1.00; and
18		2. all of the rate schedules with an existing UROR less than 0.9, or the
19		lower limit of the band of reasonableness, saw an increase to their
20		UROR under the proposed revenue allocation while remaining below
21		1.00.
22		

1	Q14.	Has the Company adjusted its billing determinants to reflect weather
2		normalization with this filing?
3	A14.	Yes. Adjustments to the five months ending November 2022 sales by month
4		and rate schedule were calculated to reflect the impact on electric sales associated with
5		the difference between the actual weather and 20-year normal weather. The Company
6		has adjusted its actual sales for 20-year weather for the months of July through
7		November 2022. Adjusting actual sales to reflect weather normalization in this filing
8		is consistent with the methodology approved by the Board in connection with the Order
9		issued in BPU Docket No. ER20120746. Forecasted sales are already weather
10		normalized and require no adjustment.
11		The development of weather normalized billing determinants, to be used in the
12		design of the volumetric components of distribution rates reduces the variations in
13		annual CIP targets between rate case test periods caused by weather differences in those
14		periods.
15		Service Classification Specific Rate Design
16		Residential Distribution Rate Design
17	Q15.	How does ACE propose to adjust the distribution rates associated with Rate
18		Schedule RS?
19	A15.	In an effort to design rates that reflect the functionalized costs associated with
20		the provision of distribution service, the following changes to the design of electric
21		distribution rates for Rate Schedule RS are proposed:
22		1. ACE proposes to increase the Customer Charge proportionately in line
23		with the allocated revenue for the service class, such that it recovers a

greater level of customer-related costs, based on the results of the						
CCOSS. The proposed approach recognizes both cost causation						
principles as well as concerns regarding customer impacts. A higher						
cost-based customer charge and lower kilowatt-hour ("kWh") rate will						
help minimize intra-class subsidies. Minimizing intra-class subsidies						
benefits customers with above average usage. It is important to note that						
a large proportion of low and moderate-income ("LMI") customers,						
approximately forty-two percent, uses more than the average						
Residential customer.						

2. The Company proposes to apply the remaining allocated revenue for this service class to increase each volumetric rate component by an equal percentage to recover the remaining revenue requirement.

The detailed development of the proposed distribution rate design for each rate schedule is provided on pages 2 through 10 of Schedule (MTN)-1.

Q16. Please discuss the proposed change to the Customer Charge in greater detail.

A16.

The current Customer Charge is below the fixed customer-related costs identified within the results of the CCOSS. This rate structure disconnects the recovery of fixed, customer-related costs from the fixed retail rate component, providing customers with an inaccurate price signal. It is also inherently unfair to most customers in the Residential rate class. The low Customer Charge favors those customers with low or no usage who pay less than the cost to provide customer-related services. As noted previously, a large portion of low-income customers have usage which is at or higher than the overall average Residential customers and therefore may benefit from

this change. The results of the CCOSS support an average customer-related cost per
Residential customer of \$15.81 per month. Based on current levels of distribution rates,
the distribution portion of the bill for customers with monthly use at or less than
approximately 180 kWhs is not sufficient to recover the average customer cost, as seen
in Schedule (MTN)-3.

A17.

While a move to a fully cost-based Customer Charge would address these concerns, the Company is proposing a modest Customer Charge increase of \$1.27 (\$1.35 including SUT), in the interest of tempering the impact to Residential customers. This is also consistent with recent ACE rate case outcomes.

Q17. Has the Board increased fixed cost recovery through the Customer Charge levels approved in recent base rate cases?

Yes. In BPU Docket No. ER17030308, the Board approved an additional increase in the Residential monthly Customer Charge to \$5.00. In order to reflect the impact of the Tax Cuts and Jobs Act of 2017 ("TCJA"), the Company reduced the Customer Charge to \$4.83, effective April 1, 2018. In BPU Docket Nos. AX18010001 and ER18030241, the Company reduced the Customer Charges to \$4.80, effective October 1, 2018, to further reflect the TCJA impact. In BPU Docket No. ER18080925, the Board approved the additional increase in the Residential monthly Customer Charge to \$5.77 (including SUT). In BPU Docket No. ER20120746, the Board approved the additional increase in the Residential monthly Customer Charge to \$6.25 (including SUT).

The Board has also implemented effective pricing structures for the larger commercial and industrial customers that consist of fixed monthly Customer Charges

and Demand Charges (\$/kW). These rate structures appropriately recognize that
distribution costs are largely fixed in nature and reflect costs that are related to the
number of customers served and their respective demands.

A18.

Q18. Has the Company evaluated the impact of the proposed Customer Charge increase on Residential customers?

Yes. The Company has performed a separate analysis on the impact of the proposed Customer Charge increase on low-income Residential customers. ACE used the customers receiving Universal Service Fund credits for the 12-months ended November 2022 to represent the low-income population. The results are presented in Schedule (MTN)-4. The analysis provides a frequency distribution of the rate impact on low-income Residential customers. The results on page 4 of Schedule (MTN)-4 show how the increase in the Customer Charge impacts the low-income Residential population.

Additional insight on the impact of increasing the fixed Customer Charge on LMI Residential customers can be found on pages 5 and 6 of Schedule (MTN)-4, by observing the frequency distribution of usage for LMI Residential customers. In general, it shows that LMI customer consumption per customer is slightly higher than the overall Residential customer consumption per customer Schedule (MTN)-4 page 5 supports that approximately 42% of LMI customers are using at or above the average usage of the overall Residential rate class. This supports the observation that a high percentage of low-income customers may benefit from an increase in the fixed Customer Charge compared to the increase only being reflected in the volumetric charge.

1	Q19.	Has the Company evaluated the impact of the proposed increase on Residential
2		customers?
3	A19.	Yes. The impact of the change to all Residential customers is provided in
4		Schedule (MTN)-3. For the typical Residential customer using an average of 669 kWh
5		per month, the proposed bill increase is \$12.22 per month or 8.80%. As discussed in
6		the Direct Testimony of Company Witness Ziminsky, the Company understands the
7		impacts rate adjustments have on customers, especially LMI customers, and is actively
8		working to provide resources that help customers manage their energy costs or seek
9		assistance.
10		Commercial and Industrial Rate Class Rate Design
11	Q20.	How does ACE propose to adjust the distribution rates associated with Rate
12		Schedules MGS Secondary and MGS Primary?
13	A20.	In an effort to develop rates that gradually move closer to the underlying cost
14		basis, the Company proposes to recover the proposed revenue increases for these
15		classes as follows:
16		1. increase the Customer Charges for MGS Secondary by the respective
17		overall class distribution revenue increase. The Company proposes no
18		increase to the MGS Primary's customer charges;
19		2. increase the demand charges (both real and reactive demand charges) for
20		MGS Secondary by the respective overall class distribution revenue
21		percentage increase. The Company proposes no increase to the MGS
22		Primary's customer charges; and

1		3. increase the volumetric charge to recover the balance of the proposed class
2		distribution revenue increase.
3		4. The MGS-P class is receiving an increase in revenue allocation. However,
4		based on an increase in usage, current revenue collected from rates was
5		decreased to arrive at the revenue requirement. The overall impact is a
6		decrease in the MGS-P energy rates to account for updated billing
7		determinants. Due to the CCOSS results as presented by Company Witness
8		Master's the level of customer and demand charges is remaining unchanged
9		and the decrease is being reflected in the volumetric charge.
10	Q21.	How does the Company propose to adjust the distribution rates associated with
11		Rate Schedules AGS Secondary and AGS Primary?
12	A21.	In an effort to develop rates that gradually move closer to the underlying cost
13		basis, the Company proposes to recover the proposed revenue increases for these
14		classes as follows:
15		1. no increase to the Customer Charge for AGS Secondary as this charge
16		already reflects the CCOSS unitized customer-component costs. For AGS
17		Primary the proposed customer charge is based on CCOSS results and
18		reflects the CCOSS unitized customer-component costs; and
19		2. the increase to the demand charges (both real and reactive demand charges)
20		for each rate schedule to recover the balance of the respective overall class
21		distribution revenue increase.

1	Q22.	How does the Company propose to adjust the distribution rates associated with
2		Rate Schedules TGS Sub transmission?
3	A22.	In an effort to develop rates that gradually move closer to the underlying cost
4		basis, the Company proposes to recover the proposed revenue increases for these
5		classes as follows:
6		1. no increase to the Customer Charge based on CCOSS results; and
7		2. increase the demand charge for each rate schedule to recover the balance of
8		the respective overall class distribution revenue increase.
9	Q23.	How does ACE propose to adjust the distribution rates associated with Rate
10		Schedules TGS Transmission and DDC?
11	A23.	No revenue increase is proposed for TGS Transmission, and DDC since their
12		respective URORs were greater than 3.0. The TGS transmission class does have a
13		decrease in rates, based on an increase in billing determinants and the resulting
14		expected revenues from rates. This is being reflected in the demand charge.
15		Street Lighting Class Rate Design
16	Q24.	How does the Company propose to adjust the distribution rates associated with
17		Rate Schedules SPL and CSL?
18	A24.	ACE proposes to adjust the existing rates for offerings delineated in Rate
19		Schedules CSL and SPL on a percentage basis equal to the percentage increase
20		proposed for the distribution rates for lighting class.

1	Q25.	Please provide a summary of the development of distribution rates for the new
2		LED lighting service offerings.
3	A25.	The Company is proposing two new LED decorative lighting options for
4		customers. These two new LED lighting options are provided in Schedule (MTN)-1.
5		The rate design for the LED light offerings is developed as a monthly fixed charge
6		consisting of the following components:
7		• Non-luminaire-related plant investment for the street lighting class. This non-
8		luminaire investment includes the recovery of costs related to electric delivery
9		service infrastructure to the lighting installation, as well as an allocation for the
10		overall distribution system infrastructure.
11		• For customers who choose to take service under Rate Schedule SPL, the charge
12		includes a component for recovery of and on the light fixture investment.
13		Customers electing to take service under Rate Schedule CSL would make an up-
14		front payment under the terms of Rate Schedule Contributed Lighting Extension
15		and would not be assessed this monthly charge.
16		Conservation Incentive Program
17	Q26.	What is the CIP?
18	A26.	As authorized by the Board in BPU Docket No. EO2009062, the CIP is a
19		modified decoupling mechanism used by the Company to account for lost sales revenue
20		resulting from the potential decrease in customer energy usage as a result of Energy
21		Efficiency programs.

1	Q27.	How were the CIP baseline revenue per customer targets calculated?
2	A27.	The CIP is calculated using a baseline revenue per customer that was initially
3		based on weather-normalized billing determinants from the 2020 base rate case and the
4		latest variable margin rates per rate schedule. This includes ACE's cumulative
5		Infrastructure Investment Program ("IIP") revenues as approved in Docket No.
6		ER21111206 and the cumulative PowerAhead Program ("PowerAhead") revenues as
7		approved in Docket No. ER22050323.
8	Q28.	Please describe the Board's directives in BPU Docket No. EO20090621 with
9		respect to the CIP in the context of a Base Rate Case?
10	A28.	The Board Order in connection with BPU Docket No. EO20090621 directed
11		that the CIP baseline usage and margin rates shall be updated with each subsequent rate
12		case, IIP, or PowerAhead rate adjustment. As such, the CIP usage and variable margin
13		rates have been updated in Schedule (MTN)-2 to calculate the proposed changes to the
14		Board-approved monthly revenue-per-customer CIP targets.
15	Q29.	How has the CIP been incorporated into the Company's proposed rate design
16		schedules?
17	A29.	The current revenue reflected in the Company's rate design Schedule (MTN)-
18		1, has been adjusted to reflect the current approved CIP revenue from the seventh roll-
19		in filing in connection with ACE's PowerAhead program, as approved in BPU Docket
20		No. ER22050323.

1		BPU Staff Proposed Rate Design
2	Q30.	Have you addressed the requirement included in the Board's May 26, 2005 Order
3		in BPU Docket No. ER03020110 to provide a distribution rate design based on the
4		cost allocation method proposed by BPU Staff?
5	A30.	Yes. The rate design is provided as Schedule (MTN)-7 to my Direct Testimony.
6		The related bill impacts are provided in Schedule (MTN)-8. The Company is not
7		proposing, nor does it endorse, the cost allocation and rate design proposed by Staff.
8		Revenue Adjustments
9	Q31.	Are you sponsoring any Revenue Adjustments?
10	A31.	Yes, I am sponsoring Adjustment No. 1 - CIP Revenue Annualization and
11		Adjustment No. 2 – Customer Count Adjustment.
12	Q32.	Please describe Adjustment No. 1 – CIP Revenue Annualization.
13	A32.	Adjustment No. 1 is developed by calculating the revenue adjustment for CIP,
14		which includes revenues for Distribution, IIP, and PowerAhead. CIP revenue was
15		calculated using the most recent targets from the PowerAhead 7 th roll-in period, BPU
16		Docket No. ER22050323 for the 12 months from July 2022 through June 2023 and
17		comparing to the actual billed and budgeted revenues for that same time period. The
18		impacts to both the CIP targets and associated billed and budgeted revenues were
19		adjusted to remove IIP revenues as this is collected through a separate rider, Rider IIP.
20		The difference between the actual billed and budgeted base distribution revenue and
21		the calculated CIP revenue, adjusted to remove IIP impacts, is the amount included as
22		the CIP Revenue Annualization adjustment.

1	Q33.	Please exp	olain A	djustment	No. 2 –	Customer	Count ad	ljustment
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2 A33. Consistent with certain pro-forma expense adjustments, the Company is 3 proposing an adjustment to reflect the impact that forecasted customer counts would 4 have on revenues included in the test period to ensure that the revenue requirement is 5 more reflective of the rate effective period. Please reference Ratemaking Adjustment 6 No. 2 of Company Witness Chen for the underlying calculations for the pro-forma 7 customers.

8 Q34. Have IIP revenues been removed from the revenue requirement calculation?

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A35.

A34. The IIP Rider is a surcharge that does not affect base distribution rates. As a result, IIP revenues have been removed from the revenue requirement. These investments will continue to be recovered from Rider IIP and excluded from the base distribution revenue requirement.

13 Q35. Have Veteran's Law revenues been included in the revenue requirement calculation?

Yes. Veteran's Law revenues have been included in the revenue requirement. N.J.S.A 48:2-21.41, effective August 10, 2018, allows for veteran's organizations to receive utility service at the Residential rate schedules for the veteran's organization primary location. Veteran's Law actual revenue for five months ending November 2022 totaled (\$1,960), and seven months of forecasted revenue ending June 2023 totals (\$2,744). Test period Veteran's Law revenue totals (\$4,704). The forecast was developed by taking a five-month average of the five months of actual Veteran's Law revenue.

1	Q36.	Have	EDGE	Rider	revenues	been	included	in	the	revenue	requirement
2		calcul	ation?								

A36. No. EDGE Rider revenues have been removed from the revenue requirement.

The Company has removed \$(17,754) from this filing. There are currently two AGS

Secondary customers and one MGS Secondary customer who receive EDGE credits.

Removing EDGE credits from the revenue requirement is consistent with Orders issued by the Board in connection with BPU Docket Nos. ER18080925 and ER20120746. See

MFR Exhibit I attached to the Petition for this calculation.

Q37. Are there any other Ratemaking Adjustments you are sponsoring other than the Revenue Adjustments described above?

A37.

Yes. On July 1, 2022, September 26, 2022, and January 30, 2023, the Company submitted compliance filings notifying the Board that ACE would set certain Rider EDIT service classifications to zero. The July 1, 2022 filing notified the Board that the MGS-P class would be set to zero on September 1, 2022. The September 26, 2022 filing notified the Board that the MGS-S and DDC classes would be set to zero on December 1, 2022. The January 31, 2023 filing notified the Board that the RS, TGS Subtransmission, TGS Transmission, and SPL and CSL classes will be set to zero on April 1, 2023. Pursuant to amended BPU Docket No. AX18010001 and BPU Docket No. ER18030241, the Board determined that: "any under- or over-credited amounts should be reconciled in the Company's base rate case filed after the expiration of the credit." Schedule (MTN)–5 provides a summary of the balances by service classifications where the entire EDIT credits have been paid and set to zero within the test period. Please reference Company Witness Ziminsky's Direct Testimony,

1 Adjustment No. 23, for additional information on how these balances are reflected 2 within the Cost of Service.

Electric Vehicle Order Considerations

Q38. Is the Company proposing a new EV rate as part of this proceeding?

A39.

A38.

Yes. The Company is proposing a new Tariff rate schedule, EV-ERR, Electric Vehicle Equivalent Residential Rate. This rate will be available to Residential unit-owners in Multi-Unit Dwellings wishing to charge their vehicle in a designated parking space. It is also available for Residential customers charging their vehicles in separately metered dwellings not intended for Residential occupancy. This new rate offering is intended to encourage EV adoption by ensuring that these Residential customers pay a rate consistent with their current Residential dwelling.

Q39. Is the Company proposing additional Residential or Commercial EV rates as part of this proceeding?

In BPU Docket No. EO18020190 ("EV Order"), ACE acknowledged its intent to develop cost-based rates for Residential and non-Residential EV charging as follows: "[t]he Signatory Parties acknowledge that ACE intends to conduct a [CCOSS] to develop and propose a cost-based rate for Residential and non-Residential EV charging sites operating on the Company's distribution system, and will seek the Board's approval to impose the rate(s) determined in that CCOSS in a future base rate proceeding, which does not refer to the base rate case initiated by ACE on December 9, 2020." Furthermore, "[t]he signatory Parties acknowledge that additional charging data is needed in order to design EV-only and whole-house time-of-use Residential distribution rates. Once sufficient data has been generated by customer participation

in offerings #1a and #1b included in Attachment A, ACE commits to design an EV
only and whole-house time-of-use Residential distribution rate and to propose that rate
in a future base rate proceeding."

As part of the Company's EVsmart program, customers participating in certain Make-ready rebates, as well as the DC fast charge EV rate, approved in the EV Order described above, would be required to provide ACE with the charging data needed to calculate a future cost-based rate. As noted in Company Witness Ziminsky's Direct Testimony, the Company has successfully onboarded 72 customers into the program and has approximately 500 applications in the queue as of January 2023. The Company expects to continue to see a steady increase in customer applications due to a heavy focus on marketing efforts for the Make-ready program. An increase in customer participation through these avenues will help to achieve the level of customer data needed to support the development of cost-based EV rates. The Company has evaluated a potential cost-based rate as part of this proceeding and has concluded that sufficient data is not yet available to propose a cost-based Residential EV rate at this time.

Likewise, the Company is not proposing a change to the Commercial EV rate as part of this proceeding as ACE has no customers on the existing Commercial EV rate schedule, tariff MGSS-SEVC, and sufficient data is not available to update the existing rate to a cost-based rate.

The Company also considered proposing a Whole-House Residential time-ofuse ("TOU") rate, which would be available to all Residential customers, including those with EVs. After further evaluation, ACE concluded that it would be in the best interest of the Company and the customer to wait until AMI data is available through the Smart Energy Network regarding customer hourly usage to develop such a rate. Hourly usage information enables the Company to both evaluate and set appropriate peak and off-peak periods, as well as rates for customers based on expected usage during those times. While estimation is possible, ACE has concerns that these estimates could change once actual data is available, potentially resulting in unwanted impacts to customers. As such, the Company is recommending delaying the development of a TOU rate until sufficient (one year) of AMI data is available for rate calculation purposes. The Company will keep BPU Staff informed on the progress of this data collection as the Smart Energy Network is deployed and customers enroll in the program.

A40.

Q40. What else is the Company doing to encourage EV adoption and gather more charging data associated with EVs in the future?

As noted above and discussed in the Direct Testimony of Company Witness Ziminsky, the Company is heavily focused on marketing efforts and onboarding additional EV charge company partners to facilitate an increase in customer participation in the EV rebate programs stemming from the Board's Order in Docket No. EO18020190. An increase in customer participation through these avenues will help to achieve the level of customer data needed to support the development of cost-based EV rates as part of a future base rate case. E-mail marketing in 2022 helped achieve a positive customer response rate seen through an increase in customer applications. Additional e-mail marketing campaigns are planned for early 2023. The Company has also updated its website to highlight the existing Commercial EV Rate

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1		Tariff available to customers and will begin actively marketing this rate to customers
2		in 2023. As the Company is able to onboard additional charge companies, it will allow
3		for more customer participation in the rebate programs and corresponding usage data.
4		Gross Receipts Tax Reserve
5	Q41.	Please describe the proposed allocation and refund method for the refund of the
6		Gross Receipts Tax Reserve.
7	A41.	As discussed in the Direct Testimony of Company Witness Ziminsky, the
8		Company proposes that the Gross Receipts Tax Reserve be refunded to customers in
9		service classifications RS, MGS-S, MGS-P, AGS-S, AGS-P, and SPL and CSL, as a
10		one-time credit per customer or per light. The amount to be refunded is \$994,337 and
11		the refund will commence within 90 days of a final Board Order in this proceeding. As
12		shown in Schedule (MTN)-1, the \$994,337 will be allocated to service classifications
13		utilizing the compliance rate design revenue allocation from the Order issued in
14		connection with BPU Docket No. ER20120746. This proposed treatment recognizes
15		the allocation of these costs during the time-period in which these costs were included
16		in the Company's revenue requirement.
17		Minimum Filing Requirements
18	Q42.	Are you sponsoring any MFRs?
19	A42.	Yes, I am sponsoring the following Minimum Filing Requirements:
20		- Exhibit E; and
21		- Exhibit I.
22		
23		

1 <u>Tariff Changes</u>

2 Q43. Are you proposing any tariff changes?

3 A43. Yes. Schedule MTN-6 summarizes tariff changes being proposed within this
4 case in addition to those associated with updating the proposed distribution rates
5 resulting from rate design. The Company's proposed and red-lined tariffs, which
6 reflect the results of the rate design in Schedule (MTN)-1, are attached as Exhibit A to
7 the Petition.

Q44. What changes are being proposed to the Company's street lighting tariff?

A44. The Company is proposing to expand its decorative option to include an offering with ribs and bands, including 100 and 150-watt options. These two additional rates are being added to provide additional options to customers. The proposed rates for these two additional lighting options are included in Schedule (MTN)-1. Finally, as detailed in Company Witness Brubaker and Whitman's Direct Testimony, the Company is proposing to close its Metal Halide and High-Pressure Sodium rate offerings to new customers. Existing customer light replacements due to failure or other customer-driven requests, as well as new customer installations, will now use a comparable LED option.

Q45. Does this conclude your Direct Testimony?

19 A45. Yes, it does.

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Schedule (MTN)-1

Atlantic City Electric Company
Development of Proposed Distribution Rate
Rate Class Allocation of Distribution Revenue Requirements

Rate Class Allocation of Distribution Revenue Requirements										
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(1)	(J)	(K)
			MONTHLY GENERAL SERVICE	MONTHI Y GENERAL	ANNUAL GENERAL SERVICE	ANNUAL GENERAL	TRANSMISSION GENERAL SERVICE	TRANSMISSION GENERAL SERVICE	STREET LIGHTING	DIRECT DISTRIBUTIO
able 1: Cost of Service Study Results (Schedule (JLM)-1)	TOTAL	RESIDENTIAL	SECONDARY	SERVICE PRIMARY	SECONDARY	SERVICE PRIMARY	SUB-TRANSMISSION	TRANSMISSION	SERVICE	CONNECTIO
perating Income	\$ 114,457,036	50,140,246	31,208,988	359,813	20,302,093	3,948,160	857,367	868,840	6,526,381	245
stribution Rate Base OR	\$ 1,952,245,281 5.86%	1,316,553,643 3.81%	236,701,048 13.18%	6,043,995 5.95%	232,032,708 8.75%	41,423,543 9.53%	6,891,464 12.44%	1,856,273 46.81%	109,435,584 5.96%	1,30 1
nitized ROR	1.00	0.65	2.25	1.02	1.49	1.63	2.12	7.98	1.02	,
			MONTHLY GENERAL	ı	ANNUAL GENERAL	ı	TRANSMISSION	TRANSMISSION		DIRECT
			SERVICE	MONTHLY GENERAL	SERVICE	ANNUAL GENERAL	GENERAL SERVICE	GENERAL SERVICE	STREET LIGHTING	DISTRIBUTION
able 2: Revenue Requirements Results (Schedule (JCZ)-3)	TOTAL	RESIDENTIAL	SECONDARY	SERVICE PRIMARY	SECONDARY	SERVICE PRIMARY	SUB-TRANSMISSION	TRANSMISSION	SERVICE	CONNECTIO
ro Forma Operating Income	\$84,302,594	\$ 36,930,476	\$ 22,986,779	\$ 265,018	\$ 14,953,376	\$ 2,907,992	\$ 631,488	\$ 639,938	\$ 4,806,964	\$ 18
djusted Net Rate Base	\$2,235,749,719 3.77%	\$ 1,507,743,144 2.45%	\$ 271,074,699 8.48%	\$ 6,921,702 3.83%	\$ 265,728,425 5.63%	\$ 47,439,057 6.13%	\$ 7,892,240 8.00%	\$ 2,125,840 30.10%	\$ 125,327,785 3.84%	\$ 1,49 1
Initized ROR	1.00	0.65	2.25	1.02	1.49	1.63	2.12	7.98	1.02	'
able 3: Revenue Increase	ACE	1								
	\$ 104.788.395									
Revenue Requirement w/ SUT	\$ 111,730,626									
	\$ 75,106,361									
roposed ROR	7.13%									
			MONTHLY GENERAL		ANNUAL GENERAL		TRANSMISSION	TRANSMISSION		DIRECT
Fable 4: December Allegation Madel Over December	TOTAL	DECIDENTIAL	SERVICE	MONTHLY GENERAL	SERVICE	ANNUAL GENERAL	GENERAL SERVICE	GENERAL SERVICE	STREET LIGHTING	DISTRIBUTION
able 4: Revenue Allocation Multi-Step Process	TOTAL	RESIDENTIAL	SECONDARY	SERVICE PRIMARY	SECONDARY	SERVICE PRIMARY	SUB-TRANSMISSION	TRANSMISSION X	SERVICE	CONNECTION
tep 1: Allocated Revenue Requirement	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -			\$ -	\$
tep 1: Remaining Revenue Requirement tep 2 - UROR Steady State	\$ 104,788,395									
Multiplier										
roposed System Average Increase										
nnualized Current Delivery Revenues	•									
tep 2: Allocated Revenue Requirement tep 2: Remaining Revenue Requirement	\$ 104,788,395									
tep 3 - Under-Earning Rate Classes	,,,	Х								
lultiplier		1.01								
ystem Average Increase nnualized Current Delivery Revenues		20.84% \$ 311,687,887								
tep 3: Allocated Revenue Requirement	\$ 65,616,879	\$ 65,616,879								
Step 3: Remaining Revenue Requirement	\$ 39,171,516									
Step 4 - Remaining Rate Classes Step 4: Allocated Revenue Requirement	\$ 39,171,516	\$ -	\$ 18,642,074	\$ 495,690	X \$ 12,529,580	X \$ 2,770,726	\$ 665,375		\$ 4,068,072	
Step 4: Remaining Revenue Requirement	\$ 39,171,310	.	\$ 10,042,074	φ 493,090	φ 12,329,360	\$ 2,770,720	\$ 000,375		4,000,072	
			MONTHLY GENERAL		ANNUAL GENERAL	I	TRANSMISSION	TRANSMISSION		DIRECT
			SERVICE	MONTHLY GENERAL	SERVICE	ANNUAL GENERAL	GENERAL SERVICE	GENERAL SERVICE	STREET LIGHTING	DISTRIBUTI
Table 5: Revenue Allocation Summary (\$)	TOTAL	RESIDENTIAL	SECONDARY	SERVICE PRIMARY	SECONDARY	SERVICE PRIMARY	SUB-TRANSMISSION	TRANSMISSION	SERVICE	CONNECTION
Step 1	\$ - \$ -	\$ - \$ -	\$ -	-	\$ - \$ -	\$ - \$ -	\$ - \$ -	\$ - \$ -	- S -	\$ \$
Step 2 Step 3	\$ 65,616,879	\$ 65,616,879	\$ - \$	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$
tep 4	\$ 39,171,516	s -	\$ 18,642,074	\$ 495,690	\$ 12,529,580	\$ 2,770,726	\$ 665,375	\$ -	\$ 4,068,072	\$
otal	\$ 104,788,395	\$ 65,616,879	\$ 18,642,074	\$ 495,690	\$ 12,529,580	\$ 2,770,726	\$ 665,375	\$ -	\$ 4,068,072	\$
			MONTHLY GENERAL		ANNUAL GENERAL		TRANSMISSION	TRANSMISSION		DIRECT
able 6: Revenue Allocation Summary (%)	TOTAL	RESIDENTIAL	SERVICE SECONDARY	MONTHLY GENERAL SERVICE PRIMARY	SERVICE SECONDARY	ANNUAL GENERAL SERVICE PRIMARY	GENERAL SERVICE SUB-TRANSMISSION	GENERAL SERVICE TRANSMISSION	STREET LIGHTING SERVICE	DISTRIBUT
tep 1	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
tep 2	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
tep 3	62.62%	62.62%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
tep 4 otal	37.38% 100.00%	0.00% 62.62%	17.79% 17.79%	0.47% 0.47%	11.96% 11.96%	2.64% 2.64%	0.63% 0.63%	0.00% 0.00%	3.88% 3.88%	0.00%
			MONTHLY GENERAL SERVICE	MONTHLY GENERAL	ANNUAL GENERAL SERVICE	ANNUAL GENERAL	TRANSMISSION GENERAL SERVICE	TRANSMISSION GENERAL SERVICE	STREET LIGHTING	DIRECT
able 7: Proposed Revenue Allocation - UROR Analysis	TOTAL	RESIDENTIAL	SECONDARY	SERVICE PRIMARY	SECONDARY	SERVICE PRIMARY	SUB-TRANSMISSION	TRANSMISSION	SERVICE	CONNECTION
OR	7.13%	5.57%	13.41%	8.96%	9.01%	10.32%	14.04%	30.10%	6.16%	
cremental Income evenue Conversion Factor	\$ 75,106,361	\$ 47,030,447	\$ 13,361,578 1.3952	\$ 355,282 1.3952	\$ 8,980,490 1,3952	\$ 1,985,899 1,3952	\$ 476,903	\$ -	\$ 2,915,763	\$
evenue Conversion Factor evenue Requirement	1.3952 \$ 104,788,395	1.3952 \$ 65,616,879	1.3952 \$ 18,642,074	1.3952 \$ 495,690	1.3952 \$ 12.529.580	1.3952 \$ 2,770,726	1.3952 \$ 665,375	1.3952	1.3952 \$ 4,068,072	s
nal Unitized ROR	1.00	0.78	1.88	1.26	1.26	1.45	1.97	4.22	0.86	•
ROR Change		0.13	(0.37)	0.24	(0.23)	(0.18)	(0.15)	(3.76)	(0.15)	
			MONTHLY GENERAL		ANNUAL GENERAL		TRANSMISSION	TRANSMISSION		DIRECT
			SERVICE	MONTHLY GENERAL	SERVICE	ANNUAL GENERAL	GENERAL SERVICE	GENERAL SERVICE	STREET LIGHTING	DISTRIBUTI
able 8: Rate Schedule Specific Revenue Increase Allocation	TOTAL	RESIDENTIAL	SECONDARY	SERVICE PRIMARY	SECONDARY	SERVICE PRIMARY	SUB-TRANSMISSION	TRANSMISSION	SERVICE	CONNECTI
nnualized Current Delivery Revenues (w/ EDIT and w/o SUT) evenue Change (\$)	\$ 502,734,762 \$ 104,788,395	\$ 311,687,887 \$ 65,616,879	\$ 89,235,950 \$ 18,642,074	\$ 2,372,769 \$ 495,690	\$ 59,976,640 \$ 12,529,580	\$ 13,262,923 \$ 2,770,726	\$ 3,185,017 \$ 665,375	\$ 2,464,167	\$ 19,473,063 \$ 4,068,072	\$ 1,0
roposed Revenue	\$ 607,523,157	\$ 377,304,767	\$ 107,878,024	\$ 2,868,458	\$ 72,506,220	\$ 16,033,649	\$ 3,850,392	\$ 2,464,167	\$ 23,541,135	\$ 1,07
evenue Change based on Annualized Current Revenue (%)	20.84%	21.05%	20.89%	20.89%	20.89%	20.89%	20.89%	0.00%	20.89%	• .,
ervice Classification Rate Change as a Percentage of Overall Distribution		4.04	4.00	4.00	100	100	4.00		4.00	
Change		1.01	1.00	1.00	1.00	1.00	1.00	_	1.00	

Revenue Change

Total Proposed Revenue

Development of Proposed Distribution Rate Rate Design Worksheet

Rate Schedule **RS & EV-ERR** w/o SUT w/ SUT Annualized Current Delivery Revenues \$

\$

377,304,767

402,301,207

21.05% Proposed Residential Class Increase 332,337,210 21.56% Proposed Customer Charge Increase (Rounding to \$7.60) 311,687,887 \$ 65,616,879 \$ 69,963,998

1	2	3	3	4	5 = 2 x 4 Calculated Rate		6		7	Re	8 = 2 x 7 ecovery under		9 = 2 x 6	10 = (6-3)/3
Blocks	Normalized Billing Determinants	Current Distribution Rates cluding SUT)		Current Distribution Rates (w/o SUT)	Class Revenue under Current stribution Rates (w/o SUT)		Proposed Distribution Rates ncluding SUT)	Pr	oposed Distribution Rates (w/o SUT)		Proposed Distribution Rates (w/o SUT)	Dis	ecovery under Proposed stribution Rates ncluding SUT)	Distribution Rate Change %
CUSTOMER	6,031,481	\$ 6.25	\$	5.86	\$ 35,354,518	\$	7.60	\$	7.13	\$	43,004,458	\$	45,839,254	21.6%
SUM 'First 750 KWh SUM '> 750 KWh	1,183,990,699 736,410,419	0.072877 0.085560		0.068349 0.080244	80,924,446 59,092,404		0.090162 0.105853		0.084560 0.099276		100,117,727 73,107,664		106,750,969 77,951,252	23.7% 23.7%
WIN	2,093,076,034	\$ 0.066324	\$	0.062203	\$ 130,195,709	\$	0.082054	\$	0.076956	\$	161,074,918	\$	171,745,261	23.7%
TOTAL ENERGY	4,013,477,152				\$ 270,212,559					\$	334,300,309	\$	356,447,482	
					\$ 305,567,076	=				\$	377,304,767	\$	402,286,736	
	TOTAL REVENUE									\$	-	\$	14,471	

Present Revenues Unadjusted Present Revenue \$ 305,567,076 CIP Annualization Adjustment \$ 6,120,811 Adjusted Present Revenue 311,687,887

Proposed Increase

\$ \$ Proposed Rate Increase w/o SUT 65,616,879 Total Proposed Revenue w/o SUT 377,304,767 Total Proposed Revenue w/ SUT 402,301,207

Development of Proposed Distribution Rate Rate Design Worksheet

 Rate Schedule
 MGS SECONDARY w/o SUT
 w/ SUT

 Annualized Current Delivery Revenue
 \$ 89,235,950
 \$ 95,147,832

 Revenue Change
 \$ 18,642,074
 \$ 19,877,111

 Total Proposed Revenue
 \$ 107,878,024
 \$ 115,024,943

20.89%	Proposed Class Increase
20.89%	Proposed Customer Charge Increase
20.89%	Proposed Demand Charge Increase

	1 2	!	3	4	c	5 = 2 x 4 Calculated Rate		6	7		8 = 2 x 7		9 = 2 x 6	10 =	(6-3)/3
ВЬОСК	Billing Determinants	Dis	Current stribution Rates uding SUT)	Current Distribution Rates (w/o SUT)		Class Revenue under Current stribution Rates (w/o SUT)	D	Proposed Distribution Rates cluding SUT)	Proposed istribution Rates (w/o SUT)		Recovery under Proposed stribution Rates (w/o SUT)		Recovery under Proposed Distribution Rates (including SUT)	Distribution Chang	
CUSTOMER															
Single Phase Service	500,653	\$	11.90	\$ 11.16	\$	5,587,594	\$	14.38	\$ 13.49	\$	6,753,810	\$	7,199,392		20.8%
3 Phase Service	179,618	\$	13.84	\$ 12.98	\$	2,331,452	\$	16.73	\$ 15.69	\$	2,818,204	\$	3,005,006		20.9%
DEMAND CHARGE - All kWs															
Summer	2,260,193	\$	3.27	\$ 3.07	\$	6,931,611	\$	3.96	\$ 3.71	\$	8,385,315	\$	8,950,364		21.1%
Winter	3,666,010	\$	2.68	\$ 2.51	\$	9,214,449	\$	3.24	\$ 3.04	\$	11,144,670	\$	11,877,872		20.9%
REACTIVE DEMAND	78,362	\$	0.64	\$ 0.60	\$	47,036	\$	0.78	\$ 0.73	\$	57,204	\$	61,122		21.9%
ENERGY CHARGE															
Summer	565,644,181	\$	0.062158	\$ 0.058296	\$	32,974,735	\$	0.065062	\$ 0.061019	\$	34,515,042	\$	36,801,942		4.7%
Winter	818,455,557		0.055017	\$ 0.051599		42,231,155		0.057587	0.054009		44,203,966		47,132,400		4.7%
TOTAL	1,384,099,738	_			\$	99,318,032				\$	107,878,212	\$	115,028,097	-	
	1,001,000,100	=				22,010,002				<u> </u>	,0.0,2.12	Ψ	3,020,001	=	
										\$	188	\$	3,154		

Present Revenues	
Unadjusted Present Revenue	\$ 99,318,032
CIP Annualization Adjustment	\$ (10,082,081
Adjusted Present Revenue	\$ 89,235,950
Proposed Increase	
Proposed Rate Increase w/o SUT	\$ 18,642,074
Total Proposed Revenue w/o SUT	\$ 107,878,024
Total Proposed Revenue w/ SUT	\$ 115 024 943

TOTAL REVENUE

Development of Proposed Distribution Rate Rate Design Worksheet

MGS PRIMARY Rate Schedule w/o SUT w/ SUT 20.89% Proposed Class Increase Annualized Current Delivery Revenues \$ 2,529,965 0.00% Proposed Customer Charge Increase 2,372,769 \$ Revenue Change 495,690 \$ 528,529 0.00% Proposed Demand Charge Increase Total Proposed Revenue 2,868,458 \$ 3,058,494

	1 2		3	Current	C	5 = 2 x 4 falculated Rate Class Revenue under Current		Proposed	7	R	8 = 2 x 7 ecovery under Proposed	Re	9 = 2 x 6 ecovery under Proposed	
вьоск	Billing Determinants		Current ribution Rates cluding SUT)	Distribution Rates (w/o SUT)		Distribution Rates (w/o SUT)		Distribution Rates Icluding SUT)	Proposed distribution Rates (w/o SUT)		Distribution Rates (w/o SUT)		Distribution Rates Icluding SUT)	Distribution Rate Change %
CUSTOMER														
Single Phase Service	951	\$	17.56	\$ 16.47	\$	15,665	\$	17.56	\$ 16.47	\$	15,666	\$	16,703	0.0%
3 Phase Service	911	\$	19.08	\$ 17.89	\$	16,309	\$	19.08	\$ 17.89	\$	16,305	\$	17,390	0.0%
DEMAND CHARGE														
SUM > 3 KW	90,723	\$	1.90	\$ 1.78	\$	161,664	\$	1.90	\$ 1.78	\$	161,487	\$	172,374	0.0%
WIN > 3 KW	167,868	\$	1.49	\$ 1.40	\$	234,583	\$	1.49	\$ 1.40	\$	235,016	\$	250,124	0.0%
REACTIVE DEMAND	127,842	\$	0.47	\$ 0.44	\$	56,353	\$	0.47	\$ 0.44	\$	56,251	\$	60,086	0.0%
ENERGY CHARGE														
SUM < 300KWh	37,584,360	\$	0.048255	\$ 0.045257	\$	1,700,946	\$	0.024715	\$ 0.023179	\$	871,168	\$	928,897	-48.8%
WIN < 300 KWh	67,354,644	\$	0.046750	\$ 0.043845	\$	2,953,181	\$	0.023944	\$ 0.022456	\$	1,512,516	\$	1,612,740	-48.8%
TOTAL	104,939,004	- =			\$	5,138,701	- =			\$	2,868,409	\$	3,058,314	:
										\$	(50)) \$	(180)	

TOTAL REVENUE

Present Revenues	
Unadjusted Present Revenue	\$ 5,138,701
CIP Annualization Adjustment	\$ (2,765,932)
Adjusted Present Revenue	\$ 2,372,769
Proposed Increase	
Proposed Rate Increase w/o SUT	\$ 495,690
Total Proposed Revenue w/o SUT	\$ 2,868,458
Total Proposed Revenue w/ SUT	\$ 3,058,494

Development of Proposed Distribution Rate Rate Design Worksheet

 Rate Schedule
 AGS SECONDARY w/o SUT w/o SUT
 w/o SUT
 W/o SUT

 Annualized Current Delivery Revenues
 \$ 59,976,640
 \$ 63,950,092

 Revenue Change
 \$ 12,529,580
 \$ 13,359,664

 Total Proposed Revenue
 \$ 72,506,220
 \$ 77,309,757

20.89%	Proposed Class Increase
0.00%	Proposed Customer Charge Increase
20.34%	Proposed Reactive Demand Charge Increase (Demand Weighting)

	1 2	_	Current		Calculated Rate Class Revenue		Proposed		6 /			8 = 2 x 7	$9 = 2 \times 6$ Recovery under	,
вьоск	Billing Determinants	Current Distribution Rat (including SU)	es	Distribution Rates (w/o SUT)		under Current stribution Rates (w/o SUT)		Distribution Rates cluding SUT)		oposed Distribution Rates (w/o SUT)	R	ecovery under Proposed Distribution Rates (w/o SUT)	Proposed Distribution Rates (including SUT)	Distribution Rate Change %
CUSTOMER	34,914	\$ 193.2	22 \$	181.21	\$	6,326,782	\$	193.22	\$	181.21	\$	6,326,782	\$ 6,746,100	0.0%
DEMAND CHARGE	4,680,245	\$ 12.4	14 \$	11.67	\$	54,604,691	\$	14.97	\$	14.04	\$	65,710,644	\$ 70,063,273	20.3%
REACTIVE DEMAND	421,142	\$ 0.9	94 \$	0.88	\$	371,277	\$	1.13	\$	1.06	\$	446,411	\$ 475,891	20.2%
ENERGY CHARGE	1,562,897,454	-		-	\$	-		-		-	\$	-	\$ -	
TOTAL REVENUE					\$	61,302,750	=				\$	72,483,837	\$ 77,285,263	:
											\$	(22,382)	\$ (24,493)	

TOTAL REVENUE

Present Revenues

Unadjusted Present Revenue	\$ 61,302,750
CIP Annualization Adjustment	\$ (1,326,110)
Adjusted Present Revenue	\$ 59,976,640
Proposed Increase	
Proposed Rate Increase w/o SUT	\$ 12,529,580
Total Proposed Revenue w/o SUT	\$ 72,506,220
Total Proposed Revenue w/ SUT	\$ 77,309,757

10 = (6-3)/3

 $9 = 2 \times 6$

Atlantic City Electric Company
Development of Proposed Distribution Rate
Rate Design Worksheet

Rate Schedule	AGS PRIMARY									
		w/o SUT		w/ SUT						
Annualized Current Delivery Revenues	\$	13,262,923	\$	14,141,592						
Revenue Change	\$	2,770,726	\$	2,954,287						
Total Proposed Revenue	\$	16,033,649	\$	17,095,879						

2

3

20.89%	Proposed Class Increase
13.20%	Proposed Customer Charge Increase
18.20%	Proposed Reactive Demand Charge Increase (Demand Weighting)

6

7

 $8 = 2 \times 7$

ВLОСК	Billing Determinants	Current ribution Rates cluding SUT)	Current Distribution Rates (w/o SUT)	Cla ur E	Iculated Rate ass Revenue ider Current Distribution Rates (w/o SUT)	•	Proposed Distribution Rates ncluding SUT)	Pr	oposed Distribution Rates (w/o SUT)	Re	covery under Proposed Distribution Rates (w/o SUT)	Di	Recovery under Proposed istribution Rates (including SUT)	Distribution Rate Change %
CUSTOMER	1,416	\$ 744.15	\$ 697.91	\$	988,187	\$	842.34	\$	790.00	\$	1,118,579	\$	1,192,689	13.2%
DEMAND CHARGE	1,343,042	\$ 9.86	\$ 9.25	\$	12,419,596	\$	11.65	\$	10.93	\$	14,679,449	\$	15,646,440	18.2%
REACTIVE DEMAND	284,066	\$ 0.74	\$ 0.69	\$	197,148	\$	0.87	\$	0.82	\$	232,934	\$	247,137	17.6%
ENERGY CHARGE	552,682,556	\$ -	\$ -	\$	-		-		-	\$	-	\$	-	
TOTAL REVENUE				\$	13,604,931	_				\$	16,030,963	\$	17,086,266	=
										\$	(2,687)	\$	(9,613)	

 $5 = 2 \times 4$

TOTAL REVENUE

\$ 13,604,931
\$ (342,008)
\$ 13,262,923
\$ 2,770,726
\$ 16,033,649
\$ 17,095,879
\$ \$ \$

 $9 = 2 \times 6$

10 = 6/3

Atlantic City Electric Company

Development of Proposed Distribution Rate Rate Design Worksheet

Rate Schedule	TGS SUB TRANSMISSION									
		w/o SUT		w/ SUT						
Annualized Current Delivery Revenues	\$	3,185,017	\$	3,396,025						
Revenue Change	\$	665,375	\$	709,456						
Total Proposed Revenue	\$	3,850,392	\$	4,105,480						

1

2

3

4

20.89%	Proposed Class Increase
0.00%	Proposed Customer Charge Increase
4.43%	Proposed Reactive Demand Charge Increase (Demand Weighting)

6

7

 $8 = 2 \times 7$

Calculated Rate Class Revenue Current under Current Recovery under Proposed Recovery under Distribution Distribution Proposed Distribution Distribution Rate Billing Current Distribution Proposed Distribution **Proposed** Rates **BLOCK Determinants Distribution Rates** Rates Rates Rates **Distribution Rates** Rates Change (including SUT) (w/o SUT) (w/o SUT) (including SUT) (w/o SUT) (w/o SUT) (including SUT) % CUSTOMER <5000 KW 337 \$ 131.75 \$ 123.56 \$ 41,614 \$ 131.75 \$ 123.56 \$ 41,613 \$ 44,371 0.0% 30 \$ 4,363.57 \$ 4,092.45 \$ 122,651 \$ 4,363.57 4,092.45 \$ 122,652 \$ 5000 - 9000 KW \$ 130,777 0.0% 31 \$ >9000 KW 7,921.01 \$ 7,428.85 \$ 230,171 \$ 7,921.01 \$ 7,428.85 \$ 230,171 \$ 245,419 0.0% **DEMAND CHARGE** <5000 KW 554,769 \$ 3.84 \$ 3.60 \$ 1,997,947 \$ 4.01 \$ 3.76 \$ 2,085,930 \$ 2,224,622 4.4% 5000 - 9000 KW 215,055 \$ 2.96 \$ 2.78 \$ 597,011 \$ 3.09 \$ 2.90 \$ 623,659 \$ 664,520 4.4% >9000 KW 384,495 \$ 1.50 \$ 1.41 \$ 540,908 \$ 1.57 \$ 1.47 \$ 565,208 \$ 603,658 4.7% REACTIVE DEMAND <5000 KW 205,553 \$ 0.52 \$ 0.49 \$ 100,246 \$ 0.54 \$ 0.51 \$ 104,832 \$ 3.8% 110,998.42 5000 - 9000 KW 53,379 \$ 0.52 \$ 0.49 \$ 26,033 \$ 0.54 \$ 0.51 \$ 27,224 \$ 28,824.93 3.8% >9000 KW 89,420 \$ 0.52 \$ 0.49 \$ 43,609 \$ 0.54 \$ 0.51 \$ 45,604 \$ 48,286.87 3.8% \$ \$ 551,547,682 \$ \$ \$ **ENERGY CHARGE TOTAL REVENUE** 3,846,892 \$ 3,700,190 4,101,477 \$ (3,500) \$ (4,003)

 $5 = 2 \times 4$

TOTAL REVENUE Present Revenues Unadjusted Present Revenue \$ 3,700,190 CIP Annualization Adjustment (515,173)Adjusted Present Revenue 3,185,017 **Proposed Increase** Proposed Rate Increase w/o SUT 665,375 Total Proposed Revenue w/o SUT 3,850,392 Total Proposed Revenue w/ SUT 4,105,480

10 = (6-3)/3

 $8 = 2 \times 7$ $9 = 2 \times (8+10) 6$

Atlantic City Electric Company

Development of Proposed Distribution Rate

Rate Design Worksheet

Rate Schedule	TGS TRANSMISSION							
		w/o SUT		w/ SUT				
Annualized Current Delivery Revenues	\$	2,464,167	\$	2,627,418				
Revenue Change	\$	-	\$	-				
Total Proposed Revenue	\$	2.464.167	\$	2.627.418				

2

3

0.00% Proposed Class Increase 0.00% Proposed Customer Charge Increase 0.00% Proposed Reactive Demand Charge Increase

6

вьоск	Billing Determinants	Distr	Current ibution Rates luding SUT)	Current distribution Rates (w/o SUT)	ur C	Class Revenue under Current Distribution Rates		Proposed		Proposed Distribution Rates (w/o SUT)		Recovery under Proposed Distribution Rates (w/o SUT)		Proposed Distribution Rates		covery under Proposed distribution Rates cluding SUT)	Distribution Rate Change %
CUSTOMER																	
<5000 KW	79	\$	128.21	\$ 120.24	\$	9,539	\$	128.21	\$	120.24	\$	9,539	\$	10,171	0.0%		
5000 - 9000 KW	36	\$	4,246.42	\$ 3,982.57	\$	144,976	\$	4,246.42	\$	3,982.57	\$	144,976	\$	154,581	0.0%		
>9000 KW	65	\$	19,316.15	\$ 18,115.97	\$	1,181,796	\$	19,316.15	\$	18,115.97	\$	1,181,796	\$	1,260,090	0.0%		
DEMAND CHARGE																	
<5000 KW	148,311	\$	2.98	\$ 2.79	\$	414,506	\$	2.79	\$	2.62	\$	388,737	\$	413,788	-6.4%		
5000 - 9000 KW	238,653	\$	2.31	\$ 2.17	\$	517,034	\$	2.17	\$	2.03	\$	484,892	\$	517,877	-6.1%		
>9000 KW	854,087	\$	0.18	\$ 0.17	\$	144,184	\$	0.17	\$	0.16	\$	135,220	\$	145,195	-5.6%		
REACTIVE DEMAND																	
<5000 KW	59,540	\$	0.50	\$ 0.47	\$	27,921	\$	0.50	\$	0.47	\$	27,921	\$	29,770	0.0%		
5000 - 9000 KW	66,771	\$	0.50	\$ 0.47	\$	31,311	\$	0.50	\$	0.47	\$	31,311	\$	33,385	0.0%		
>9000 KW	127,472	\$	0.50	\$ 0.47	\$	59,776	\$	0.50	\$	0.47	\$	59,776	\$	63,736	0.0%		
ENERGY CHARGE	527,992,816	\$	-	\$ -	\$	-		-	\$	-	\$	-	\$	-			
TOTAL REVENUE					\$	2,531,042	3				\$	2,464,167	\$	2,628,592	<u>.</u>		
TOTAL REVENU	E	_									\$	-	\$	1,174			

 $5 = 2 \times 4$

Present Revenues

Unadjusted Present Revenue 2,531,042 CIP Annualization Adjustment (66,875)Adjusted Present Revenue 2,464,167

Proposed Increase

Proposed Rate Increase w/o SUT \$ Total Proposed Revenue w/o SUT 2,464,167 Total Proposed Revenue w/ SUT 2,627,418

Atlantic City Electric Company
Development of Proposed Distribution Rate
Rate Design Worksheet
Rate Design Worksheet
Rate Schedde
Distribution Functional Revenue Requirements Total
Spt. \$
Spt. \$
19,530,457
CSL \$
4,010,077
DDC \$
1,778,346

Lamp Code	Watts	and Private Lighting	Style	Current Rate (w/ SUT)	Current Rate (w/o SUT)	Number of Lights	Current Annualized Revenue		Proposed Rate (w/o SUT)	Proposed Rate (w/SUT)	Number of Lights	Proposed Annualized Revenue
10	103	Type INCANDESCENT	Standard	\$ 8.33	\$ 7.81	955	\$ 89,499	S	9.74	\$ 10.39	955	\$ 111,644
50 160	202 327	INCANDESCENT INCANDESCENT	Standard Standard	\$ 14.35 \$ 19.89	\$ 13.46 \$ 18.65	166 21	\$ 26,807 \$ 4,701	S S		\$ 17.90 \$ 24.81		\$ 33,440 \$ 5,864
210	448	INCANDESCENT	Standard	\$ 26.57	\$ 24.92	10	\$ 2,991	Š	31.09	\$ 33.15	10	\$ 3,731
100	100	MERCURY VAPOR	Standard	\$ 13.89	\$ 13.03	6.411	\$ 1,002,127	Š	16.25	\$ 17.33	6,411	\$ 1.250.084
300 400	175 250	MERCURY VAPOR		\$ 18.49 \$ 23.40	\$ 17.34 \$ 21.94	933	\$ 194,135 \$ 79,789	Ś		\$ 23.06 \$ 29.19		\$ 242,170 \$ 99,531
400 510	400	MERCURY VAPOR		\$ 23.40	\$ 21.94 \$ 31.55	303 228	\$ 79.789	S	27.37 39.36	S 29.19 S 41.97	3U3 228	\$ 99.531 \$ 107,694
730	700	MERCURY VAPOR	Standard	\$ 53.61	\$ 50.28	2	\$ 1.207	Š	62.72	\$ 66.88	2	
881	1000	MERCURY VAPOR	Standard	\$ 92.48	\$ 86.74	34	\$ 35,389	s	108.20	\$ 115.37		\$ 44,145
450 630	150 360	HPS HPS	Retrofit Retrofit	\$ 16.95 \$ 31.47	\$ 15.90 \$ 29.52	7.222 440	\$ 1.377.538 \$ 155.855	S	19.83 36.82	\$ 21.14 \$ 39.26	7.222 440	\$ 1.718.384 \$ 194.419
14	50	HPS OH	Cobra Head	\$ 15.13	\$ 14.19	15,058	\$ 2,564,040	Š	17.70	\$ 18.87	15,058	\$ 3,198,463
15	70	HPS OH	Cobra Head	\$ 15.68	\$ 14.70	8,418	\$ 1,485,077	s		\$ 19.55	8,418	\$ 1,852,532 \$ 1.535.942 \$ 1,239,613 \$ 595,678 \$ 603,959
16 17	100 150	HPS OH HPS OH	Cobra Head Cobra Head	\$ 16.50 \$ 17.94	\$ 15.47 \$ 16.83	6.631 4,921	\$ 1.231.284 \$ 993,733	S	19.30 20.99	\$ 20.58 \$ 22.38	6.631 4,921	\$ 1.535.942 \$ 1,239,613
18	250	HPS OH	Cobra Head	\$ 25.38	S 23.80	1,672	\$ 477,524	Š	29.69	\$ 31.66	1,672	\$ 595,678
19	400	HPS OH	Cobra Head	\$ 29.35	\$ 27.52	1,466	\$ 484,162	\$	34.33	\$ 36.61	1,466	\$ 603,959
26 27	150 250	HPS OH HPS OH	Shoe Box Shoe Box	\$ 21.83 \$ 28.30	\$ 20.47 \$ 26.54	69 50	\$ 16.949 \$ 15,923	S	25.53 33.11	\$ 27.23 \$ 35.30	69 50	\$ 21.142 \$ 19,863
28	400	HPS OH	Shoe Box	\$ 32.68	\$ 30.65	38	\$ 13,977	Š	38.24	\$ 40.77	38	\$ 17,435
28 63	50	HPS OH	Post Top	\$ 16.79	\$ 15.74	38 58	\$ 10,958	Š		\$ 20.94	38 58	\$ 17,435 \$ 13,670 \$ 83,687
64 65	100	HPS OH HPS OH	Post Top Post Top	\$ 18.29 \$ 21.49	\$ 17.15 \$ 20.16	326 24	\$ 67,087 \$ 5,806	Š	21.39 25.15	\$ 22.81 \$ 26.81	326 24	\$ 83,687 \$ 7,242
69	150	HPS OH HPS OH	Post Top Flood/Profile	\$ 21.49 \$ 17.58	\$ 20.16 \$ 16.49	1,009	\$ 5,806 \$ 199,625	3	25.15 20.57	\$ 26.81	1,009	\$ 7,242 \$ 249,018
70	250	HPS OH	Flood/Profile	\$ 22.17	S 20.79	1,731	\$ 431,862	Š	25.93	\$ 27.65	1,731 2,578	\$ 538,717 \$ 1,024,527
70 71	400	HPS OH	Flood/Profile	\$ 28.31	\$ 26.55	2,578	\$ 821,310	s	33.12	\$ 35.31	2,578	\$ 1,024,527
800 801	50/70 100	HPS OH HPS OH	Decorative 50/70 OH Decorative 100 OH	\$ 20.57 \$ 23.16	\$ 19.30 \$ 21.72	2 70	\$ 463 \$ 18,248	\$ \$	24.07 27.10	\$ 25.66 \$ 28.89	2 70	\$ 578 \$ 22.763
802	150	HPS OH	Decorative 150 OH	\$ 25.52	\$ 23.93	8	\$ 2,297	Š	29.85	\$ 31.83	8	\$ 2,866
106	400	METAL HALIDE	Flood/Profile	\$ 34.78	\$ 32.62	461	\$ 180,441	s	40.69	\$ 43.38	461	\$ 225,088
107	1000	METAL HALIDE HPS UG	Flood/Profile Cobra Head	\$ 59.22 \$ 23.21	\$ 55.54 \$ 21.76	416 932	\$ 277.255 \$ 243,404	S	69.28	\$ 73.87 \$ 28.95	416	\$ 345.857
2	50 70	HPS UG HPS UG	Cobra Head Cobra Head	\$ 23.21	S 22.25	932 435	\$ 243,404 \$ 116,120	S	27.15 27.75	\$ 29.59	932 435	\$ 578 \$ 22,763 \$ 2,866 \$ 225,085 \$ 345,857 \$ 303,630 \$ 144,851 \$ 207,223
3	100	HPS UG	Cobra Head	\$ 24.48	\$ 22.96	603	\$ 166,120	Š	28.64	\$ 30.53	603	\$ 207,223
4	150 250	HPS UG	Cobra Head	\$ 26.01	\$ 24.39	623	\$ 182,354	S		\$ 32.44	623	\$ 227,474 \$ 171,267
5	250 400	HPS UG HPS UG	Cobra Head Cobra Head	\$ 31.44 \$ 35.40	\$ 29.49 \$ 33.20	388 412	\$ 137,296 \$ 164,139	Ş	36.78 41.41	\$ 39.22 \$ 44.16	388 412	\$ 204,752
51	150	HPS UG	Shoe Box	\$ 29.92	\$ 28.06	345	\$ 116,183	s s	35.01	\$ 37.33	345	\$ 144,930
52	250	HPS UG	Shoe Box	\$ 36.33	\$ 34.07	319	\$ 130.429	s	42.50	\$ 45.32		\$ 162.701
53 66	400 50	HPS UG HPS UG	Shoe Box Post Top	\$ 40.74 \$ 20.55	\$ 38.21 \$ 19.28	330 594	\$ 151,293 \$ 137,398	S	47.66 24.05	\$ 50.82 \$ 25.64	330 594	\$ 188,728 \$ 171,394
67	100	HPS UG			\$ 20.65	2,002	\$ 496,098	Š	25.76	\$ 27.47	2,002	\$ 188,728 \$ 171,394 \$ 618,849 \$ 278,893 \$ 35,401 \$ 74,096 \$ 191,657
68	150	HPS UG	Post Too		S 28.14	662	\$ 223.574	Š	35.11	\$ 37.43	662	\$ 278.893
93 94	150 250	HPS UG HPS UG	Flood/Profile	\$ 27.41 \$ 31.99	\$ 25.71 \$ 30.00	92 165	\$ 28,379 \$ 59,399	S	32.07 37.42	\$ 34.19 \$ 39.90	92 165	\$ 35,401 \$ 74,096
95	400	HPS UG	Flood/Profile	\$ 36.40	\$ 30.00 \$ 34.14	375	\$ 153.642	3	42.59	\$ 45.41	375	\$ 191,657
115	400	HPS UG	Flood/Profile	\$ 43.03	\$ 40.35	93 65	\$ 45.033	Š	50.34	\$ 53.67	93	\$ 56.175
116	1000	HPS UG	Flood/Profile	\$ 67.44	\$ 63.25	65	\$ 49,338	S	78.91	\$ 84.13	65	\$ 61,546
811 812	50/70 100	HPS UG HPS UG	Decorative 50/70 UG Decorative 100 UG	\$ 27.37 \$ 29.92	\$ 25.67 \$ 28.06	88 262	\$ 27,103 \$ 88,231	S	32.02 35.01	\$ 34.14 \$ 37.33	88 262	\$ 33,809 \$ 110,063
813	150	HPS UG	Decorative 150 UG	\$ 39.10	\$ 36.67	252	\$ 110.892	Š	45.74	\$ 48.77	252	\$ 138.330
351	50 70	LED OH	Cobra Head	\$ 8.90	\$ 8.35	90 599	\$ 9,020	ş	10.42	\$ 11.11	90 599	\$ 11,251 \$ 77,402
352 353	70 100	LED OH LED OH	Cobra Head Cobra Head	\$ 9.20 \$ 9.43	\$ 8.63 \$ 8.84	599 246	\$ 62,049 \$ 26.104	S	10.77	\$ 11.48 \$ 11.76	599 246	\$ 77,402
354	150	LED OH	Cobra Head	\$ 9.97	\$ 9.35	486	\$ 54,556	Š	11.67	\$ 12.44	486	\$ 56.175 \$ 61,546 \$ 33,809 \$ 110,063 \$ 138.330 \$ 11,251 \$ 77,402 \$ 32,564 \$ 68,055
355	250	LED OH	Cobra Head	\$ 11.35	\$ 10.65	145	\$ 18,529	s	13.28	\$ 14.16	145	\$ 23,113
324 358	400 150	LED OH LED OH	Cobra Head Decorative 150 OH	\$ 15.40 \$ 20.65	\$ 14.45 \$ 19.37	8	\$ 1,387 \$ 930	S	18.02 24.16	\$ 19.21 \$ 25.76	8 4	\$ 1,730 \$ 1,160
325	250	LED OH	Mongoose	\$ 18.97	\$ 17.80	7	\$ 1,495	Š	22.20	\$ 23.67	7	\$ 1,865
326	400	LED OH	Mongoose		\$ 19.70		s -	s		\$ 26.21		s -
327 328	70 100	LED OH	Acorn (Granville)	\$ 23.68 \$ 23.68	\$ 22.21 \$ 22.21	-	s -	S	27.71 27.71	\$ 29.54	-	s -
329	150	LED OH	Acorn (Granville)	\$ 23.68	\$ 22.21 \$ 22.21		s -	s S	27.71	\$ 29.54		s -
	100	LED OH	Acorn (Granville) w/ ribs and bands		\$ 26.04	-	s -	Š	32.48	\$ 34.63		s -
	150	LED OH	Acorn (Granville) w/ ribs and bands	\$ 27.76	\$ 26.04	-	s -	S	32.48	\$ 34.63		s -
356 357	70 100	LED OH LED OH	Post Top Post Top	\$ 11.61 \$ 12.15	\$ 10.89 \$ 11.39	30	\$ 4.101	S	13.58 14.21	\$ 14.48 \$ 15.15	30	\$ - \$ 5,115
359	100	LED OH	Shoe Box	\$ 10.34	\$ 9.70		s -	Š	12.09	\$ 12.90		S -
360	150 250	LED OH	Shoe Box	\$ 11.24	\$ 10.54	2	\$ 253	ş		\$ 14.02		\$ 315
361 362	250 100	LED OH LED OH	Shoe Box Tear Drop	\$ 11.73 \$ 19.10	\$ 11.00 \$ 17.91		s -	5	13.72 22.34	\$ 14.63 \$ 23.82		s -
363	150	LED OH	Tear Drop	\$ 19.10	S 17.91		s -	S	22.34	\$ 23.82		
339	150	LED OH	Flood/Profile	\$ 17.03	\$ 15.98	21	\$ 4,026	s	19.93	\$ 21.25	21	\$ 5,022 \$ 12,943 \$ 68,674
337 341	250 400	LED OH LED OH	Flood/Profile Flood/Profile	\$ 17.73 \$ 20.38	\$ 16.63 \$ 19.12	52 240	\$ 10,376 \$ 55,052	Ş	20.74 23.85	\$ 22.12 \$ 25.42	52 240	\$ 12,943 \$ 68,674
341	1000	LED OH	Flood/Profile	\$ 21.21	\$ 19.12 \$ 19.89	240 85	\$ 20.285	3	24.81	\$ 26.45	240 85	\$ 25.305
364	50	LED UG	Cobra Head	\$ 16.67	\$ 15.63	2	\$ 375	š	19.50	\$ 20.79		
365 366	70 100	LED UG	Cobra Head Cobra Head	\$ 16.97 \$ 17.20	\$ 15.92 \$ 16.14	13 46	\$ 2,483 \$ 8,907	S	19.85 20.13	\$ 21.17 \$ 21.46	13 46	\$ 3,097 \$ 11,111
367	150	LED UG LED UG	Cobra Head	\$ 17.74	S 16.64	79	\$ 15.772	\$ \$	20.75	\$ 22.13	46 79	\$ 11,111 \$ 19.675
368	250 400	LED UG	Cobra Head	\$ 19.12	\$ 17.93	69 12	\$ 14,847	\$	22.37	\$ 23.85	69 12	\$ 18,521
331	400	LED UG	Cobra Head	\$ 20.02	\$ 18.78	12	\$ 2.704	S	23.43	\$ 24.98	12	\$ 3.373
371 332	150 250	LED UG LED UG	Decorative 150 UG Mongoose	\$ 28.43 \$ 23.61	\$ 26.66 \$ 22.14	62	\$ 19,834 \$	ş	33.26 27.62	\$ 35.46 \$ 29.45		\$ 24,742 \$ -
333	400	LED UG	Mongoose	\$ 25.63	\$ 24.04		\$ -	\$	29.98	\$ 31.97		S -
334	70 100	LED UG	Acorn (Granville)	\$ 28.30	S 26.54	-	s -	s	33.11	\$ 35.30	-	\$ - \$ 10.331
335 336	100 150	LED UG LED UG	Acorn (Granville) Acorn (Granville)	\$ 28.30 \$ 28.30	\$ 26.54 \$ 26.54	26	\$ 8,282 \$	Ş	33.11 33.11	\$ 35.30 \$ 35.30	26	\$ 10,331 \$ -
	100	LED UG	Acorn (Granville) w/ ribs and bands	\$ 31.93	\$ 29.95		š .	S	37.36	\$ 39.83		s -
	150	LED UG	Acorn (Granville) w/ ribs and bands	\$ 31.93	\$ 29.95	-	s -	Š	37.36	\$ 39.83		\$ -
369 370	70 100	LED UG	Post Top Post Top	\$ 19.38 \$ 19.92	\$ 18.17 \$ 18.68	24 130	\$ 5,234 \$ 29,147	ş	22.67 23.31	\$ 24.17 \$ 24.85	24 130	\$ 6,529 \$ 36,359
370	100	LED UG LED UG	Shoe Box	\$ 19.92 \$ 18.11	\$ 18.68 \$ 16.99	130 17	\$ 29,147 \$ 3.466	3	23.31	\$ 24.85 \$ 22.60	130 17	\$ 36,359 \$ 4.323
373	150	LED UG	Shoe Box	\$ 19.01	\$ 17.83	35	\$ 7,489	\$	22.24	\$ 23.72	35	\$ 9,342
374 375	250 100	LED UG	Shoe Box Tear Drop	\$ 19.50 \$ 26.85	\$ 18.29 \$ 25.18	11	\$ 2,415 \$ 4.533	Š	22.82 31.42	\$ 24.33 \$ 33.50	11	\$ 3,012 \$ 5,655
375 376	100 150	LED UG LED UG	Tear Drop Tear Drop	\$ 26.85 \$ 26.85	\$ 25.18 \$ 25.18	15	\$ 4,533 s	S S		\$ 33.50 \$ 33.50		\$ 5,655 \$ -
3/6	150	LED UG	Flood/Profile	\$ 24.79	\$ 23.25	3	\$ 837	S	31.42 29.00	\$ 33.50	3	\$ 1,044
344	250	LED UG	Flood/Profile	\$ 25.49	S 23.91	29	\$ 8.321	š	29.83	\$ 31.80	29	\$ 10.380
345	400	LED UG	Flood/Profile	\$ 28.16	\$ 26.41	121	\$ 38,345	S		\$ 35.12		\$ 47,832
346	1000	LED UG	Flood/Profile	\$ 28.98	S 27.18	73,583	\$ 34.574 \$ 15,656,544	s	33.91	S 36.15	73,583	\$ 43.128 \$ 19,530,457
Lamp		ibuted Street Lighting		Current Rate	Current Rate		Current Annualized		Proposed Rate	Proposed Rate		Proposed Annualized
201	Watts 50	HPS	Style All	(w/ SUT) \$ 6.67	(w/o SUT) \$ 6.25	Number of Lights 12,957	Revenue 972,273			(w/ SUT) \$ 8.32	Number of Lights 12,957	Revenue \$ 1,212,844
202 203	70 100	HPS HPS	All All	\$ 7.23 \$ 8.09	\$ 6.78 \$ 7.59	5.871 7,235	\$ 477.998 \$ 658,708	S	8.46 9.46	\$ 9.02 \$ 10.09	5.871 7,235	\$ 596.270 \$ 821,693
204	450	HPS	A.II	. 0.00		230	. 500,700	3	44.00	. 10.05	,,230	\$ 706,056

Rate Schedule Lamp Code	e CSL (Contri Watts	ibuted Street L	ighting) Type Style		Current Rate (w/ SUT)		Current Rate (w/o SUT)	Number of Lights		Current Annualized Revenue		Proposed Rate (w/o SUT)		oposed Rate // SUT)	Number of Lights		Proposed Annualized Revenue
201	50	HPS	All	\$	6.67	\$	6.25	12,957	\$	972,273	\$	7.80	\$	8.32	12,957	\$	1,212,844
202	70	HPS	All	\$	7.23		6.78		S	477.998	s	8.46		9.02	5.871		596.270
203	100	HPS	All	\$		\$	7.59	7,235	\$	658,708	\$		\$	10.09		\$	821,693
204	150	HPS	All	\$	9.59	\$	8.99	5,246	\$	566,008	\$	11.22	\$	11.96	5,246		706,056
205	250	HPS	All	\$		\$	12.21	683	\$	100,076	\$		\$	16.24		\$	124,838
206	400	HPS	All	\$		\$	16.10	507	\$	97,962	\$		\$	21.42	507	\$	122,201
271	1000	MH	Flood	\$		\$	12.21	10	\$	1,465	\$		\$	16.24		\$	1,828
286	175	MH	Flood	\$	12.30	\$	11.54	45	\$	6,231	\$		\$	15.35		\$	7,772
308	175	MH	Decorative - Two Lights	\$	41.25		38.69	211	\$	97,955	\$		\$	51.46	211		122,192
309	175	MH	Decorative	\$	29.17		27.35	80	\$	26,260	\$	34.12		36.38		\$	32,757
377	50	LED	Cobra Head	S	3.51		3.29	809	\$	31.985	S	4.11	S	4.38	809		39.899
378	70	LED	Cobra Head	\$	3.51	\$	3.29	403	\$	15,933	\$		\$	4.38	403		19,875
379	100	LED	Cobra Head	\$	3.51	\$	3.29	1,661	\$	65,669	\$		\$	4.38	1,661		81,918
380	150	LED	Cobra Head	\$	3.51	\$	3.29	1,624	\$	64,206	\$	4.11	\$	4.38	1,624		80,093
381	250	LED	Cobra Head	\$	3.51	\$	3.29	336	\$	13,284	\$		\$	4.38		\$	16,571
404	400	LED	Cobra Head	\$	3.51	\$	3.29	11	\$	435	\$		\$	4.38	11		543
384	150	LED	Post Too	\$	3.51	\$	3.29	175	\$	6,919	\$		\$	4.38	175		8,631
382	70	LED	Colonial Post Top	\$	3.51	\$	3.29	16	\$	633	\$	4.11		4.38	16		789
383	100	LED	Colonial Post Top	S	3.51		3.29	123	\$	4.863	S	4.11		4.38	123		6.066
405	250	LED	Mongoose	\$		\$	3.29		\$		\$	4.11		4.38		\$	-
406	400	LED	Mongoose	\$		\$	3.29		\$		\$	4.11	\$	4.38		\$	-
407	70	LED	Acorn (Granville)	\$	3.51	\$	3.29	-	\$	-	\$		\$	4.38		\$	-
408	100	LED	Acorn (Granville)	S		S	3.29		S		S	4.11		4.38		S	-
409	150	LED	Acorn (Granville)	\$	3.51	\$	3.29		\$		\$		\$	4.38		\$	-
	100	LED	Acorn (Granville) w/ ribs and bands			\$	3.29	-	\$	-	\$	4.11		4.38		\$	-
	150	LED	Acorn (Granville) w/ ribs and bands	\$	3.51	\$	3.29	-	\$	-	\$	4.11		4.38		\$	-
385	100	LED	Shoe Box	S		S	3.29		S		S	4.11	S	4.38		S	-
386	150	LED	Shoe Box	\$	3.51	\$	3.29		\$		\$		\$	4.38		\$	-
387	250	LED	Shoe Box	\$	3.51	\$	3.29	17	\$	672	\$	4.11		4.38		\$	838
388	100	LED	Tear Drop	\$	3.51	\$	3.29		\$		\$	4.11	\$	4.38	-	\$	-
389	150	LED	Tear Drop	\$	3.51		3.29	31	S	1.226	s	4.11		4.38	31		1.529
347	150	LED	Flood	\$	3.51		3.29	19	\$	751	\$	4.11		4.38	19		937
348	250	LED	Flood	\$		\$	3.29	17	\$	672	\$	4.11	\$	4.38	17	\$	838
349	400	LED	Flood	\$	3.51	\$	3.29	60	\$	2,372	\$	4.11	\$	4.38		\$	2,959
338	1000	LED	Flood	\$	3.51	S	3.29	15	s	593	S	4.11	S	4.38	15	\$	740
								20 102		2 245 450					20 162		4.040.077

DDC		Rate		Rate	-	Annualized		Rate		Annualized		Rate	Annualized
		(w/ SU	r)	(w/o SUT)		Revenue		(w/o SUT)	R	evenue (w/o SUT)		(w/ SUT)	Revenue
Service and Demand (per day per connection)	3,973,698	\$ 0.163	82 \$	0.153793	\$	611,127	\$	0.1537	33 \$	611,127	\$	0.163982	\$ 651,615
Energy (per day for each kW of effective load)	628.026	\$ 0.789	39 S	0.740763	S	465.219	S	0.7407	33 \$	465.219	S	0.789839	\$ 496.040
					S	1.076.345			S	1.076.345			\$ 1.147.654

Atlantic City Electric Base Rate Case New LED Streetlight Offerings

Line		Watts		Monthly Distribution	Tariff CLE
No.	Lamp Style	(Equivalent)	Lumens	Charge ^{1,2}	Lamp Price ^{3,4}
(A)	(B)	(C)	(D)	(E)	(F)

Rate Schedule SPL (Street and Private Lighting)

		Overh	ead			
1	Acorn (Granville) w/ Ribs and Bands	100	8,000	\$	27.76	\$1,955.21
2	Acorn (Granville) w/ Ribs and Bands	150	10,000	\$	27.76	\$1,955.21
		<u>Undergr</u>	<u>cound</u>			
3	Acorn (Granville) w/ Ribs and Bands	100	8,000	\$	31.93	\$1,955.21
4	Acorn (Granville) w/ Ribs and Bands	150	10,000	\$	31.93	\$1,955.21
	Rate Schedule	CSL (Conti	ributed Street	Lighting	<u>)</u>	
5	Acorn (Granville) w/ Ribs and Bands	100	8,000	\$	3.51	\$1,955.21
6	Acorn (Granville) w/ Ribs and Bands	150	10,000	\$	3.51	\$1,955.21

Notes

- Rates shown in this schedule are subject to the approved rate increase in this docket.
- Monthly Distribution Charge is based on a 15 year revenue requirement net present value calculation at the Company's approved Cost of Capital. This will be updated upon final approval of rates.
- To be added to Tariff Section III, Rate Schedule CLE, Sheet No. 7a
- ⁴ Includes loaders for High Use, Low Value (HULV), Stores Handling and Labor

Atlantic City Electric Company
Development of Proposed Distribution Rate
Rate Design Worksheet Stand By Rate

					Distribution
	Dema	nd Rates (\$/kW)	Stand	lby Rates (\$/kW)	Standby
Rate Schedule		Distribution		Distribution	Factor
MGS Secondary	\$	3.51	\$	0.53	0.150000000
MGS Primary	\$	1.63	\$	0.24	0.150000000
AGS Secondary	\$	14.97	\$	2.25	0.150000000
AGS Primary	\$	11.65	\$	1.75	0.150000000
TGS - Sub Transmission	\$	-	\$	-	0.150000000
TGS Transmission	\$	-	\$	-	0.150000000

Atlantic City Electric Development of Proposed Distribution Rates Annual Distribution Revenues with CIP Test Year: 5+7 Ending June 2023

	Residential	MGSS	MGSP	AGSS	AGSP	TGST	TGS	SPL/CSL	DDC	Total
5 Month Actual Revenue July - November 2022 \$	149,476,431 \$	46,380,059 \$	2,253,293 \$	24,344,265 \$	5,578,620 \$	1,434,856 \$	1,012,057 \$	7,988,820 \$	243,086 \$	238,711,487
7 Month Forecast Revenue December 2022 - June 2023 \$	147,385,188 \$	52,406,457 \$	2,888,717 \$	33,880,165 \$	7,329,533 \$	2,114,906 \$	1,314,434 \$	10,767,088 \$	816,069 \$	258,902,556
5+7me June 2023 Revenues w/ IIP Revenues, Veteran's Law,										
and EDGE Credits = \$	296,861,619 \$	98,786,516 \$	5,142,010 \$	58,224,430 \$ 13	2,908,152 \$	3,549,762 \$	2,326,491 \$	18,755,908 \$	1,059,155 \$	497,614,043
Add: CIP Revenue Annualization \$	4,780,947 \$	(11,005,928) \$	(2,832,686) \$	(1,301,150) \$	(277,687) \$	(545,458) \$	(45,440) \$	- \$	- \$	(11,227,402)
5+7me June 2023 Revenues w/ CIP Annualization Adj = $\$$	301,642,566 \$	87,780,588 \$	2,309,324 \$	56,923,280 \$ 13	2,630,465 \$	3,004,304 \$	2,281,051 \$	18,755,908 \$	1,059,155 \$	486,386,641
Remove:										
IIP Revenue (Removal) \$	(5,012,451) \$	(1,692,066) \$	(84,544) \$	(1,084,709) \$	(213,233) \$	(66,948) \$	(43,329) \$	(266,256) \$	(3,168) \$	(8,466,703)
CIP IIP Revenue Annualization (Removal) \$	55,790 \$	216,095 \$	46,634 \$	34,071 \$	4,576 \$	8,294 \$	(5,372) \$	- \$	- \$	360,089
EDGE Credits (Removal) \$	- \$	165 \$	- \$	17,589 \$	- \$	- \$	- \$	- \$	- \$	17,754
EDIT Credits \$	(15,001,982) \$	(2,931,169) \$	(101,354) \$	(4,086,409) \$	(841,115) \$	(239,367) \$	(231,816) \$	(983,411) \$	(20,359) \$	(24,436,982)
Annualized Revenue Total = \$	311,687,887 \$	89,235,950 \$	2,372,769 \$	59,976,640 \$ 1:	3,262,923 \$	3,185,017 \$	2,464,167 \$	19,473,063 \$	1,076,345 \$	502,734,762

Atlantic City Electric Development of Proposed Distribution Rates 5+7me June 2023

July 2022 - June 2023 Customer Counts

	Actual/Forecast (a/f)	RES	MGSS	MGSP	AGSS	AGSP	TGST	TGS	SPL/CSL	DDC	TOTAL
Jul-22	(a)	501,579	56,692	142	2,916	117	36	12	6,040	1,063	568,597
Aug-22	(a)	501,762	56,717	148	2,914	117	35	14	6,028	1,064	568,799
Sep-22	(a)	501,866	56,645	154	2,908	118	34	15	6,006	1,064	568,810
Oct-22	(a)	501,761	56,590	160	2,899	118	34	16	5,992	1,064	568,634
Nov-22	(a)	502,039	56,608	159	2,895	119	35	14	5,997	1,067	568,933
Dec-22	(f)	501,957	56,738	136	2,924	117	37	14	5,846	1,072	568,842
Jan-23	(f)	503,134	56,663	160	2,907	118	31	16	5,797	1,076	569,904
Feb-23	(f)	503,354	56,681	160	2,908	118	31	16	5,798	1,076	570,143
Mar-23	(f)	503,481	56,683	160	2,908	118	31	16	5,797	1,076	570,272
Apr-23	(f)	503,251	56,733	161	2,911	118	31	16	6,103	1,076	570,401
May-23	(f)	503,465	56,765	161	2,912	118	31	16	6,106	1,077	570,651
Jun-23	(f)	503,831	56,756	161	2,911	118	31	16	6,105	1,076	571,005
		6,031,481	680,271	1,863	34,914	1,416	398	181	71,616	12,852	6,834,990

July 2022 - June 2023 Demands

	Actual/Forecast (a/f)	RES	MGSS	MGSP	AGSS	AGSP	TGST	TGS	SPL/CSL	DDC	TOTAL
Jul-22	(a)	-	558,558	23,142	400,707	106,347	92,607	116,646	-	1,828	1,299,835
Aug-22	(a)	-	599,294	23,148	402,136	119,184	99,482	120,192	-	1,829	1,365,264
Sep-22	(a)	-	589,140	27,093	398,749	121,741	105,557	124,926	-	1,827	1,369,033
Oct-22	(a)	-	523,566	28,377	383,155	116,923	95,182	127,185	-	1,828	1,276,216
Nov-22	(a)	-	476,071	26,800	357,414	104,242	89,585	98,858	-	1,827	1,154,797
Dec-22	(f)	-	515,501	26,011	410,582	134,307	112,063	84,585	-	1,614	1,284,664
Jan-23	(f)	-	433,820	16,440	411,664	107,585	90,288	86,683	-	1,588	1,148,069
Feb-23	(f)	-	418,096	17,429	389,266	100,015	72,748	138,131	-	1,622	1,137,306
Mar-23	(f)	-	406,060	21,362	379,537	105,175	73,833	117,690	-	1,465	1,105,122
Apr-23	(f)	-	440,664	16,540	389,887	109,537	105,783	65,370	-	1,483	1,129,263
May-23	(f)	-	452,232	14,909	378,283	103,694	105,486	73,163	-	1,426	1,129,192
Jun-23	(f)	-	513,201	17,341	378,866	114,291	111,706	87,623	-	1,620	1,224,648
		-	5,926,203	258,592	4,680,245	1,343,042	1,154,319	1,241,051	-	19,957	14,623,408

July 2022 - June 2023 Reactive Demands

	Actual/Forecast (a/f)	RES	MGSS	MGSP	AGSS	AGSP	TGST	TGS	SPL/CSL	DDC	TOTAL
Jul-22	(a)	-	9,010	4,968	45,302	26,327	19,612	15,655	-	-	120,875
Aug-22	(a)	-	9,267	4,971	43,892	30,882	21,776	16,588	-	-	127,376
Sep-22	(a)	-	11,454	4,838	46,620	33,270	20,850	19,602	-	-	136,634
Oct-22	(a)	-	9,969	4,903	41,594	30,676	20,517	23,243	-	-	130,901
Nov-22	(a)	-	9,389	4,586	37,733	25,325	18,164	17,974	-	-	113,171
Dec-22	(f)	-	4,098	8,716	28,582	18,975	33,916	20,646	-	-	114,933
Jan-23	(f)	-	4,169	17,620	29,812	20,656	37,147	24,191	-	-	133,594
Feb-23	(f)	-	4,212	15,124	29,497	19,404	34,992	22,916	-	-	126,145
Mar-23	(f)	-	4,054	15,644	28,597	19,268	34,773	22,632	-	-	124,968
Apr-23	(f)	-	4,075	15,180	28,669	19,159	34,399	22,719	-	-	124,200
May-23	(f)	-	4,045	14,085	28,213	18,421	33,152	21,904	-	-	119,820
Jun-23	(f)		4,620	17,208	32,633	21,702	39,054	25,713	-	-	140,930
	(f)	-	78,362	127,842	421,142	284,066	348,352	253,783	-	-	1,513,548

July 2022 - June 2023 Sales - Weather Normalized

	Actual/Forecast (a/f)	RES	MGSS	MGSP	AGSS	AGSP	TGST	TGS	SPL/CSL	DDC	TOTAL
Jul-22	(a)	475,306,007	143,316,536	6,497,095	151,413,220	46,275,357	49,083,084	45,896,698	4,440,206	1,226,687	923,454,890
Aug-22	(a)	529,842,336	154,442,384	10,447,604	152,516,689	54,495,468	54,531,818	38,840,370	4,870,013	1,290,801	1,001,277,483
Sep-22	(a)	475,686,452	152,329,499	10,711,091	157,092,780	55,084,182	55,834,418	36,911,614	4,512,616	1,256,349	949,419,001
Oct-22	(a)	273,710,508	105,828,003	9,139,642	129,447,510	50,838,972	48,955,761	65,434,485	6,416,657	1,216,967	690,988,505
Nov-22	(a)	220,236,632	95,167,990	9,163,404	114,059,147	43,569,888	43,576,791	37,846,283	6,178,932	1,184,821	570,983,888
Dec-22	(f)	286,521,166	102,998,272	4,866,452	119,305,639	41,401,051	40,817,778	38,648,147	6,657,848	1,137,568	642,353,921
Jan-23	(f)	370,303,346	106,665,462	9,156,181	124,961,775	44,016,736	43,805,816	44,449,616	7,495,511	1,220,712	752,075,154
Feb-23	(f)	333,021,306	104,561,229	8,979,564	122,615,726	43,274,235	42,942,859	43,800,915	6,266,586	1,173,575	706,635,993
Mar-23	(f)	290,232,796	101,900,916	8,746,853	119,369,905	42,039,962	41,848,989	42,444,863	6,125,746	1,144,231	653,854,261
Apr-23	(f)	251,936,576	101,906,013	8,757,214	119,670,643	42,353,442	41,854,096	43,011,599	5,466,311	1,129,671	616,085,565
May-23	(f)	208,269,905	99,427,672	8,545,334	116,792,794	41,357,770	40,836,543	42,027,863	4,645,856	1,087,626	562,991,364
Jun-23	(f)	298,410,121	115,555,762	9,928,570	135,651,626	47,975,494	47,459,729	48,680,363	4,602,956	1,247,152	709,511,774
	_	4,013,477,152	1,384,099,738	104,939,004	1,562,897,454	552,682,556	551,547,682	527,992,816	67,679,238	14,316,159	8,779,631,800

July 2022 - June 2023 - As Billed

	Actual/Forecast (a/f)	RES	MGSS	MGSP	AGSS	AGSP	TGST	TGS	SPL/CSL	DDC	TOTAL	Residential Average kWh
Jul-22	(a)	456,316,877	141,753,724	6,443,673	149,559,212	45,737,561	48,542,187	45,629,658	4,440,206	1,226,687	899,649,785	910
Aug-22	(a)	575,178,832	158,173,593	10,575,148	156,943,127	55,779,455	55,823,208	39,477,927	4,870,013	1,290,801	1,058,112,104	1,146
Sep-22	(a)	490,324,337	153,534,202	10,752,271	158,521,953	55,498,746	56,251,372	37,117,463	4,512,616	1,256,349	967,769,309	977
Oct-22	(a)	258,595,211	105,189,136	9,112,420	128,190,178	50,377,775	48,487,679	65,177,062	6,416,657	1,216,967	672,763,085	515
Nov-22	(a)	214,568,608	93,953,281	9,128,598	113,234,993	43,450,576	43,461,576	37,822,129	6,178,932	1,184,821	562,983,514	427
Dec-22	(f)	286,521,166	102,998,272	4,866,452	119,305,639	41,401,051	40,817,778	38,648,147	6,657,848	1,137,568	642,353,921	571
Jan-23	(f)	370,303,346	106,665,462	9,156,181	124,961,775	44,016,736	43,805,816	44,449,616	7,495,511	1,220,712	752,075,154	736
Feb-23	(f)	333,021,306	104,561,229	8,979,564	122,615,726	43,274,235	42,942,859	43,800,915	6,266,586	1,173,575	706,635,993	662
Mar-23	(f)	290,232,796	101,900,916	8,746,853	119,369,905	42,039,962	41,848,989	42,444,863	6,125,746	1,144,231	653,854,261	576
Apr-23	(f)	251,936,576	101,906,013	8,757,214	119,670,643	42,353,442	41,854,096	43,011,599	5,466,311	1,129,671	616,085,565	501
May-23	(f)	208,269,905	99,427,672	8,545,334	116,792,794	41,357,770	40,836,543	42,027,863	4,645,856	1,087,626	562,991,364	414
Jun-23	(f)	298,410,121	115,555,762	9,928,570	135,651,626	47,975,494	47,459,729	48,680,363	4,602,956	1,247,152	709,511,774	592
	_	4,033,679,082	1,385,619,262	104,992,278	1,564,817,571	553,262,802	552,131,832	528,287,605	67,679,238	14,316,159	8,804,785,830	669

Allocation of Weather Normalization Effect to Grouped Rate Classes

	Actual/Forecast (a/f)	RES	MGSS	MGSP	AGSS	AGSP	TGST	TGS	SPL/CSL	DDC	TOTAL
Jul-22	(a)	18,989,130	1,562,812	53,422	1,854,008	537,796	540,897	267,040	-	-	23,805,105
Aug-22	(a)	(45,336,496)	(3,731,209)	(127,544)	(4,426,438)	(1,283,987)	(1,291,390)	(637,557)	-	-	(56,834,621)
Sep-22	(a)	(14,637,885)	(1,204,703)	(41,180)	(1,429,173)	(414,564)	(416,954)	(205,849)	-	-	(18,350,308)
Oct-22	(a)	15,115,297	638,867	27,222	1,257,332	461,197	468,082	257,423	-	-	18,225,420
Nov-22	(a)	5,668,024	1,214,709	34,806	824,154	119,312	115,215	24,154	-	-	8,000,374
Dec-22	(f)	-	-	-	-	-	-	-	-	-	-
Jan-23	(f)	-	-	-	-	-	-	-	-	-	-
Feb-23	(f)	-	-	-	-	-	-	-	-	-	-
Mar-23	(f)	-	-	-	-	-	-	-	-	-	-
Apr-23	(f)	-	-	-	-	-	-	-	-	-	-
May-23	(f)	-	-	-	-	-	-	-	-	-	-
Jun-23	(f)	-	-			-	-	-	-	-	-
	_	(20,201,930)	(1,519,524)	(53,274)	(1,920,117)	(580,246)	(584,150)	(294,789)	-	-	(25,154,030)

Weather Normalization Effect

					Weath	er Normalization E	ffect				
											Total
		RES	MGSS	MGSP	AGSS	AGSP	TGST	TGS	SPL/CSL	DDC	ACE
		Effect	Effect	Effect	Effect	Effect	Effect	Effect	Effect	Effect	Effect
		(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)
Jul-22	(a)	18,989	1,563	53	1,854	538	541	267	0	0	23,805
Aug-22	(a)	(45,336)	(3,731)	(128)	(4,426)	(1,284)	(1,291)	(638)	0	0	(56,835)
Sep-22	(a)	(14,638)	(1,205)	(41)	(1,429)	(415)	(417)	(206)	0	0	(18,350)
Oct-22	(a)	15,115	639	27	1,257	461	468	257	0	0	18,225
Nov-22	(a)	5,668	1,215	35	824	119	115	24	0	0	8,000
Dec-22	(f)	0	0	0	0	0	0	0	0	0	0
Jan-23	(f)	0	0	0	0	0	0	0	0	0	0
Feb-23	(f)	0	0	0	0	0	0	0	0	0	0
Mar-23	(f)	0	0	0	0	0	0	0	0	0	0
Apr-23	(f)	0	0	0	0	0	0	0	0	0	0
May-23	(f)	0	0	0	0	0	0	0	0	0	0
Jun-23	(f)	0	0	0	0	0	0	0	0	0	0
Total		(20,202)	(1,520)	(53)	(1,920)	(580)	(584)	(295)	0	0	(25,154)

The total Weather Normalization Effect is the adjustment required to convert actual sales to weather normalized sales. If degree days are above normal, the weather normalization effect must be negative to remove the extra sales caused by the excess of degree days.

Atlantic City Electric Company Development of One-Time Gross Receipts Tax Reserve Regulatory Liability Allocation

Regulatory Liability (excludes SUT) Regulatory Liability (including SUT)	\$ \$	(994,337) (1,060,212)										
Docket No. ER20120746 Revenue Allocation Proposed Annualized Distribution Revenue Revenue Allocation %	\$	Total 468,834,688 100.0%	R 87,226,512 61.26%	\$ MGS Secondary 81,895,149 17.47%	MGS Primary 1,647,641 0.35%	\$ AGS Secondary 60,263,122 12.85%	\$ AGS Primary 12,792,347 2.73%	TGS Subtrans 3,128,671 0.67%	\$ TGS Trans 2,154,311 0.46%	\$	Coi	ect Dist. nnection 572,050 0.12%
Allocation of Regulatory Liability	\$	(994,337)	\$ (609,170)	\$ (173,689)	\$ (3,494)	\$ (127,810)	\$ (27,131)	\$ (6,636)	\$ (4,569)	\$ (40,625)	\$	(1,213)
Count of Contracts as of September 2022 Installations with no meters to be excluded			501,866	56,645	154	2,908	118	34	 15			1,064
Credit per Customer*			\$ (1.21)	\$ (3.07)	\$ (22.69)	\$ (43.95)	\$ (229.92)	\$ (195.16)	\$ (304.60)		\$	(1.14)
Number of Lamps as of September 2022										111,745		
Credit per Lamp*										\$ (0.36)		

^{*} For actual credits paid, customer and light counts may be different then amounts shown here. When these credits are processed the most recent available data will be utilized.

^{**}For illustrative purposes only, actual one-time refund issued to customers by rate class will be based on actuals at that point in time.
*** Credits will include SUT

Schedule (MTN)-2

2022-2023 ACE BRC CIP Targets - Proposed Rates

	Residential MGS Seconds 2022-2023 BRC 2022-2023 BI			_	GS Primary 2-2023 BRC	202	S Secondary 2-2023 BRC	20	GS Primary 22-2023 BRC	Sub	ansmission - otransmission 22-2023 BRC		ansmission 2-2023 BRC	
T	Φ.	57.50	Ф	127.10	Φ.			Revenue per Cu		10,000,62	Φ.	0.402.11	Φ.	4 222 24
January	\$	57.52	\$	127.18	\$	1,468.61	\$	2,020.52	\$	10,089.63	\$	8,483.11	\$	4,322.24
February	\$	51.71	\$	124.25	\$	1,451.55	\$	1,910.07	\$	9,378.29	\$	6,833.58	\$	6,888.56
March	\$	45.05	\$	121.00	\$	1,453.05	\$	1,862.34	\$	9,863.95	\$	6,935.47	\$	5,872.60
April	\$	39.13	\$	122.78	\$	1,410.43	\$	1,911.53	\$	10,266.06	\$	9,929.68	\$	3,260.78
May	\$	32.33	\$	120.94	\$	1,364.69	\$	1,853.69	\$	9,715.06	\$	9,896.55	\$	3,649.66
June	\$	54.27	\$	160.24	\$	1,671.81	\$	1,856.93	\$	10,711.67	\$	10,481.30	\$	4,373.90
July	\$	86.42	\$	193.80	\$	1,388.05	\$	1,960.94	\$	10,080.24	\$	7,433.50	\$	7,608.31
August	\$	97.51	\$	208.58	\$	1,969.53	\$	1,969.28	\$	11,297.01	\$	8,106.62	\$	6,246.29
September	\$	86.43	\$	205.86	\$	1,980.04	\$	1,956.72	\$	11,441.59	\$	8,993.31	\$	5,400.11
October	\$	45.65	\$	138.64	\$	1,614.70	\$	1,886.04	\$	10,988.78	\$	7,939.40	\$	11,075.30
November	\$	34.29	\$	118.43	\$	1,576.18	\$	1,761.76	\$	9,714.65	\$	7,344.54	\$	6,829.31
December	\$	44.61	\$	127.89	\$	1,100.41	\$	2,003.63	\$	12,716.64	\$	8,758.92	\$	5,156.31
	\$	674.92	\$	1,769.58	\$	18,449.04	\$	22,953.45	\$	126,263.56	\$	101,135.98	\$	70,683.37

Residential

Volumes		Estimate Jan-23	Estimate Feb-23	Estimate Mar-23	Estimate Apr-23	Estimate May-23	Estimate <u>Jun-23</u>	Actual Jul-22	Actual Aug-22	Actual Sep-22	Actual Oct-22	Actual Nov-22	Estimate Dec-22
RS kWh - Summer < 750 RS kWh - Summer > 750		-	-	-	-	-	179,513,681 118,896,439	299,835,320 175,470,687	292,894,174 236,948,162	300,419,206 175,267,246	111,328,318 29,827,884	-	
RS kWh - Winter		370,303,346	333,021,306	290,232,796	251,936,576	208,269,905	-	-	-	-	132,554,305	220,236,632	286,521,166
	Total Volume	370,303,346	333,021,306	290,232,796	251,936,576	208,269,905	298,410,121	475,306,007	529,842,336	475,686,452	273,710,508	220,236,632	286,521,166
Distribution Base Rates (w/o SUT)*													
SUM First 750 kWh	\$	0.084560 \$	0.084560 \$	0.084560 \$	0.084560 \$	0.084560 \$	0.084560 \$	0.084560 \$	0.084560 \$	0.084560 \$	0.084560 \$	0.084560 \$	0.084560
SUM '> 750 kWh	\$	0.099276 \$	0.099276 \$	0.099276 \$	0.099276 \$	0.099276 \$	0.099276 \$	0.099276 \$	0.099276 \$	0.099276 \$	0.099276 \$	0.099276 \$	0.099276
WIN	\$	0.076956 \$	0.076956 \$	0.076956 \$	0.076956 \$	0.076956 \$	0.076956 \$	0.076956 \$	0.076956 \$	0.076956 \$	0.076956 \$	0.076956 \$	0.076956
IIP Apr 2022 - All kWh (w/o SUT)	\$	0.001202 \$	0.001202 \$	0.001202 \$	0.001202 \$	0.001202 \$	0.001202 \$	0.001202 \$	0.001202 \$	0.001202 \$	0.001202 \$	0.001202 \$	0.001202
Distribution Base Rates + IIP (w/o SUT)													
SUM 'First 750 KWh	\$	0.085762 \$	0.085762 \$	0.085762 \$	0.085762 \$	0.085762 \$	0.085762 \$	0.085762 \$	0.085762 \$	0.085762 \$	0.085762 \$	0.085762 \$	0.085762
SUM '> 750 KWh	\$	0.100478 \$	0.100478 \$	0.100478 \$	0.100478 \$	0.100478 \$	0.100478 \$		0.100478 \$	0.100478 \$	0.100478 \$	0.100478 \$	0.100478
WIN	\$	0.078158 \$	0.078158 \$	0.078158 \$	0.078158 \$	0.078158 \$	0.078158 \$	0.078158 \$	0.078158 \$	0.078158 \$	0.078158 \$	0.078158 \$	0.078158
Revenues													
Volume Charge Revenues	\$	28,942,197 \$	26,028,305 \$	22,684,037 \$	19,690,878 \$	16,277,975 \$	27,341,814 \$	43,345,235 \$	48,927,067 \$	43,374,869 \$	22,904,917 \$	17,213,271 \$	22,393,943
Demand Charge Revenues	\$	- S	- \$	- \$	- \$	- S	- S	- \$	- \$	- \$	- \$	- \$	-
	Total Revenue \$	28,942,197 \$	26,028,305 \$	22,684,037 \$	19,690,878 \$	16,277,975 \$	27,341,814 \$	43,345,235 \$	48,927,067 \$	43,374,869 \$	22,904,917 \$	17,213,271 \$	22,393,943
Customers													
<u>Customers</u>	Total Customers	503,134	503,354	503,481	503,251	503,465	503,831	501,579	501,762	501,866	501,761	502,039	501,957
	Baseline Revenue Per Customer \$	57.52 \$	51.71 \$	45.05 \$	39.13 \$	32.33 \$	54.27 \$	86.42 \$	97.51 \$	86.43 \$	45.65 \$	34.29 \$	44.61

Notes:
*Distribution Base Rates are inclusive of PowerAhead 1-7.

Medium General Service - Secondary (MGSS)

		Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Actual	Actual	Actual	Actual	Actual	Estimate
V. I		<u>Jan-23</u>	Feb-23	Mar-23	Apr-23	May-23	<u>Jun-23</u>	<u>Jul-22</u>	Aug-22	Sep-22	Oct-22	Nov-22	Dec-22
Volumes Summer kWh							115,555,762	143,316,536	154,442,384	152,329,499	58,304,673		
Winter kWh		106.665.462	104.561.229	101,900,916	101,906,013	99.427.672		143,310,330	134,442,384	132,329,499	47.523.330	95,167,990	102.998.272
Willer KWII	Total Volume	106,665,462	104,561,229	101,900,916	101,906,013	99,427,672	115,555,762	143,316,536	154.442.384	152.329.499	105.828.003	95,167,990	102,998,272
n 1	Total volume	100,003,402	104,301,227	101,500,510	101,900,013	99,421,012	113,333,702	143,310,330	134,442,304	132,329,499	103,828,003	93,107,990	102,990,272
<u>Demand</u> Summer kW							512.201	550.550	500.204	500.140			
Summer kW Winter kW		433.820	410.005	406.060	440,664	452,232	513,201	558,558	599,294	589,140	-	476.071	
Winter KW	T (I D)	433,820	418,096 418,096	406,060	440,664	452,232	513,201	558,558	599,294	589,140	523,566 523,566	476,071	515,501 515,501
	Total Demand	433,820	418,096	406,060	440,664	452,232	513,201	338,338	599,294	589,140	323,366	4/6,0/1	515,501
Distribution Base Rates (w/o SUT)*													
Summer kWh	\$	0.061019 \$	0.061019 \$	0.061019	0.061019	\$ 0.061019 \$	0.061019 \$	0.061019 \$	0.061019 \$	0.061019 \$	0.061019 \$	0.061019 \$	0.061019
Winter kWh	\$	0.054009 \$	0.054009 \$	0.054009 \$	0.054009	\$ 0.054009 \$	0.054009 \$	0.054009 \$	0.054009 \$	0.054009 \$	0.054009 \$	0.054009 \$	0.054009
Summer kW	\$	3.71 \$	3.71 \$	3.71 \$	3.71	\$ 3.71 \$	3.71 \$	3.71 \$	3.71 \$	3.71 \$	3.71 \$	3.71 \$	3.71
Winter kW	\$	3.04 \$	3.04 \$	3.04 \$	3.04	\$ 3.04 \$	3.04 \$	3.04 \$	3.04 \$	3.04 \$	3.04 \$	3.04 \$	3.04
IIP Apr 2022 - All kWh (w/o SUT)	\$	0.001027 \$	0.001027 \$	0.001027	0.001027	\$ 0.001027 \$	0.001027 \$	0.001027 \$	0.001027 \$	0.001027 \$	0.001027 \$	0.001027 \$	0.001027
IIP Apr 2022 - All kW (w/o SUT)	\$	0.04 \$	0.04 \$	0.04	0.04	\$ 0.04 \$	0.04 \$	0.04 \$	0.04 \$	0.04 \$	0.04 \$	0.04 \$	0.04
Distribution Base Rates + IIP (w/o SUT)													
Summer kWh	\$	0.062046 \$	0.062046 \$	0.062046	0.062046	\$ 0.062046 \$	0.062046 \$	0.062046 \$	0.062046 \$	0.062046 \$	0.062046 \$	0.062046 \$	0.062046
Winter kWh	\$	0.055036 \$	0.055036 \$	0.055036	0.055036	\$ 0.055036 \$	0.055036 \$	0.055036 \$	0.055036 \$	0.055036 \$	0.055036 \$	0.055036 \$	0.055036
Summer kW	\$	3.75 \$	3.75 \$	3.75 \$							3.75 \$	3.75 \$	
Winter kW	\$	3.08 \$	3.08 \$	3.08	3.08	\$ 3.08 \$	3.08 \$	3.08 \$	3.08 \$	3.08 \$	3.08 \$	3.08 \$	3.08
Revenues													
Volume Charge Revenues	\$	5,870,440 \$	5,754,632 \$	5,608,219	5,608,499	\$ 5,472,101 \$	7,169,773 \$	8,892,218 \$	9,582,532 \$	9,451,436 \$	6,233,066 \$	5,237,665 \$	5,668,613
Demand Charge Revenues	\$	1,336,167 \$	1,287,735 \$	1,250,663	1,357,246	\$ 1,392,874 \$	1,924,504 \$	2,094,593 \$	2,247,351 \$	2,209,275 \$	1,612,583 \$	1,466,299 \$	1,587,742
	Total Revenue \$	7,206,607 \$	7,042,367 \$	6,858,882	6,965,745	\$ 6,864,976 \$	9,094,277 \$	10,986,810 \$	11,829,884 \$	11,660,711 \$	7,845,649 \$	6,703,964 \$	7,256,355
Customers													
Single Phase Service		41,144	41,156	41,158	41,195	41,218	41,211	42,476	42,567	42,614	42,666	42,581	40,667
3 Phase Service		15,519	15,524	15,525	15,539	15,547	15,545	14,216	14,150	14,031	13,924	14,027	16,072
	Total Customers	56,663	56,681	56,683	56,733	56,765	56,756	56,692	56,717	56,645	56,590	56,608	56,738
	Baseline Revenue Per Customer \$	127.18 \$	124.25 \$	121.00 \$	122.78	§ 120.94 \$	160.24 \$	193.80 \$	208.58 \$	205.86 \$	138.64 \$	118.43 \$	127.89

Notes: *Distribution Base Rates are inclusive of PowerAhead 1-7.

Medium General Service - Primary (MGSP)

		Estimate Jan-23	Estimate Feb-23	Estimate Mar-23	Estimate Apr-23	Estimate May-23	Estimate Jun-23	Actual Jul-22	Actual Aug-22	Actual Sep-22	Actual Oct-22	Actual Nov-22	Estimate Dec-22
Volumes													
Summer kWh		-	-	-	-	-	9,928,570	6,497,095	10,447,604	10,711,091	8,346,483	-	-
Winter kWh		9,156,181	8,979,564	8,746,853	8,757,214	8,545,334	-	-	-	-	793,159	9,163,404	4,866,452
	Total Volume	9,156,181	8,979,564	8,746,853	8,757,214	8,545,334	9,928,570	6,497,095	10,447,604	10,711,091	9,139,642	9,163,404	4,866,452
Demand													
Summer kW		-	-	-	-	-	17,341	23,142	23,148	27,093	-	-	-
Winter kW		16,440	17,429	21,362	16,540	14,909	-	-	-	-	28,377	26,800	26,011
	Total Demand	16,440	17,429	21,362	16,540	14,909	17,341	23,142	23,148	27,093	28,377	26,800	26,011
Distribution Base Rates (w/o SUT)*													
Summer kWh	\$	0.023179 \$	0.023179 \$	0.023179 \$	0.023179 \$	0.023179 \$	0.023179 \$	0.023179 \$	0.023179 \$	0.023179 \$	0.023179 \$	0.023179 \$	0.023179
Winter kWh	\$	0.022456 \$	0.022456 \$	0.022456 \$	0.022456 \$	0.022456 \$	0.022456 \$	0.022456 \$	0.022456 \$	0.022456 \$	0.022456 \$	0.022456 \$	0.022456
Summer kW	\$	1.78 \$	1.78 \$	1.78 \$	1.78 \$	1.78 \$	1.78 \$	1.78 \$	1.78 \$	1.78 \$	1.78 \$	1.78 \$	1.78
Winter kW	\$	1.40 \$	1.40 \$	1.40 \$	1.40 \$	1.40 \$	1.40 \$	1.40 \$	1.40 \$	1.40 \$	1.40 \$	1.40 \$	1.40
IIP Apr 2022 - All kWh (w/o SUT)	\$	0.000711 \$	0.000711 \$	0.000711 \$	0.000711 \$	0.000711 \$	0.000711 \$	0.000711 \$	0.000711 \$	0.000711 \$	0.000711 \$	0.000711 \$	0.000711
IIP Apr 2022 - All kW (w/o SUT)	\$	0.03 \$	0.03 \$	0.03 \$	0.03 \$	0.03 \$	0.03 \$	0.03 \$	0.03 \$	0.03 \$	0.03 \$	0.03 \$	0.03
Distribution Base Rates + IIP (w/o SUT)													
Summer kWh	S	0.023890 \$	0.023890 \$	0.023890 \$	0.023890 \$	0.023890 \$	0.023890 \$	0.023890 \$	0.023890 \$	0.023890 \$	0.023890 \$	0.023890 \$	0.023890
Winter kWh	s	0.023167 \$	0.023167 \$	0.023167 \$		0.023167 \$	0.023167 \$	0.023167 \$	0.023167 \$	0.023167 \$	0.023167 \$	0.023167 \$	0.023167
Summer kW	s	1.81 \$	1.81 \$	1.81 \$		1.81 \$	1.81 \$	1.81 \$	1.81 \$	1.81 \$	1.81 \$	1.81 \$	1.81
Winter kW	\$	1.43 \$	1.43 \$	1.43 \$		1.43 \$	1.43 \$	1.43 \$	1.43 \$	1.43 \$		1.43 \$	1.43
Revenues													
Volume Charge Revenues	S	212,121 \$	208,030 \$	202,638 \$	202,878 \$	197,970 \$	237,194 \$	155,216 \$	249,593 \$	255,888 \$	217,773 \$	212,289 \$	112,741
Demand Charge Revenues	\$	23,509 \$	24,924 \$	30,548 \$	23,652 \$	21,320 \$	31,386 \$	41,887 \$	41,897 \$	49,038 \$	40,579 \$	38,324 \$	37,196
	Total Revenue \$	235,630 \$	232,953 \$	233,186 \$	226,530 \$	219,290 \$	268,580 \$	197,103 \$	291,490 \$	304,926 \$	258,352 \$	250,613 \$	149,938
Customers													
Single Phase Service		77	77	77	77	77	77	75	83	88	89	96	61
3 Phase Service		84	84	84	84	84	84	67	65	66	71	63	75
	Total Customers	160	160	160	161	161	161	142	148	154	160	159	136
Base	eline Revenue Per Customer \$	1,468.61 \$	1,451.55 \$	1,453.05 \$	1,410.43 \$	1,364.69 \$	1,671.81 \$	1,388.05 \$	1,969.53 \$	1,980.04 \$	1,614.70 \$	1,576.18 \$	1,100.41

Notes:

^{*}Distribution Base Rates are inclusive of PowerAhead 1-7.

Annual General Service - Secondary (Ad	GSS)	Estimate Jan-23	Estimate Feb-23	Estimate Mar-23	Estimate Apr-23	Estimate May-23	Estimate <u>Jun-23</u>	Actual Jul-22	Actual Aug-22	Actual Sep-22	Actual Oct-22	Actual Nov-22	Estimate Dec-22
Volumes	Total Volume	124,961,775	122,615,726	119.369.905	119,670,643	116.792.794	135,651,626	151,413,220	152,516,689	157.092.780	129,447,510	114,059,147	119,305,639
<u>Demand</u>		, , , , , ,	, ,	.,,		.,,	,		- , - , - , - , - , - , - , - , - , - ,				.,,
	Total Demand	411,664	389,266	379,537	389,887	378,283	378,866	400,707	402,136	398,749	383,155	357,414	410,582
Distribution Base Rates (w/o SUT)*													
Summer kWh	\$	- \$	- \$	-	\$ - 5	-	\$ - 5	- 5	S -	\$ - \$	- S	- 5	\$ -
Winter kWh	\$	- \$	- \$	-			\$ - \$		s - :				
Summer kW	\$	14.04 \$	14.04 \$										
Winter kW	\$	14.04 \$	14.04 \$	14.04	\$ 14.04 5	14.04	\$ 14.04 \$	14.04	\$ 14.04	\$ 14.04 \$	14.04 \$	14.04	\$ 14.04
IIP Apr 2022 - All kW (w/o SUT)	\$	0.23 \$	0.23 \$	0.23	\$ 0.23	0.23	\$ 0.23 \$	0.23	0.23	\$ 0.23 \$	0.23 \$	0.23	0.23
Distribution Base Rates + IIP (w/o SUT	<u>)</u>												
Summer kWh	\$	- \$	- \$				\$ - \$			\$ - \$			
Winter kWh	\$	- \$	- \$	-			\$ - \$			\$ - \$			
Summer kW	\$	14.27 \$	14.27 \$										
Winter kW	\$	14.27 \$	14.27 \$	14.27	\$ 14.27	3 14.27	\$ 14.27 \$	14.27	14.27	\$ 14.27 \$	14.27 \$	14.27	\$ 14.27
Revenues													
Volume Charge Revenues	\$	- \$	- \$	-	,		\$ - \$		\$ - :	4	- \$	-	
Demand Charge Revenues		5,874,443 \$	5,554,823 \$	5,415,991	\$ 5,563,688	,.,.,.,	\$ 5,406,414 \$. , ,	5,738,481	\$ 5,690,148 \$	5,467,622 \$	5,100,298	
	Total Revenue \$	5,874,443 \$	5,554,823 \$	5,415,991	\$ 5,563,688 \$	5,398,099	\$ 5,406,414 \$	5,718,089	5,738,481	\$ 5,690,148 \$	5,467,622 \$	5,100,298	\$ 5,859,007
Customers	Total Customers	2,907	2,908	2,908	2,911	2,912	2,911	2,916	2,914	2,908	2,899	2,895	2,924
	Baseline Revenue Per Customer \$	2.020.52 \$	1.910.07 \$	1.862.34	\$ 1.911.53 S	1.853.69	\$ 1,856.93 \$	1,960.94	1,969.28	\$ 1,956.72 \$	1,886.04 \$	1,761.76	\$ 2,003.63

Notes:

^{*}Distribution Base Rates are inclusive of PowerAhead 1-7.

Annual General Service - Primary (AGSP)

		Estimate <u>Jan-23</u>	Estimate Feb-23	Estimate Mar-23	Estimate Apr-23	Estimate May-23	Estimate Jun-23	Actual Jul-22	Actual Aug-22	Actual Sep-22	Actual Oct-22	Actual Nov-22	Estimate Dec-22
Volumes													
	Total Volume	44,016,736	43,274,235	42,039,962	42,353,442	41,357,770	47,975,494	46,275,357	54,495,468	55,084,182	50,838,972	43,569,888	41,401,051
<u>Demand</u>	Total Demand	107,585	100,015	105,175	109,537	103,694	114,291	106,347	119,184	121,741	116,923	104,242	134,307
Distribution Base Rates (w/o SUT)*													
Summer kWh	\$	- \$	- \$	- S	- \$	- \$	- \$	- \$	- S	- \$	- \$	- \$	-
Winter kWh	\$	- S	- \$	- S	- \$	- \$	- \$	- \$	- S	- \$	- \$	- \$	-
Summer kW	\$	10.93 \$	10.93 \$	10.93 \$			10.93 \$	10.93 \$	10.93 \$		10.93 \$	10.93 \$	
Winter kW	\$	10.93 \$	10.93 \$	10.93 \$	10.93 \$	10.93 \$	10.93 \$	10.93 \$	10.93 \$	10.93 \$	10.93 \$	10.93 \$	10.93
IIP Apr 2022 - All kW (w/o SUT)	\$	0.16 \$	0.16 \$	0.16 \$	0.16 \$	0.16 \$	0.16 \$	0.16 \$	0.16 \$	0.16 \$	0.16 \$	0.16 \$	0.16
Distribution Base Rates + IIP (w/o SUT)													
Summer kWh	\$	- \$	- \$	- S		- \$	- \$	- \$	- S	-	- \$	- S	
Winter kWh	\$	- \$	- \$	- S		-	- \$	- \$	- S	-	- \$	- \$	
Summer kW Winter kW	\$	11.09 \$	11.09 \$	11.09 \$			11.09 \$	11.09 \$	11.09 \$		11.09 \$	11.09 \$	
Winter KW	2	11.09 \$	11.09 \$	11.09 \$	11.09 \$	11.09 \$	11.09 \$	11.09 \$	11.09 \$	11.09 \$	11.09 \$	11.09 \$	11.09
Revenues													
Volume Charge Revenues	\$	- \$	- \$	- S	- \$	- \$	- \$	- \$	- S	- S	- \$	- \$	-
Demand Charge Revenues	\$	1,193,121 \$	1,109,164 \$	1,166,391 \$		1,149,963 \$	1,267,492 \$	1,179,388 \$	1,321,751 \$	1,350,108 \$	1,296,676 \$	1,156,044 \$	
	Total Revenue \$	1,193,121 \$	1,109,164 \$	1,166,391 \$	1,214,771 \$	1,149,963 \$	1,267,492 \$	1,179,388 \$	1,321,751 \$	1,350,108 \$	1,296,676 \$	1,156,044 \$	1,489,468
Customers	Total Customers	118	118	118	118	118	118	117	117	118	118	119	117
	Baseline Revenue Per Customer \$	10,089.63 \$	9,378.29 \$	9,863.95 \$	10,266.06 \$	9,715.06 \$	10,711.67 \$	10,080.24 \$	11,297.01 \$	11,441.59 \$	10,988.78 \$	9,714.65 \$	12,716.64

Notes:
*Distribution Base Rates are inclusive of PowerAhead 1-7.

<u>Transmission General Service - Subtransmission (TGST)</u>

Volumes		Estimate <u>Jan-23</u>	Estimate Feb-23	Estimate Mar-23	Estimate Apr-23	Estimate May-23	Estimate Jun-23	Actual Jul-22	Actual Aug-22	Actual Sep-22	Actual Oct-22	Actual Nov-22	Estimate Dec-22
Summer/Winter kWh	_												
	Total Volume	43,805,816	42,942,859	41,848,989	41,854,096	40,836,543	47,459,729	49,083,084	54,531,818	55,834,418	48,955,761	43,576,791	40,817,778
Demand													
<5000 kW		45,478	36,643	37,190	53,283	53,133	56,266	44,296	45,646	50,792	39,043	38,350	54,648
5000 - 9000 kW		14,985	12,074	12,254	17,556	17,507	18,539	17,118	18,878	19,550	24,408	22,499	19,688
>9000 kW		29,825	24,031	24,390	34,944	34,846	36,900	31,192	34,958	35,214	31,731	28,736	37,728
	Total Demand	90,288	72,748	73,833	105,783	105,486	111,706	92,607	99,482	105,557	95,182	89,585	112,063
D' 4 T 4' B B 4 (/ CHITI)#													
Distribution Base Rates (w/o SUT)* Summer/Winter kWh	\$	- \$	- S	- \$	- S	- \$	- \$	- \$	- s	- \$	- S	- S	
<5000 kW	\$	3.76 \$	3.76 \$	3.76 \$	3.76 \$	3.76 \$	3.76 \$	3.76 \$	3.76 \$	3.76 \$	3.76 \$	3.76 \$	3.76
5000 - 9000 kW	S	2.90 \$	2.90 \$	2.90 \$	2.90 \$	2.90 \$	2.90 \$	2.90 \$	2.90 \$	2.90 \$	2.90 \$	2.90 \$	2.90
>9000 kW	\$	1.47 \$	1.47 \$	1.47 \$	1.47 \$	1.47 \$	1.47 \$	1.47 \$	1.47 \$	1.47 \$	1.47 \$	1.47 \$	1.47
IIP Apr 2022 - All kW (w/o SUT)	\$	0.06 \$	0.06 \$	0.06 \$	0.06 \$	0.06 \$	0.06 \$	0.06 \$	0.06 \$	0.06 \$	0.06 \$	0.06 \$	0.06
Distribution Base Rates + IIP (w/o SUT)													
Summer/Winter kWh	\$	- \$	- \$	- \$	- \$	- \$	- \$	- \$	- \$	- \$	- \$	- \$	-
<5000 kW	\$	3.82 \$	3.82 \$	3.82 \$	3.82 \$	3.82 \$	3.82 \$	3.82 \$	3.82 \$	3.82 \$	3.82 \$	3.82 \$	3.82
5000 - 9000 kW	\$	2.96 \$	2.96 \$	2.96 \$	2.96 \$	2.96 \$	2.96 \$	2.96 \$	2.96 \$	2.96 \$	2.96 \$	2.96 \$	2.96
>9000 kW	\$	1.53 \$	1.53 \$	1.53 \$	1.53 \$	1.53 \$	1.53 \$	1.53 \$	1.53 \$	1.53 \$	1.53 \$	1.53 \$	1.53
Revenues													
Volume Charge Revenues	\$	- \$	- \$	- \$		- \$	- \$	- \$	- \$	- \$	- \$	- \$	-
Demand Charge Revenues		263,714 \$	212,482 \$	215,653 \$	308,970 \$	308,105 \$	326,270 \$	267,606 \$	283,732 \$	305,772 \$	269,940 \$	257,059 \$	324,755
	Total Revenue \$	263,714 \$	212,482 \$	215,653 \$	308,970 \$	308,105 \$	326,270 \$	267,606 \$	283,732 \$	305,772 \$	269,940 \$	257,059 \$	324,755
Customers							25		20		**	**	
<5000 kW 5000 - 9000 kW		27	27 2	27 2	27 2	27 2	27 2.	31	30 2	29 2	28	28 4	31 3
>9000 kW		2	2 2	2	2	2	2	2	2	2	3	4 2	3
>2000 KH	Total Customers	31	31	31	31	31	31	36	35	34	34	35	37
	Baseline Revenue Per Customer \$	8,483.11 \$	6,833.58 \$	6,935.47 \$	9,929.68 \$	9,896.55 \$	10,481.30 \$	7,433.50 \$	8,106.62 \$	8,993.31 \$	7,939.40 \$	7,344.54 \$	8,758.92

Notes:
*Distribution Base Rates are inclusive of PowerAhead 1-7.

Transmission General Service (TGS)

Volumes		Estimate <u>Jan-23</u>	Estimate Feb-23	Estimate Mar-23	Estimate Apr-23	Estimate May-23	Estimate <u>Jun-23</u>	Actual Jul-22	Actual Aug-22	Actual Sep-22	Actual Oct-22	Actual Nov-22	Estimate Dec-22
Summer/Winter kWh	Total Volume	44,449,616	43,800,915	42,444,863	43,011,599	42,027,863	48,680,363	45,896,698	38,840,370	36,911,614	65,434,485	37,846,283	38,648,147
Demand													
<5000 kW		10,284	16,387	13,962	7,755	8,680	10,395	14,082	11,579	8,597	23,565	11,031	11,993
5000 - 9000 kW		14,234	22,682	19,326	10,734	12,014	14,388	17,874	18,733	18,710	50,145	26,068	13,745
>9000 kW		62,165	99.061	84,402	46,880	52,469	62.839	84.691	89.881	97,619	53,474	61.759	58,847
	Total Demand	86,683	138,131	117,690	65,370	73,163	87,623	116,646	120,192	124,926	127,185	98,858	84,585
Distribution Base Rates (w/o SUT)*													
Summer/Winter kWh	s	- S	- S	- S	- S	- S	- S	- S	- S	- S	- S	- S	-
<5000 kW	S	2.62 \$	2.62 \$	2.62 \$		2.62 \$	2.62 \$	2.62 \$	2.62 \$	2.62 \$	2.62 \$	2.62 \$	2.62
5000 - 9000 kW	S	2.03 \$	2.03 \$	2.03 \$	2.03 \$	2.03 \$	2.03 \$	2.03 \$	2.03 \$	2.03 \$	2.03 \$	2.03 \$	2.03
>9000 kW	s	0.16 \$	0.16 \$	0.16 \$	0.16 \$	0.16 \$	0.16 \$	0.16 \$	0.16 \$	0.16 \$	0.16 \$	0.16 \$	0.16
IIP Apr 2022 - All kW (w/o SUT)	s	0.04 \$	0.04 \$	0.04 \$	0.04 \$	0.04 \$	0.04 \$	0.04 \$	0.04 \$	0.04 \$	0.04 \$	0.04 \$	0.04
Distribution Base Rates + IIP (w/o SUT)													
Summer/Winter kWh	S		- \$	- \$		- S	- S	- \$	- S	- S	- S	- S	
<5000 kW	S	2.66 \$	2.66 \$	2.66 \$		2.66 \$	2.66 \$	2.66 \$	2.66 \$	2.66 \$	2.66 \$	2.66 \$	2.66
5000 - 9000 kW >9000 kW	5	2.07 \$ 0.20 \$	2.07 \$ 0.20 \$	2.07 \$ 0.20 \$		2.07 \$ 0.20 \$	2.07 \$ 0.20 \$	2.07 \$ 0.20 \$	2.07 \$ 0.20 \$	2.07 \$ 0.20 \$	2.07 \$ 0.20 \$	2.07 \$	2.07 0.20
>9000 kW	3	0.20 \$	0.20 \$	0.20 \$	0.20 \$	0.20 \$	0.20 \$	0.20 \$	0.20 \$	0.20 \$	0.20 \$	0.20 \$	0.20
Revenues													
Volume Charge Revenues	S	- \$	- \$	- \$		- S	- S	- \$	- S	- S	- S	- S	-
Demand Charge Revenues	<u>_s</u>	69,184 \$	110,246 \$	93,932 \$		58,393 \$	69,935 \$	91,300 \$	87,448 \$	81,002 \$	177,205 \$	95,610 \$	72,062
	Total Revenue S	69,184 \$	110,246 \$	93,932 \$	52,174 \$	58,393 \$	69,935 \$	91,300 \$	87,448 \$	81,002 \$	177,205 \$	95,610 \$	72,062
Customers													
<5000 kW		7	7	7	7	7	7	5	6	6	6	5	7
5000 - 9000 kW		3	3	3	3	3	3	3	3	3	3	4	2
>9000 kW	T . 10 .	6	6	6	6	6	6	4		6	7		<u>5</u> 14
	Total Customers	16	16	16	16	16	16	12	14	15	16	14	14
	Baseline Revenue Per Customer \$	4,322.24 \$	6,888.56 \$	5,872.60 \$	3,260.78 \$	3,649.66 \$	4,373.90 \$	7,608.31 \$	6,246.29 \$	5,400.11 \$	11,075.30 \$	6,829.31 \$	5,156.31

Notes: *Distribution Base Rates are inclusive of PowerAhead 1-7.

Schedule (MTN)-3

ATLANTIC CITY ELECTRIC COMPANY RESIDENTIAL SERVICE ("RS") 8 WINTER MONTHS (October Through May)

Present Rates vs. Proposed Rates

Monthly	, 1	Present		Present	F	Present	Ne	w		New	New		<u></u>	iffer	enc	<u>e</u>		<u>Total</u>	
<u>Usage</u>	1	Delivery	9	Supply+T		<u>Total</u>	Deliv	<u>ery</u>	5	Supply+T	Total		Delive	У	S	upply+T	<u>D</u>	<u>ifference</u>	
(kWh)		(\$)		(\$)		(\$)	(\$)		(\$)	(\$)		(\$)			(\$)		(\$)	(%)
0	\$	6.25	\$	-	\$	6.25	\$	7.60	\$	-	\$ 7.60		*	.35	\$	-	\$	1.35	21.60%
25	\$	8.40	\$	2.79	\$	11.19	\$	10.14	\$	2.79	\$ 12.93		*	.74	\$	-	\$	1.74	15.55%
50	\$	10.55	\$	5.58	\$	16.13	\$	12.69	\$	5.58	\$ 18.27			.14	\$	-	\$	2.14	13.27%
75	\$	12.70	\$	8.38	\$	21.08	\$	15.23	\$	8.38	\$ 23.61			.53	\$	-	\$	2.53	12.00%
100	\$	14.85	\$	11.17	\$	26.02	\$	17.78	\$	11.17	\$ 28.95			.93	\$	-	\$	2.93	11.26%
150	\$	19.16	\$	16.75	\$	35.91	\$	22.87	\$	16.75	\$ 39.62			.71	\$	-	\$	3.71	10.33%
200	\$	23.46	\$	22.33	\$	45.79	\$:	27.95	\$	22.33	\$ 50.28		*	.49	\$	-	\$	4.49	9.81%
250	\$	27.76	\$	27.92	\$	55.68	\$,	33.04	\$	27.92	\$ 60.96			.28	\$	-	\$	5.28	9.48%
300	\$	32.06	\$	33.50	\$	65.56	\$,	38.13	\$	33.50	\$ 71.63			.07	\$	-	\$	6.07	9.26%
350	\$	36.36	\$	39.08	\$	75.44	\$ 	43.22	\$	39.08	\$ 82.30			.86	\$	-	\$	6.86	9.09%
400	\$	40.67	\$	44.67	\$	85.34	\$ 	48.31	\$	44.67	\$ 92.98		*	.64	\$	-	\$	7.64	8.95%
450	\$	44.97	\$	50.25	\$	95.22	\$!	53.40	\$	50.25	\$ 103.65	:	\$ 8	.43	\$	-	\$	8.43	8.85%
500	\$	49.27	\$	55.83	\$	105.10	\$ 	58.48	\$	55.83	\$ 114.31			.21	\$	-	\$	9.21	8.76%
600	\$	57.87	\$	67.00	\$	124.87	\$	88.66	\$	67.00	\$ 135.66			.79	\$	-	\$	10.79	8.64%
650	\$	62.17	\$	72.58	\$	134.75	\$	73.75	\$	72.58	\$ 146.33	:	\$ 11	.58	\$	-	\$	11.58	8.59%
669	\$	63.81	\$	74.71	\$	138.52	\$	75.68	\$	74.71	\$ 150.39	:	\$ 11	.87	\$	-	\$	11.87	8.57%
700	\$	66.48	\$	78.17	\$	144.65	\$	78.84	\$	78.17	\$ 157.01	:	\$ 12	.36	\$	-	\$	12.36	8.54%
750	\$	70.78	\$	83.75	\$	154.53	\$ 	33.93	\$	83.75	\$ 167.68	;		.15	\$	-	\$	13.15	8.51%
800	\$	75.08	\$	89.33	\$	164.41	\$ 	39.01	\$	89.33	\$ 178.34	:	\$ 13	.93	\$	-	\$	13.93	8.47%
900	\$	83.68	\$	100.50	\$	184.18	\$ 	99.19	\$	100.50	\$ 199.69	:	§ 15	.51	\$	-	\$	15.51	8.42%
1000	\$	92.29	\$	111.67	\$	203.96	\$ 10	09.37	\$	111.67	\$ 221.04	:	§ 17	.08	\$	-	\$	17.08	8.37%
1200	\$	109.50	\$	134.00	\$	243.50	\$ 12	29.72	\$	134.00	\$ 263.72	;	\$ 20	.22	\$	-	\$	20.22	8.30%
1500	\$	135.31	\$	167.50	\$	302.81	\$ 10	30.25	\$	167.50	\$ 327.75	:	\$ 24	.94	\$	-	\$	24.94	8.24%
2000	\$	178.33	\$	223.34	\$	401.67	\$ 2	11.14	\$	223.34	\$ 434.48	;	32	.81	\$	-	\$	32.81	8.17%
2500	\$	221.35	\$	279.17	\$	500.52	\$ 20	32.02	\$	279.17	\$ 541.19	:	\$ 40	.67	\$	-	\$	40.67	8.13%
3000	\$	264.36	\$	335.00	\$	599.36	\$	12.90	\$	335.00	\$ 647.90	:	\$ 48	.54	\$	-	\$	48.54	8.10%
3500	\$	307.38	\$	390.84	\$	698.22	\$ 30	33.79	\$	390.84	\$ 754.63	:	§ 56	.41	\$	-	\$	56.41	8.08%
4000	\$	350.40	\$	446.67	\$	797.07	\$ 4	14.67	\$	446.67	\$ 861.34	,	\$ 64	.27	\$	-	\$	64.27	8.06%

ATLANTIC CITY ELECTRIC COMPANY RESIDENTIAL SERVICE ("RS") 4 SUMMER MONTHS (June Through September)

Present Rates vs. Proposed Rates

Monthly	F	Present		Present	F	Present		New		New	New		Differ	enc	<u>e</u>		<u>Total</u>
<u>Usage</u>	<u></u>	Delivery	<u>S</u>	Supply+T		<u>Total</u>	<u>[</u>	Delivery	9	Supply+T	<u>Total</u>	<u>[</u>	Delivery	S	Supply+T	<u>Di</u>	<u>fference</u>
(kWh)		(\$)		(\$)		(\$)		(\$)		(\$)	(\$)		(\$)		(\$)	(\$)	(%)
0	\$	6.25	\$	-	\$	6.25	\$	7.60	\$	-	\$ 7.60	\$	1.35	\$	-	\$ 1.35	21.60%
25	\$	8.56	\$	2.66	\$	11.22	\$	10.35	\$	2.66	\$ 13.01	\$	1.79	\$	-	\$ 1.79	15.95%
50	\$	10.88	\$	5.32	\$	16.20	\$	13.09	\$	5.32	\$ 18.41	\$	2.21	\$	-	\$ 2.21	13.64%
75	\$	13.19	\$	7.98	\$	21.17	\$	15.84	\$	7.98	\$ 23.82	\$	2.65	\$	-	\$ 2.65	12.52%
100	\$	15.51	\$	10.65	\$	26.16	\$	18.59	\$	10.65	\$ 29.24	\$	3.08	\$	-	\$ 3.08	11.77%
150	\$	20.14	\$	15.97	\$	36.11	\$	24.08	\$	15.97	\$ 40.05	\$	3.94	\$	-	\$ 3.94	10.91%
200	\$	24.77	\$	21.29	\$	46.06	\$	29.58	\$	21.29	\$ 50.87	\$	4.81	\$	-	\$ 4.81	10.44%
250	\$	29.40	\$	26.61	\$	56.01	\$	35.07	\$	26.61	\$ 61.68	\$	5.67	\$	-	\$ 5.67	10.12%
300	\$	34.03	\$	31.94	\$	65.97	\$	40.56	\$	31.94	\$ 72.50	\$	6.53	\$	-	\$ 6.53	9.90%
350	\$	38.66	\$	37.26	\$	75.92	\$	46.06	\$	37.26	\$ 83.32	\$	7.40	\$	-	\$ 7.40	9.75%
400	\$	43.29	\$	42.58	\$	85.87	\$	51.55	\$	42.58	\$ 94.13	\$	8.26	\$	-	\$ 8.26	9.62%
450	\$	47.92	\$	47.90	\$	95.82	\$	57.04	\$	47.90	\$ 104.94	\$	9.12	\$	-	\$ 9.12	9.52%
500	\$	52.55	\$	53.23	\$	105.78	\$	62.54	\$	53.23	\$ 115.77	\$	9.99	\$	-	\$ 9.99	9.44%
600	\$	61.80	\$	63.87	\$	125.67	\$	73.53	\$	63.87	\$ 137.40	\$	11.73	\$	-	\$ 11.73	9.33%
650	\$	66.43	\$	69.19	\$	135.62	\$	79.02	\$	69.19	\$ 148.21	\$	12.59	\$	-	\$ 12.59	9.28%
669	\$	68.19	\$	71.22	\$	139.41	\$	81.11	\$	71.22	\$ 152.33	\$	12.92	\$	-	\$ 12.92	9.27%
700	\$	71.06	\$	74.52	\$	145.58	\$	84.51	\$	74.52	\$ 159.03	\$	13.45	\$	-	\$ 13.45	9.24%
750	\$	75.69	\$	79.84	\$	155.53	\$	90.01	\$	79.84	\$ 169.85	\$	14.32	\$	-	\$ 14.32	9.21%
800	\$	80.96	\$	85.66	\$	166.62	\$	96.29	\$	85.66	\$ 181.95	\$	15.33	\$	-	\$ 15.33	9.20%
900	\$	91.48	\$	97.31	\$	188.79	\$	108.84	\$	97.31	\$ 206.15	\$	17.36	\$	-	\$ 17.36	9.20%
1000	\$	102.01	\$	108.96	\$	210.97	\$	121.40	\$	108.96	\$ 230.36	\$	19.39	\$	-	\$ 19.39	9.19%
1200	\$	123.07	\$	132.25	\$	255.32	\$	146.51	\$	132.25	\$ 278.76	\$	23.44	\$	-	\$ 23.44	9.18%
1500	\$	154.65	\$	167.19	\$	321.84	\$	184.18	\$	167.19	\$ 351.37	\$	29.53	\$	-	\$ 29.53	9.18%
2000	\$	207.29	\$	225.43	\$	432.72	\$	246.97	\$	225.43	\$ 472.40	\$	39.68	\$	-	\$ 39.68	9.17%
2500	\$	259.92	\$	283.67	\$	543.59	\$	309.75	\$	283.67	\$ 593.42	\$	49.83	\$	-	\$ 49.83	9.17%
3000	\$	312.56	\$	341.90	\$	654.46	\$	372.53	\$	341.90	\$ 714.43	\$	59.97	\$	-	\$ 59.97	9.16%
3500	\$	365.20	\$	400.14	\$	765.34	\$	435.32	\$	400.14	\$ 835.46	\$	70.12	\$	-	\$ 70.12	9.16%
4000	\$	417.83	\$	458.37	\$	876.20	\$	498.10	\$	458.37	\$ 956.47	\$	80.27	\$	-	\$ 80.27	9.16%

ATLANTIC CITY ELECTRIC COMPANY RESIDENTIAL SERVICE ("RS") Annual Average

Present Rates vs. Proposed Rates

Monthly	F	Present		Present	F	Present	New		New	New	<u>Differ</u>	enc	<u>e</u>		<u>Total</u>
<u>Usage</u>	<u></u>	<u>Delivery</u>	5	Supply+T		Total	Delivery		Supply+T	Total	Delivery	S	upply+T	D	<u>ifference</u>
(kWh)		(\$)		(\$)		(\$)	(\$)		(\$)	(\$)	(\$)		(\$)	(\$)	(%)
0	\$	6.25	\$	-	\$	6.25	\$ 7.60) \$	-	\$ 7.60	\$ 1.35	\$	-	\$ 1.35	21.60%
25	\$	8.45	\$	2.75	\$	11.20	\$ 10.2	۱ \$	2.75	\$ 12.96	\$ 1.76	\$	-	\$ 1.76	15.71%
50	\$	10.66	\$	5.49	\$	16.15	\$ 12.82	2 \$	5.49	\$ 18.31	\$ 2.16	\$	-	\$ 2.16	13.37%
75	\$	12.86	\$	8.25	\$	21.11	\$ 15.43	3 \$	8.25	\$ 23.68	\$ 2.57	\$	-	\$ 2.57	12.17%
100	\$	15.07	\$	11.00	\$	26.07	\$ 18.0	5 \$	11.00	\$ 29.05	\$ 2.98	\$	-	\$ 2.98	11.43%
150	\$	19.49	\$	16.49	\$	35.98	\$ 23.2	7 \$	16.49	\$ 39.76	\$ 3.78	\$	-	\$ 3.78	10.51%
200	\$	23.90	\$	21.98	\$	45.88	\$ 28.49	\$	21.98	\$ 50.47	\$ 4.59	\$	-	\$ 4.59	10.00%
250	\$	28.31	\$	27.48	\$	55.79	\$ 33.72	2 \$	27.48	\$ 61.20	\$ 5.41	\$	-	\$ 5.41	9.70%
300	\$	32.72	\$	32.98	\$	65.70	\$ 38.94	1 \$	32.98	\$ 71.92	\$ 6.22	\$	-	\$ 6.22	9.47%
350	\$	37.13	\$	38.47	\$	75.60	\$ 44.17	7 \$	38.47	\$ 82.64	\$ 7.04	\$	-	\$ 7.04	9.31%
400	\$	41.54	\$	43.97	\$	85.51	\$ 49.39	9 \$	43.97	\$ 93.36	\$ 7.85	\$	-	\$ 7.85	9.18%
450	\$	45.95	\$	49.47	\$	95.42	\$ 54.6	۱ \$	49.47	\$ 104.08	\$ 8.66	\$	-	\$ 8.66	9.08%
500	\$	50.36	\$	54.96	\$	105.32	\$ 59.83	3 \$	54.96	\$ 114.79	\$ 9.47	\$	-	\$ 9.47	8.99%
600	\$	59.18	\$	65.96	\$	125.14	\$ 70.28	3 \$	65.96	\$ 136.24	\$ 11.10	\$	-	\$ 11.10	8.87%
650	\$	63.59	\$	71.45	\$	135.04	\$ 75.5°	۱ \$	71.45	\$ 146.96	\$ 11.92	\$	-	\$ 11.92	8.83%
669	\$	65.27	\$	73.55	\$	138.82	\$ 77.49	\$	73.55	\$ 151.04	\$ 12.22	\$	-	\$ 12.22	8.80%
700	\$	68.01	\$	76.95	\$	144.96	\$ 80.73	3 \$	76.95	\$ 157.68	\$ 12.72	\$	-	\$ 12.72	8.77%
750	\$	72.42	\$	82.45	\$	154.87	\$ 85.96	5 \$	82.45	\$ 168.41	\$ 13.54	\$	-	\$ 13.54	8.74%
800	\$	77.04	\$	88.11	\$	165.15	\$ 91.4	1 \$	88.11	\$ 179.55	\$ 14.40	\$	-	\$ 14.40	8.72%
900	\$	86.28	\$	99.44	\$	185.72	\$ 102.4	۱ \$	99.44	\$ 201.85	\$ 16.13	\$	-	\$ 16.13	8.69%
1000	\$	95.53	\$	110.77	\$	206.30	\$ 113.38	3 \$	110.77	\$ 224.15	\$ 17.85	\$	-	\$ 17.85	8.65%
1200	\$	114.02	\$	133.42	\$	247.44	\$ 135.32	2 \$	133.42	\$ 268.74	\$ 21.30	\$	-	\$ 21.30	8.61%
1500	\$	141.76	\$	167.40	\$	309.16	\$ 168.23	3 \$	167.40	\$ 335.63	\$ 26.47	\$	-	\$ 26.47	8.56%
2000	\$	187.98	\$	224.04	\$	412.02	\$ 223.08	3 \$	224.04	\$ 447.12	\$ 35.10	\$	-	\$ 35.10	8.52%
2500	\$	234.21	\$	280.67	\$	514.88	\$ 277.93	3 \$	280.67	\$ 558.60	\$ 43.72	\$	-	\$ 43.72	8.49%
3000	\$	280.43	\$	337.30	\$	617.73	\$ 332.78	3 \$	337.30	\$ 670.08	\$ 52.35	\$	-	\$ 52.35	8.47%
3500	\$	326.65	\$	393.94	\$	720.59	\$ 387.63	3 \$	393.94	\$ 781.57	\$ 60.98	\$	-	\$ 60.98	8.46%
4000	\$	372.88	\$	450.57	\$	823.45	\$ 442.48	3 \$	450.57	\$ 893.05	\$ 69.60	\$	-	\$ 69.60	8.45%

ATLANTIC CITY ELECTRIC COMPANY MONTHLY GENERAL SERVICE SECONDARY ("MGS Secondary") 8 WINTER MONTHS (October Through May)

Present Rates

								Prop	osed Rates								
	Load					Present	Present	Present			New	New	New	Difference	Difference	Total	Total
Demand		Energy				<u>Distribution</u>	BGS and Other Charges	<u>Total</u>		_	Distribution	BGS and Other Charges	<u>Total</u>		BGS and Other Charges	Difference	Difference
(kW)	(%)	(kWh) 730	5.00	<u>Trans kW D Demand</u> 2 \$ 13.60		(\$)	(\$)	(\$)	D Demand D \$ 16.40 \$		(\$)	(\$)	(\$) \$ 150.96	(\$) \$ 7.16	(\$)	\$ 7.16	(%)
5 5	20 30	1.095	5.00		\$ 40.96 \$ 61.44		\$ 77.34 \$ 109.91		\$ 16.40 \$ \$ 16.40 \$	42.84 64.26	\$ 73.62 \$ 95.04		\$ 150.96 \$ 204.94		\$ -	\$ 7.16 \$ 8.09	5.0% 4.1%
5	40	1,460	5.00		\$ 81.92		\$ 142.48		\$ 16.40 \$				\$ 258.93	\$ 9.03	\$ -	\$ 9.03	3.6%
5	50	1,825	5.00		\$ 102.40		\$ 175.04	\$ 302.95				•	\$ 312.92	\$ 9.97	\$ -	\$ 9.97	3.3%
5	60	2,190	5.00	2 \$ 13.60	\$ 122.89	\$ 148.39	\$ 207.61	\$ 356.00	\$ 16.40 \$	128.51	\$ 159.29	\$ 207.61	\$ 366.91	\$ 10.91	\$ -	\$ 10.91	3.1%
5	70	2,555	5.00	2 \$ 13.60	\$ 143.37	\$ 168.87	\$ 240.18	\$ 409.05	\$ 16.40 \$	149.93	\$ 180.71	\$ 240.18	\$ 420.90	\$ 11.85	\$ -	\$ 11.85	2.9%
5	80	2,920	5.00		\$ 163.85		\$ 272.75						\$ 474.88	\$ 12.78	\$ -	\$ 12.78	2.8%
10	20	1,460	10.00		\$ 81.92		\$ 172.98	\$ 294.00	\$ 32.80 \$	00.00			\$ 305.83	\$ 11.83	\$ -	\$ 11.83	4.0%
10	30	2,190	10.00		\$ 122.89		\$ 238.11		\$ 32.80 \$				\$ 413.81	\$ 13.71	\$ -	\$ 13.71	3.4%
10 10	40 50	2,920 3.650	10.00 10.00		\$ 163.85 \$ 204.81		\$ 303.25 \$ 368.39	\$ 506.20 \$ 612.30		171.35 214.19	\$ 218.53 \$ 261.37		\$ 521.78 \$ 629.76	\$ 15.58 \$ 17.46	\$ -	\$ 15.58 \$ 17.46	3.1% 2.9%
10	60	4.380	10.00		\$ 245.77		\$ 433.53	\$ 718.40					\$ 737.73	\$ 17.46	\$ -	\$ 17.46	2.7%
10	70	5,110	10.00		\$ 286.73		\$ 498.67	\$ 824.50	\$ 32.80 \$				\$ 845.71	\$ 21.21	\$ -	\$ 21.21	2.6%
10	80	5,840	10.00		\$ 327.69		\$ 563.80	\$ 930.60	\$ 32.80 \$		\$ 389.88		\$ 953.69	\$ 23.09	\$ -	\$ 23.09	2.5%
20	20	2,920	20.00	17 \$ 54.40	\$ 163.85		\$ 364.25	\$ 594.40			\$ 251.33	\$ 364.25	\$ 615.58	\$ 21.18	\$ -	\$ 21.18	3.6%
20	30	4,380	20.00	17 \$ 54.40	\$ 245.77	\$ 312.07	\$ 494.53	\$ 806.60	\$ 65.60 \$	257.03	\$ 337.01	\$ 494.53	\$ 831.53	\$ 24.94	\$ -	\$ 24.94	3.1%
20	40	5,840	20.00		\$ 327.69		\$ 624.80	\$ 1,018.80			\$ 422.68		\$ 1,047.49	\$ 28.69	\$ -	\$ 28.69	2.8%
20	50	7,300	20.00		\$ 409.62		\$ 755.08	\$ 1,231.00	\$ 65.60 \$		\$ 508.36		\$ 1,263.44	\$ 32.44	\$ -	\$ 32.44	2.6%
20	60	8,760	20.00		\$ 491.54		\$ 885.35	\$ 1,443.20			\$ 594.03		\$ 1,479.39	\$ 36.19	\$ -	\$ 36.19	2.5%
20 20	70 80	10,220 11,680	20.00 20.00		\$ 573.46 \$ 655.39		\$ 1,015.63 \$ 1,145.91	\$ 1,655.40	\$ 65.60 \$ \$ 65.60 \$				\$ 1,695.34	\$ 39.95 \$ 43.70	\$ - \$ -	\$ 39.95 \$ 43.70	2.4%
30	20	4.380	30.00		\$ 655.39 \$ 245.77		\$ 1,145.91 \$ 555.53	\$ 1,867.59 \$ 894.80	\$ 65.60 \$ \$ 98.40 \$				\$ 1,911.29 \$ 925.33	\$ 43.70 \$ 30.54	\$ -	\$ 43.70	2.3% 3.4%
30	30	6,570	30.00		\$ 368.66		\$ 750.94	\$ 1,213.10	\$ 98.40 \$		\$ 498.32		\$ 1,249.26	\$ 36.16	\$ -	\$ 36.16	3.0%
30	40	8.760	30.00		\$ 491.54		\$ 946.35	\$ 1,531.40	\$ 98.40 \$		\$ 626.83		\$ 1,573.19	\$ 41.79	\$ -	\$ 41.79	2.7%
30	50	10,950	30.00		\$ 614.43		\$ 1,141.77						\$ 1,897.12	\$ 47.42	\$ -	\$ 47.42	2.6%
30	60	13,140	30.00	27 \$ 81.60	\$ 737.31	\$ 830.81	\$ 1,337.18	\$ 2,167.99	\$ 98.40 \$	771.08	\$ 883.86	\$ 1,337.18	\$ 2,221.04	\$ 53.05	\$ -	\$ 53.05	2.4%
30	70	15,330	30.00	27 \$ 81.60	\$ 860.20		\$ 1,532.60	\$ 2,486.29	\$ 98.40 \$	899.60	\$ 1,012.38		\$ 2,544.97	\$ 58.68	\$ -	\$ 58.68	2.4%
30	80	17,520	30.00		\$ 983.08	\$ 1,076.58	\$ 1,728.01	\$ 2,804.59			\$ 1,140.89		\$ 2,868.90	\$ 64.31	\$ -	\$ 64.31	2.3%
50	20	7,300	50.00		\$ 409.62	ψ 001.0 <u>L</u>	\$ 938.08	\$ 1,495.60			Ψ 0000		\$ 1,544.84	\$ 49.24	\$ -	\$ 49.24	3.3%
50 50	30 40	10,950 14,600	50.00 50.00		\$ 614.43 \$ 819.24	\$ 762.33 \$ 967.14	\$ 1,263.77 \$ 1,589.46	\$ 2,026.09 \$ 2,556.59			\$ 820.95 \$ 1.035.14		\$ 2,084.72 \$ 2,624.60	\$ 58.62 \$ 68.00	\$ -	\$ 58.62 \$ 68.00	2.9% 2.7%
50	50	18,250	50.00	47 \$ 136.00			\$ 1,569.46				\$ 1,035.14		\$ 3,164.47	\$ 77.38	\$ -	\$ 77.38	2.5%
50	60	21,900	50.00		1	·	\$ 2,240.84	\$ 3,617.59					\$ 3,704.35	\$ 86.76	\$ -	\$ 86.76	2.4%
50	70	25,550	50.00			\$ 1,581.56	\$ 2,566.53						\$ 4,244.23	\$ 96.14	\$ -	\$ 96.14	2.3%
50	80	29,200	50.00				\$ 2,892.22	\$ 4,678.59			\$ 1,891.89		\$ 4,784.11	\$ 105.52	\$ -	\$ 105.52	2.3%
75	30	16,425	75.00	72 \$ 204.00	\$ 921.64	\$ 1,137.54	\$ 1,904.80	\$ 3,042.34	\$ 246.00 \$	963.85	\$ 1,224.23	\$ 1,904.80	\$ 3,129.03	\$ 86.69	\$ -	\$ 86.69	2.8%
75	40	21,900	75.00	72 \$ 204.00		\$ 1,444.75	\$ 2,393.34		\$ 246.00 \$				\$ 3,938.85	\$ 100.76	\$ -	\$ 100.76	2.6%
75	50	27,375	75.00	72 \$ 204.00		.,	\$ 2,881.87		\$ 246.00 \$		\$ 1,866.80		\$ 4,748.67	\$ 114.83	\$ -	\$ 114.83	2.5%
75 75	60	32,850	75.00	72 \$ 204.00		-,		\$ 5,429.58			\$ 2,188.08		\$ 5,558.49	\$ 128.90	\$ -	\$ 128.90	2.4%
75 75	70 80	38,325 43,800	75.00 75.00	72 \$ 204.00 72 \$ 204.00	+ -,	\$ 2,366.39 \$ 2,673.61	\$ 3,858.94 \$ 4,347.47	\$ 6,225.33 \$ 7,021.08		,	\$ 2,509.37 \$ 2,830.65		\$ 6,368.31 \$ 7,178.13	\$ 142.98 \$ 157.05	\$ -	\$ 142.98 \$ 157.05	2.3% 2.2%
75	90	49,275	75.00				\$ 4,836.01	\$ 7,816.83					\$ 7,987.94	\$ 171.12	\$ -	\$ 171.12	2.2%
100	30	21.900	100.00	97 \$ 272.00			\$ 2.545.84						\$ 4.173.35	\$ 114.76	\$ -	\$ 114.76	2.8%
100	40	29,200	100.00				\$ 3,197.22				\$ 2,055.89		\$ 5,253.11	\$ 133.52	\$ -	\$ 133.52	2.6%
100	50	36,500	100.00	97 \$ 272.00	\$ 2,048.09	\$ 2,331.99	\$ 3,848.60	\$ 6,180.58	\$ 328.00 \$ 2	2,141.89	\$ 2,484.27	\$ 3,848.60	\$ 6,332.87	\$ 152.29	\$ -	\$ 152.29	2.5%
100	60	43,800	100.00	97 \$ 272.00	\$ 2,457.71	\$ 2,741.61		\$ 7,241.58	\$ 328.00 \$ 2	2,570.27	\$ 2,912.65	\$ 4,499.97	\$ 7,412.63	\$ 171.05	\$ -	\$ 171.05	2.4%
100	70	51,100	100.00		+ -,	ψ 0,101. <u>LL</u>		\$ 8,302.58			Ψ 0,011.00		\$ 8,492.38	\$ 189.81	\$ -	\$ 189.81	2.3%
100	80	58,400	100.00	97 \$ 272.00		,		\$ 9,363.57			,		\$ 9,572.14	\$ 208.57	\$ -	\$ 208.57	2.2%
100 200	90 30	65,700 43,800	100.00 200.00		\$ 3,686.56 \$ 2,457.71	\$ 3,970.46 \$ 3.013.61		\$ 10,424.57 \$ 8,123.58			\$ 4,197.79 \$ 3,240.65		\$ 10,651.90 \$ 8.350.63	\$ 227.33 \$ 227.05	\$ -	\$ 227.33 \$ 227.05	2.2%
200	40	43,800 58,400	200.00		*			\$ 8,123.58 \$ 10.245.57			\$ 3,240.65 \$ 4.097.41		\$ 8,350.63	\$ 227.05 \$ 264.57	\$ -	\$ 227.05	2.8%
200	50	73,000	200.00				\$ 7,715.49				\$ 4,097.41		\$ 12,669.66	\$ 302.09	\$ -	\$ 302.09	2.4%
200	60	87,600	200.00				\$ 9,018.25				\$ 5,810.92		\$ 14,829.17		\$ -	\$ 339.61	2.3%
200	70	102,200	200.00		i -/	\$ 6,290.55		\$ 16,611.55			\$ 6,667.68		\$ 16,988.69	\$ 377.13	\$ -	\$ 377.13	2.3%
200	80	116,800	200.00	197 \$ 544.00		\$ 7,109.78		\$ 18,733.55	\$ 656.00 \$ 6			\$ 11,623.76	\$ 19,148.20	\$ 414.66		\$ 414.66	2.2%
200	90	131,400	200.00	197 \$ 544.00	\$ 7,373.12	\$ 7,929.02	\$ 12,926.52	\$ 20,855.54	\$ 656.00 \$ 7	7,710.81	\$ 8,381.19	\$ 12,926.52	\$ 21,307.72	\$ 452.18	\$ -	\$ 452.18	2.2%

ATLANTIC CITY ELECTRIC COMPANY MONTHLY GENERAL SERVICE SECONDARY ("MGS Secondary") 4 SUMMER MONTHS (June Through September)

Present Rates vs.

						_			posed Rates								
Domond	Load	Energy				Present	Present	Present			New	New PCS and Other Charges	New	Difference	Difference	Total Difference	Total
Demand (kW)	(%)	Energy (kWh)	Dist kW	Trans kW D Demand	D Energy	Distribution (\$)	BGS and Other Charges (\$)	Total (\$)	D Demand	D Energy	Distribution (\$)	BGS and Other Charges (\$)	Total (\$)	(\$)	BGS and Other Charges (\$)	(\$)	Difference (%)
5	20	730	5.00	2 \$ 16.55		\$ 74.62		\$ 154.25		\$ 48.29	\$ 82.67	\$ 79.63			\$ -	\$ 8.05	5.2%
5	30	1,095	5.00	2 \$ 16.55	\$ 69.26	\$ 97.71	\$ 112.96	\$ 210.67	\$ 20.00	\$ 72.44	\$ 106.82	\$ 112.96	\$ 219.78	\$ 9.11	\$ -	\$ 9.11	4.3%
5	40	1,460	5.00	2 \$ 16.55	Ψ 02.00	\$ 120.80	\$ 146.29	\$ 267.09		\$ 96.59	\$ 130.97			\$ 10.17	\$ -	\$ 10.17	3.8%
5	50	1,825	5.00	2 \$ 16.55	\$ 115.44	\$ 143.89	\$ 179.63	\$ 323.51		\$ 120.74	\$ 155.12		\$ 334.74	*	\$ -	\$ 11.23	3.5%
5	60	2,190	5.00	2 \$ 16.55	\$ 138.52	\$ 166.97	\$ 212.96 \$ 246.30	\$ 379.94		\$ 144.88	\$ 179.26	\$ 212.96	\$ 392.23		\$ -	\$ 12.29 \$ 13.35	3.2%
5 5	70 80	2,555 2,920	5.00 5.00	2 \$ 16.55 2 \$ 16.55	\$ 161.61 \$ 184.70	\$ 190.06 \$ 213.15	\$ 246.30 \$ 279.63	\$ 436.36 \$ 492.78	\$ 20.00 \$ 20.00	\$ 169.03 \$ 193.18	\$ 203.41 \$ 227.56	\$ 246.30 \$ 279.63	\$ 449.71 \$ 507.19	\$ 13.35 \$ 14.41	\$ - \$ -	\$ 13.35 \$ 14.41	3.1% 2.9%
10	20	1,460	10.00	7 \$ 33.10		\$ 137.35	\$ 178.69	\$ 316.04	\$ 40.00	\$ 96.59	\$ 150.97	\$ 178.69	\$ 329.66	\$ 13.62	\$ -	\$ 13.62	4.3%
10	30	2,190	10.00			\$ 183.52	\$ 245.36	\$ 428.89		\$ 144.88	\$ 199.26	\$ 245.36	\$ 444.63		\$ -	\$ 15.74	3.7%
10	40	2,920	10.00			\$ 229.70	\$ 312.03	\$ 541.73		\$ 193.18	\$ 247.56	\$ 312.03	\$ 559.59		\$ -	\$ 17.86	3.3%
10	50	3,650	10.00	7 \$ 33.10	\$ 230.87	\$ 275.87	\$ 378.70	\$ 654.57	\$ 40.00	\$ 241.47	\$ 295.85	\$ 378.70	\$ 674.55	\$ 19.98	\$ -	\$ 19.98	3.1%
10	60	4,380	10.00	7 \$ 33.10		\$ 322.05	\$ 445.36	\$ 767.41		\$ 289.77	\$ 344.15		\$ 789.51	\$ 22.10	\$ -	\$ 22.10	2.9%
10	70	5,110	10.00	7 \$ 33.10		\$ 368.22	\$ 512.03	\$ 880.25	\$ 40.00	\$ 338.06	\$ 392.44	\$ 512.03	\$ 904.47	\$ 24.22	\$ -	\$ 24.22	2.8%
10	80	5,840	10.00	7 \$ 33.10		\$ 414.40	\$ 578.70	\$ 993.10	\$ 40.00	\$ 386.36	\$ 440.74		\$ 1,019.43	T	\$ -	\$ 26.34	2.7%
20	20	2,920	20.00			\$ 262.80	\$ 376.83	\$ 639.63		\$ 193.18	\$ 287.56	\$ 376.83		\$ 24.76	\$ - \$ -	\$ 24.76 \$ 29.00	3.9%
20 20	30 40	4,380 5.840	20.00 20.00	17 \$ 66.20 17 \$ 66.20	\$ 277.05 \$ 369.40	\$ 355.15 \$ 447.50	\$ 510.16 \$ 643.50	\$ 865.31 \$ 1.091.00		\$ 289.77 \$ 386.36	\$ 384.15 \$ 480.74			Ψ 20.00	\$ -	\$ 29.00 \$ 33.24	3.4% 3.0%
20	50	7,300	20.00	17 \$ 66.20		\$ 539.85	\$ 776.83	\$ 1,316.68		\$ 482.95	\$ 577.33	\$ 776.83		i ::::::::::::::::::::::::::::::::::::	\$ - \$	\$ 37.48	2.8%
20	60	8,760	20.00	17 \$ 66.20	\$ 554.10	\$ 632.20	\$ 910.17	\$ 1,542.36		\$ 579.54	\$ 673.92	\$ 910.17	\$ 1,584.08	\$ 41.72	\$ -	\$ 41.72	2.7%
20	70	10,220	20.00	17 \$ 66.20	\$ 646.45	\$ 724.55	\$ 1,043.50	\$ 1.768.05	\$ 80.00	\$ 676.12		\$ 1,043.50		\$ 45.96	\$ -	\$ 45.96	2.6%
20	80	11,680	20.00	17 \$ 66.20	\$ 738.80	\$ 816.90	\$ 1,176.84	\$ 1,993.73	\$ 80.00	\$ 772.71	\$ 867.09	\$ 1,176.84	\$ 2,043.93	\$ 50.20	\$ -	\$ 50.20	2.5%
30	20	4,380	30.00	27 \$ 99.30	\$ 277.05	\$ 388.25	\$ 574.96	\$ 963.21	\$ 120.00	\$ 289.77	\$ 424.15	\$ 574.96		\$ 35.90	\$ -	\$ 35.90	3.7%
30	30	6,570	30.00	27 \$ 99.30	+	\$ 526.77	\$ 774.97	\$ 1,301.74		\$ 434.65	\$ 569.03	\$ 774.97	\$ 1,344.00	T	\$ -	\$ 42.26	3.2%
30	40	8,760	30.00	27 \$ 99.30	\$ 554.10	\$ 665.30	\$ 974.97	\$ 1,640.26			\$ 713.92	\$ 974.97		\$ 48.62	\$ -	\$ 48.62	3.0%
30	50	10,950	30.00	27 \$ 99.30	Ψ 002.02	\$ 803.82	\$ 1,174.97	\$ 1,978.79		\$ 724.42	\$ 858.80	\$ 1,174.97		\$ 54.98	\$ -	\$ 54.98	2.8%
30 30	60 70	13,140 15.330	30.00 30.00	27 \$ 99.30	\$ 831.14	\$ 942.34 \$ 1.080.87	\$ 1,374.97 \$ 1.574.97	\$ 2,317.31 \$ 2.655.84		\$ 869.30	\$ 1,003.68		\$ 2,378.65 \$ 2,723.54	\$ 61.34 \$ 67.70	\$ -	\$ 61.34 \$ 67.70	2.6% 2.5%
30	80	17,520	30.00	27 \$ 99.30 27 \$ 99.30		\$ 1,080.87 \$ 1,219.39	.,	\$ 2,655.84 \$ 2,994.37		\$ 1,014.19 \$ 1,159.07	\$ 1,148.57 \$ 1,293.45	.,	\$ 2,723.54	\$ 67.70 \$ 74.06	\$ -	\$ 74.06	2.5%
50	20	7,300	50.00	47 \$ 165.50		\$ 639.15	\$ 971.23	\$ 1,610.38		\$ 482.95	\$ 697.33		\$ 1,668.56		\$ -	\$ 58.18	3.6%
50	30	10.950	50.00	47 \$ 165.50		\$ 870.02	\$ 1.304.57	\$ 2.174.59		\$ 724.42	\$ 938.80		\$ 2,243.37	\$ 68.78	\$ -	\$ 68.78	3.2%
50	40	14,600	50.00	47 \$ 165.50		\$ 1,100.89	\$ 1,637.91	\$ 2,738.80		\$ 965.89	\$ 1,180.27	\$ 1,637.91	\$ 2,818.18		\$ -	\$ 79.38	2.9%
50	50	18,250	50.00	47 \$ 165.50	\$ 1,154.37	\$ 1,331.77	\$ 1,971.24	\$ 3,303.01	\$ 200.00	\$ 1,207.37	\$ 1,421.75	\$ 1,971.24	\$ 3,392.99	\$ 89.98	\$ -	\$ 89.98	2.7%
50	60	21,900	50.00				\$ 2,304.58	\$ 3,867.22			\$ 1,663.22		\$ 3,967.80	\$ 100.58	\$ -	\$ 100.58	2.6%
50	70	25,550	50.00			\$ 1,793.51	\$ 2,637.91	\$ 4,431.43		\$ 1,690.31	\$ 1,904.69	\$ 2,637.91		\$ 111.18	\$ -	\$ 111.18	2.5%
50	80	29,200	50.00			\$ 2,024.39	\$ 2,971.25	\$ 4,995.64			\$ 2,146.16		\$ 5,117.41	Ψ	\$ -	\$ 121.78	2.4%
75 75	30	16,425	75.00	72 \$ 248.25		\$ 1,299.08	\$ 1,966.57	\$ 3,265.65		\$ 1,086.63	\$ 1,401.01	\$ 1,966.57		*	\$ -	\$ 101.93	3.1%
75 75	40 50	21,900 27.375	75.00 75.00	72 \$ 248.25 72 \$ 248.25		\$ 1,645.39 \$ 1,991.70	\$ 2,466.58 \$ 2,966.58	\$ 4,111.97 \$ 4,958.28		\$ 1,448.84 \$ 1,811.05	\$ 1,763.22 \$ 2,125.43		\$ 4,229.80 \$ 5,092.01	\$ 117.83 \$ 133.73	\$ - \$ -	\$ 117.83 \$ 133.73	2.9% 2.7%
75 75	60	32.850	75.00	72 \$ 248.25		\$ 2.338.01	\$ 3,466,59	\$ 5.804.60		\$ 2,173,26	\$ 2,125.45		\$ 5,092.01	\$ 149.63	\$ - \$	\$ 149.63	2.6%
75	70	38.325	75.00		* **	\$ 2,684.32	\$ 3.966.59	\$ 6.650.91		\$ 2,535.47		\$ 3.966.59			\$ -	\$ 165.53	2.5%
75	80	43,800	75.00	72 \$ 248.25		\$ 3,030.63	\$ 4,466.60	\$ 7,497.23		\$ 2,897.68	\$ 3,212.06		\$ 7,678.65	\$ 181.43	\$ -	\$ 181.43	2.4%
75	90	49,275	75.00	72 \$ 248.25	\$ 3,116.79	\$ 3,376.94	\$ 4,966.60	\$ 8,343.54	\$ 300.00	\$ 3,259.89	\$ 3,574.27	\$ 4,966.60	\$ 8,540.87	\$ 197.32	\$ -	\$ 197.32	2.4%
100	30	21,900	100.00	97 \$ 331.00	\$ 1,385.24	\$ 1,728.14	\$ 2,628.58	\$ 4,356.72	\$ 400.00	\$ 1,448.84	\$ 1,863.22	\$ 2,628.58	\$ 4,491.80	\$ 135.08	\$ -	\$ 135.08	3.1%
100	40	29,200	100.00	97 \$ 331.00		\$ 2,189.89	\$ 3,295.25	\$ 5,485.14			\$ 2,346.16		\$ 5,641.41		\$ -	\$ 156.28	2.8%
100	50	36,500	100.00			\$ 2,651.63	\$ 3,961.92	\$ 6,613.56		\$ 2,414.73	\$ 2,829.11		\$ 6,791.03	\$ 177.48	\$ -	\$ 177.48	2.7%
100	60	43,800	100.00	97 \$ 331.00		\$ 3,113.38	\$ 4,628.60	\$ 7,741.98		\$ 2,897.68			\$ 7,940.65		\$ -	\$ 198.68 \$ 219.87	2.6%
100 100	70 80	51,100 58.400	100.00 100.00	97 \$ 331.00 97 \$ 331.00		\$ 3,575.13 \$ 4,036.88	\$ 5,295.27 \$ 5,961.94	\$ 8,870.40 \$ 9,998.82		\$ 3,380.62	\$ 3,795.00 \$ 4,277.95		\$ 9,090.27 \$ 10,239.89	\$ 219.87 \$ 241.07	\$ - \$ -	\$ 219.87 \$ 241.07	2.5% 2.4%
100	90	65,700	100.00	97 \$ 331.00		\$ 4,036.66		\$ 11,127.23		\$ 4,346.51	\$ 4,760.89		\$ 11,389.51		\$ - \$	\$ 262.27	2.4%
200	30	43.800	200.00	197 \$ 662.00		\$ 3,444,38	\$ 5,276.60	\$ 8,720.98		\$ 2.897.68	\$ 3.712.06	,	\$ 8.988.65	\$ 267.68	\$ -	\$ 267.68	3.1%
200	40	58,400	200.00	197 \$ 662.00		\$ 4,367.88	\$ 6,609.94	\$ 10,977.82		\$ 3,863.57	\$ 4,677.95		\$ 11,287.89	\$ 310.07	\$ -	\$ 310.07	2.8%
200	50	73,000	200.00	197 \$ 662.00		\$ 5,291.37	\$ 7,943.29	\$ 13,234.65		\$ 4,829.46	\$ 5,643.84		\$ 13,587.13	\$ 352.47	\$ -	\$ 352.47	2.7%
200	60	87,600	200.00	197 \$ 662.00	\$ 5,540.96	\$ 6,214.86	\$ 9,276.63	\$ 15,491.49	\$ 800.00	\$ 5,795.35	\$ 6,609.73	\$ 9,276.63	\$ 15,886.36	\$ 394.87	\$ -	\$ 394.87	2.5%
200	70	102,200	200.00			\$ 7,138.36		\$ 17,748.33			\$ 7,575.63		\$ 18,185.60	\$ 437.27	\$ -	\$ 437.27	2.5%
200	80	116,800	200.00	197 \$ 662.00		\$ 8,061.85		\$ 20,005.17			\$ 8,541.52		\$ 20,484.84	\$ 479.67		\$ 479.67	2.4%
200	90	131,400	200.00	197 \$ 662.00	\$ 8,311.44	\$ 8,985.34	\$ 13,276.67	\$ 22,262.01	\$ 800.00	\$ 8,693.03	\$ 9,507.41	\$ 13,276.67	\$ 22,784.07	\$ 522.07	\$ -	\$ 522.07	2.3%

ATLANTIC CITY ELECTRIC COMPANY MONTHLY GENERAL SERVICE SECONDARY ("MGS Secondary") Annual Average

Present Rates vs.

Proposed Rates Proposed Rates Now Now Now Difference Difference Tetal Total																	
Domond	Load	Energy				Present	Present	Present			New	New PCS and Other Charges	New	Difference	Difference	Total Difference	Total
Demand (kW)	(%)	Energy (kWh)	Dist kW	Trans kW D Demand	D Energy	Distribution (\$)	BGS and Other Charges (\$)	<u>Total</u> (\$)	D Demand	D Energy	Distribution (\$)	BGS and Other Charges (\$)	Total (\$)	(\$)	BGS and Other Charges (\$)	(\$)	Difference (%)
5	20	730	5.00		\$ 42.70		\$ 78.10			\$ 44.66		\$ 78.10	\$ 154.74		\$ -	\$ 7.45	5.1%
5	30	1,095	5.00	2 \$ 14.58	\$ 64.05	\$ 90.53	\$ 110.92	\$ 201.46	\$ 17.60	\$ 66.99	\$ 98.97	\$ 110.92	\$ 209.89	\$ 8.43	\$ -	\$ 8.43	4.2%
5	40	1,460	5.00	2 \$ 14.58	Ψ 00.10		\$ 143.75			\$ 89.31	\$ 121.29	\$ 143.75	\$ 265.04		\$ -	\$ 9.41	3.7%
5	50	1,825	5.00		\$ 106.75		\$ 176.57	\$ 309.80		\$ 111.64	\$ 143.62	\$ 176.57	\$ 320.19		\$ -	\$ 10.39	3.4%
5	60	2,190	5.00		\$ 128.10		\$ 209.40			\$ 133.97	\$ 165.95	\$ 209.40 \$ 242.22	\$ 375.35		\$ -	\$ 11.37 \$ 12.35	3.1%
5 5	70 80	2,555 2,920	5.00 5.00		\$ 149.45 \$ 170.80		\$ 242.22 \$ 275.04			\$ 156.30 \$ 178.63	\$ 188.28 \$ 210.61	\$ 242.22 \$ 275.04	\$ 430.50 \$ 485.65	\$ 12.35 \$ 13.33	\$ - \$ -	\$ 12.35 \$ 13.33	3.0% 2.8%
10	20	1,460	10.00		\$ 85.40		\$ 174.88	\$ 301.35	\$ 35.20	\$ 89.31	\$ 138.89	\$ 174.88	\$ 313.78		\$ -	\$ 12.43	4.1%
10	30	2,190	10.00	7 \$ 29.17			\$ 240.53			\$ 133.97	\$ 183.55	\$ 240.53	\$ 424.08		\$ -	\$ 14.39	3.5%
10	40	2,920	10.00	7 \$ 29.17			\$ 306.18			\$ 178.63	\$ 228.21	\$ 306.18	\$ 534.38		\$ -	\$ 16.34	3.2%
10	50	3,650	10.00	7 \$ 29.17	\$ 213.50	\$ 254.56	\$ 371.83	\$ 626.39	\$ 35.20	\$ 223.28	\$ 272.86	\$ 371.83	\$ 644.69	\$ 18.30	\$ -	\$ 18.30	2.9%
10	60	4,380	10.00	7 \$ 29.17		Ψ <u>L</u> 0L0	\$ 437.47			\$ 267.94	\$ 317.52	\$ 437.47	\$ 754.99	\$ 20.26	\$ -	\$ 20.26	2.8%
10	70	5,110	10.00	7 \$ 29.17			\$ 503.12		\$ 35.20	\$ 312.60	\$ 362.18	\$ 503.12		\$ 22.21	\$ -	\$ 22.21	2.6%
10	80	5,840	10.00				\$ 568.77	\$ 951.43	\$ 35.20	\$ 357.25	\$ 406.83	\$ 568.77	\$ 975.60		\$ -	\$ 24.17	2.5%
20	20 30	2,920	20.00 20.00	17 \$ 58.33	\$ 170.80 \$ 256.20		\$ 368.44 \$ 499.74	\$ 609.48		\$ 178.63 \$ 267.94	\$ 263.41 \$ 352.72	\$ 368.44 \$ 499.74	\$ 631.85 \$ 852.46	\$ 22.38 \$ 26.29	\$ - \$ -	\$ 22.38 \$ 26.29	3.7%
20 20	40	4,380 5.840	20.00		\$ 256.20		\$ 499.74 \$ 631.03	\$ 826.17 \$ 1.042.86		\$ 267.94 \$ 357.25	\$ 352.72 \$ 442.03	\$ 499.74 \$ 631.03	\$ 1.073.07		\$ -	\$ 20.29	3.2% 2.9%
20	50	7,300	20.00		1 1		\$ 762.33	\$ 1,259.56		\$ 446.57	\$ 531.35	\$ 762.33	\$ 1,293.68		\$ -	\$ 34.12	2.7%
20	60	8,760	20.00		\$ 512.39		\$ 893.63	\$ 1,476.25		\$ 535.88	\$ 620.66	\$ 893.63	\$ 1,514.29	\$ 38.04	\$ -	\$ 38.04	2.6%
20	70	10,220	20.00		\$ 597.79		\$ 1,024.92			\$ 625.19	\$ 709.97	\$ 1,024.92	\$ 1,734.90	\$ 41.95	\$ -	\$ 41.95	2.5%
20	80	11,680	20.00	17 \$ 58.33	\$ 683.19	\$ 753.42	\$ 1,156.22	\$ 1,909.64	\$ 70.40	\$ 714.51	\$ 799.29	\$ 1,156.22	\$ 1,955.50	\$ 45.86	\$ -	\$ 45.86	2.4%
30	20	4,380	30.00		Ψ 200.20		\$ 562.01	\$ 917.60			\$ 387.92	\$ 562.01	\$ 949.93	Ψ 02.02	\$ -	\$ 32.32	3.5%
30	30	6,570	30.00		Ψ 001.20		\$ 758.95	\$ 1,242.64		\$ 401.91	\$ 521.89	\$ 758.95	\$ 1,280.84	Ψ 00.20	\$ -	\$ 38.20	3.1%
30	40	8,760	30.00	27 \$ 87.50			\$ 955.89	\$ 1,567.69		\$ 535.88	\$ 655.86	\$ 955.89	\$ 1,611.75	\$ 44.07	\$ -	\$ 44.07	2.8%
30	50	10,950	30.00		Ψ 0.0.10		\$ 1,152.84	\$ 1,892.73		\$ 669.85	\$ 789.83	\$ 1,152.84	\$ 1,942.67	\$ 49.94	\$ -	\$ 49.94	2.6%
30 30	60 70	13,140 15.330	30.00 30.00		\$ 768.59 \$ 896.69		\$ 1,349.78 \$ 1.546.72	\$ 2,217.77 \$ 2,542.81		\$ 803.82 \$ 937.79	\$ 923.80 \$ 1.057.77	\$ 1,349.78 \$ 1.546.72	\$ 2,273.58 \$ 2,604.49	\$ 55.81 \$ 61.68	\$ - \$ -	\$ 55.81 \$ 61.68	2.5% 2.4%
30	80	17,520	30.00	27 \$ 87.50			\$ 1,743.66	\$ 2,867.85		\$ 1,071.76	\$ 1,037.77	* .,	\$ 2,935.41	\$ 67.56	\$ - \$	\$ 67.56	2.4%
50	20	7,300	50.00				\$ 949.13			\$ 446.57	\$ 636.95		\$ 1,586.08		\$ -	\$ 52.22	3.4%
50	30	10.950	50.00				\$ 1.277.37	\$ 2.075.59		\$ 669.85	\$ 860.23		\$ 2,137.60		\$ -	\$ 62.01	3.0%
50	40	14,600	50.00	47 \$ 145.83	\$ 853.99	\$ 1,011.72	\$ 1,605.61	\$ 2,617.33	\$ 176.00	\$ 893.14	\$ 1,083.52	\$ 1,605.61	\$ 2,689.12	\$ 71.79	\$ -	\$ 71.79	2.7%
50	50	18,250	50.00	47 \$ 145.83	\$ 1,067.49	\$ 1,225.22	\$ 1,933.85	\$ 3,159.06	\$ 176.00	\$ 1,116.42	\$ 1,306.80	\$ 1,933.85	\$ 3,240.64	\$ 81.58	\$ -	\$ 81.58	2.6%
50	60	21,900	50.00		+ -,=	.,	\$ 2,262.08	\$ 3,700.80			\$ 1,530.08		\$ 3,792.17	+	\$ -	\$ 91.37	2.5%
50	70	25,550	50.00	47 \$ 145.83		Ψ .,ooz.z.	\$ 2,590.32	\$ 4,242.53		\$ 1,562.99	\$ 1,753.37		\$ 4,343.69	\$ 101.15	\$ -	\$ 101.15	2.4%
50	80	29,200	50.00	47 \$ 145.83		.,	\$ 2,918.56				\$ 1,976.65		\$ 4,895.21	Ψ 110.01	\$ -	\$ 110.94	2.3%
75 75	30 40	16,425 21.900	75.00 75.00	72 \$ 218.75 72 \$ 218.75		.,	\$ 1,925.39	\$ 3,116.78 \$ 3,929.38		\$ 1,004.78	\$ 1,283.16 \$ 1,618.08		\$ 3,208.55 \$ 4.035.83		\$ -	\$ 91.77 \$ 106.45	2.9% 2.7%
75 75	50	27,375	75.00 75.00	72 \$218.75		\$ 1,511.63 \$ 1,831.88	\$ 2,417.75 \$ 2,910.11	\$ 4,741.99		\$ 1,674.63	\$ 1,018.08		\$ 4,035.83 \$ 4,863.12	\$ 106.45 \$ 121.13	\$ - \$	\$ 106.45	2.7%
75 75	60	32.850	75.00	72 \$218.75				\$ 5.554.59			\$ 2,287,93		\$ 5,690.40	\$ 135.81	\$ -	\$ 135.81	2.4%
75	70	38.325	75.00	72 \$ 218.75	* **		\$ 3.894.82			\$ 2.344.48	\$ 2,622,86		\$ 6.517.68		\$ -	\$ 150.49	2.4%
75	80	43,800	75.00	72 \$ 218.75	\$ 2,561.96	\$ 2,792.61	\$ 4,387.18	\$ 7,179.80	\$ 264.00	\$ 2,679.41	\$ 2,957.79	\$ 4,387.18	\$ 7,344.97	\$ 165.17	\$ -	\$ 165.17	2.3%
75	90	49,275	75.00	72 \$ 218.75	\$ 2,882.21	\$ 3,112.86	\$ 4,879.54	\$ 7,992.40	\$ 264.00	\$ 3,014.33	\$ 3,292.71	\$ 4,879.54	\$ 8,172.25	\$ 179.85	\$ -	\$ 179.85	2.3%
100	30	21,900	100.00	97 \$ 291.67		.,	\$ 2,573.42				\$ 1,706.08		\$ 4,279.50	· ·-···	\$ -	\$ 121.53	2.9%
100	40	29,200	100.00	97 \$ 291.67			\$ 3,229.89	\$ 5,241.44			\$ 2,152.65		\$ 5,382.55		\$ -	\$ 141.11	2.7%
100	50	36,500	100.00	97 \$ 291.67		-,	\$ 3,886.37	\$ 6,324.91		\$ 2,232.84	\$ 2,599.22		\$ 6,485.59	Ψ .00.00	\$ -	\$ 160.68	2.5%
100 100	60 70	43,800 51,100	100.00 100.00	97 \$ 291.67 97 \$ 291.67		-,	\$ 4,542.85 \$ 5,199.32	\$ 7,408.38 \$ 8,491.85			\$ 3,045.79 \$ 3,492.35		\$ 7,588.63 \$ 8,691.68	\$ 180.26 \$ 199.83	\$ -	\$ 180.26 \$ 199.83	2.4% 2.4%
100	80	58,400	100.00	97 \$ 291.67			\$ 5,855.80	\$ 9,575.32			\$ 3,938.92		\$ 9,794.72		\$ -	\$ 219.40	2.3%
100	90	65,700	100.00				\$ 6.512.28	\$ 10,658.79			\$ 4,385.49		\$ 10,897.77		\$ -	\$ 238.98	2.2%
200	30	43,800	200.00	197 \$ 583.33			\$ 5,165.51				\$ 3,397.79		\$ 8,563.30	\$ 240.59	\$ -	\$ 240.59	2.9%
200	40	58,400	200.00	197 \$ 583.33				\$ 10,489.65		\$ 3,572.54	\$ 4,290.92		\$ 10,769.39		\$ -	\$ 279.74	2.7%
200	50	73,000	200.00	197 \$ 583.33		\$ 4,865.17		\$ 12,656.60		\$ 4,465.68	\$ 5,184.06		\$ 12,975.48	\$ 318.88	\$ -	\$ 318.88	2.5%
200	60	87,600	200.00	197 \$ 583.33		\$ 5,719.16	\$ 9,104.38	\$ 14,823.54		\$ 5,358.81	\$ 6,077.19	\$ 9,104.38	\$ 15,181.57	+	\$ -	\$ 358.03	2.4%
200	70	102,200	200.00	197 \$ 583.33		\$ 6,573.15		\$ 16,990.48			\$ 6,970.33		\$ 17,387.66	\$ 397.18	\$ -	\$ 397.18	2.3%
200	80	116,800	200.00	197 \$ 583.33		Ψ .,		\$ 19,157.42					\$ 19,593.75	\$ 436.33		\$ 436.33	2.3%
200	90	131,400	200.00	197 \$ 583.33	\$ 7,685.89	\$ 8,281.13	\$ 13,043.24	\$ 21,324.36	\$ 704.00	\$ 8,038.22	\$ 8,756.60	\$ 13,043.24	\$ 21,799.84	\$ 475.47	\$ -	\$ 475.47	2.2%

ATLANTIC CITY ELECTRIC COMPANY MONTHLY GENERAL SERVICE PRIMARY ("MGS Primary") 8 WINTER MONTHS (October Through May)

Present Rates

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	vs.		

								Pro	osed Rates								
	Loa	ad				Present	Present	Present			New	New	New	Difference	Difference	Total	Total
Demar						Distribution	BGS and Other Charges	<u>Total</u>		_	Distribution	BGS and Other Charges	Total	Distribution	BGS and Other Charges	Difference	Difference
(kW)				Trans kW D Demand		(\$) ** 50.04 t	(\$)	(\$)	D Demand D		(\$)	(\$)	(\$)	(\$)	(\$)	(\$)	(%)
5 5	20 30		5.00 5.00	- ψ 1.00	\$ 34.68 \$ 52.02	\$ 59.84 \$ \$ 77.18 \$,	\$ 108.92 \$ 147.52	\$ 7.60 \$ \$ 7.60 \$	18.03 27.05	+	\$ 49.08 \$ 70.34	\$ 92.27 \$ 122.55	\$ (16.65) \$ (24.97)		\$ (16.65) \$ (24.97)	-15.3% -16.9%
5	40		5.00		\$ 69.36		, , , , ,	\$ 186.12	\$ 7.60 \$		\$ 61.22		\$ 152.82	\$ (33.30)		\$ (33.30)	-17.9%
5	50		5.00		\$ 86.70		,	\$ 224.72	\$ 7.60 \$				\$ 183.10	\$ (41.62)		\$ (41.62)	-18.5%
5	60		5.00		\$ 104.04	\$ 129.20		\$ 263.32	\$ 7.60 \$	54.10		\$ 134.11		\$ (49.95)		\$ (49.95)	-19.0%
5	70		5.00		\$ 121.38		,	\$ 301.92	\$ 7.60 \$		\$ 88.27		\$ 243.65	\$ (58.27)		\$ (58.27)	-19.3%
5	80		5.00		\$ 138.72	\$ 163.88	,	\$ 340.52	\$ 7.60 \$				\$ 273.92	\$ (66.59)		\$ (66.59)	-19.6%
10 10	20 30		10.00 10.00		\$ 69.36	\$ 102.12 \$ \$ 136.80 \$		\$ 210.12	\$ 15.20 \$				\$ 176.82 \$ 237.37	\$ (33.30)		\$ (33.30) \$ (49.95)	-15.8% -17.4%
10	40		10.00		\$ 104.04 \$ 138.72			\$ 287.32 \$ 364.52	\$ 15.20 \$ \$ 15.20 \$				\$ 237.37 \$ 297.92	\$ (49.95) \$ (66.59)		\$ (49.95)	-17.4%
10	50		10.00		\$ 173.40	\$ 206.16		\$ 441.71	\$ 15.20 \$ \$ 15.20 \$				\$ 358.47	\$ (83.24)		\$ (83.24)	-18.8%
10	60		10.00		\$ 208.09			\$ 518.91	\$ 15.20 \$				\$ 419.02	\$ (99.89)		\$ (99.89)	-19.2%
10	70	5,110	10.00	7 \$ 15.20	\$ 242.77	\$ 275.53	320.59	\$ 596.11	\$ 15.20 \$	126.23	\$ 158.99	\$ 320.59	\$ 479.57	\$ (116.54)	\$ -	\$ (116.54)	-19.5%
10	80		10.00		\$ 277.45	\$ 310.21	,		\$ 15.20 \$		\$ 177.02	\$ 363.10		\$ (133.19)		\$ (133.19)	-19.8%
20	20		20.00		\$ 138.72	\$ 186.68		\$ 412.52	\$ 30.40 \$		Ψ .20.00		\$ 345.92	\$ (66.59)		\$ (66.59)	-16.1%
20	30 40		20.00		\$ 208.09 \$ 277.45	\$ 256.05	,	\$ 566.91	\$ 30.40 \$				\$ 467.02	\$ (99.89)		\$ (99.89)	-17.6%
20 20	50		20.00 20.00		\$ 277.45 \$ 346.81	\$ 325.41 \$ \$ 394.77 \$,	\$ 721.31 \$ 875.71	\$ 30.40 \$ \$ 30.40 \$		\$ 192.22 \$ 228.28	\$ 395.90 \$ 480.94	\$ 588.12 \$ 709.23	\$ (133.19) \$ (166.48)		\$ (133.19) \$ (166.48)	-18.5% -19.0%
20	60		20.00		\$ 416.17			\$ 1,030.11	\$ 30.40 \$				\$ 830.33	\$ (199.78)		\$ (199.78)	-19.4%
20	70		20.00		\$ 485.53	\$ 533.49		\$ 1,184.51	\$ 30.40 \$		\$ 300.41		\$ 951.43	\$ (233.08)		\$ (233.08)	-19.7%
20	80	11,680	20.00	17 \$ 30.40	\$ 554.89	\$ 602.85	736.05	\$ 1,338.90	\$ 30.40 \$	288.52	\$ 336.48	\$ 736.05	\$ 1,072.53	\$ (266.37)	\$ -	\$ (266.37)	-19.9%
30	20		30.00		\$ 208.09	\$ 271.25	,	\$ 614.91	\$ 45.60 \$		\$ 171.35		\$ 515.02	\$ (99.89)		\$ (99.89)	-16.2%
30	30		30.00		\$ 312.13		,	\$ 846.51	\$ 45.60 \$			\$ 471.22		\$ (149.84)		\$ (149.84)	-17.7%
30 30	40 50		30.00	Σ, φ 10.00	\$ 416.17	\$ 479.33 \$ 583.37		\$ 1,078.11	\$ 45.60 \$		Ψ 2.0.00		\$ 878.33	\$ (199.78)		\$ (199.78)	-18.5%
30	60		30.00 30.00		\$ 520.21 \$ 624.26	\$ 583.37 \$ \$ 687.42 \$		\$ 1,309.70 \$ 1,541.30	\$ 45.60 \$ \$ 45.60 \$				\$ 1,059.98 \$ 1,241.63	\$ (249.73) \$ (299.67)		\$ (249.73) \$ (299.67)	-19.1% -19.4%
30	70		30.00		\$ 728.30			\$ 1,772.90	\$ 45.60 \$		\$ 441.84		\$ 1,423.28	\$ (349.62)		\$ (349.62)	-19.7%
30	80		30.00		\$ 832.34			\$ 2,004.50	\$ 45.60 \$				\$ 1,604.93	\$ (399.56)		\$ (399.56)	-19.9%
50	20		50.00	47 \$ 76.00	\$ 346.81	\$ 440.37	579.34	\$ 1,019.71	\$ 76.00 \$	180.32	\$ 273.88	\$ 579.34	\$ 853.23	\$ (166.48)	\$ -	\$ (166.48)	-16.3%
50	30		50.00		\$ 520.21	ψ 0.0		\$ 1,405.70	\$ 76.00 \$		\$ 364.05		\$ 1,155.98	\$ (249.73)		\$ (249.73)	-17.8%
50	40		50.00		\$ 693.62	\$ 787.18	.,	\$ 1,791.70	\$ 76.00 \$		\$ 454.21		\$ 1,458.73	\$ (332.97)		\$ (332.97)	-18.6%
50 50	50 60		50.00 50.00		\$ 867.02 \$ 1.040.43			\$ 2,177.69 \$ 2,563.69	\$ 76.00 \$ \$ 76.00 \$		\$ 544.37 \$ 634.53		\$ 1,761.48 \$ 2.064.24	\$ (416.21) \$ (499.45)		\$ (416.21) \$ (499.45)	-19.1% -19.5%
50	70					\$ 1,307.39		\$ 2,949.68	\$ 76.00 \$				\$ 2,366.99	\$ (582.69)		\$ (582.69)	-19.8%
50	80		50.00		\$ 1,387.23			\$ 3,335.68			\$ 814.86	\$ 1,854.88		\$ (665.94)		\$ (665.94)	-20.0%
75	30				\$ 780.32			\$ 2,104.70	\$ 114.00 \$		\$ 537.29		\$ 1,730.11	\$ (374.59)		\$ (374.59)	-17.8%
75	40		75.00			\$ 1,171.99		\$ 2,683.69	\$ 114.00 \$		\$ 672.53	\$ 1,511.70		\$ (499.45)		\$ (499.45)	-18.6%
75	50				+ .,	\$ 1,432.09		\$ 3,262.68			+		\$ 2,638.37	\$ (624.31)		\$ (624.31)	-19.1%
75	60		75.00		\$ 1,560.64	Ψ 1,00 <u>2.2</u> 0 1		\$ 3,841.67			\$ 943.02		\$ 3,092.50	\$ (749.18)		\$ (749.18)	-19.5%
75 75	70 80		75.00 75.00		\$ 1,820.74 \$ 2,080.85	\$ 1,952.30 \$ \$ 2,212.41 \$		\$ 4,420.67 \$ 4,999.66	\$ 114.00 \$ \$ 114.00 \$		\$ 1,078.26 \$ 1,213.51	\$ 2,468.36 \$ 2,787.25	\$ 3,546.63 \$ 4,000.75	\$ (874.04) \$ (998.90)		\$ (874.04) \$ (998.90)	-19.8% -20.0%
75	90		75.00			\$ 2,472.52		\$ 5.578.65			1	\$ 3.106.13		\$ (1,123.77)		\$ (1,123.77)	-20.1%
100	30		100.00		\$ 1,040.43			\$ 2,803.69	\$ 152.00 \$,	\$ 710.53	., ., .	\$ 2,304.24	\$ (499.45)		\$ (499.45)	-17.8%
100	40		100.00	97 \$ 152.00	\$ 1,387.23	\$ 1,556.79	2,018.88	\$ 3,575.68	\$ 152.00 \$	721.30	\$ 890.86	\$ 2,018.88	\$ 2,909.74	\$ (665.94)	\$ -	\$ (665.94)	-18.6%
100	50		100.00			\$ 1,903.60		\$ 4,347.67			\$ 1,071.18		\$ 3,515.25	\$ (832.42)		\$ (832.42)	-19.1%
100	60		100.00			\$ 2,250.41	-,	\$ 5,119.66			\$ 1,251.51		\$ 4,120.75	\$ (998.90)		\$ (998.90)	-19.5%
100 100	70 80		100.00 100.00		\$ 2,427.66 \$ 2,774.47	\$ 2,597.22 \$ \$ 2,944.03 \$		\$ 5,891.65 \$ 6.663.64	\$ 152.00 \$ \$ 152.00 \$		\$ 1,431.83 \$ 1.612.16	\$ 3,294.43 \$ 3,719.61	\$ 4,726.26 \$ 5.331.77	\$ (1,165.39)		\$ (1,165.39)	-19.8% -20.0%
100	90		100.00			\$ 2,944.03 3 \$ 3.290.84		\$ 7.435.63		,	\$ 1,612.16 \$ 1.792.48	\$ 3,719.61		\$ (1,331.87) \$ (1,498.35)		\$ (1,331.87) \$ (1,498.35)	-20.0%
200	30		200.00			\$ 2,402.41		\$ 5,599.66			\$ 1,403.51		\$ 4,600.75	\$ (998.90)		\$ (998.90)	-17.8%
200	40			197 \$ 304.00		-,		\$ 7,143.64			1		\$ 5,811.77	\$ (1,331.87)		\$ (1,331.87)	-18.6%
200	50		200.00		\$ 3,468.08			\$ 8,687.62	\$ 304.00 \$	1,803.25	\$ 2,124.81		\$ 7,022.78	\$ (1,664.84)	\$ -	\$ (1,664.84)	-19.2%
200	60		200.00		\$ 4,161.70	,		\$ 10,231.60			\$ 2,485.46	\$ 5,748.33		\$ (1,997.81)		\$ (1,997.81)	-19.5%
200	70			197 \$ 304.00		\$ 5,176.88		\$ 11,775.57		2,524.54			\$ 9,444.80	\$ (2,330.77)		\$ (2,330.77)	-19.8%
200	80 90			197 \$ 304.00		\$ 5,870.49 \$ \$ 6,564.11 \$		\$ 13,319.55 \$ 14,863.53	\$ 304.00 \$				\$ 10,655.81 \$ 11,866.82	\$ (2,663.74)		\$ (2,663.74) \$ (2,996.71)	-20.0% -20.2%
200	90	131,400	200.00	197 \$ 304.00	Φ 0,242.00	φ 0,004.11 S	p δ,299.42	p 14,863.53	\$ 304.00 \$	3,245.84	a 3,567.40	φ 8,∠99.42	\$ 11,800.82	\$ (2,996.71)	φ -	φ (∠,996./1)	-20.2%

ATLANTIC CITY ELECTRIC COMPANY MONTHLY GENERAL SERVICE PRIMARY ("MGS Primary") 4 SUMMER MONTHS (June Through September)

Present Rates vs.

										posed Rates								
_		Load	F				Present Distribution	Present	Present			New	New	New	Difference	Difference	Total	Total
	emand kW)	(%)	(kWh)	Diet kW	Trans kW D Demand	D Energy	(\$)	BGS and Other Charges (\$)	Total (\$)	D Demand	D Energy	Distribution (\$)	BGS and Other Charges (\$)	Total (\$)	(\$)	BGS and Other Charges (\$)	(\$)	Difference (%)
	5	20	730	5.00	2 \$ 9.65	\$ 35.78		\$ 51.28	\$ 114.27	\$ 9.65	\$ 18.60			\$ 97.09	(+/	\$ -	\$ (17.18)	-15.0%
	5	30	1,095	5.00		\$ 53.67		\$ 73.30			\$ 27.89			\$ 128.40	\$ (25.78)		\$ (25.78)	-16.7%
	5	40	1,460	5.00	2 \$ 9.65	\$ 71.56	\$ 98.77	\$ 95.31	\$ 194.08	\$ 9.65	\$ 37.19	\$ 64.40	\$ 95.31	\$ 159.71	\$ (34.37)	\$ -	\$ (34.37)	-17.7%
	5	50	1,825	5.00	2 \$ 9.65	\$ 89.45	\$ 116.66	\$ 117.32	\$ 233.98	\$ 9.65	\$ 46.49			\$ 191.02	\$ (42.96)	\$ -	\$ (42.96)	-18.4%
	5	60	2,190	5.00		\$ 107.34		\$ 139.33	\$ 273.88	\$ 9.65	\$ 55.79			\$ 222.33	\$ (51.55)		\$ (51.55)	-18.8%
	5	70	2,555	5.00		\$ 125.23			\$ 313.78	\$ 9.65	\$ 65.08			\$ 253.64	\$ (60.14)	*	\$ (60.14)	-19.2%
	5	80	2,920	5.00		\$ 143.12		\$ 183.35	\$ 353.68	\$ 9.65	\$ 74.38			\$ 284.94	\$ (68.74)		\$ (68.74)	-19.4%
	10 10	20 30	1,460 2.190	10.00 10.00		\$ 71.56 \$ 107.34		\$ 113.46 \$ 157.48		\$ 19.30 \$ 19.30	\$ 37.19 \$ 55.79			\$ 187.51 \$ 250.13	\$ (34.37) \$ (51.55)		\$ (34.37) \$ (51.55)	-15.5% -17.1%
	10	40	2,190	10.00		\$ 143.12		\$ 201.50	\$ 301.68 \$ 381.48	\$ 19.30 \$ 19.30	\$ 74.38			\$ 250.13 \$ 312.74	\$ (51.55) \$ (68.74)		\$ (68.74)	-17.1%
	10	50	3,650	10.00		\$ 178.90		\$ 245.53			\$ 92.98		\$ 245.53	\$ 375.36		\$ -	\$ (85.92)	-18.6%
	10	60	4,380	10.00		\$ 214.68		\$ 289.55			\$ 111.57			\$ 437.98	\$ (103.11)	*	\$ (103.11)	-19.1%
	10	70	5,110	10.00		\$ 250.46		\$ 333.57	\$ 620.89		\$ 130.17			\$ 500.60	\$ (120.29)		\$ (120.29)	-19.4%
	10	80	5,840	10.00		\$ 286.24			\$ 700.69	\$ 19.30	\$ 148.76			\$ 563.22	\$ (137.47)		\$ (137.47)	-19.6%
	20	20	2,920	20.00	17 \$ 38.60	\$ 143.12	\$ 199.28	\$ 237.80	\$ 437.08	\$ 38.60	\$ 74.38	\$ 130.54	\$ 237.80	\$ 368.34	\$ (68.74)	\$ -	\$ (68.74)	-15.7%
	20	30	4,380	20.00		\$ 214.68			\$ 596.69	\$ 38.60	\$ 111.57			\$ 493.58	\$ (103.11)		\$ (103.11)	-17.3%
	20	40	5,840	20.00		\$ 286.24		\$ 413.90	\$ 756.29	\$ 38.60	\$ 148.76			\$ 618.82	\$ (137.47)		\$ (137.47)	-18.2%
	20	50	7,300	20.00		\$ 357.79		\$ 501.94	\$ 915.90	\$ 38.60	\$ 185.95			\$ 744.06	\$ (171.84)		\$ (171.84)	-18.8%
	20	60	8,760	20.00		\$ 429.35		\$ 589.99	\$ 1,075.50	\$ 38.60	\$ 223.14			\$ 869.29	\$ (206.21)	*	\$ (206.21)	-19.2%
	20 20	70 80	10,220 11.680	20.00 20.00		\$ 500.91 \$ 572.47			\$ 1,235.11 \$ 1,394.72	\$ 38.60 \$ 38.60	\$ 260.33 \$ 297.52			\$ 994.53 \$ 1.119.77	\$ (240.58) \$ (274.95)	\$ -	\$ (240.58) \$ (274.95)	-19.5% -19.7%
	30	20	4.380	30.00		\$ 214.68		\$ 766.08 \$ 362.15			\$ 111.57			\$ 1,119.77	\$ (274.95)		\$ (274.93)	-15.8%
	30	30	6.570	30.00		\$ 322.02		\$ 494.22	\$ 891.70	\$ 57.90	\$ 167.36			\$ 737.04	\$ (154.66)		\$ (154.66)	-17.3%
	30	40	8.760	30.00		\$ 429.35			\$ 1,131.10	\$ 57.90	\$ 223.14			\$ 924.89	\$ (206.21)		\$ (206.21)	-18.2%
	30	50	10.950	30.00		\$ 536.69			\$ 1,370.51		\$ 278.93			\$ 1,112.75	\$ (257.76)		\$ (257.76)	-18.8%
	30	60	13,140	30.00	27 \$ 57.90	\$ 644.03		\$ 890.43	\$ 1,609.92	\$ 57.90	\$ 334.72	\$ 410.18		\$ 1,300.61		\$ -	\$ (309.32)	-19.2%
	30	70	15,330	30.00	27 \$ 57.90	\$ 751.37	\$ 826.83	\$ 1,022.50	\$ 1,849.33	\$ 57.90	\$ 390.50	\$ 465.96	\$ 1,022.50	\$ 1,488.46	\$ (360.87)	\$ -	\$ (360.87)	-19.5%
	30	80	17,520	30.00	27 \$ 57.90	\$ 858.71			\$ 2,088.74	\$ 57.90	\$ 446.29			\$ 1,676.32	\$ (412.42)	\$ -	\$ (412.42)	-19.7%
	50	20	7,300	50.00		\$ 357.79			\$ 1,082.70	\$ 96.50	\$ 185.95			\$ 910.86		\$ -	\$ (171.84)	-15.9%
	50	30	10,950	50.00		\$ 536.69		\$ 830.96	\$ 1,481.71	\$ 96.50	\$ 278.93			\$ 1,223.95	\$ (257.76)	*	\$ (257.76)	-17.4%
	50	40	14,600	50.00		\$ 715.59		\$ 1,051.08	\$ 1,880.73		\$ 371.91		* ***	\$ 1,537.04	\$ (343.68)		\$ (343.68)	-18.3%
	50 50	50 60	18,250 21,900	50.00 50.00		\$ 894.49 \$ 1.073.38	.,	\$ 1,271.19 \$ 1.491.31	\$ 2,279.74 \$ 2,678.76	\$ 96.50 \$ 96.50	\$ 464.88 \$ 557.86		\$ 1,271.19 \$ 1.491.31	\$ 1,850.14 \$ 2,163.23	\$ (429.61) \$ (515.53)		\$ (429.61) \$ (515.53)	-18.8% -19.2%
	50	70	25,550	50.00					\$ 3,077.77		\$ 650.84			\$ 2,476.32	\$ (601.45)		\$ (601.45)	-19.5%
	50	80	29,200	50.00		\$ 1,431.18			\$ 3,476.78		\$ 743.81	\$ 857.87		\$ 2,789.42	\$ (687.37)		\$ (687.37)	-19.8%
	75	30	16.425	75.00		\$ 805.04		\$ 1,251.89	\$ 2,219.23		\$ 418.39			\$ 1.832.59	\$ (386.64)		\$ (386.64)	-17.4%
	75	40	21,900	75.00	72 \$ 144.75	\$ 1,073.38	\$ 1,235.69		\$ 2,817.76	\$ 144.75	\$ 557.86	\$ 720.17		\$ 2,302.23	\$ (515.53)	\$ -	\$ (515.53)	-18.3%
	75	50	27,375	75.00	72 \$ 144.75	\$ 1,341.73	\$ 1,504.04	\$ 1,912.24	\$ 3,416.28	\$ 144.75	\$ 697.32	\$ 859.63	\$ 1,912.24	\$ 2,771.87	\$ (644.41)	\$ -	\$ (644.41)	-18.9%
	75	60	32,850	75.00		\$ 1,610.08	Ψ 1,7.12.00		\$ 4,014.80		\$ 836.79			\$ 3,241.51	\$ (773.29)		\$ (773.29)	-19.3%
	75	70	38,325	75.00			-,		\$ 4,613.32		\$ 976.25		*	\$ 3,711.15	\$ (902.17)		\$ (902.17)	-19.6%
	75	80	43,800	75.00					\$ 5,211.84	\$ 144.75				\$ 4,180.79	\$ (1,031.05)		\$ (1,031.05)	-19.8%
	75 100	90 30	49,275 21.900	75.00	72 \$ 144.75				\$ 5,810.36		\$ 1,255.18 \$ 557.86			\$ 4,650.43	\$ (1,159.93)		\$ (1,159.93) \$ (515.53)	-20.0% -17.4%
	100	30 40	21,900	100.00 100.00		\$ 1,073.38 \$ 1,431.18	. ,		\$ 2,956.76 \$ 3,754.78		\$ 557.86		*	\$ 2,441.23 \$ 3,067.42	\$ (515.53) \$ (687.37)		\$ (515.53) \$ (687.37)	-17.4% -18.3%
	100	50	36.500	100.00		\$ 1,431.16		\$ 2,113.03	\$ 4.552.81		\$ 929.76			\$ 3,693.60	\$ (859.21)		\$ (859.21)	-18.9%
	100	60	43,800	100.00		\$ 2,146.77			\$ 5,350.84		\$ 1,115.72			\$ 4,319.79	\$ (1,031.05)		\$ (1,031.05)	-19.3%
	100	70	51,100	100.00			\$ 2,715.12		\$ 6,148.87		\$ 1,301.67			\$ 4,945.98	\$ (1,202.89)		\$ (1,202.89)	-19.6%
	100	80	58,400	100.00		\$ 2,862.36		\$ 3,873.98	\$ 6,946.90		\$ 1,487.62			\$ 5,572.16	\$ (1,374.74)		\$ (1,374.74)	-19.8%
	100	90	65,700	100.00		+ -,	\$ 3,430.71		\$ 7,744.93		\$ 1,673.58			\$ 6,198.35	\$ (1,546.58)		\$ (1,546.58)	-20.0%
	200	30	43,800	200.00		\$ 2,146.77			\$ 5,906.84		\$ 1,115.72		\$ 3,356.51	\$ 4,875.79	\$ (1,031.05)		\$ (1,031.05)	-17.5%
	200	40	58,400	200.00		Ψ L ,00 L .00		\$ 4,236.98	\$ 7,502.90		\$ 1,487.62			\$ 6,128.16	\$ (1,374.74)		\$ (1,374.74)	-18.3%
	200	50	73,000	200.00		+ -,	\$ 3,981.51		\$ 9,098.96		\$ 1,859.53			\$ 7,380.54	\$ (1,718.42)		\$ (1,718.42)	-18.9%
	200	60	87,600	200.00		\$ 4,293.54			\$ 10,695.01		\$ 2,231.43			\$ 8,632.91	\$ (2,062.10)		\$ (2,062.10)	-19.3%
	200 200	70	102,200	200.00		+ -,	Φ 0,112.00		\$ 12,291.07		\$ 2,603.34			\$ 9,885.28	\$ (2,405.79)		\$ (2,405.79)	-19.6%
	200 200		116,800 131,400	200.00 200.00	197 \$ 386.00				\$ 13,887.13 \$ 15,483.19		\$ 2,975.25			\$ 11,137.66	\$ (2,749.47)		\$ (2,749.47) \$ (3,093.16)	-19.8% -20.0%
_	200	an	131,400	200.00	197 \$ 386.00	φ 6,44U.3T	\$ 6,843.87	φ 8,639.32	p 15,483.19	\$ 386.00	φ 3,341.15	\$ 3,750.71	φ 8,639.32	\$ 12,390.03	\$ (3,093.16)	a -	a (პ,U9პ.16)	-20.0%

ATLANTIC CITY ELECTRIC COMPANY MONTHLY GENERAL SERVICE PRIMARY ("MGS Primary") Annual Average

Present Rates vs.

										posed Rates								
ъ.		Load	F				Present Distribution	Present	Present			New	New	New	Difference	Difference	Total	Total
	mand F W)	(%)	(kWh)	Diet kW	Trans kW D Demand	D Energy	(\$)	BGS and Other Charges (\$)	Total (\$)	D Demand	D Energy	Distribution (\$)	BGS and Other Charges (\$)	Total (\$)	(\$)	BGS and Other Charges (\$)	(\$)	Difference (%)
_	5	20	730	5.00	2 \$ 8.28	\$ 35.05	(+/	\$ 49.81	\$ 110.70	\$ 8.28	\$ 18.22			\$ 93.88	\$ (16.83)	(+/	\$ (16.83)	-15.2%
	5	30	1,095	5.00	2 \$ 8.28		\$ 78.41				\$ 27.33				\$ (25.24)		\$ (25.24)	-16.9%
	5	40	1,460	5.00	2 \$ 8.28	\$ 70.09	\$ 95.94	\$ 92.83	\$ 188.77	\$ 8.28	\$ 36.44	\$ 62.28	\$ 92.83	\$ 155.12	\$ (33.65)	\$ -	\$ (33.65)	-17.8%
	5	50	1,825	5.00	2 \$ 8.28	\$ 87.62		\$ 114.34	\$ 227.80	\$ 8.28	\$ 45.55			\$ 185.74	\$ (42.07)		\$ (42.07)	-18.5%
	5	60	2,190	5.00	2 \$ 8.28	\$ 105.14			\$ 266.84	\$ 8.28	\$ 54.66			\$ 216.36	\$ (50.48)		\$ (50.48)	-18.9%
	5	70	2,555	5.00	2 \$ 8.28	\$ 122.66			\$ 305.87	\$ 8.28	\$ 63.77			\$ 246.98	. (,	•	\$ (58.89)	-19.3%
	5 0	80 20	2,920 1.460	5.00 10.00	2 \$ 8.28 7 \$ 16.57	\$ 140.19 \$ 70.09		\$ 178.87 \$ 109.82	\$ 344.90 \$ 214.04	\$ 8.28 \$ 16.57	\$ 72.88 \$ 36.44			\$ 277.60 \$ 180.38	\$ (67.31) \$ (33.65)		\$ (67.31) \$ (33.65)	-19.5% -15.7%
	0	30	2.190	10.00		\$ 105.14			\$ 292.10		\$ 54.66			\$ 241.62	\$ (33.65) \$ (50.48)		\$ (50.48)	-17.3%
	0	40	2,130	10.00	7 \$ 16.57	\$ 140.19		\$ 195.86	\$ 370.17		\$ 72.88			\$ 302.86	\$ (67.31)		\$ (67.31)	-18.2%
	Ö	50	3,650	10.00		\$ 175.24			\$ 448.24		\$ 91.10			\$ 364.10	\$ (84.13)		\$ (84.13)	-18.8%
	0	60	4,380	10.00		\$ 210.28		\$ 281.90	\$ 526.30		\$ 109.32			\$ 425.34			\$ (100.96)	-19.2%
	0	70	5,110	10.00	7 \$ 16.57	\$ 245.33	\$ 279.46	\$ 324.92	\$ 604.37	\$ 16.57	\$ 127.54	\$ 161.67	\$ 324.92	\$ 486.58	\$ (117.79)	\$ -	\$ (117.79)	-19.5%
	0	80	5,840	10.00		\$ 280.38		\$ 367.94	\$ 682.44		\$ 145.76				\$ (134.62)	\$ -	\$ (134.62)	-19.7%
	20	20	2,920	20.00		\$ 140.19		\$ 229.82			\$ 72.88		\$ 229.82		\$ (67.31)		\$ (67.31)	-16.0%
	20	30	4,380	20.00					\$ 576.84		\$ 109.32				\$ (100.96)		\$ (100.96)	-17.5%
	20 20	40 50	5,840 7.300	20.00		\$ 280.38		\$ 401.90 \$ 487.94	\$ 732.97		\$ 145.76			\$ 598.36			\$ (134.62) \$ (168.27)	-18.4% -18.9%
	20	60	7,300 8.760	20.00 20.00		\$ 350.47 \$ 420.56			\$ 889.11 \$ 1.045.24	\$ 33.13 \$ 33.13	\$ 182.20 \$ 218.64			\$ 720.84 \$ 843.32	\$ (168.27) \$ (201.92)	•	\$ (168.27) \$ (201.92)	-18.9% -19.3%
	20	70	10.220	20.00		\$ 490.66		\$ 660.02			\$ 255.08			\$ 965.80	\$ (235.58)		\$ (235.58)	-19.6%
	20	80	11.680	20.00		\$ 560.75			\$ 1,357.51		\$ 291.52						\$ (269.23)	-19.8%
	10	20	4,380	30.00		\$ 210.28		\$ 349.83	\$ 627.37		\$ 109.32			\$ 526.41	\$ (100.96)		\$ (100.96)	-16.1%
	10	30	6,570	30.00		\$ 315.42	\$ 382.68	\$ 478.89	\$ 861.57	\$ 49.70	\$ 163.98	\$ 231.24		\$ 710.13	\$ (151.44)		\$ (151.44)	-17.6%
	0	40	8,760	30.00	27 \$ 49.70	\$ 420.56	\$ 487.82	\$ 607.95	\$ 1,095.77	\$ 49.70	\$ 218.64	\$ 285.90		\$ 893.85	\$ (201.92)	\$ -	\$ (201.92)	-18.4%
	10	50	10,950	30.00		\$ 525.71			\$ 1,329.97		\$ 273.30			\$ 1,077.57	\$ (252.40)		\$ (252.40)	-19.0%
	10	60	13,140	30.00		\$ 630.85		\$ 866.07	\$ 1,564.17		\$ 327.96			\$ 1,261.29	\$ (302.89)		\$ (302.89)	-19.4%
	0	70	15,330	30.00		\$ 735.99			\$ 1,798.38		\$ 382.62				\$ (353.37)		\$ (353.37)	-19.6%
	i0 i0	80 20	17,520 7.300	30.00 50.00		\$ 841.13 \$ 350.47		\$ 1,124.19 \$ 589.84	\$ 2,032.58 \$ 1.040.71	\$ 49.70 \$ 82.83	\$ 437.28 \$ 182.20				\$ (403.85) \$ (168.27)		\$ (403.85) \$ (168.27)	-19.9% -16.2%
	60	30	10.950	50.00	47 \$ 82.83	\$ 525.71			\$ 1,431.04	\$ 82.83	\$ 273.30				\$ (252.40)		\$ (252.40)	-17.6%
	60	40	14,600	50.00		\$ 700.94		7	\$ 1.821.38	\$ 82.83	\$ 364.40			. ,	\$ (336.54)		\$ (336.54)	-18.5%
	0	50	18,250	50.00	47 \$ 82.83	\$ 876.18		\$ 1,235.14		\$ 82.83	\$ 455.50			. ,	. (,		\$ (420.67)	-19.0%
	0	60	21,900	50.00	47 \$ 82.83	\$ 1,051.41	\$ 1,151.81	\$ 1,450.24	\$ 2,602.04	\$ 82.83	\$ 546.60	\$ 647.00	\$ 1,450.24	\$ 2,097.23	\$ (504.81)	\$ -	\$ (504.81)	-19.4%
	0	70	25,550	50.00	47 \$ 82.83	\$ 1,226.65			\$ 2,992.38		\$ 637.70			\$ 2,403.43	\$ (588.94)	\$ -	\$ (588.94)	-19.7%
	0	80	29,200	50.00		\$ 1,401.88	,		\$ 3,382.71		\$ 728.80			\$ 2,709.63	\$ (673.08)		\$ (673.08)	-19.9%
	5	30	16,425	75.00	72 \$ 124.25	\$ 788.56			\$ 2,142.88	\$ 124.25	\$ 409.95			\$ 1,764.27	\$ (378.61)		\$ (378.61)	-17.7%
	'5 '5	40 50	21,900 27,375	75.00 75.00		\$ 1,051.41			\$ 2,728.38 \$ 3,313.88		\$ 546.60 \$ 683.25			\$ 2,223.57 \$ 2,682.87	\$ (504.81) \$ (631.01)		\$ (504.81) \$ (631.01)	-18.5% -19.0%
	5 '5	60	32,850	75.00		\$ 1,314.26 \$ 1.577.12			\$ 3,899.38		\$ 819.90			\$ 2,002.07	\$ (757.21)		\$ (757.21)	-19.4%
	5	70	38.325	75.00		\$ 1,839.97			\$ 4,484.88		\$ 956.55			\$ 3,601.47	\$ (883.42)		\$ (883.42)	-19.7%
	5	80	43,800	75.00					\$ 5,070.39		\$ 1,093.20			\$ 4,060.77	\$ (1,009.62)		\$ (1,009.62)	-19.9%
	5	90	49,275	75.00		\$ 2,365.68			\$ 5,655.89		\$ 1,229.85			\$ 4,520.07	\$ (1,135.82)		\$ (1,135.82)	-20.1%
	00	30	21,900	100.00	97 \$ 165.67	\$ 1,051.41			\$ 2,854.71	\$ 165.67	\$ 546.60	\$ 729.83	\$ 1,620.07	\$ 2,349.90	\$ (504.81)		\$ (504.81)	-17.7%
	00	40	29,200	100.00	97 \$ 165.67			*	\$ 3,635.38		\$ 728.80			\$ 2,962.30	\$ (673.08)	•	\$ (673.08)	-18.5%
	00	50	36,500	100.00		\$ 1,752.35		\$ 2,480.47			\$ 911.00						\$ (841.35)	-19.1%
	00	60	43,800	100.00		\$ 2,102.82	-,		\$ 5,196.72		\$ 1,093.20			\$ 4,187.10	\$ (1,009.62)		\$ (1,009.62)	-19.4%
	00 00	70 80	51,100 58,400	100.00 100.00			. ,		\$ 5,977.39 \$ 6.758.06		\$ 1,275.40 \$ 1.457.61			\$ 4,799.50	\$ (1,177.89)		\$ (1,177.89)	-19.7% -19.9%
	00	90	58,400 65.700	100.00		\$ 2,803.76 \$ 3,154.24			\$ 6,758.06		\$ 1,457.61			\$ 5,411.90 \$ 6,024.30	\$ (1,346.16) \$ (1,514.43)		\$ (1,346.16) \$ (1,514.43)	-19.9% -20.1%
	00	30	43,800	200.00					\$ 5,702.05		\$ 1,039.01			\$ 4,692.43	\$ (1,009.62)		\$ (1,009.62)	-17.7%
	00	40	58.400	200.00					\$ 7,263.39		\$ 1,457.61			\$ 5,917.23	\$ (1,346.16)		\$ (1,346.16)	-18.5%
	00	50	73,000	200.00					\$ 8,824.73		\$ 1,822.01			\$ 7,142.03	\$ (1,682.70)		\$ (1,682.70)	-19.1%
	00	60	87,600	200.00	197 \$ 331.33				\$ 10,386.07		\$ 2,186.41			\$ 8,366.83	\$ (2,019.24)		\$ (2,019.24)	-19.4%
			102,200	200.00		Ψ 1,000.00	φ 0,200.10		\$ 11,947.41		\$ 2,550.81			\$ 9,591.63	\$ (2,355.78)		\$ (2,355.78)	-19.7%
	00		116,800	200.00	197 \$ 331.33				\$ 13,508.75		\$ 2,915.21			\$ 10,816.43	\$ (2,692.32)		\$ (2,692.32)	-19.9%
	00	90	131,400	200.00	197 \$ 331.33	\$ 6,308.47	\$ 6,657.36	\$ 8,412.72	\$ 15,070.08	\$ 331.33	\$ 3,279.61	\$ 3,628.51	\$ 8,412.72	\$ 12,041.23	\$ (3,028.86)	\$ -	\$ (3,028.86)	-20.1%

ATLANTIC CITY ELECTRIC COMPANY ANNUAL GENERAL SERVICE SECONDARY ("AGS Secondary") 8 WINTER MONTHS (October Through May)

Present Rates

									Dear	vs. osed Rates								
	Load						Present	Present	Present	oseu Raies		New	New	New	Difference	Difference To	tal	Total
Deman	d Factor	Energy					Distribution	BGS and Other Charges	Total			Distribution	BGS and Other Charges	Total	Distribution BGS a			Difference
(kW)	(%)	(kWh)	Metered kW B	Billed kW	D Demand	D Energy	(\$)	(\$)	(\$)	D Demand	D Energy	(\$)	(\$)	(\$)	(\$)	(\$)	\$)	(%)
25	20	3,650	25	25		\$ (10.17)			\$ 982.44		\$ (10.17) \$			\$ 1,045.69	\$ 63.25 \$		63.25	6.4%
25	30	5,475	25	25		\$ (15.25)			\$ 1,147.79		\$ (15.25) \$			\$ 1,211.04	\$ 63.25 \$		63.25	5.5%
25 25	40 50	7,300 9.125	25 25	25 S		\$ (20.33) \$ (25.41)			\$ 1,313.15 \$ 1,478.51		\$ (20.33) \$ \$ (25.41) \$			\$ 1,376.40 \$ 1,541.76	\$ 63.25 \$ \$ 63.25 \$		63.25 63.25	4.8% 4.3%
25	60	10,950	25 25	25		\$ (25.41)			\$ 1,476.51		\$ (30.50) \$		\$ 1,164.14		\$ 63.25 \$		63.25	3.8%
25	70	12,775	25	25		\$ (35.58)		\$ 1,334.58	\$ 1.809.22		\$ (35.58) \$			\$ 1,872.47	\$ 63.25 \$		63.25	3.5%
25	80	14.600	25	25		\$ (40.66)			\$ 1,974.58		\$ (40.66) \$			\$ 2.037.83	\$ 63.25 \$		63.25	3.2%
50	20	7,300	50	50		\$ (20.33)		\$ 964.76	\$ 1,771.65	\$ 760.50	\$ (20.33) \$	933.39		\$ 1,898.15	\$ 126.50 \$	- \$	26.50	7.1%
50	30	10,950	50	50		\$ (30.50)			\$ 2,102.37		\$ (30.50) \$		\$ 1,305.64		\$ 126.50 \$		26.50	6.0%
50	40	14,600	50	50		\$ (40.66)		\$ 1,646.52	\$ 2,433.08	*	\$ (40.66) \$			\$ 2,559.58	\$ 126.50 \$		26.50	5.2%
50	50	18,250	50	50		\$ (50.83)			\$ 2,763.80		\$ (50.83) \$			\$ 2,890.30	\$ 126.50 \$		26.50	4.6%
50 50	60 70	21,900 25,550	50 50	50 5 50 5		\$ (60.99) \$ (71.16)		\$ 2,328.28 \$ 2,669.17	\$ 3,094.51 \$ 3,425.23		\$ (60.99) \$ \$ (71.16) \$		\$ 2,328.28 \$ 2,669.17	\$ 3,221.01 \$ 3,551.73	\$ 126.50 \$ \$ 126.50 \$		26.50 26.50	4.1% 3.7%
50	80	29,200	50	50		\$ (81.32)			\$ 3,425.23		\$ (81.32) \$		\$ 3,010.05		\$ 126.50 \$ \$ 126.50 \$		26.50	3.1%
100	20	14,600	100		\$ 1,268.00	\$ (40.66)		\$ 1,929.52	\$ 3,350.08				\$ 1,929.52		\$ 253.00 \$		253.00	7.6%
100	30	21.900	100		\$ 1,268.00	\$ (60.99)		\$ 2,611.28	\$ 4.011.51				\$ 2,611.28		\$ 253.00 \$		53.00	6.3%
100	40	29,200	100		\$ 1,268.00	\$ (81.32)		\$ 3,293.05	\$ 4,672.94					\$ 4,925.94	\$ 253.00 \$		53.00	5.4%
100	50	36,500	100	100	\$ 1,268.00	\$ (101.65)	\$ 1,359.57	\$ 3,974.81	\$ 5,334.38	\$ 1,521.00	\$ (101.65) \$	1,612.57	\$ 3,974.81	\$ 5,587.38	\$ 253.00 \$	- \$ 2	53.00	4.7%
100	60	43,800	100		\$ 1,268.00	\$ (121.98)			\$ 5,995.81				\$ 4,656.57		\$ 253.00 \$		53.00	4.2%
100	70	51,100	100		\$ 1,268.00	\$ (142.31)			\$ 6,657.24	+ .,		,		\$ 6,910.24	\$ 253.00 \$		53.00	3.8%
100 300	80 20	58,400 43,800	100		\$ 1,268.00	\$ (162.64)		\$ 6,020.09	\$ 7,318.67					\$ 7,571.67	\$ 253.00 \$		53.00	3.5% 7.9%
300	30	43,800 65,700	300 300		\$ 3,804.00 \$ 3,804.00	\$ (121.98) \$ (182.97)			\$ 9,663.81 \$ 11,648.10			,		\$ 10,422.81 \$ 12,407.10	\$ 759.00 \$ \$ 759.00 \$		59.00 59.00	7.9% 6.5%
300	40	87.600	300		\$ 3,804.00	\$ (243.97)			\$ 13,632.39					\$ 12,407.10	\$ 759.00 \$ \$ 759.00 \$		59.00	5.6%
300	50	109,500	300		\$ 3,804.00	\$ (304.96)			\$ 15,616.69					\$ 16,375.69	\$ 759.00 \$		59.00	4.9%
300	60	131,400	300		\$ 3,804.00	\$ (365.95)			\$ 17,600.98					\$ 18,359.98	\$ 759.00 \$		59.00	4.3%
300	70	153,300	300	300	\$ 3,804.00	\$ (426.94)	\$ 3,570.28	\$ 16,014.99	\$ 19,585.27	\$ 4,563.00	\$ (426.94) \$	4,329.28	\$ 16,014.99	\$ 20,344.27	\$ 759.00 \$	- \$	59.00	3.9%
300	80	175,200	300		\$ 3,804.00	\$ (487.93)			\$ 21,569.57	+ .,		.,		\$ 22,328.57	\$ 759.00 \$		59.00	3.5%
500	20	73,000	500		\$ 6,340.00	\$ (203.31)			\$ 15,977.53					\$ 17,242.53	\$1,265.00 \$		65.00	7.9%
500	30 40	109,500	500		\$ 6,340.00	\$ (304.96)			\$ 19,284.69	+ .,		,		\$ 20,549.69	\$1,265.00 \$		65.00	6.6%
500 500	40 50	146,000 182,500	500 500		\$ 6,340.00 \$ 6,340.00	\$ (406.61) \$ (508.26)			\$ 22,591.84 \$ 25,899.00					\$ 23,856.84 \$ 27,164.00	\$1,265.00 \$ \$1,265.00 \$		65.00 65.00	5.6% 4.9%
500	60	219,000	500		\$ 6,340.00	\$ (609.92)			\$ 29,206.15					\$ 30,471.15	\$1,265.00 \$		65.00	4.3%
500	70	255,500	500		\$ 6,340.00	\$ (711.57)		,	\$ 32.513.31					\$ 33,778.31	\$1,265.00 \$		65.00	3.9%
500	80	292,000	500	500	\$ 6,340.00	\$ (813.22)	\$ 5,720.00	\$ 30,100.46	\$ 35,820.46	\$ 7,605.00	\$ (813.22) \$	6,985.00		\$ 37,085.46	\$1,265.00 \$	- \$ 1,2	65.00	3.5%
750	30	164,250	750		\$ 9,510.00	\$ (457.44)			\$ 28,830.42			11,143.28		\$ 30,727.92	\$1,897.50 \$	- \$ 1,8		6.6%
750	40	219,000	750		\$ 9,510.00	\$ (609.92)			\$ 33,791.15			,		\$ 35,688.65	\$1,897.50 \$		97.50	5.6%
750	50	273,750	750		\$ 9,510.00	\$ (762.39)			\$ 38,751.89			10,838.33		\$ 40,649.39	\$1,897.50 \$		97.50	4.9%
750	60	328,500	750		\$ 9,510.00	\$ (914.87)			\$ 43,712.62			,		\$ 45,610.12	\$1,897.50 \$		97.50	4.3%
750 750	70 80	383,250 438,000	750 750			\$ (1,067.35) \$ (1,219.83)			\$ 48,673.35 \$ 53,634.09		\$ (1,067.35) \$ \$ (1,219.83) \$			\$ 50,570.85 \$ 55,531.59	\$1,897.50 \$ \$1.897.50 \$		97.50 97.50	3.9% 3.5%
750	90	492,750	750 750			\$ (1,219.03)			\$ 58,594.82		\$ (1,219.03) \$ \$ (1,372.31) \$			\$ 60,492.32	\$1,897.50 \$		97.50	3.5%
1000	30	219,000	1.000			\$ (609.92)			\$ 38,376.15		\$ (609.92)			\$ 40,906.15	\$2,530.00 \$		30.00	6.6%
1000	40	292,000	1,000	1,000	\$ 12,680.00	\$ (813.22)			\$ 44,990.46		\$ (813.22) \$			\$ 47,520.46	\$2,530.00 \$	- \$ 2,5	30.00	5.6%
1000	50	365,000	1,000	1,000	\$ 12,680.00	\$ (1,016.53)		\$ 39,748.08	\$ 51,604.78	\$ 15,210.00	\$ (1,016.53) \$	14,386.70	\$ 39,748.08	\$ 54,134.78	\$2,530.00 \$	- \$ 2,5	30.00	4.9%
1000	60	438,000	1,000			\$ (1,219.83)					\$ (1,219.83) \$			\$ 60,749.09	\$2,530.00 \$		30.00	4.3%
1000	70	511,000	1,000			\$ (1,423.14)			\$ 64,833.40		\$ (1,423.14) \$			\$ 67,363.40	\$2,530.00 \$		30.00	3.9%
1000	80	584,000	1,000			\$ (1,626.44)			\$ 71,447.71		\$ (1,626.44) \$			\$ 73,977.71	\$2,530.00 \$		30.00	3.5%
1000 2000	90 30	657,000 438,000	1,000 2,000			\$ (1,829.75) \$ (1,219.83)			\$ 78,062.02 \$ 76,559.09		\$ (1,829.75) \$ \$ (1,219.83) \$			\$ 80,592.02 \$ 81,619.09	\$2,530.00 \$ \$5,060.00 \$		30.00 60.00	3.2% 6.6%
2000	40	584.000	2,000			\$ (1,219.63)			\$ 89,787.71		\$ (1,626.44) \$			\$ 94,847.71	\$5,060.00 \$		60.00	5.6%
2000	50	730.000	2,000			\$ (2,033.05)			\$ 103,016.33		\$ (2,033.05)			\$ 108,076.33	\$5,060.00 \$		60.00	4.9%
2000	60	876,000	2,000			\$ (2,439.66)			\$ 116,244.95		\$ (2,439.66) \$			\$ 121,304.95	\$5,060.00 \$		60.00	4.4%
2000	70	1,022,000	2,000			\$ (2,846.27)	\$ 22,706.95	\$ 106,766.62	\$ 129,473.57	\$ 30,420.00	\$ (2,846.27) \$	27,766.95		\$ 134,533.57	\$5,060.00 \$	- \$ 5,0	60.00	3.9%
2000	80	1,168,000	2,000			\$ (3,252.88)			\$ 142,702.20		\$ (3,252.88) \$			\$ 147,762.20	\$5,060.00 \$		60.00	3.5%
2000	90	1,314,000	2,000	2,000	\$ 25,360.00	\$ (3,659.49)	\$ 21,893.73	\$ 134,037.09	\$ 155,930.82	\$ 30,420.00	\$ (3,659.49) \$	26,953.73	\$ 134,037.09	\$ 160,990.82	\$5,060.00 \$	- \$ 5,0	60.00	3.2%

ATLANTIC CITY ELECTRIC COMPANY ANNUAL GENERAL SERVICE SECONDARY ("AGS Secondary") 4 SUMMER MONTHS (June Through September)

Present Rates vs.

											osed Rates								
_	Lo							Present	Present	Present			New	New	New	Difference	Difference	Total	Total
	nd Fac		ergy					<u>Distribution</u>	BGS and Other Charges	Total			Distribution	BGS and Other Charges	Total		and Other Charges	Difference	Difference
(kW 25) (9		Wh) Metere 650	ed kW Bil 25	lled kW 25 9	D Demand 317.00	D Energy \$ (10.17) \$	(\$) 500.05	\$ 490.59	(\$) \$ 990.65	D Demand \$ 380.25	D Energy \$ (10,17)	\$ 563.30	\$ 490.59 \$	(\$) 1.053.90	(\$) \$ 63.25 \$	(\$)	\$ 63.25	(%) 6.4%
25	31		475	25 25	25 \$		\$ (10.17) \$ \$ (15.25) \$		\$ 665.14					\$ 665.14 \$		\$ 63.25 \$ \$ 63.25 \$	-	\$ 63.25	5.5%
25	41		300	25	25 9		\$ (20.33) \$			\$ 1,329.58			\$ 553.14			\$ 63.25 \$		\$ 63.25	4.8%
25	50		125	25	25 9		\$ (25.41) \$			\$ 1,499.04		\$ (25.41)		\$ 1,014.23 \$		\$ 63.25 \$		\$ 63.25	4.2%
25	6		,950	25	25 \$		\$ (30.50) \$			\$ 1,668.50				\$ 1,188.78 \$		\$ 63.25 \$	_	\$ 63.25	3.8%
25	70		.775	25	25 9		\$ (35.58) \$		\$ 1,363,33	\$ 1.837.97				\$ 1,363.33 \$		\$ 63.25 \$	-	\$ 63.25	3.4%
25	8	0 14,	,600	25	25 \$	317.00	\$ (40.66) \$	469.56	\$ 1,537.87	\$ 2,007.43				\$ 1,537.87 \$	2,070.68	\$ 63.25 \$	-	\$ 63.25	3.2%
50	20	0 7,	300	50	50 \$	634.00	\$ (20.33) \$	806.89	\$ 981.19	\$ 1,788.08	\$ 760.50	\$ (20.33)	\$ 933.39	\$ 981.19 \$	1,914.58	\$ 126.50 \$	-	\$ 126.50	7.1%
50	30	0 10,	,950	50	50 \$	634.00	\$ (30.50) \$	796.72	\$ 1,330.28	\$ 2,127.00	\$ 760.50	\$ (30.50)	\$ 923.22	\$ 1,330.28 \$		\$ 126.50 \$	-	\$ 126.50	5.9%
50	40		,600	50	50 \$		\$ (40.66) \$		\$ 1,679.37	\$ 2,465.93	*			\$ 1,679.37 \$		\$ 126.50 \$	-	\$ 126.50	5.1%
50	50		,250	50	50 \$		\$ (50.83) \$	776.39		\$ 2,804.86	*	+ ()		\$ 2,028.47 \$		\$ 126.50 \$	-	\$ 126.50	4.5%
50	6		,900	50	50 \$		\$ (60.99) \$	766.23		\$ 3,143.79	*	,		\$ 2,377.56 \$		\$ 126.50 \$	-	\$ 126.50	4.0%
50	70		,550	50	50 \$		\$ (71.16) \$			\$ 3,482.72			\$ 882.56	. ,		\$ 126.50 \$	-	\$ 126.50	3.6%
50 100	80		,200 .600	50 100	50 \$		\$ (81.32) \$ \$ (40.66) \$		\$ 3,075.75	\$ 3,821.64 \$ 3.382.93	*			\$ 3,075.75 \$ \$ 1.962.37 \$		\$ 126.50 \$ \$ 253.00 \$	-	\$ 126.50 \$ 253.00	3.3% 7.5%
100			.900	100		,=	\$ (40.66) \$ \$ (60.99) \$		\$ 1,962.37 \$ 2,660.56	\$ 3,382.93 \$ 4,060.79	¥ .,==	+ ()	.,	\$ 1,962.37 \$ \$ 2,660.56 \$		\$ 253.00 \$ \$ 253.00 \$	-	\$ 253.00	7.5% 6.2%
100			,900	100			\$ (81.32) \$			\$ 4,060.79				\$ 2,000.50 \$		\$ 253.00 \$	-	\$ 253.00	5.3%
100			.500	100			\$ (101.65) \$,		\$ 5.416.50				\$ 4.056.93 \$,	\$ 253.00 \$		\$ 253.00	4.7%
100			,800	100			\$ (121.98) \$,		\$ 6,094.36				\$ 4,755.12 \$		\$ 253.00 \$	_	\$ 253.00	4.2%
100	70		.100	100			\$ (142.31) \$			\$ 6,772,21				\$ 5,453.31 \$		\$ 253.00 \$	-	\$ 253.00	3.7%
100	8	0 58,	400	100			\$ (162.64) \$			\$ 7,450.07				\$ 6,151.49 \$		\$ 253.00 \$		\$ 253.00	3.4%
300	20	0 43,	,800	300	300 \$	3,804.00	\$ (121.98) \$	3,875.24	\$ 5,887.12	\$ 9,762.36	\$ 4,563.00	\$ (121.98)	\$ 4,634.24	\$ 5,887.12 \$	10,521.36	\$ 759.00 \$	-	\$ 759.00	7.8%
300	30	0 65,	,700	300	300 \$	\$ 3,804.00	\$ (182.97) \$	3,814.25	\$ 7,981.68	\$ 11,795.92	\$ 4,563.00	\$ (182.97)	\$ 4,573.25	\$ 7,981.68 \$	12,554.92	\$ 759.00 \$	-	\$ 759.00	6.4%
300	40		,600	300	300 \$	\$ 3,804.00	\$ (243.97) \$	3,753.25	\$ 10,076.24	\$ 13,829.49	\$ 4,563.00	\$ (243.97)	\$ 4,512.25	\$ 10,076.24 \$		\$ 759.00 \$	-	\$ 759.00	5.5%
300			9,500	300			\$ (304.96) \$	-,		\$ 15,863.06					16,622.06	\$ 759.00 \$	-	\$ 759.00	4.8%
300	6		1,400	300		,	\$ (365.95) \$			\$ 17,896.63	\$ 4,563.00				18,655.63	\$ 759.00 \$	-	\$ 759.00	4.2%
300			3,300	300		,	\$ (426.94) \$		\$ 16,359.92	\$ 19,930.20				\$ 16,359.92 \$		\$ 759.00 \$	-	\$ 759.00	3.8%
300	80		5,200	300			\$ (487.93) \$			\$ 21,963.77	+ .,		4 .,=	\$ 18,454.48 \$		\$ 759.00 \$	-	\$ 759.00	3.5%
500 500	20		,000 9,500	500 500			\$ (203.31) \$ \$ (304.96) \$			\$ 16,141.78 \$ 19,531.06			+ · · · · · · · · · · · · · · · · · · ·	\$ 9,811.87 \$ \$ 13.302.80 \$	20,796.06	\$1,265.00 \$ \$1,265.00 \$	-	\$ 1,265.00 \$ 1,265.00	7.8% 6.5%
500			5,000 6,000	500			\$ (304.96) \$ \$ (406.61) \$			\$ 22,920.34			.,	\$ 13,302.80 \$ \$ 16,793.73 \$		\$1,265.00 \$	-	\$ 1,265.00	5.5%
500			2,500	500			\$ (508.26) \$			\$ 26,309.62				\$ 20,284.67 \$		\$1,265.00 \$		\$ 1,265.00	4.8%
500	6		9.000	500			\$ (609.92) \$			\$ 29.698.90				\$ 23,775.60 \$		\$1,265.00 \$		\$ 1,265.00	4.3%
500			5,500	500			\$ (711.57) \$			\$ 33,088.18					34.353.18	\$1,265.00 \$	_	\$ 1,265.00	3.8%
500			2,000	500			\$ (813.22) \$								37,742.46	\$1,265.00 \$	-	\$ 1,265.00	3.5%
750	30	0 164	1,250	750			\$ (457.44) \$			\$ 29,199.98				\$ 19,954.20 \$		\$1,897.50 \$		\$ 1,897.50	6.5%
750	40	0 219	9,000	750	750 \$	9,510.00	\$ (609.92) \$	9,093.31		\$ 34,283.90	\$ 11,407.50	\$ (609.92)	\$ 10,990.81	\$ 25,190.60 \$		\$1,897.50 \$	-	\$ 1,897.50	5.5%
750	50	0 273	3,750	750	750 \$	\$ 9,510.00	\$ (762.39) \$	8,940.83	\$ 30,427.00	\$ 39,367.82	\$ 11,407.50	\$ (762.39)	\$ 10,838.33	\$ 30,427.00 \$	41,265.32	\$1,897.50 \$	-	\$ 1,897.50	4.8%
750	6		3,500	750	750 \$	\$ 9,510.00	\$ (914.87) \$	8,788.35	\$ 35,663.40	\$ 44,451.74	\$ 11,407.50	\$ (914.87)	\$ 10,685.85		46,349.24	\$1,897.50 \$	-	\$ 1,897.50	4.3%
750			3,250	750			\$ (1,067.35) \$		\$ 40,899.80	\$ 49,535.67		\$ (1,067.35)		\$ 40,899.80 \$		\$1,897.50 \$	-	\$ 1,897.50	3.8%
750	80		3,000	750			\$ (1,219.83) \$	8,483.39		\$ 54,619.59		\$ (1,219.83)			56,517.09	\$1,897.50 \$	-	\$ 1,897.50	3.5%
750	90		2,750	750			\$ (1,372.31) \$			\$ 59,703.51			\$ 10,228.41			\$1,897.50 \$	-	\$ 1,897.50	3.2%
100				1,000			\$ (609.92) \$			\$ 38,868.90		\$ (609.92)		\$ 26,605.60 \$		\$2,530.00 \$	-	\$ 2,530.00	6.5%
100				1,000			\$ (813.22) \$			\$ 45,647.46				\$ 33,587.46 \$ \$ 40.569.33 \$		\$2,530.00 \$ \$2,530.00 \$	-	\$ 2,530.00	5.5%
100				1,000 1,000			\$ (1,016.53) \$ \$ (1,219.83) \$			\$ 52,426.03 \$ 59,204.59		\$ (1,016.53) \$ (1,219.83)		\$ 40,569.33 \$ \$ 47,551.20 \$		\$2,530.00 \$ \$2,530.00 \$	-	\$ 2,530.00 \$ 2,530.00	4.8% 4.3%
100				1,000			\$ (1,219.03) \$ \$ (1,423.14) \$			\$ 65,983.15		\$ (1,423.14)		\$ 54,533.06 \$		\$2,530.00 \$	-	\$ 2,530.00	3.8%
100				1,000			\$ (1,626.44) \$			\$ 72,761.71		\$ (1,626.44)			75.291.71	\$2,530.00 \$ \$2,530.00 \$	-	\$ 2,530.00	3.5%
100				1,000			\$ (1,829.75) \$			\$ 79,540.27	\$ 15,210.00			\$ 68,496.79 \$		\$2,530.00 \$	_	\$ 2,530.00	3.2%
200				2,000			\$ (1,219.83) \$			\$ 77,544.59		\$ (1,219.83)		\$ 53,211.20 \$		\$5,060.00 \$	-	\$ 5,060.00	6.5%
200				2,000			\$ (1,626.44) \$			\$ 91,101.71		\$ (1,626.44)		\$ 67,174.93 \$		\$5,060.00 \$	-	\$ 5,060.00	5.6%
200	50	0 730	0,000	2,000	2,000	\$ 25,360.00	\$ (2,033.05) \$	23,520.17	\$ 81,138.66	\$ 104,658.83		\$ (2,033.05)		\$ 81,138.66 \$	109,718.83	\$5,060.00 \$	-	\$ 5,060.00	4.8%
200				2,000	2,000	\$ 25,360.00	\$ (2,439.66) \$	23,113.56	\$ 95,102.39	\$ 118,215.95	\$ 30,420.00	\$ (2,439.66)	\$ 28,173.56		123,275.95	\$5,060.00 \$	-	\$ 5,060.00	4.3%
200				2,000			\$ (2,846.27) \$			\$ 131,773.07	\$ 30,420.00			\$ 109,066.12 \$		\$5,060.00 \$	-	\$ 5,060.00	3.8%
200				2,000			\$ (3,252.88) \$			\$ 145,330.20			\$ 27,360.34			\$5,060.00 \$	-	\$ 5,060.00	3.5%
200	91	0 1,31	4,000	2,000	2,000	\$ 25,360.00	\$ (3,659.49) \$	21,893.73	\$ 136,993.59	\$ 158,887.32	\$ 30,420.00	\$ (3,659.49)	\$ 26,953.73	\$ 136,993.59 \$	163,947.32	\$5,060.00 \$	-	\$ 5,060.00	3.2%

ATLANTIC CITY ELECTRIC COMPANY ANNUAL GENERAL SERVICE SECONDARY ("AGS Secondary") Annual Average

Present Rates vs.

								Pron	vs. osed Rates							
	Load					Present	Present	Present	oscu rates		New	New	New	Difference	Difference Tota	Total
Deman	d Factor	Energy				Distribution	BGS and Other Charges	Total			Distribution	BGS and Other Charges	Total	Distribution BGS a	nd Other Charges Differen	ce Difference
(kW)	(%)	(kWh)		illed kW D Demand	D Energy	(\$)	(\$)	(\$)	D Demand	D Energy	(\$)	(\$)	(\$)	(\$)	(\$)	(%)
25	20	3,650	25.00	22 \$ 317.00				\$ 985.17	\$ 380.25	\$ (10.17)		\$ 485.12		\$ 63.25 \$	- \$ 63	
25	30	5,475	25.00	22 \$ 317.00				\$ 1,151.90					\$ 1,215.15	\$ 63.25 \$	- \$ 63	
25	40	7,300	25.00	22 \$ 317.00				\$ 1,318.63			\$ 553.14			\$ 63.25 \$	- \$ 63 - \$ 63	
25 25	50 60	9,125 10.950	25.00 25.00	22 \$ 317.00 22 \$ 317.00				\$ 1,485.35 \$ 1.652.08	Ψ 000.20	Ψ (20.11)			\$ 1,548.60 \$ 1.715.33	\$ 63.25 \$ \$ 63.25 \$		25 4.3% 25 3.8%
25	70	12,775	25.00	22 \$ 317.00				\$ 1,052.06					\$ 1,715.33	\$ 63.25 \$ \$ 63.25 \$		25 3.5%
25	80	14,600	25.00	22 \$ 317.00				\$ 1,985.53		,			\$ 2.048.78	\$ 63.25 \$	- \$ 63	
50	20	7.300	50.00	47 \$ 634.00				\$ 1,777.13					\$ 1,903.63	\$ 126.50 \$	- \$ 126	
50	30	10.950	50.00	47 \$ 634.00				\$ 2,110,58					\$ 2,237.08	\$ 126.50 \$	- \$ 126	
50	40	14,600	50.00	47 \$ 634.00	\$ (40.66) \$	786.56	\$ 1,657.47	\$ 2,444.03	\$ 760.50	\$ (40.66)	\$ 913.06	\$ 1,657.47	\$ 2,570.53	\$ 126.50 \$	- \$ 126	50 5.2%
50	50	18,250	50.00	47 \$ 634.00	\$ (50.83) \$	776.39	\$ 2,001.09	\$ 2,777.49	\$ 760.50	\$ (50.83)	\$ 902.89	\$ 2,001.09	\$ 2,903.99	\$ 126.50 \$	- \$ 126	50 4.6%
50	60	21,900	50.00	47 \$ 634.00				\$ 3,110.94				\$ 2,344.71		\$ 126.50 \$	- \$ 126	
50	70	25,550	50.00	47 \$ 634.00				\$ 3,444.39		\$ (71.16)			\$ 3,570.89	\$ 126.50 \$	- \$ 126	
50	80	29,200	50.00	47 \$ 634.00				\$ 3,777.84			ψ 0. <u>L</u> . 10	\$ 3,031.95		\$ 126.50 \$	- \$ 126	
100	20	14,600	100.00	97 \$ 1,268.00				\$ 3,361.03					\$ 3,614.03	\$ 253.00 \$	- \$ 253	
100	30	21,900	100.00	97 \$ 1,268.00				\$ 4,027.94				\$ 2,627.71		\$ 253.00 \$	- \$ 253	
100 100	40 50	29,200 36.500	100.00 100.00	97 \$ 1,268.00				\$ 4,694.84 \$ 5.361.75	+ .,				\$ 4,947.84 \$ 5.614.75	\$ 253.00 \$ \$ 253.00 \$	- \$ 253 - \$ 253	
100	60	43,800	100.00	97 \$ 1,268.00 97 \$ 1,268.00		,		\$ 6,028.66				\$ 4,002.18 \$ 4,689.42		\$ 253.00 \$ \$ 253.00 \$	- \$ 253 - \$ 253	
100	70	51,100	100.00	97 \$ 1,268.00				\$ 6,695,56			\$ 1,592.24		\$ 6.948.56	\$ 253.00 \$ \$ 253.00 \$	- \$ 250 - \$ 253	
100	80	58,400	100.00	97 \$ 1,268.00				\$ 7,362.47				\$ 6,063.89		\$ 253.00 \$	- \$ 253	
300	20	43.800	300.00	297 \$ 3,804.00				\$ 9.696.66					\$ 10.455.66	\$ 759.00 \$	- \$ 759	
300	30	65,700	300.00	297 \$ 3,804.00				\$ 11,697.37					\$ 12,456.37	\$ 759.00 \$	- \$ 759	
300	40	87,600	300.00	297 \$ 3,804.00			\$ 9,944.84	\$ 13,698.09	\$ 4,563.00			\$ 9,944.84	\$ 14,457.09	\$ 759.00 \$	- \$ 759	
300	50	109,500	300.00	297 \$ 3,804.00	\$ (304.96) \$	3,692.26	\$ 12,006.55	\$ 15,698.81	\$ 4,563.00	\$ (304.96)	\$ 4,451.26	\$ 12,006.55	\$ 16,457.81	\$ 759.00 \$	- \$ 759	00 4.8%
300	60	131,400	300.00	297 \$ 3,804.00			\$ 14,068.26	\$ 17,699.53					\$ 18,458.53	\$ 759.00 \$	- \$ 759	
300	70	153,300	300.00	297 \$ 3,804.00				\$ 19,700.25					\$ 20,459.25	\$ 759.00 \$	- \$ 759	
300	80	175,200	300.00	297 \$ 3,804.00				\$ 21,700.97					\$ 22,459.97	\$ 759.00 \$	- \$ 759	
500	20	73,000	500.00	497 \$ 6,340.00				\$ 16,032.28					\$ 17,297.28	\$1,265.00 \$	- \$ 1,265	
500 500	30 40	109,500 146,000	500.00	497 \$ 6,340.00				\$ 19,366.81	+ .,				\$ 20,631.81	\$1,265.00 \$ \$1,265.00 \$	- \$ 1,265 - \$ 1,265	
500	50	182,500	500.00 500.00	497 \$ 6,340.00 497 \$ 6.340.00				\$ 22,701.34 \$ 26.035.87	* .,		\$ 7,391.61 \$ 7,289.96		\$ 23,966.34 \$ 27,300.87	\$1,265.00 \$ \$1,265.00 \$	- \$ 1,265 - \$ 1,265	
500	60	219.000	500.00	497 \$ 6,340.00		.,	,	\$ 29,370.40			\$ 7,289.96		\$ 30.635.40	\$1,265.00 \$	- \$ 1,265 - \$ 1.265	
500	70	255,500	500.00	497 \$ 6.340.00				\$ 32.704.93					\$ 33,969,93	\$1,265.00 \$ \$1.265.00 \$	- \$ 1,265	
500	80	292,000	500.00	497 \$ 6,340.00		.,		\$ 36,039.46					\$ 37,304.46	\$1,265.00 \$	- \$ 1,265	
750	30	164,250	750.00	747 \$ 9,510.00				\$ 28,953,61					\$ 30,851.11	\$1.897.50 \$	- \$ 1.897	
750	40	219,000	750.00	747 \$ 9,510.00	\$ (609.92) \$	9,093.31	\$ 24,862.10	\$ 33,955.40	\$ 11,407.50	\$ (609.92)	\$ 10,990.81		\$ 35,852.90	\$1,897.50 \$	- \$ 1,897	50 5.6%
750	50	273,750	750.00	747 \$ 9,510.00		8,940.83		\$ 38,957.20					\$ 40,854.70	\$1,897.50 \$	- \$ 1,897	
750	60	328,500	750.00	747 \$ 9,510.00				\$ 43,958.99					\$ 45,856.49	\$1,897.50 \$	- \$ 1,897	
750	70	383,250	750.00		\$ (1,067.35) \$			\$ 48,960.79	\$ 11,407.50				\$ 50,858.29	\$1,897.50 \$	- \$ 1,897	
750	80	438,000	750.00	747 \$ 9,510.00				\$ 53,962.59	\$ 11,407.50				\$ 55,860.09	\$1,897.50 \$	- \$ 1,897	
750	90	492,750	750.00	747 \$ 9,510.00		,		\$ 58,964.38	\$ 11,407.50				\$ 60,861.88	\$1,897.50 \$	- \$ 1,897	
1,000	30	219,000	1,000.00	997 \$ 12,680.00				\$ 38,540.40					\$ 41,070.40	\$2,530.00 \$	- \$ 2,530	
1,000	40	292,000	1,000.00	997 \$ 12,680.00				\$ 45,209.46			,		\$ 47,739.46	\$2,530.00 \$	- \$ 2,530	
1,000	50 60	365,000 438,000	1,000.00 1,000.00	997 \$ 12,680.00	\$ (1,016.53) \$ \$ (1,219.83) \$			\$ 51,878.53 \$ 58,547.59	\$ 15,210.00 \$ 15,210.00				\$ 54,408.53 \$ 61,077.59	\$2,530.00 \$ \$2,530.00 \$	- \$ 2,530 - \$ 2,530	
1,000	70	511,000	1,000.00		\$ (1,219.83) \$			\$ 65,216.65					\$ 67,746.65	\$2,530.00 \$ \$2,530.00 \$	- \$ 2,530 - \$ 2,530	
1,000	80	584.000	1,000.00	997 \$ 12,680.00				\$ 71,885.71					\$ 74,415.71	\$2,530.00 \$	- \$ 2,530 - \$ 2,530	
1,000	90	657,000	1,000.00		\$ (1,829.75) \$			\$ 78,554.77	\$ 15,210.00				\$ 81,084.77	\$2,530.00 \$	- \$ 2,530	
2,000	30	438,000	2,000.00	1997 \$ 25,360.00				\$ 76,887.59	\$ 30,420.00				\$ 81,947.59	\$5,060.00 \$	- \$ 5,060	
2,000	40	584,000	2,000.00	1997 \$ 25,360.00				\$ 90,225.71	\$ 30,420.00				\$ 95,285.71	\$5,060.00 \$	- \$ 5,060	
2,000	50	730,000	2,000.00		\$ (2,033.05) \$			\$ 103,563.83	\$ 30,420.00				\$ 108,623.83	\$5,060.00 \$	- \$ 5,060	
2,000	60	876,000	2,000.00	1997 \$ 25,360.00			\$ 93,788.39	\$ 116,901.95					\$ 121,961.95	\$5,060.00 \$	- \$ 5,060	
2,000	70	1,022,000	2,000.00	1997 \$ 25,360.00				\$ 130,240.07	\$ 30,420.00			\$ 107,533.12		\$5,060.00 \$	- \$ 5,060	
2,000	80	1,168,000	2,000.00		\$ (3,252.88) \$			\$ 143,578.20	\$ 30,420.00					\$5,060.00 \$	- \$ 5,060	
2,000	90	1,314,000	2,000.00	1997 \$ 25,360.00	\$ (3,659.49) \$	21,893.73	\$ 135,022.59	\$ 156,916.32	\$ 30,420.00	\$ (3,659.49)	\$ 26,953.73	\$ 135,022.59	\$ 161,976.32	\$5,060.00 \$	- \$ 5,060	00 3.2%

ATLANTIC CITY ELECTRIC COMPANY ANNUAL GENERAL SERVICE PRIMARY ("AGS Primary") 8 WINTER MONTHS (October Through May)

Present Rates vs.

									Pr	oposed Rates								
	Load	_					Present	Present	Present			New	New	New	Difference		Total	Total
Demand (kW)	Factor (%)	Energy (kWh)	Metered kW B	Mal land	D Domond	D Energy	Distribution (\$)	BGS and Other Charges (\$)	Total (\$)	D Demand	D Energy	Distribution (\$)	BGS and Other Charges (\$)	Total (\$)	Distribution (\$)	BGS and Other Charges (\$)	Difference (\$)	Difference (%)
25	20	3,650	25	25 \$		\$ (5.92)		\$ 464.64				4		(+/	\$ 142.94		\$ 142.94	9.8%
25	30	5,475	25	25 \$				\$ 626.34		\$ 295.50			\$ 626.34		\$ 142.94		\$ 142.94	8.9%
25	40	7,300	25	25 \$		\$ (11.83)								\$ 1,914.04	\$ 142.94		\$ 142.94	8.1%
25	50	9,125	25	25 \$	250.75	\$ (14.79)	\$ 980.11	\$ 949.73	\$ 1,929.84	\$ 295.50	\$ (14.79)	\$ 1,123.05	\$ 949.73	\$ 2,072.78	\$ 142.94	\$ -	\$ 142.94	7.4%
25	60	10,950	25	25 \$		\$ (17.75)		\$ 1,111.43				\$ 1,120.09		\$ 2,231.52	\$ 142.94		\$ 142.94	6.8%
25	70	12,775	25	25 \$		\$ (20.71)		\$ 1,273.13				\$ 1,117.13		\$ 2,390.26	\$ 142.94		\$ 142.94	6.4%
25	80	14,600	25	25 \$		\$ (23.67)		\$ 1,434.82				\$ 1,114.17		\$ 2,549.00	\$ 142.94		\$ 142.94	5.9%
50 50	20 30	7,300 10.950	50 50	50 \$ 50 \$		\$ (11.83) \$ (17.75)		\$ 929.29 \$ 1,252.68				, .=		\$ 2,350.79 \$ 2,668.27	\$ 187.69 \$ 187.69		\$ 187.69 \$ 187.69	8.7% 7.6%
50	40	14,600	50	50 \$				\$ 1,576.07				\$ 1,409.67		\$ 2,000.27	\$ 187.69		\$ 187.69	6.7%
50	50	18,250	50	50 \$		\$ (29.58)		\$ 1,899.47					\$ 1,899.47		\$ 187.69		\$ 187.69	6.0%
50	60	21,900	50	50 \$		\$ (35.50)				\$ 591.00				\$ 3,620.70	\$ 187.69		\$ 187.69	5.5%
50	70	25,550	50	50 \$	501.50	\$ (41.42)	\$ 1,204.23	\$ 2,546.26			\$ (41.42)	\$ 1,391.92	\$ 2,546.26	\$ 3,938.18	\$ 187.69		\$ 187.69	5.0%
50	80	29,200	50	50 \$	501.50	\$ (47.33)		\$ 2,869.65			\$ (47.33)	\$ 1,386.01	\$ 2,869.65	\$ 4,255.66	\$ 187.69		\$ 187.69	4.6%
100	20	14,600	100		1,003.00	\$ (23.67)		\$ 1,858.57				\$ 2,000.67	\$ 1,858.57		\$ 277.19		\$ 277.19	7.7%
100	30	21,900	100		1,003.00	\$ (35.50)		\$ 2,505.36		\$ 1,182.00		\$ 1,988.84		\$ 4,494.20	\$ 277.19		\$ 277.19	6.6%
100	40	29,200	100		1,003.00	\$ (47.33)		\$ 3,152.15		\$ 1,182.00		\$ 1,977.01		\$ 5,129.16	\$ 277.19		\$ 277.19	5.7%
100 100	50 60	36,500 43,800	100 100		1,003.00 1.003.00	\$ (59.17) \$ (71.00)		\$ 3,798.94 \$ 4.445.72		\$ 1,182.00 \$ 1.182.00		\$ 1,965.17 \$ 1,953.34	\$ 3,798.94 \$ 4.445.72	\$ 5,764.11 \$ 6.399.06	\$ 277.19 \$ 277.19		\$ 277.19 \$ 277.19	5.1% 4.5%
100	70	51,100	100		,			\$ 4,445.72 \$ 5,092.51				\$ 1,955.54		\$ 7,034.02	\$ 277.19		\$ 277.19	4.1%
100	80	58,400	100		1,003.00	\$ (94.67)		\$ 5,739.30				\$ 1,929.67		\$ 7.668.97	\$ 277.19		\$ 277.19	3.7%
300	20	43,800	300			\$ (71.00)		\$ 5,575.72				\$ 4,317.34		\$ 9,893.06	\$ 635.19		\$ 635.19	6.9%
300	30	65,700	300	300 \$	3,009.00	\$ (106.50)	\$ 3,646.65	\$ 7,516.09	\$ 11,162.74	\$ 3,546.00	\$ (106.50)	\$ 4,281.84	\$ 7,516.09	\$ 11,797.93	\$ 635.19	\$ -	\$ 635.19	5.7%
300	40	87,600	300	300 \$	3,009.00	\$ (142.00)		\$ 9,456.45	\$ 13,067.60	\$ 3,546.00		\$ 4,246.34	\$ 9,456.45	\$ 13,702.79	\$ 635.19	\$ -	\$ 635.19	4.9%
300	50	109,500	300			\$ (177.50)			\$ 14,972.46			\$ 4,210.84	\$ 11,396.81		\$ 635.19		\$ 635.19	4.2%
300	60	131,400	300			\$ (213.00)			\$ 16,877.32			\$ 4,175.34	\$ 13,337.17		\$ 635.19		\$ 635.19	3.8%
300	70	153,300	300				φ 0,001.00		\$ 18,782.18			\$ 4,139.84	\$ 15,277.53		\$ 635.19		\$ 635.19 \$ 635.19	3.4%
300 500	80 20	175,200 73.000	300 500			\$ (284.00) \$ (118.33)			\$ 20,687.05 \$ 14,933.69	\$ 3,546.00 \$ 5.910.00		\$ 4,104.34 \$ 6.634.01	\$ 17,217.90	\$ 21,322.24 \$ 15.926.88	\$ 635.19 \$ 993.19		\$ 635.19 \$ 993.19	3.1% 6.7%
500	30	109,500	500			\$ (177.50)			\$ 18,108.46			\$ 6,574.84		\$ 19,101.65	\$ 993.19		\$ 993.19	5.5%
500	40	146,000	500						\$ 21,283.23			\$ 6,515.67		\$ 22,276.42	\$ 993.19		\$ 993.19	4.7%
500	50	182,500	500			\$ (295.83)			\$ 24,458.00			\$ 6,456.51		\$ 25,451.19	\$ 993.19	\$ -	\$ 993.19	4.1%
500	60	219,000	500	500 \$	5,015.00	\$ (355.00)			\$ 27,632.77			\$ 6,397.34	\$ 22,228.62		\$ 993.19		\$ 993.19	3.6%
500	70	255,500	500			\$ (414.17)			\$ 30,807.54			\$ 6,338.17	\$ 25,462.56		\$ 993.19		\$ 993.19	3.2%
500	80	292,000	500			\$ (473.33)			\$ 33,982.31	\$ 5,910.00		\$ 6,279.01		\$ 34,975.50	\$ 993.19		\$ 993.19	2.9%
750 750	30 40	164,250 219.000	750			\$ (266.25) \$ (355.00)	φ 0,000.10		\$ 26,790.62			\$ 9,441.09	\$ 18,790.21		\$1,440.69		\$ 1,440.69 \$ 1,440.69	5.4%
750	50	273,750	750 750		7,522.50 7,522.50	\$ (355.00)			\$ 31,552.77 \$ 36,314.93	\$ 8,865.00 \$ 8.865.00		\$ 9,352.34 \$ 9,263.59	\$ 23,641.12 \$ 28,492.02		\$1,440.69 \$1,440.69		\$ 1,440.69 \$ 1.440.69	4.6% 4.0%
750	60	328,500	750 750			\$ (532.50)			\$ 41,077.08			\$ 9,174.84		\$ 42,517.77	\$1,440.69		\$ 1,440.69	3.5%
750	70	383,250	750				\$ 7.645.40		\$ 45,839.24			\$ 9,086.09	\$ 38,193.83		\$1,440.69		\$ 1,440.69	3.1%
750	80	438,000	750			\$ (710.00)			\$ 50,601.39			\$ 8,997.34		\$ 52,042.08	\$1,440.69		\$ 1,440.69	2.8%
750	90	492,750	750	750 \$	7,522.50	\$ (798.75)	\$ 7,467.90	\$ 47,895.64	\$ 55,363.55	\$ 8,865.00	\$ (798.75)	\$ 8,908.59	\$ 47,895.64	\$ 56,804.24	\$1,440.69	\$ -	\$ 1,440.69	2.6%
1000	30	219,000	1,000	1,000 \$	10,030.00	\$ (355.00)	\$ 10,419.15	\$ 25,053.62	\$ 35,472.77	\$ 11,820.00	\$ (355.00)	\$ 12,307.34	\$ 25,053.62	\$ 37,360.96	\$1,888.19	\$ -	\$ 1,888.19	5.3%
1000	40	292,000	1,000				\$ 10,300.82		\$ 41,822.31	\$ 11,820.00		\$ 12,189.01	\$ 31,521.49		\$1,888.19		\$ 1,888.19	4.5%
1000	50	365,000	1,000			\$ (591.67)			\$ 48,171.85	\$ 11,820.00		\$ 12,070.68	\$ 37,989.37		\$1,888.19		\$ 1,888.19	3.9%
1000 1000	60 70	438,000 511,000	1,000 1,000			\$ (710.00) \$ (828.33)	\$ 10,064.15 \$ 9,945.82		\$ 54,521.39 \$ 60,870.93			\$ 11,952.34 \$ 11,834.01	\$ 44,457.24 \$ 50,925.11		\$1,888.19 \$1,888.19		\$ 1,888.19 \$ 1,888.19	3.5% 3.1%
1000	80	584,000	1,000						\$ 67,220.47	\$ 11,820.00		\$ 11,715.68	\$ 57,392.98		\$1,888.19		\$ 1,888.19	2.8%
1000	90	657,000	1,000				\$ 9,709.15		\$ 73,570.01		\$ (1,065.00)		\$ 63,860.86		\$1,888.19		\$ 1,888.19	2.6%
2000	30	438,000	2,000			\$ (710.00)			\$ 70,201.39		\$ (710.00)		\$ 50,107.24		\$3,678.19		\$ 3,678.19	5.2%
2000	40	584,000	2,000			\$ (946.66)			\$ 82,900.47		\$ (946.66)		\$ 63,042.98		\$3,678.19		\$ 3,678.19	4.4%
2000	50	730,000	2,000						\$ 95,599.55		\$ (1,183.33)		\$ 75,978.73		\$3,678.19		\$ 3,678.19	3.8%
2000	60	876,000	2,000						\$ 108,298.63		\$ (1,420.00)		\$ 88,914.48		\$3,678.19		\$ 3,678.19	3.4%
2000	70	1,022,000	2,000			\$ (1,656.66)			\$ 120,997.71		\$ (1,656.66)		\$ 101,850.22		\$3,678.19		\$ 3,678.19	3.0%
2000 2000	80 90	1,168,000 1.314.000	2,000 2,000			\$ (1,893.33)	\$ 18,910.82 \$ 18,674.16		\$ 133,696.79 \$ 146,395.87		\$ (1,893.33)		\$ 114,785.97 \$ 127,721,71		\$3,678.19 \$3.678.19		\$ 3,678.19 \$ 3,678.19	2.8% 2.5%
2000	90	1,314,000	2,000	2,000 \$	20,000.00	φ (Z, 1Z9.99)	φ 10,074.16	φ 121,721.71	y 140,395.87	\$ 23,040.00	\$ (2,129.99)	φ ∠∠,,35∠,35	φ 121,121./1	9 13U,U14.Ub	და,ი <i>1</i> 8.19	φ -	φ 3,070.19	2.5%

ATLANTIC CITY ELECTRIC COMPANY ANNUAL GENERAL SERVICE PRIMARY ("AGS Primary") 4 SUMMER MONTHS (June Through September)

Present Rates vs.

										posed Rates								
	Load	_					Present	Present	Present			New	New	New	Difference	Difference	Total	Total
Demand (kW)	Factor (%)	Energy (kWh)	Metered kW B	NA balls	D Domond	D Energy	Distribution (\$)	BGS and Other Charges (\$)	Total (\$)	D Demand	D Energy	Distribution (\$)	BGS and Other Charges (\$)	Total (\$)	Distribution (\$)	BGS and Other Charges (\$)	Difference (\$)	Difference (%)
25	20	3,650	25	25		\$ (5.92) S		\$ 472.31	\$ 1,461.30	\$ 295.50		\$ 1.131.92	\+/	\$ 1.604.24	(+)	\$ -	\$ 142.94	9.8%
25	30	5,475	25	25		\$ (8.87)			\$ 1,623.87	\$ 295.50		\$ 1,128.97		\$ 1,766.81		\$ -	\$ 142.94	8.8%
25	40	7,300	25	25								\$ 1,126.01		\$ 1,929.38		\$ -	\$ 142.94	8.0%
25	50	9,125	25	25	\$ 250.75	\$ (14.79)	980.11	\$ 968.91	\$ 1,949.01	\$ 295.50	\$ (14.79)	\$ 1,123.05	\$ 968.91	\$ 2,091.95	\$ 142.94	\$ -	\$ 142.94	7.3%
25	60	10,950	25	25		\$ (17.75)				\$ 295.50				\$ 2,254.53		\$ -	\$ 142.94	6.8%
25	70	12,775	25	25		\$ (20.71)			\$ 2,274.16	\$ 295.50				\$ 2,417.10	Ψ 112.01	\$ -	\$ 142.94	6.3%
25	80	14,600	25	25		\$ (23.67)			\$ 2,436.73	\$ 295.50		\$ 1,114.17		\$ 2,579.67	Ψ	\$ -	\$ 142.94	5.9%
50 50	20 30	7,300 10.950	50 50	50 50		\$ (11.83) \$ \$ (17.75) \$			\$ 2,178.44 \$ 2,503.59	\$ 591.00 \$ 591.00		\$ 1,421.51 \$ 1,415.59		\$ 2,366.13 \$ 2.691.28	\$ 187.69 \$ 187.69	\$ - \$ -	\$ 187.69 \$ 187.69	8.6% 7.5%
50	40	14,600	50	50		\$ (23.67)			\$ 2,828.73	,		\$ 1,409.67		\$ 2,091.26		\$ -	\$ 187.69	6.6%
50	50	18,250	50	50		\$ (29.58)			\$ 3,153,88	\$ 591.00		\$ 1,403.76	\$ 1,937.81		\$ 187.69	\$ -	\$ 187.69	6.0%
50	60	21,900	50	50		\$ (35.50)						\$ 1,397.84		\$ 3,666.71		\$ -	\$ 187.69	5.4%
50	70	25,550	50	50		\$ (41.42)		\$ 2,599.94				\$ 1,391.92				\$ -	\$ 187.69	4.9%
50	80	29,200	50	50	\$ 501.50	\$ (47.33)	1,198.32	\$ 2,931.00	\$ 4,129.32	\$ 591.00	\$ (47.33)	\$ 1,386.01	\$ 2,931.00	\$ 4,317.01	\$ 187.69	\$ -	\$ 187.69	4.5%
100	20	14,600	100	100		\$ (23.67)			\$ 3,612.73	\$ 1,182.00		\$ 2,000.67	\$ 1,889.25		\$ 277.19	\$ -	\$ 277.19	7.7%
100	30	21,900	100	100		\$ (35.50)			\$ 4,263.02					\$ 4,540.21	Ψ 2υ	\$ -	\$ 277.19	6.5%
100	40	29,200	100		\$ 1,003.00	\$ (47.33)			\$ 4,913.32			\$ 1,977.01		\$ 5,190.51		\$ -	\$ 277.19	5.6%
100 100	50 60	36,500 43,800	100 100		\$ 1,003.00	\$ (59.17)		\$ 3,875.62 \$ 4,537.75				\$ 1,965.17		\$ 5,840.80 \$ 6,491.09		\$ - \$ -	\$ 277.19 \$ 277.19	5.0% 4.5%
100	70	51,100	100		\$ 1,003.00 \$ 1,003.00	\$ (71.00) \$ \$ (82.83) \$			\$ 6,213.90 \$ 6,864.19			.,		\$ 6,491.09 \$ 7.141.38	Ψ 2.77.10	\$ - \$	\$ 277.19	4.0%
100	80	58,400	100		\$ 1,003.00	\$ (94.67)			\$ 7,514.48					\$ 7,791.67	\$ 277.19	\$ -	\$ 277.19	3.7%
300	20	43,800	300		\$ 3,009.00	\$ (71.00)			\$ 9,349.90	\$ 3,546.00			\$ 5,667.75			\$ -	\$ 635.19	6.8%
300	30	65,700	300		\$ 3,009.00	\$ (106.50)			\$ 11,300.77					\$ 11,935.96	\$ 635.19	\$ -	\$ 635.19	5.6%
300	40	87,600	300	300	\$ 3,009.00	\$ (142.00)	3,611.15	\$ 9,640.50	\$ 13,251.65	\$ 3,546.00	\$ (142.00)	\$ 4,246.34	\$ 9,640.50	\$ 13,886.84	\$ 635.19	\$ -	\$ 635.19	4.8%
300	50	109,500	300		\$ 3,009.00	\$ (177.50)			\$ 15,202.52			+ .,=	\$ 11,626.87		\$ 635.19	\$ -	\$ 635.19	4.2%
300	60	131,400	300		\$ 3,009.00	\$ (213.00)			\$ 17,153.39			\$ 4,175.34	\$ 13,613.24		\$ 635.19	\$ -	\$ 635.19	3.7%
300 300	70 80	153,300 175,200	300 300		\$ 3,009.00	\$ (248.50) \$ \$ (284.00) \$			\$ 19,104.27			\$ 4,139.84		\$ 19,739.46 \$ 21,690.33		\$ -	\$ 635.19 \$ 635.19	3.3%
500	20	73,000	500		\$ 3,009.00 \$ 5,015.00	\$ (284.00) \$ \$ (118.33) \$,		\$ 21,055.14 \$ 15,087.06	\$ 3,546.00 \$ 5,910.00		\$ 4,104.34 \$ 6,634.01		\$ 16,080.25		\$ - \$ -	\$ 635.19 \$ 993.19	3.0% 6.6%
500	30	109,500	500		\$ 5,015.00	\$ (177.50)			\$ 18,338.52			\$ 6,574.84		\$ 19,331.71		\$ -	\$ 993.19	5.4%
500	40	146.000	500		\$ 5,015.00	\$ (236.67)			\$ 21,589.98				\$ 16,067.49			\$ -	\$ 993.19	4.6%
500	50	182,500	500		\$ 5,015.00	\$ (295.83)			\$ 24,841.43				\$ 19,378.12		\$ 993.19	\$ -	\$ 993.19	4.0%
500	60	219,000	500		\$ 5,015.00	\$ (355.00)			\$ 28,092.89	\$ 5,910.00		\$ 6,397.34	\$ 22,688.74			\$ -	\$ 993.19	3.5%
500	70	255,500	500		\$ 5,015.00	\$ (414.17)			\$ 31,344.35			\$ 6,338.17		\$ 32,337.54		\$ -	\$ 993.19	3.2%
500	80	292,000	500		\$ 5,015.00	\$ (473.33)			\$ 34,595.80			\$ 6,279.01		\$ 35,588.99		\$ -	\$ 993.19	2.9%
750	30	164,250	750		\$ 7,522.50	\$ (266.25)			\$ 27,135.70	,		,		\$ 28,576.39	¥ · · , · · · · · · · ·	\$ -	\$ 1,440.69	5.3%
750 750	40 50	219,000 273,750	750 750		\$ 7,522.50 \$ 7,522.50	\$ (355.00) \$ \$ (443.75) \$			\$ 32,012.89 \$ 36,890.07			\$ 9,352.34 \$ 9,263.59	\$ 24,101.24 \$ 29,067.17		\$1,440.69 \$1,440.69	\$ - \$ -	\$ 1,440.69 \$ 1,440.69	4.5% 3.9%
750	60	328,500	750 750		\$ 7,522.50	\$ (532.50)			\$ 41.767.26			\$ 9,174.84	\$ 34.033.11			\$ -	\$ 1,440.69	3.4%
750	70	383.250	750		\$ 7.522.50	\$ (621.25)			\$ 46,644,44	,			\$ 38.999.04			\$ -	\$ 1,440.69	3.1%
750	80	438,000	750	750	\$ 7,522.50	\$ (710.00)	7,556.65	\$ 43,964.98	\$ 51,521.63	\$ 8,865.00		\$ 8,997.34	\$ 43,964.98	\$ 52,962.32	\$1,440.69	\$ -	\$ 1,440.69	2.8%
750	90	492,750	750	750	\$ 7,522.50	\$ (798.75)	7,467.90	\$ 48,930.91	\$ 56,398.81	\$ 8,865.00	\$ (798.75)	\$ 8,908.59	\$ 48,930.91	\$ 57,839.50	\$1,440.69	\$ -	\$ 1,440.69	2.6%
1000	30	219,000	1,000		\$ 10,030.00	\$ (355.00)			\$ 35,932.89			\$ 12,307.34	\$ 25,513.74			\$ -	\$ 1,888.19	5.3%
1000	40	292,000	1,000		\$ 10,030.00	\$ (473.33)			\$ 42,435.80					\$ 44,323.99		\$ -	\$ 1,888.19	4.4%
1000	50	365,000	1,000		\$ 10,030.00	\$ (591.67)			\$ 48,938.72			\$ 12,070.68	\$ 38,756.23		+.,	\$ -	\$ 1,888.19	3.9%
1000 1000	60 70	438,000 511,000	1,000 1,000		\$ 10,030.00 \$ 10,030.00	\$ (710.00) \$ \$ (828.33) \$			\$ 55,441.63 \$ 61,944.54	\$ 11,820.00 \$ 11,820.00		\$ 11,952.34 \$ 11,834.01	\$ 45,377.48 \$ 51,998.72			\$ - \$ -	\$ 1,888.19 \$ 1,888.19	3.4% 3.0%
1000	80	584.000	1,000		\$ 10,030.00	\$ (946.66)			\$ 68,447.45	\$ 11,820.00		\$ 11,715.68	\$ 58,619.97			\$ - \$ -	\$ 1,888.19	2.8%
1000	90	657,000	1,000						\$ 74,950.37		\$ (1,065.00)		\$ 65,241.21			\$ -	\$ 1,888.19	2.5%
2000	30	438,000	2,000		\$ 20,060.00	\$ (710.00)			\$ 71,121.63	\$ 23,640.00		\$ 23,772.34	\$ 51,027.48		\$3,678.19	\$ -	\$ 3,678.19	5.2%
2000	40	584,000	2,000		\$ 20,060.00	\$ (946.66)			\$ 84,127.45	\$ 23,640.00			\$ 64,269.97			\$ -	\$ 3,678.19	4.4%
2000	50	730,000	2,000			\$ (1,183.33)			\$ 97,133.28		\$ (1,183.33)		\$ 77,512.46			\$ -	\$ 3,678.19	3.8%
2000	60	876,000	2,000						\$ 110,139.11		\$ (1,420.00)		\$ 90,754.95			\$ -	\$ 3,678.19	3.3%
2000	70	1,022,000	2,000			\$ (1,656.66)			\$ 123,144.93		\$ (1,656.66)		\$ 103,997.44		φο,οι ο. το	\$ -	\$ 3,678.19	3.0%
2000 2000	80 90	1,168,000 1,314,000	2,000 2,000			\$ (1,893.33) \$ \$ (2,129.99) \$			\$ 136,150.76 \$ 149,156.58			\$ 22,589.01 \$ 22,352.35			\$3,678.19 \$3.678.19		\$ 3,678.19 \$ 3,678.19	2.7% 2.5%
2000	90	1,314,000	2,000	2,000	φ ∠υ,υου.υυ	φ (Z, 1Z9.99) ÷	p 10,074.16	φ 130,482.43	φ 149,100.58	a 23,040.00	φ (2,129.99)	φ ∠∠,১ɔ∠.১5	φ 130,462.43	9 132,034.//	93,070.19	φ -	φ 3,070.19	2.5%

ATLANTIC CITY ELECTRIC COMPANY ANNUAL GENERAL SERVICE PRIMARY ("AGS Primary") Annual Average

Present Rates vs.

									posed Rates								
D	Load	F				Present	Present	Present			New	New	New	Difference	Difference	Total	Total
Demand (kW)	(%)	Energy (kWh)	Matered kW Ri	illed kW D Demand	D Energy	Distribution (\$)	BGS and Other Charges (\$)	Total (\$)	D Demand	D Energy	Distribution (\$)	BGS and Other Charges (\$)	Total (\$)	(\$)	BGS and Other Charges (\$)	Difference (\$)	Difference (%)
25	20	3,650	25.00	22 \$ 250.75 \$			\$ 467.20		\$ 295.50			\$ 467.20			\$ -	\$ 142.94	9.8%
25	30	5,475	25.00	22 \$ 250.75 \$			\$ 630.17		\$ 295.50		\$ 1,128.97	\$ 630.17			\$ -	\$ 142.94	8.8%
25	40	7,300	25.00	22 \$ 250.75 \$			\$ 793.15		\$ 295.50				\$ 1,919.16	\$ 142.94	\$ -	\$ 142.94	8.0%
25	50	9,125	25.00	22 \$ 250.75 \$	(14.79)	\$ 980.11	\$ 956.12	\$ 1,936.23	\$ 295.50	\$ (14.79)	\$ 1,123.05	\$ 956.12	\$ 2,079.17	\$ 142.94	\$ -	\$ 142.94	7.4%
25	60	10,950	25.00	22 \$ 250.75 \$			\$ 1,119.10		\$ 295.50		\$ 1,120.09	\$ 1,119.10		· · · · · · · · · · · · · · · · · · ·	\$ -	\$ 142.94	6.8%
25	70	12,775	25.00	22 \$ 250.75 \$			\$ 1,282.07		\$ 295.50		\$ 1,117.13	\$ 1,282.07			\$ -	\$ 142.94	6.3%
25	80	14,600	25.00	22 \$ 250.75 \$			\$ 1,445.05		\$ 295.50		\$ 1,114.17	\$ 1,445.05		· · · · · · · · · · · · · · · · · · ·	\$ -	\$ 142.94	5.9%
50 50	20 30	7,300 10.950	50.00 50.00	47 \$ 501.50 \$ 47 \$ 501.50 \$			\$ 934.40 \$ 1.260.35		\$ 591.00 \$ 591.00		\$ 1,421.51		\$ 2,355.91 \$ 2.675.94	\$ 187.69 \$ 187.69		\$ 187.69 \$ 187.69	8.7% 7.5%
50	40	14,600	50.00	47 \$ 501.50 \$ 47 \$ 501.50 \$			\$ 1,260.35 \$ 1,586.30		\$ 591.00		\$ 1,415.59 \$ 1,409.67		\$ 2,675.94 \$ 2,995.97	\$ 187.69		\$ 187.69	7.5% 6.7%
50	50	18,250	50.00	47 \$ 501.50 \$ 47 \$ 501.50 \$			\$ 1,912.25		\$ 591.00		\$ 1,403.76		\$ 3,316.01	\$ 187.69		\$ 187.69	6.0%
50	60	21,900	50.00	47 \$ 501.50 \$			\$ 2,238.20		\$ 591.00				\$ 3,636.04	\$ 187.69		\$ 187.69	5.4%
50	70	25,550	50.00	47 \$ 501.50 \$			\$ 2,564.15		\$ 591.00		\$ 1,391.92	\$ 2,564.15		\$ 187.69		\$ 187.69	5.0%
50	80	29,200	50.00	47 \$ 501.50 \$	(47.33)	\$ 1,198.32	\$ 2,890.10	\$ 4,088.42	\$ 591.00	\$ (47.33)	\$ 1,386.01	\$ 2,890.10	\$ 4,276.11	\$ 187.69	\$ -	\$ 187.69	4.6%
100	20	14,600	100.00	97 \$ 1,003.00 \$			\$ 1,868.80		\$ 1,182.00	\$ (23.67)	\$ 2,000.67		\$ 3,869.47	\$ 277.19		\$ 277.19	7.7%
100	30	21,900	100.00	97 \$ 1,003.00 \$			\$ 2,520.70		\$ 1,182.00		\$ 1,988.84		\$ 4,509.54	\$ 277.19		\$ 277.19	6.5%
100	40	29,200	100.00	97 \$ 1,003.00 \$			\$ 3,172.60		\$ 1,182.00		\$ 1,977.01		\$ 5,149.61	\$ 277.19		\$ 277.19	5.7%
100	50	36,500	100.00	97 \$ 1,003.00 \$			\$ 3,824.50		\$ 1,182.00		\$ 1,965.17		\$ 5,789.67	\$ 277.19		\$ 277.19	5.0%
100 100	60 70	43,800 51,100	100.00 100.00	97 \$ 1,003.00 \$ 97 \$ 1.003.00 \$			\$ 4,476.40 \$ 5.128.30		\$ 1,182.00 \$ 1.182.00		\$ 1,953.34 \$ 1,941.51	\$ 4,476.40		\$ 277.19 \$ 277.19		\$ 277.19 \$ 277.19	4.5% 4.1%
100	80	58,400	100.00	97 \$ 1,003.00 \$			\$ 5,780.20		\$ 1,182.00				\$ 7,069.81 \$ 7,709.87	\$ 277.19		\$ 277.19	3.7%
300	20	43,800	300.00	297 \$ 3,009.00 \$			\$ 5,606.40		\$ 3.546.00		\$ 4,317.34		\$ 9,923.74	\$ 635.19		\$ 635.19	6.8%
300	30	65,700	300.00	297 \$ 3,009.00 \$				\$ 11,208.75	\$ 3,546.00		\$ 4,281.84		\$ 11,843.94	\$ 635.19		\$ 635.19	5.7%
300	40	87,600	300.00	297 \$ 3,009.00 \$				\$ 13,128.95	\$ 3,546.00		\$ 4,246.34		\$ 13,764.14	\$ 635.19		\$ 635.19	4.8%
300	50	109,500	300.00	297 \$ 3,009.00 \$	(177.50)	\$ 3,575.65	\$ 11,473.50	\$ 15,049.15	\$ 3,546.00	\$ (177.50)	\$ 4,210.84	\$ 11,473.50	\$ 15,684.34	\$ 635.19	\$ -	\$ 635.19	4.2%
300	60	131,400	300.00	297 \$ 3,009.00 \$	(213.00)	\$ 3,540.15	\$ 13,429.20	\$ 16,969.35	\$ 3,546.00	\$ (213.00)	\$ 4,175.34	\$ 13,429.20	\$ 17,604.54	\$ 635.19		\$ 635.19	3.7%
300	70	153,300	300.00	297 \$ 3,009.00 \$			\$ 15,384.89		\$ 3,546.00		\$ 4,139.84		\$ 19,524.74	\$ 635.19		\$ 635.19	3.4%
300	80	175,200	300.00	297 \$ 3,009.00 \$				\$ 20,809.74	\$ 3,546.00		\$ 4,104.34		\$ 21,444.93	\$ 635.19		\$ 635.19	3.1%
500	20 30	73,000	500.00	497 \$ 5,015.00 \$				\$ 14,984.81	\$ 5,910.00		\$ 6,634.01		\$ 15,978.00	\$ 993.19 \$ 993.19		\$ 993.19 \$ 993.19	6.6% 5.5%
500 500	30 40	109,500 146,000	500.00 500.00	497 \$ 5,015.00 \$ 497 \$ 5,015.00 \$	(177.50) \$ (236.67) \$			\$ 18,185.15 \$ 21,385.48	\$ 5,910.00 \$ 5,910.00		\$ 6,574.84 \$ 6,515.67	\$ 12,603.50	\$ 19,178.34	\$ 993.19		\$ 993.19 \$ 993.19	5.5% 4.6%
500	50	182,500	500.00	497 \$ 5,015.00 \$				\$ 24,585.81	\$ 5,910.00		\$ 6,456.51		\$ 25,579.00	\$ 993.19		\$ 993.19	4.0%
500	60	219,000	500.00	497 \$ 5,015.00 \$				\$ 27,786.14	\$ 5,910.00		\$ 6,397.34		\$ 28,779.33	\$ 993.19		\$ 993.19	3.6%
500	70	255,500	500.00		(414.17)	\$ 5,344.98		\$ 30,986.48	\$ 5,910.00		\$ 6,338.17	\$ 25,641.49		\$ 993.19	\$ -	\$ 993.19	3.2%
500	80	292,000	500.00	497 \$ 5,015.00 \$	(473.33)	\$ 5,285.82	\$ 28,900.99	\$ 34,186.81	\$ 5,910.00	\$ (473.33)	\$ 6,279.01	\$ 28,900.99	\$ 35,180.00	\$ 993.19	\$ -	\$ 993.19	2.9%
750	30	164,250	750.00	747 \$ 7,522.50 \$				\$ 26,905.64	\$ 8,865.00		\$ 9,441.09		\$ 28,346.33	\$1,440.69		\$ 1,440.69	5.4%
750	40	219,000	750.00	747 \$ 7,522.50 \$				\$ 31,706.14	\$ 8,865.00		\$ 9,352.34		\$ 33,146.83	\$1,440.69	\$ -	\$ 1,440.69	4.5%
750	50	273,750	750.00	747 \$ 7,522.50 \$				\$ 36,506.64	\$ 8,865.00		\$ 9,263.59	\$ 28,683.74			\$ -	\$ 1,440.69	3.9%
750	60	328,500	750.00	747 \$ 7,522.50 \$				\$ 41,307.14	\$ 8,865.00		\$ 9,174.84		\$ 42,747.83	\$1,440.69		\$ 1,440.69	3.5%
750 750	70 80	383,250 438,000	750.00 750.00	747 \$ 7,522.50 \$ 747 \$ 7,522.50 \$				\$ 46,107.64 \$ 50,908.14	\$ 8,865.00 \$ 8,865.00		\$ 9,086.09 \$ 8,997.34		\$ 47,548.33 \$ 52,348.83	\$1,440.69 \$1.440.69	\$ -	\$ 1,440.69 \$ 1,440.69	3.1% 2.8%
750	90	492,750	750.00	747 \$ 7,522.50 \$				\$ 55,708.63	\$ 8,865.00		\$ 8,908.59		\$ 57,149.32		\$ -	\$ 1,440.69	2.6%
1.000	30	219.000	1.000.00		(355.00)			\$ 35,626.14	\$ 11.820.00		\$ 12.307.34		\$ 37,514.33	\$1,888.19		\$ 1,888.19	5.3%
1,000	40	292,000	1,000.00	997 \$ 10,030.00 \$				\$ 42,026.81	\$ 11,820.00		\$ 12,189.01	\$ 31,725.99		\$1,888.19		\$ 1,888.19	4.5%
1,000	50	365,000	1,000.00	997 \$ 10,030.00 \$			\$ 38,244.99		\$ 11,820.00		\$ 12,070.68	\$ 38,244.99		\$1,888.19	\$ -	\$ 1,888.19	3.9%
1,000	60	438,000	1,000.00	997 \$ 10,030.00 \$				\$ 54,828.14	\$ 11,820.00		\$ 11,952.34		\$ 56,716.33	\$1,888.19		\$ 1,888.19	3.4%
1,000	70	511,000	1,000.00	997 \$ 10,030.00 \$				\$ 61,228.80	\$ 11,820.00		\$ 11,834.01	\$ 51,282.98		\$1,888.19		\$ 1,888.19	3.1%
1,000	80	584,000	1,000.00		(946.66)			\$ 67,629.46		\$ (946.66)			\$ 69,517.65	\$1,888.19		\$ 1,888.19	2.8%
1,000	90	657,000 438,000	1,000.00	997 \$ 10,030.00 \$				\$ 74,030.13		\$ (1,065.00)			\$ 75,918.32	\$1,888.19		\$ 1,888.19	2.6%
2,000	30 40	438,000 584,000	2,000.00 2,000.00		(710.00) S (946.66) S			\$ 70,508.14 \$ 83,309.46	\$ 23,640.00 \$ 23.640.00	\$ (710.00)	\$ 23,772.34 \$ 23,535.68	\$ 50,413.98 \$ 63,451.98		\$3,678.19 \$3.678.19		\$ 3,678.19 \$ 3,678.19	5.2% 4.4%
2,000	50	730,000	2,000.00	1997 \$ 20,060.00 \$				\$ 96.110.79		\$ (1,183.33)		\$ 76,489,97		\$3,678.19		\$ 3,678.19	3.8%
2,000	60	876,000	2.000.00	1997 \$ 20,060.00 \$				\$ 108,912,12		\$ (1,420.00)		\$ 89.527.97		\$3,678.19		\$ 3,678.19	3.4%
2,000		1,022,000	2,000.00	1997 \$ 20,060.00 \$				\$ 121,713.45		\$ (1,656.66)		\$ 102,565.96		\$3,678.19		\$ 3,678.19	3.0%
2,000	80	1,168,000	2,000.00	1997 \$ 20,060.00 \$	(1,893.33)	\$ 18,910.82	\$ 115,603.96	\$ 134,514.78	\$ 23,640.00	\$ (1,893.33)	\$ 22,589.01	\$ 115,603.96	\$ 138,192.97	\$3,678.19	\$ -	\$ 3,678.19	2.7%
2,000	90	1,314,000	2,000.00	1997 \$ 20,060.00 \$	(2,129.99)	\$ 18,674.16	\$ 128,641.95	\$ 147,316.11	\$ 23,640.00	\$ (2,129.99)	\$ 22,352.35	\$ 128,641.95	\$ 150,994.30	\$3,678.19	\$ -	\$ 3,678.19	2.5%

Schedule (MTN)-4

Atlantic City Electric Company
Frequency Distribution of Residential Bill Impact

		Low Income Cus	tomer Population	
<u>-</u>		Percentage of		Cumulative
Difference	Number of	Total Class	Cumulative Number	Percentage of
in Bill	Customers	Population	of Customers	Total Class
7.70%	1	0.00%	1	0.00%
8.00%	3	0.01%	4	0.01%
8.10%	114	0.39%	118	0.40%
8.20%	308	1.04%	426	1.44%
8.30%	483	1.64%	909	3.08%
8.40%	731	2.48%	1,640	5.56%
8.50%	1,026	3.48%	2,666	9.03%
8.60%	1,466	4.97%	4,132	14.00%
8.70%	1,941	6.58%	6,073	20.58%
8.80%	2,541	8.61%	8,614	29.19%
8.90%	3,074	10.42%	11,688	39.61%
9.00%	3,315	11.23%	15,003	50.84%
9.10%	3,024	10.25%	18,027	61.09%
9.20%	2,243	7.60%	20,270	68.69%
9.30%	1,729	5.86%	21,999	74.55%
9.40%	1,269	4.30%	23,268	78.85%
9.50%	970	3.29%	24,238	82.14%
9.60%	818	2.77%	25,056	84.91%
9.70%	664	2.25%	25,720	87.16%
9.80%	544	1.84%	26,264	89.00%
9.90%	471	1.60%	26,735	90.60%
10.00%	363	1.23%	27,098	91.83%
10.10%	330	1.12%	27,428	92.95%
10.20%	286	0.97%	27,714	93.92%
10.30%	232	0.79%	27,946	94.70%
10.40%	193	0.65%	28,139	95.36%
10.50%	159	0.54%	28,298	95.90%
10.60%	135	0.46%	28,433	96.35%
10.70%	120	0.41%	28,553	96.76%
10.80%	110	0.37%	28,663	97.13%
10.90%	100	0.34%	28,763	97.47%
11.00%	94	0.32%	28,857	97.79%
11.10%	68	0.23%	28,925	98.02%
11.20%	51	0.17%	28,976	98.19%
11.30%	36	0.12%	29,012	98.32%
11.40%	45	0.15%	29,057	98.47%

Frequency Distribution of Residential Bill Impact

		Low Income Cus	tomer Population	
•		Percentage of	·	Cumulative
Difference	Number of	Total Class	Cumulative Number	Percentage of
in Bill	Customers	Population	of Customers	Total Class
11.50%	29	0.10%	29,086	98.57%
11.60%	34	0.12%	29,120	98.68%
11.70%	24	0.08%	29,144	98.76%
11.80%	28	0.09%	29,172	98.86%
11.90%	16	0.05%	29,188	98.91%
12.00%	30	0.10%	29,218	99.01%
12.10%	23	0.08%	29,241	99.09%
12.20%	13	0.04%	29,254	99.14%
12.30%	13	0.04%	29,267	99.18%
12.40%	14	0.05%	29,281	99.23%
12.50%	12	0.04%	29,293	99.27%
12.60%	9	0.03%	29,302	99.30%
12.70%	10	0.03%	29,312	99.33%
12.80%	8	0.03%	29,320	99.36%
12.90%	12	0.04%	29,332	99.40%
13.00%	9	0.03%	29,341	99.43%
13.10%	11	0.04%	29,352	99.47%
13.20%	9	0.03%	29,361	99.50%
13.30%	7	0.02%	29,368	99.52%
13.40%	8	0.03%	29,376	99.55%
13.50%	8	0.03%	29,384	99.58%
13.60%	5	0.02%	29,389	99.59%
13.70%	3	0.01%	29,392	99.60%
13.80%	6	0.02%	29,398	99.62%
13.90%	4	0.01%	29,402	99.64%
14.00%	4	0.01%	29,406	99.65%
14.10%	3	0.01%	29,409	99.66%
14.20%	5	0.02%	29,414	99.68%
14.30%	4	0.01%	29,418	99.69%
14.40%	3	0.01%	29,421	99.70%
14.50%	3	0.01%	29,424	99.71%
14.60%	3	0.01%	29,427	99.72%
14.70%	7	0.02%	29,434	99.75%
14.80%	1	0.00%	29,435	99.75%
14.90%	3	0.01%	29,438	99.76%
15.00%	1	0.00%	29,439	99.76%
15.10%	3	0.01%	29,442	99.77%

21.30%

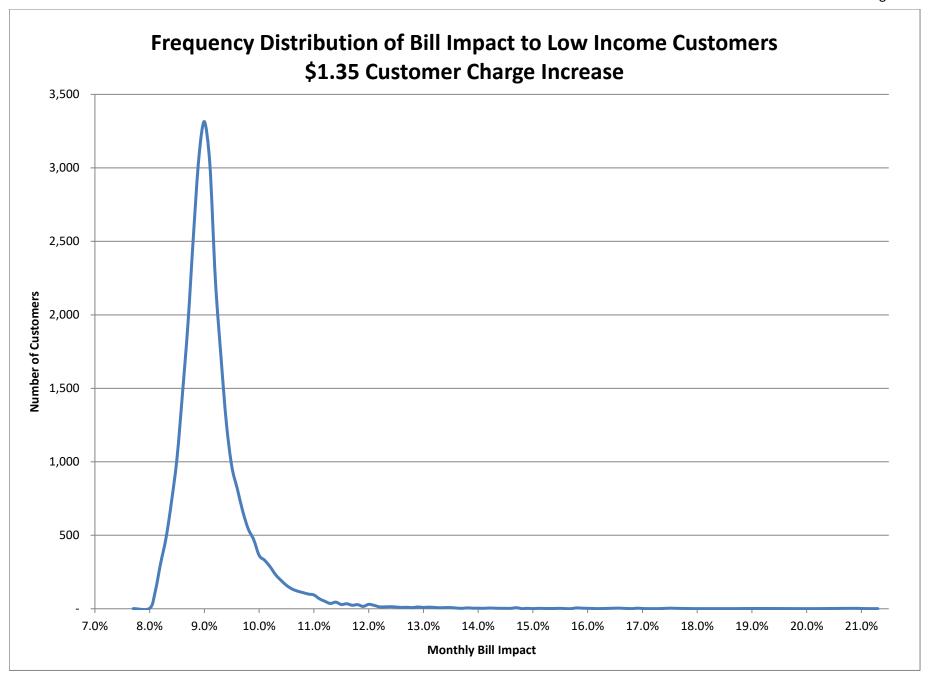
Frequency Distribution of Residential Bill Impact

			stomer Population	
		Percentage of		Cumulative
Difference	Number of	Total Class	Cumulative Number	Percentage of
in Bill	Customers	Population	of Customers	Total Class
15.20%	2	0.01%	29,444	99.78%
15.30%	2	0.01%	29,446	99.79%
15.40%	2	0.01%	29,448	99.79%
15.50%	3	0.01%	29,451	99.80%
15.60%	1	0.00%	29,452	99.81%
15.70%	1	0.00%	29,453	99.81%
15.80%	6	0.02%	29,459	99.83%
15.90%	4	0.01%	29,463	99.84%
16.10%	2	0.01%	29,465	99.85%
16.20%	1	0.00%	29,466	99.85%
16.50%	4	0.01%	29,470	99.87%
16.60%	4	0.01%	29,474	99.88%
16.80%	1	0.00%	29,475	99.88%
16.90%	4	0.01%	29,479	99.90%
17.00%	2	0.01%	29,481	99.91%
17.10%	1	0.00%	29,482	99.91%
17.20%	1	0.00%	29,483	99.91%
17.30%	1	0.00%	29,484	99.92%
17.50%	4	0.01%	29,488	99.93%
17.60%	3	0.01%	29,491	99.94%
17.80%	2	0.01%	29,493	99.95%
17.90%	1	0.00%	29,494	99.95%
18.00%	1	0.00%	29,495	99.95%
18.60%	1	0.00%	29,496	99.96%
18.70%	1	0.00%	29,497	99.96%
19.10%	2	0.01%	29,499	99.97%
19.80%	1	0.00%	29,500	99.97%
20.00%	1	0.00%	29,501	99.97%
20.20%	1	0.00%	29,502	99.98%
20.80%	3	0.01%	29,505	99.99%
21.00%	2	0.01%	29,507	99.99%
21.10%	1	0.00%	29,508	100.00%
04.000/				100 000/

0.00%

29,509

100.00%

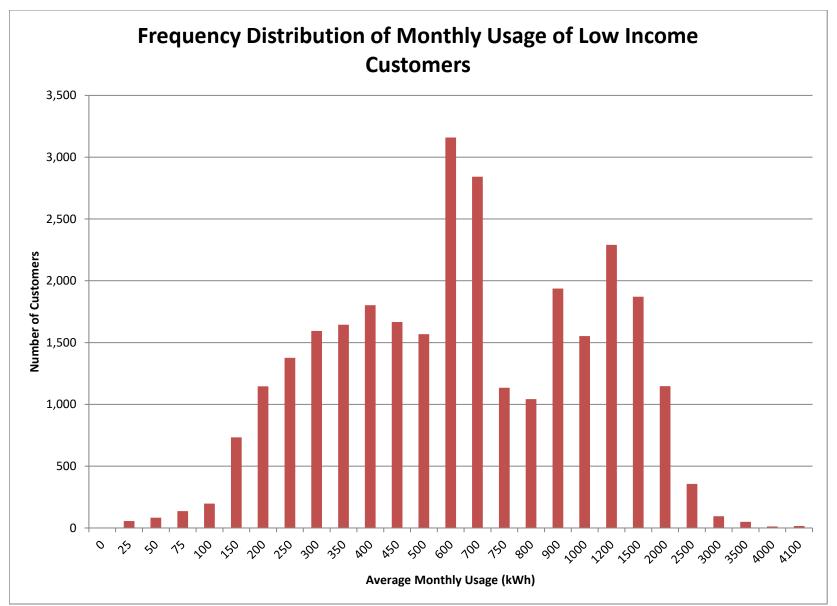


Atlantic City Electric Company

Frequency Distribution of Monthly Usage of Low Income Customers

	<u>-</u>		Low Income Cus	tomer Population	
	Average Monthly Usage (kWh)	Number of Customers	Percentage of Total Class Population	Cumulative Number of Customers	Cumulative Percentage of Total Class Population
<=	0	0	0.00%	-	0.00%
<=	25	56	0.19%	56	0.19%
<=	50	83	0.28%	139	0.47%
<=	75	136	0.46%	275	0.93%
<=	100	197	0.67%	472	1.60%
<=	150	733	2.48%	1,205	4.08%
<=	200	1,146	3.88%	2,351	7.97%
<=	250	1,376	4.66%	3,727	12.63%
<=	300	1,594	5.40%	5,321	18.03%
<=	350	1,645	5.57%	6,966	23.61%
<=	400	1,803	6.11%	8,769	29.72%
<=	450	1,666	5.65%	10,435	35.36%
<=	500	1,568	5.31%	12,003	40.68%
<=	600	3,159	10.71%	15,162	51.38%
<=	700	2,842	9.63%	18,004	61.01%
<=	750	1,135	3.85%	19,139	64.86%
<=	800	1,042	3.53%	20,181	68.39%
<=	900	1,937	6.56%	22,118	74.95%
<=	1000	1,553	5.26%	23,671	80.22%
<=	1200	2,291	7.76%	25,962	87.98%
<=	1500	1,871	6.34%	27,833	94.32%
<=	2000	1,147	3.89%	28,980	98.21%
<=	2500	356	1.21%	29,336	99.41%
<=	3000	95	0.32%	29,431	99.74%
<=	3500	50	0.17%	29,481	99.91%
<=	4000	12	0.04%	29,493	99.95%
<=	4100	16	0.05%	29,509	100.00%
	Total RS LMI Annualized Customers	256,475			

Total RS LMI Annualized Customers	256,475
Total RS LMI Usage (kWh)	175,185,558
Monthly LMI Avg Usage (kWh)	683
Residential Average Usage (kWh)	669
Count of Customers Above Average	
Usage	12,360
Percentage of Customer Above Average	
Usage	41.9%



Schedule (MTN)-5

Summary of Atlantic City Electric EDIT Credits for Rate Schedules with Expiring EDIT Credits

	Original Liability		Credits Provide	d			Fore	ecaste	d Credits	Prov	ided (Dece	ember -	June 2	023)				Ba	latory Asset lance as of 6/30/23
ACE EDIT Liability Summary	BPU Docket No. ER18030241 Settlement 5-Year Liability (1)	 Time Credit aber 2018 (2)	 T Acceleration y-Dec 2022 (3)	Credits Provided to Customers as of Nov 2022	Dec-22	Ja	Jan-23 Feb-2		eb-23	N	Iar-23	Apr	Apr-23 May-2		ay-23	Jı	ın-23	Re	emaining (4)
Residential	\$ (94,753,828)	\$ (2,929,757)	\$ (10,265,976)	\$ (75,813,770)	\$ (1,312,421)	\$ (1,	696,174)	\$ (1,	,525,417)	\$ (1.	,329,423)	\$	-	\$	-	\$	-	\$	119,110
Monthly General Service Secondary	\$ (27,703,216)	\$ (882,037)	\$ (3,030,909)	\$ (24,007,681)	\$ -	\$	-	\$	-	\$	-	\$	-	\$	-	\$	-	\$	217,411
Monthly General Service Primary	\$ (728,009)	\$ (20,035)	\$ (85,770)	\$ (706,404)	\$ -	\$	-	\$	-	\$	-	\$	-	\$	-	\$	-	\$	84,199
Transmission General Service - Subtransmission	\$ (1,460,683)	\$ (49,065)	\$ -	\$ (1,281,493)	\$ (23,144)	\$	(24,838)	\$	(24,349)	\$	(23,728)	\$	-	\$	-	\$	-	\$	(34,066)
Transmission General Service - Transmission	\$ (1,206,577)	\$ (29,804)	\$ -	\$ (1,087,953)	\$ (22,841)	\$	(26,270)	\$	(25,886)	\$	(25,085)	\$	-	\$	-	\$	-	\$	11,261
Street and Private Lighting/ Contributed Street Lighting	\$ (6,768,214)	\$ (210,678)	\$ (541,892)	\$ (5,390,846)	\$ (123,622)	\$ (139,176)	\$ (116,357)	\$ ((113,742)	\$	-	\$	-	\$	-	\$	(131,901)
Direct Distribution Connection	\$ (216,148)	\$ (7,815)	\$ -	\$ (202,025)	\$ -	\$	-	\$	-	\$	-	\$	-	\$	-	\$	-	\$	(6,308)
Total ACE EDIT	\$ (132,836,676)	\$ (4,129,191)	\$ (13,924,546)	\$ (108,490,172)	\$ (1,482,028)	\$ (1,	886,458)	\$ (1,	(692,009)	\$ (1	,491,978)	\$	-	\$	-	\$	-	\$	259,707

⁽¹⁾ Liability has been grossed up by the revenue conversion factor.

⁽²⁾ BPU Docket No. ER18030241 required ACE to provide a One-Time Credit to customers by November 7, 2018 for the January through March 2018 for the stub period over-collection, and the flowback of excess ADIT for the period of January through June 2018.

(3) BPU Docket No. ER20120746 acknowledge the delayed increase to distribution rates becoming effective January 1, 2022 resulted in the Company not receiving an estimated \$21.4m to base revenues. The Order approved ACE to be amortized in

an accelerated manner between July 1, 2021 through December 31, 2021.

⁽⁴⁾ Actual asset balance will change based on the rate effective date when 5-Year EDIT Credits set to \$0.00.

Cumulative YTD ACE - EDIT Credits									
Rate Category	Acronym	Rider EDIT Credit	Original Liability (1)	2018 One- Time Credit (2)	Accelerated EDIT Credit	Oct-18	Nov-18	Dec-18	<u>Jan-19</u>
Residential	R	EDIT Credit 5 Year	(94,753,828)	(2,929,757)	(10,265,976)	(633,132)	(1,119,668)	(1,377,912)	(1,624,799)
Monthly General Service Secondary	MGSS	EDIT Credit 5 Year	(27,703,216)	(882,037)	(3,030,909)	(209,079)	(399,270)	(426,043)	(472,778)
Monthly General Service Primary	MGSP	EDIT Credit 5 Year	(728,009)	(20,035)	(85,770)	(1,935)	(11,226)	(7,688)	(10,663)
Annual General Service Secondary	AGSS	EDIT Credit 5 Year	(24,867,127)	(687,346)	(1,744,368)	(145,650)	(384,862)	(384,296)	(375,709)
Annual General Service Primary	AGSP	EDIT Credit 5 Year	(4,540,418)	(133,095)	(372,881)	(4,318)	(79,940)	(63,499)	(77,853)
Transmission General Service - Subtransmission	TGST	EDIT Credit 5 Year	(1,460,683)	(49,065)	-	-	(27,651)	(25,734)	(26,996)
Transmission General Service - Transmission	TGS	EDIT Credit 5 Year	(1,206,577)	(29,804)	-	-	(23,436)	(23,131)	(20,770)
Street and Private Lighting/ Contributed Street Lighting	SPL/CSL	EDIT Credit 5 Year	(6,768,214)	(210,678)	(541,892)	(19,914)	(154,852)	(129,484)	(146,234
Direct Distribution Connection	DDC	EDIT Credit 5 Year	(216,148)	(7,815)	-	(2,023)	(4,111)	(3,896)	(4,391
Total	ALL	Total EDIT Credit Revenues	(162,244,220)	(4,949,632)	(16,041,795)	(1,016,050)	(2,205,016)	(2,441,683)	(2,760,193)

⁽¹⁾ Liability has been grossed up by the revenue conversion factor.

⁽²⁾ BPU Docket No. ER18030241 required ACE to provide a One-Time Credit to customers by November 7, 2018 for the January through March 2018 for the stub period over-collection, and the flowback of excess ADIT for the period of January through June 2018.

(3) BPU Docket No. ER2103746 acknowledge the delayed increase to distribution rates becoming effective January 1, 2022 resulted in the Company not receiving an estimated \$21.4m to base revenues. The Order approved ACE to be amortized in an accelerated manner between July 1, 2021 through December 31, 2021.

Cumulative YTD ACE - EDIT Credits													
Rate Category	Acronym	Rider EDIT Credit	Feb-19	<u>Mar-19</u>	Apr-19	May-19	<u>Jun-19</u>	<u>Jul-19</u>	Aug-19	Sep-19	Oct-19	Nov-19	Dec-19
Residential	R	EDIT Credit 5 Year	(1,415,908)	(1,275,645)	(1,064,234)	(1,015,257)	(1,379,423)	(2,272,954)	(2,587,452)	(2,003,531)	(1,292,802)	(1,016,619)	(1,290,615)
Monthly General Service Secondary	MGSS	EDIT Credit 5 Year	(439,485)	(440,842)	(381,392)	(402,282)	(477,046)	(615,116)	(670,139)	(601,606)	(476,137)	(396,323)	(415,880)
Monthly General Service Primary	MGSP	EDIT Credit 5 Year	(7,664)	(9,054)	(7,927)	(13,161)	(8,005)	(11,552)	(12,552)	(20,491)	(2,227)	(15,444)	(10,457)
Annual General Service Secondary	AGSS	EDIT Credit 5 Year	(349,678)	(385,173)	(344,660)	(369,865)	(404,578)	(430,355)	(435,748)	(446,124)	(388,121)	(354,771)	(345,764)
Annual General Service Primary	AGSP	EDIT Credit 5 Year	(65,704)	(72,398)	(64,542)	(71,039)	(63,735)	(85,403)	(58,899)	(94,415)	(77,991)	(73,154)	(73,815)
Transmission General Service - Subtransmission	TGST	EDIT Credit 5 Year	(27,688)	(25,533)	(27,254)	(26,096)	(27,370)	(29,914)	(34,744)	(33,387)	(29,323)	(26,785)	(25,155)
Transmission General Service - Transmission	TGS	EDIT Credit 5 Year	(21,468)	(20,046)	(21,865)	(23,408)	(22,998)	(22,775)	(29,341)	(24,579)	(22,845)	(22,258)	(21,421)
Street and Private Lighting/ Contributed Street Lighting	SPL/CSL	EDIT Credit 5 Year	(129,701)	(114,112)	(112,054)	(95,926)	(83,291)	(87,965)	(91,817)	(100,699)	(113,112)	(118,009)	(134,445)
Direct Distribution Connection	DDC	EDIT Credit 5 Year	(3,809)	(3,873)	(4,002)	(4,128)	(4,112)	(4,043)	(4,119)	(4,105)	(3,961)	(3,885)	(4,171)
Total	ALL	Total EDIT Credit Revenues	(2,461,103)	(2,346,675)	(2,027,931)	(2,021,161)	(2,470,559)	(3,560,076)	(3,924,811)	(3,328,935)	(2,406,519)	(2,027,247)	(2,321,722)

⁽¹⁾ Liability has been grossed up by the revenue conversion factor.

⁽²⁾ BPU Docket No. ER18030241 required ACE to provide a One-Time Credit to customers by November 7, 2018 for the January of excess ADIT for the period of January through June 2018.

(3) BPU Docket No. ER20120746 acknowledge the delayed increase to distribution rates becoming effective January 1, 2022 resul The Order approved ACE to be amortized in an accelerated manner between July 1, 2021 through December 31, 2021.

Cumulative YTD ACE - EDIT Credits														
Rate Category	Acronym	Rider EDIT Credit	Jan-20	Feb-20	<u>Mar-20</u>	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20
Residential	R	EDIT Credit 5 Year	(1,574,058)	(1,223,712)	(1,136,197)	(1,147,244)	(1,029,066)	(1,387,577)	(2,457,447)	(2,760,989)	(2,191,328)	(1,233,035)	(1,056,335)	(1,358,500)
Monthly General Service Secondary	MGSS	EDIT Credit 5 Year	(485,356)	(410,330)	(400,354)	(367,709)	(317,132)	(382,675)	(579,426)	(645,916)	(576,205)	(436,747)	(384,276)	(408,117)
Monthly General Service Primary	MGSP	EDIT Credit 5 Year	(11,054)	(7,224)	(12,633)	(11,717)	(7,318)	(4,593)	(13,156)	(14,538)	(11,853)	(7,847)	(16,466)	(11,378)
Annual General Service Secondary	AGSS	EDIT Credit 5 Year	(386,325)	(347,914)	(328,144)	(355,267)	(278,610)	(281,186)	(442,690)	(415,171)	(427,365)	(306,685)	(369,726)	(326,885)
Annual General Service Primary	AGSP	EDIT Credit 5 Year	(75,149)	(59,411)	(71,422)	(71,144)	(57,196)	(53,951)	(84,809)	(85,852)	(82,462)	(62,261)	(64,382)	(82,242)
Transmission General Service - Subtransmission	TGST	EDIT Credit 5 Year	(25,824)	(25,959)	(24,642)	(23,188)	(17,068)	(17,990)	(20,408)	(29,646)	(31,120)	(26,602)	(24,024)	(14,256)
Transmission General Service - Transmission	TGS	EDIT Credit 5 Year	(19,276)	(19,851)	(19,570)	(24,323)	(10,336)	(16,845)	(15,014)	(23,489)	(22,799)	(19,992)	(21,148)	(21,105)
Street and Private Lighting/ Contributed Street Lighting	SPL/CSL	EDIT Credit 5 Year	(142,237)	(106,690)	(133,078)	(108,767)	(91,670)	(88,273)	(85,629)	(87,794)	(101,776)	(103,763)	(123,897)	(134,421)
Direct Distribution Connection	DDC	EDIT Credit 5 Year	(4,462)	(3,837)	(3,957)	(4,143)	(3,921)	(4,126)	(4,258)	(4,059)	(4,083)	(4,058)	(3,854)	(4,199)
Total	ALL	Total EDIT Credit Revenues	(2,723,741)	(2,204,927)	(2,129,997)	(2,113,502)	(1,812,318)	(2,237,216)	(3,702,838)	(4,067,454)	(3,448,990)	(2,200,988)	(2,064,108)	(2,361,104)

⁽¹⁾ Liability has been grossed up by the revenue conversion factor.

⁽²⁾ BPU Docket No. ER18030241 required ACE to provide a One-Time Credit to customers by November 7, 2018 for the January of excess ADIT for the period of January through June 2018.

(3) BPU Docket No. ER20120746 acknowledge the delayed increase to distribution rates becoming effective January 1, 2022 resul The Order approved ACE to be amortized in an accelerated manner between July 1, 2021 through December 31, 2021.

Cumulative YTD ACE - EDIT Credits												
Rate Category	Acronym	Rider EDIT Credit	<u>Jan-21</u>	Feb-21	<u>Mar-21</u>	Apr-21	May-21	<u>Jun-21</u>	<u>Jul-21</u>	Aug-21	Sep-21	Oct-21
Residential	R	EDIT Credit 5 Year	(1,603,099)	(1,360,239)	(1,392,535)	(1,153,338)	(1,004,316)	(1,482,511)	(2,310,211)	(2,473,351)	(2,323,058)	(1,348,436)
Monthly General Service Secondary	MGSS	EDIT Credit 5 Year	(452,168)	(411,485)	(441,348)	(429,246)	(395,546)	(455,781)	(666,471)	(685,595)	(668,800)	(499,131)
Monthly General Service Primary	MGSP	EDIT Credit 5 Year	(11,386)	(7,526)	(15,595)	(11,156)	(12,046)	(14,333)	(15,139)	(23,671)	(22,386)	(17,851)
Annual General Service Secondary	AGSS	EDIT Credit 5 Year	(348,217)	(278,745)	(352,761)	(331,462)	(273,591)	(376,362)	(420,067)	(419,904)	(430,238)	(356,220)
Annual General Service Primary	AGSP	EDIT Credit 5 Year	(64,950)	(59,196)	(70,363)	(63,035)	(54,689)	(68,756)	(85,203)	(77,249)	(88,401)	(72,327)
Transmission General Service - Subtransmission	TGST	EDIT Credit 5 Year	(20,734)	(36,079)	(22,065)	(23,904)	(21,120)	(26,231)	(23,387)	(34,574)	(32,597)	(25,335)
Transmission General Service - Transmission	TGS	EDIT Credit 5 Year	5,835	(41,997)	(22,592)	(17,828)	(13,414)	(18,412)	(26,781)	(21,286)	(37,420)	(1,446)
Street and Private Lighting/ Contributed Street Lighting	SPL/CSL	EDIT Credit 5 Year	(125,381)	(128,197)	(120,167)	(114,603)	(89,410)	(88,275)	(83,763)	(91,002)	(100,043)	(102,987)
Direct Distribution Connection	DDC	EDIT Credit 5 Year	(4,273)	(3,751)	(3,947)	(4,235)	(4,203)	(4,246)	(4,046)	(4,328)	(4,195)	(3,787)
Total	ALL	Total EDIT Credit Revenues	(2,624,373)	(2,327,213)	(2,441,374)	(2,148,808)	(1,868,335)	(2,534,908)	(3,635,068)	(3,830,958)	(3,707,138)	(2,427,520)

⁽¹⁾ Liability has been grossed up by the revenue conversion factor.

⁽²⁾ BPU Docket No. ER18030241 required ACE to provide a One-Time Credit to customers by November 7, 2018 for the January of excess ADIT for the period of January through June 2018.

(3) BPU Docket No. ER20120746 acknowledge the delayed increase to distribution rates becoming effective January 1, 2022 resul The Order approved ACE to be amortized in an accelerated manner between July 1, 2021 through December 31, 2021.

Cumulative YTD ACE - EDIT Credits												
Rate Category	Acronym	Rider EDIT Credit	Nov-21	Dec-21	Jan-22	Feb-22	<u>Mar-22</u>	Apr-22	May-22	Jun-22	<u>Jul-22</u>	Aug-22
Residential	R	EDIT Credit 5 Year	(1,037,199)	(1,288,673)	(1,634,782)	(1,369,013)	(1,256,891)	(1,139,540)	(1,023,198)	(1,549,395)	(2,090,199)	(2,634,566)
Monthly General Service Secondary	MGSS	EDIT Credit 5 Year	(415,231)	(447,732)	(512,900)	(461,733)	(476,620)	(460,364)	(430,088)	(546,403)	(636,635)	(710,374)
Monthly General Service Primary	MGSP	EDIT Credit 5 Year	(23,064)	(15,058)	(31,396)	(18,778)	(20,849)	(21,192)	(19,737)	(24,068)	(24,765)	(29,001)
Annual General Service Secondary	AGSS	EDIT Credit 5 Year	(322,307)	(318,410)	(342,566)	(313,885)	(311,662)	(321,799)	(302,315)	(357,087)	(390,492)	(409,782)
Annual General Service Primary	AGSP	EDIT Credit 5 Year	(71,493)	(55,577)	(75,602)	(66,030)	(59,895)	(63,938)	(63,516)	(70,778)	(69,534)	(84,800)
Transmission General Service - Subtransmission	TGST	EDIT Credit 5 Year	(26,538)	(23,388)	(27,158)	(24,115)	(23,260)	(24,622)	(23,291)	(25,428)	(27,543)	(31,675)
Transmission General Service - Transmission	TGS	EDIT Credit 5 Year	(46,048)	(26,694)	(22,738)	(18,925)	(20,945)	(23,194)	(22,810)	(25,434)	(26,961)	(22,835)
Street and Private Lighting/ Contributed Street Lighting	SPL/CSL	EDIT Credit 5 Year	(118,040)	(130,537)	(146,597)	(121,317)	(112,646)	(108,059)	(90,537)	(89,166)	(82,438)	(90,421)
Direct Distribution Connection	DDC	EDIT Credit 5 Year	(3,891)	(4,361)	(4,594)	(3,666)	(3,958)	(4,240)	(3,852)	(4,510)	(4,044)	(4,255)
Total	ALL	Total EDIT Credit Revenues	(2,063,811)	(2,310,429)	(2,798,332)	(2,397,462)	(2,286,726)	(2,166,947)	(1,979,344)	(2,692,267)	(3,352,611)	(4,017,709)

(1) Liability has been grossed up by the revenue conversion factor.

⁽²⁾ BPU Docket No. ER18030241 required ACE to provide a One-Time Credit to customers by November 7, 2018 for the January of excess ADIT for the period of January through June 2018.

(3) BPU Docket No. ER20120746 acknowledge the delayed increase to distribution rates becoming effective January 1, 2022 resul The Order approved ACE to be amortized in an accelerated manner between July 1, 2021 through December 31, 2021.

Cumulative YTD ACE - EDIT Credits									Fore	casted EDIT Credits		
Rate Category	Acronym	Rider EDIT Credit	Sep-22	Oct-22	Nov-22	<u>Dec-22</u>	Jan-23	Feb-23	Mar-23	Apr-23	May-23	<u>Jun-23</u>
Residential	R	EDIT Credit 5 Year	(2,245,512)	(1,184,510)	(983,759)	(1,312,421)	(1,696,174)	(1,525,417)	(1,329,423)	Scheduled to be set to ze	ero effective A	oril 1, 2023
Monthly General Service Secondary	MGSS	EDIT Credit 5 Year	(689,546)	(474,886)	(421,939)	Scheduled to be set	to zero effect	ive December	1, 2022			
Monthly General Service Primary	MGSP	EDIT Credit 5 Year	(38,325)	(5,053)	(4,209)	-	-	-	-	-	-	-
Annual General Service Secondary	AGSS	EDIT Credit 5 Year	(413,903)	(334,553)	(295,657)	(311,621)	(326,395)	(320,267)	(311,789)	(312,575)	(305,058)	(354,316)
Annual General Service Primary	AGSP	EDIT Credit 5 Year	(84,374)	(76,588)	(66,057)	(62,941)	(66,918)	(65,789)	(63,913)	(64,389)	(62,875)	(72,936)
Transmission General Service - Subtransmission	TGST	EDIT Credit 5 Year	(31,918)	(27,512)	(24,661)	(23,144)	(24,838)	(24,349)	(23,728)	Scheduled to be set to ze	ro effective A	oril 1, 2023
Transmission General Service - Transmission	TGS	EDIT Credit 5 Year	(21,757)	(37,834)	(22,347)	(22,841)	(26,270)	(25,886)	(25,085)	Scheduled to be set to ze	ro effective A	oril 1, 2023
Street and Private Lighting/ Contributed Street Lighting	SPL/CSL	EDIT Credit 5 Year	(83,785)	(119,142)	(114,728)	(123,622)	(139,176)	(116,357)	(113,742)	Scheduled to be set to ze	ro effective A	oril 1, 2023
Direct Distribution Connection	DDC	EDIT Credit 5 Year	(4,142)	(4,011)	(3,906)	Scheduled to be set	to zero effect	ive December	1, 2022			
					_							
Total	ALL	Total EDIT Credit Revenues	(3,613,261)	(2,264,090)	(1,937,264)	(1,856,591)	(2,279,771)	(2,078,065)	(1,867,680)	(376,964)	(367,933)	(427,253)

⁽¹⁾ Liability has been grossed up by the revenue conversion factor.

⁽²⁾ BPU Docket No. ER18030241 required ACE to provide a One-Time Credit to customers by November 7, 2018 for the January of excess ADIT for the period of January through June 2018.

(3) BPU Docket No. ER20120746 acknowledge the delayed increase to distribution rates becoming effective January 1, 2022 resul The Order approved ACE to be amortized in an accelerated manner between July 1, 2021 through December 31, 2021.

Cumulative YTD ACE- EDIT Credits														
Rate Category	Acronym	Rider EDIT Credit	Original Liability (1)	2018 One- Time Credit (2)	Accelerated EDIT Credit	Oct-18	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	May-19	<u>Jun-19</u>
Residential Residential	R	EDIT Credit 5 Year	(94,753,828)	(2,929,757)	(10,265,976)	(80,924,964)	(79,805,296)	(78,427,383)	(76,802,584)	(75,386,676)	(74,111,032)	(73,046,797)	(72,031,541)	(70,652,118)
Monthly General Service Secondary	MGSS	EDIT Credit 5 Year	(27,703,216)	(882,037)	(3,030,909)	(23,581,191)	(23,181,921)	(22,755,877)	(22,283,100)	(21,843,615)	(21,402,773)	(21,021,381)	(20,619,099)	(20,142,053)
Monthly General Service Primary	MGSP	EDIT Credit 5 Year	(728,009)	(20,035)	(85,770)	(620,270)	(609,044)	(601,357)	(590,694)	(583,030)	(573,976)	(566,049)	(552,888)	(544,882)
Annual General Service Secondary	AGSS	EDIT Credit 5 Year	(24,867,127)	(687,346)	(1,744,368)	(22,289,763)	(21,904,901)	(21,520,605)	(21,144,896)	(20,795,218)	(20,410,046)	(20,065,386)	(19,695,521)	(19,290,943)
Annual General Service Primary	AGSP	EDIT Credit 5 Year	(4,540,418)	(133,095)	(372,881)	(4,030,124)	(3,950,184)	(3,886,685)	(3,808,832)	(3,743,129)	(3,670,731)	(3,606,188)	(3,535,150)	(3,471,414)
Transmission General Service - Subtransmission	TGST	EDIT Credit 5 Year	(1,460,683)	(49,065)	-	(1,411,618)	(1,383,966)	(1,358,232)	(1,331,236)	(1,303,548)	(1,278,015)	(1,250,761)	(1,224,665)	(1,197,295)
Transmission General Service - Transmission	TGS	EDIT Credit 5 Year	(1,206,577)	(29,804)	-	(1,176,773)	(1,153,337)	(1,130,207)	(1,109,436)	(1,087,968)	(1,067,923)	(1,046,058)	(1,022,650)	(999,652)
Street and Private Lighting/ Contributed Street Lighting	SPL/CSL	EDIT Credit 5 Year	(6,768,214)	(210,678)	(541,892)	(5,995,730)	(5,840,879)	(5,711,395)	(5,565,161)	(5,435,460)	(5,321,348)	(5,209,293)	(5,113,368)	(5,030,077)
Direct Distribution Connection	DDC	EDIT Credit 5 Year	(216,148)	(7,815)	- "	(206,310)	(202,199)	(198,303)	(193,912)	(190,103)	(186,230)	(182,228)	(178,100)	(173,988)
Total	ALL	Total EDIT Credit Revenues	(162,244,220)	(4,949,632)	(16,041,795)	(140,236,743)	(138,031,727)	(135,590,045)	(132,829,852)	(130,368,748)	(128,022,073)	(125,994,142)	(123,972,981)	(121,502,422)

⁽¹⁾ Liability has been grossed up by the revenue conversion factor.

⁽²⁾ BPU Docket No. ER18030241 required ACE to provide a One-Time Credit to customers by November 7, 2018 for the January through March 2018 for the stub period over-collection, and the flowback of excess ADIT for the period of January through June 2018.

⁽³⁾ BPU Docket No. ER20120746 acknowledge the delayed increase to distribution rates becoming effective January 1, 2022 resulted in the Company not receiving an estimated \$21.4m to base revenues. The Order approved ACE to be amortized in an accelerated manner between July 1, 2021 through December 31, 2021.

Cumulative YTD ACE- EDIT Credits														
Rate Category	Acronym	Rider EDIT Credit	<u>Jul-19</u>	Aug-19	Sep-19	Oct-19	Nov-19	Dec-19	<u>Jan-20</u>	Feb-20	Mar-20	Apr-20	May-20	<u>Jun-20</u>
Residential	R	EDIT Credit 5 Year	(68,379,164)	(65,791,713)	(63,788,181)	(62,495,379)	(61,478,760)	(60,188,145)	(58,614,086)	(57,390,375)	(56,254,178)	(55,106,933)	(54,077,867)	(52,690,290)
Monthly General Service Secondary	MGSS	EDIT Credit 5 Year	(19,526,937)	(18,856,798)	(18,255,193)	(17,779,056)	(17,382,733)	(16,966,853)	(16,481,497)	(16,071,167)	(15,670,814)	(15,303,105)	(14,985,973)	(14,603,298)
Monthly General Service Primary	MGSP	EDIT Credit 5 Year	(533,331)	(520,779)	(500,288)	(498,061)	(482,618)	(472,161)	(461,106)	(453,882)	(441,249)	(429,532)	(422,214)	(417,621)
Annual General Service Secondary	AGSS	EDIT Credit 5 Year	(18,860,588)	(18,424,840)	(17,978,717)	(17,590,596)	(17,235,825)	(16,890,062)	(16,503,737)	(16,155,823)	(15,827,679)	(15,472,412)	(15,193,802)	(14,912,615)
Annual General Service Primary	AGSP	EDIT Credit 5 Year	(3,386,012)	(3,327,112)	(3,232,697)	(3,154,705)	(3,081,552)	(3,007,736)	(2,932,587)	(2,873,176)	(2,801,754)	(2,730,610)	(2,673,414)	(2,619,463)
Transmission General Service - Subtransmission	TGST	EDIT Credit 5 Year	(1,167,381)	(1,132,637)	(1,099,250)	(1,069,927)	(1,043,142)	(1,017,986)	(992,162)	(966,203)	(941,561)	(918,374)	(901,306)	(883,316)
Transmission General Service - Transmission	TGS	EDIT Credit 5 Year	(976,877)	(947,536)	(922,957)	(900,111)	(877,853)	(856,433)	(837,157)	(817,306)	(797,736)	(773,413)	(763,077)	(746,232)
Street and Private Lighting/ Contributed Street Lighting	SPL/CSL	EDIT Credit 5 Year	(4,942,112)	(4,850,295)	(4,749,597)	(4,636,485)	(4,518,476)	(4,384,031)	(4,241,794)	(4,135,104)	(4,002,026)	(3,893,259)	(3,801,589)	(3,713,316)
Direct Distribution Connection	DDC	EDIT Credit 5 Year	(169,945)	(165,826)	(161,722)	(157,761)	(153,876)	(149,705)	(145,243)	(141,407)	(137,449)	(133,306)	(129,385)	(125,260)
Total	ALL	Total EDIT Credit Revenues	(117,942,347)	(114,017,536)	(110,688,601)	(108,282,081)	(106,254,834)	(103,933,112)	(101,209,370)	(99,004,444)	(96,874,446)	(94,760,945)	(92,948,627)	(90,711,410)

⁽¹⁾ Liability has been grossed up by the revenue conversion factor.

⁽²⁾ BPU Docket No. ER18030241 required ACE to provide a One-Time Credit to customers by November 7, 2018 for the January excess ADIT for the period of January through June 2018.

⁽³⁾ BPU Docket No. ER20120746 acknowledge the delayed increase to distribution rates becoming effective January 1, 2022 resul Order approved ACE to be amortized in an accelerated manner between July 1, 2021 through December 31, 2021.

Cumulative YTD ACE- EDIT Credits															
Rate Category	Acronym	Rider EDIT Credit	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20	<u>Jan-21</u>	Feb-21	<u>Mar-21</u>	Apr-21	May-21	<u>Jun-21</u>	<u>Jul-21</u>
Residential	R	EDIT Credit 5 Year	(50,232,843)	(47,471,854)	(45,280,526)	(44,047,492)	(42,991,157)	(41,632,656)	(40,029,557)	(38,669,319)	(37,276,783)	(36,123,445)	(35,119,129)	(33,636,618)	(31,326,407)
Monthly General Service Secondary	MGSS	EDIT Credit 5 Year	(14,023,872)	(13,377,956)	(12,801,751)	(12,365,004)	(11,980,728)	(11,572,611)	(11,120,443)	(10,708,957)	(10,267,609)	(9,838,363)	(9,442,817)	(8,987,035)	(8,320,564)
Monthly General Service Primary	MGSP	EDIT Credit 5 Year	(404,464)	(389,926)	(378,073)	(370,226)	(353,761)	(342,383)	(330,997)	(323,470)	(307,876)	(296,720)	(284,674)	(270,341)	(255,203)
Annual General Service Secondary	AGSS	EDIT Credit 5 Year	(14,469,925)	(14,054,754)	(13,627,389)	(13,320,704)	(12,950,978)	(12,624,093)	(12,275,876)	(11,997,131)	(11,644,370)	(11,312,908)	(11,039,317)	(10,662,954)	(10,242,887)
Annual General Service Primary	AGSP	EDIT Credit 5 Year	(2,534,654)	(2,448,802)	(2,366,340)	(2,304,079)	(2,239,698)	(2,157,456)	(2,092,505)	(2,033,310)	(1,962,947)	(1,899,912)	(1,845,223)	(1,776,467)	(1,691,264)
Transmission General Service - Subtransmission	TGST	EDIT Credit 5 Year	(862,907)	(833,262)	(802,142)	(775,540)	(751,516)	(737,260)	(716,527)	(680,448)	(658,383)	(634,478)	(613,358)	(587,128)	(563,741)
Transmission General Service - Transmission	TGS	EDIT Credit 5 Year	(731,218)	(707,729)	(684,930)	(664,938)	(643,790)	(622,685)	(628,520)	(586,523)	(563,931)	(546,103)	(532,689)	(514,276)	(487,495)
Street and Private Lighting/ Contributed Street Lighting	SPL/CSL	EDIT Credit 5 Year	(3,627,688)	(3,539,894)	(3,438,117)	(3,334,355)	(3,210,458)	(3,076,037)	(2,950,657)	(2,822,460)	(2,702,293)	(2,587,689)	(2,498,279)	(2,410,004)	(2,326,241)
Direct Distribution Connection	DDC	EDIT Credit 5 Year	(121,001)	(116,943)	(112,859)	(108,801)	(104,947)	(100,748)	(96,475)	(92,724)	(88,777)	(84,542)	(80,340)	(76,093)	(72,047)
Total	ALL	Total EDIT Credit Revenues	(87,008,572)	(82,941,119)	(79,492,129)	(77,291,141)	(75,227,033)	(72,865,929)	(70,241,556)	(67,914,343)	(65,472,968)	(63,324,160)	(61,455,825)	(58,920,917)	(55,285,849)

(1) Liability has been grossed up by the revenue conversion factor.

⁽²⁾ BPU Docket No. ER18030241 required ACE to provide a One-Time Credit to customers by November 7, 2018 for the January excess ADIT for the period of January through June 2018.

⁽³⁾ BPU Docket No. ER20120746 acknowledge the delayed increase to distribution rates becoming effective January 1, 2022 resul Order approved ACE to be amortized in an accelerated manner between July 1, 2021 through December 31, 2021.

Cumulative YTD ACE- EDIT Credits															
Rate Category	Acronym	Rider EDIT Credit	Aug-21	Sep-21	Oct-21	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	May-22	<u>Jun-22</u>	<u>Jul-22</u>	Aug-22
Residential	R	EDIT Credit 5 Year	(28,853,056)	(26,529,999)	(25,181,563)	(24,144,364)	(22,855,690)	(21,220,908)	(19,851,896)	(18,595,005)	(17,455,465)	(16,432,267)	(14,882,872)	(12,792,673)	(10,158,107)
Monthly General Service Secondary	MGSS	EDIT Credit 5 Year	(7,634,969)	(6,966,169)	(6,467,038)	(6,051,807)	(5,604,076)	(5,091,176)	(4,629,442)	(4,152,823)	(3,692,459)	(3,262,371)	(2,715,968)	(2,079,334)	(1,368,960)
Monthly General Service Primary	MGSP	EDIT Credit 5 Year	(231,532)	(209,147)	(191,296)	(168,232)	(153,174)	(121,778)	(103,001)	(82,151)	(60,960)	(41,222)	(17,155)	7,611	36,611
Annual General Service Secondary	AGSS	EDIT Credit 5 Year	(9,822,984)	(9,392,745)	(9,036,525)	(8,714,218)	(8,395,808)	(8,053,242)	(7,739,357)	(7,427,695)	(7,105,896)	(6,803,581)	(6,446,494)	(6,056,003)	(5,646,221)
Annual General Service Primary	AGSP	EDIT Credit 5 Year	(1,614,015)	(1,525,614)	(1,453,287)	(1,381,794)	(1,326,217)	(1,250,615)	(1,184,586)	(1,124,691)	(1,060,752)	(997,236)	(926,459)	(856,925)	(772,125)
Transmission General Service - Subtransmission	TGST	EDIT Credit 5 Year	(529,167)	(496,570)	(471,234)	(444,697)	(421,309)	(394,150)	(370,035)	(346,775)	(322,153)	(298,862)	(273,433)	(245,890)	(214,215)
Transmission General Service - Transmission	TGS	EDIT Credit 5 Year	(466,209)	(428,789)	(427,343)	(381,295)	(354,600)	(331,862)	(312,937)	(291,992)	(268,798)	(245,989)	(220,555)	(193,594)	(170,759)
Street and Private Lighting/ Contributed Street Lighting	SPL/CSL	EDIT Credit 5 Year	(2,235,239)	(2,135,196)	(2,032,209)	(1,914,170)	(1,783,633)	(1,637,036)	(1,515,719)	(1,403,073)	(1,295,015)	(1,204,478)	(1,115,312)	(1,032,874)	(942,453)
Direct Distribution Connection	DDC	EDIT Credit 5 Year	(67,720)	(63,525)	(59,738)	(55,847)	(51,486)	(46,893)	(43,226)	(39,268)	(35,028)	(31,177)	(26,666)	(22,622)	(18,367)
Total	ALL	Total EDIT Credit Revenues	(51,454,891)	(47,747,753)	(45,320,233)	(43,256,423)	(40,945,994)	(38,147,662)	(35,750,199)	(33,463,474)	(31,296,527)	(29,317,183)	(26,624,915)	(23,272,304)	(19,254,595)

⁽¹⁾ Liability has been grossed up by the revenue conversion factor.

⁽²⁾ BPU Docket No. ER18030241 required ACE to provide a One-Time Credit to customers by November 7, 2018 for the January excess ADIT for the period of January through June 2018.

⁽³⁾ BPU Docket No. ER20120746 acknowledge the delayed increase to distribution rates becoming effective January 1, 2022 resul Order approved ACE to be amortized in an accelerated manner between July 1, 2021 through December 31, 2021.

Cumulative YTD ACE- EDIT Credits	Forecasted EDIT Credits											
Rate Category	Acronym	Rider EDIT Credit	Sep-22	Oct-22	Nov-22	Dec-22	Jan-23	Feb-23	Mar-23	Apr-23	May-23	Jun-23
Residential Residential	R	EDIT Credit 5 Year	(7,912,594)	(6,728,085)	(5,744,325)	(4,431,904)	(2,735,729)	(1,210,312)	119.110	Scheduled to be s		
Monthly General Service Secondary	MGSS	EDIT Credit 5 Year	(679,414)	(204,527)	217,411	Scheduled to be set	,			peneduled to be a	et to zero enceu.	C.1p111 1, 2020
Monthly General Service Primary	MGSP	EDIT Credit 5 Year	74,937	79,990	84,199	-	-	-	-	-	-	-
Annual General Service Secondary	AGSS	EDIT Credit 5 Year	(5,232,318)	(4,897,764)	(4,602,107)	(4,290,486)	(3,964,091)	(3,643,824)	(3,332,035)	(3,019,460)	(2,714,402)	(2,360,086)
Annual General Service Primary	AGSP	EDIT Credit 5 Year	(687,751)	(611,163)	(545,105)	(482,164)	(415,246)	(349,457)	(285,545)	(221,156)	(158,280)	(85,344)
Transmission General Service - Subtransmission	TGST	EDIT Credit 5 Year	(182,298)	(154,786)	(130,125)	(106,981)	(82,143)	(57,795)	(34,066)	Scheduled to be s	et to zero effectiv	e April 1, 2023
Transmission General Service - Transmission	TGS	EDIT Credit 5 Year	(149,002)	(111,168)	(88,821)	(65,980)	(39,710)	(13,824)	11,261	Scheduled to be s	et to zero effectiv	e April 1, 2023
Street and Private Lighting/ Contributed Street Lighting	SPL/CSL	EDIT Credit 5 Year	(858,668)	(739,527)	(624,799)	(501,177)	(362,001)	(245,644)	(131,901)	Scheduled to be s	et to zero effectiv	e April 1, 2023
Direct Distribution Connection	DDC	EDIT Credit 5 Year	(14,225)	(10,213)	(6,308)	Scheduled to be set	t to zero effect	ive December	1, 2022			
					-							
Total	ALL	Total EDIT Credit Revenues	(15,641,333)	(13,377,243)	(11,439,979)	(9,878,691)	(7,598,921)	(5,520,855)	(3,653,176)	(3,240,615)	(2,872,682)	(2,445,430)

(1) Liability has been grossed up by the revenue conversion factor.

⁽²⁾ BPU Docket No. ER18030241 required ACE to provide a One-Time Credit to customers by November 7, 2018 for the January excess ADIT for the period of January through June 2018.

⁽³⁾ BPU Docket No. ER20120746 acknowledge the delayed increase to distribution rates becoming effective January 1, 2022 resul Order approved ACE to be amortized in an accelerated manner between July 1, 2021 through December 31, 2021.

Schedule (MTN)-6

List of Proposed Tariff Changes 2023 Base Rate Case Atlantic City Electric Company Tariff Section II

SHEET	SECTION II	PARAGRAPH	CHANGE AND EXPLANATION OF
NO.	Tariff Section		CHANGE
8	Terms and Conditions of Service	2.7 Multiple Service for Non-	Clarifying language changes
		Residential Customers	
8	Terms and Conditions of Service	2.11 Reconnection of Service	Clarifying language changes
		Requirements	
12	Terms and Conditions of Service	4.1 Additional Loads	Clarifying language changes
13	Terms and Conditions of Service	4.5 Residential Use	Clarifying language changes
17	Terms and Conditions of Service	6.4 Payment of Bills	Update to late payment charge language to
			reflect current practice; update of the
			courtesy center addresses
18	Terms and Conditions of Service	6.12 Opting out of AMI Meters	Addition of language to include Smart
			Energy Network Opt-out (AMI) charges
26	Terms and Conditions of Service	10. General Interconnection	Update to language to include reference to
		Requirements for Customer's	current guidelines
		Generation	

List of Proposed Tariff Changes 2023 Base Rate Case Atlantic City Electric Company Tariff Section III

SHEET NO.	SECTION III Tariff Section	PARAGRAPH	CHANGE AND EXPLANATION OF CHANGE
3	Rate Schedule RUE (Residential Underground Extensions)	Additional Charges	Multi-phase Constructions – Updating with current Regulation
7	Contributed Lighting Extension	Rate	Closing High Pressure Sodium "HPS" offerings; Update language for clarity; Closing Induction lighting offerings
7a	Contributed Lighting Extension	Light Emitting Diode	Proposing two new lighting offerings
7a	(Contributed Lighting Extension)	Light Emitting Diode	Clarifying language

List of Proposed Tariff Changes 2023 Base Rate Case Atlantic City Electric Company Tariff Section IV

SHEET NO.	SECTION IV Tariff Section	PARAGRAPH	CHANGE AND EXPLANATION OF CHANGE
4	Rate Schedule CHG	Service Charges	Addition of Smart Energy Network (AMI) Opt-out Charges
10a -10c	Rate Schedule EV-ERR (Electric Vehicle Equivalent Residential Rate)	N/A	Addition of Electric Vehicle Equivalent Residential Rate Schedule
21-28	AGS TOU Secondary AGS TOU Primary AGS TOU Sub-Transmission AGS TOU Transmission	N/A	Removal of AGS TOU Secondary, Primary, Sub Transmission and Transmission. Tariff was eliminated effective August 1, 2003
35	Rate Schedule SPL	Availability of Service	Update to match CSL Rate Schedule
35	Rate Schedule SPL	Corporate Business Tax, SUT, PTC	Moved Tax and Price to Compare language to match the structure of the CLS rate schedule
36	Rate Schedule SPL (Street and Private Lighting) (Mounted on Existing Pole)	Rate Table	Closing High Pressure Sodium "HPS" and Metal Halide lights
37	Rate Schedule SPL (Continued) (Street and Private Lighting) RATE (Underground)	Rate Table	Closing High Pressure Sodium "HPS" lights
37a	Rate Schedule SPL (Continued) (Street and Private Lighting) Experimental Light Emitting Diode (LED)	Rate Table	Removing word "Experimental" and proposing two new light types; updating Lumens
38	Rate Schedule SPL (Continued)	Upgrades to Existing Fixtures	Additional language for clarity

38	Rate Schedule SPL (Continued) (Street and Private Lighting)	Terms of Contract	Additional language added to match CSL rate schedule
38	RATE SCHEDULE SPL (Continued) (Street and Private Lighting)	Terms and Conditions of Service	Updating language for clarity; moving Tax and Price to Compare language to match the structure of the CLS rate schedule
39	Rate Schedule CSL (Contributed Street Lighting)	Availability	Additional language for clarity
40	Rate Schedule CSL (Contributed Street Lighting)	Rates Table	Closing High Pressure Sodium "HPS" and Metal Halide lights
40	Rate Schedule CSL (Contributed Street Lighting)	Rates Table	Removing word "Experimental" and proposing two new light types and updating LED missing lumens
40a	Rate Schedule CSL (Contributed Street Lighting)	Upgrades to Existing Fixtures	Additional language for clarity
40a	Rate Schedule CSL (Contributed Street Lighting)	Terms and Conditions of Service	Additional language for clarity
44	Rider STB-Standby Service (Applicable to MGS, AGS, TGS and SPP Rate Schedules)	Availability	Updated language for clarity
46-48	Rider IS – Interruptible Service	N/A	Removal of Rider IS – Interruptible Service. Discontinued as of December 31, 1999.
54	Rider MTC	N/A	Removal of Rider MTC. Replaced by Rider NGC, effective June 1, 2005
55	Rider NNC	N/A	Removal of Rider NNC. Replaced by Rider NGC, effective June 1, 2005.
61	Rider NEM Net Energy Metering	Connection to the Company's System	Updating language to include reference to current guidelines
63b	Rider ANEM (Continued) Aggregated Net Energy Metering	Connection to the Company's System	Updating language to include reference to current guidelines

Schedule (MTN)-7

Atlantic City Electric Company
Development of Proposed Distribution Rate
Rate Class Allocation of Distribution Revenue Requirements

Rate Class Allocation of Distribution Revenue Requirements										
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(1)	(J)	(K)
			MONTHLY GENERAL SERVICE	MONTHLY GENERAL	ANNUAL GENERAL SERVICE	ANNUAL GENERAL	TRANSMISSION GENERAL SERVICE	TRANSMISSION GENERAL SERVICE	STREET LIGHTING	DIRECT DISTRIBUTIO
Table 1: Cost of Service Study Results (Schedule (JLM)-5)	TOTAL	RESIDENTIAL	SECONDARY	SERVICE PRIMARY	SECONDARY	SERVICE PRIMARY	SUB-TRANSMISSION	TRANSMISSION	SERVICE	CONNECTIO
Operating Income	\$ 114,457,025	52,515,589	30,985,598	208,164	19,185,270	2,803,407	763,237	868,840	6,952,258	174
Distribution Rate Base ROR	\$ 1,952,245,281 5.86%	1,287,195,177 4.08%	240,250,674 12.90%	7,610,794 2.74%	247,441,809 7.75%	53,250,982 5.26%	8,350,654 9.14%	1,856,273 46.81%	103,999,452 6.68%	2,289 7
Jnitized ROR	1.00	0.70	2.20	0.47	1.32	0.90	1.56	7.98	1.14	,
			HOUTH WORKER	1	ANNUAL GENERAL	1	TRANSMISSION	TRANSMISSION		DIRECT
			MONTHLY GENERAL SERVICE	MONTHLY GENERAL	SERVICE	ANNUAL GENERAL	GENERAL SERVICE	TRANSMISSION GENERAL SERVICE	STREET LIGHTING	DISTRIBUTIO
Table 2: Revenue Requirements Results (Schedule (JCZ)-3)	TOTAL	RESIDENTIAL	SECONDARY	SERVICE PRIMARY	SECONDARY	SERVICE PRIMARY	SUB-TRANSMISSION	TRANSMISSION	SERVICE	CONNECTIO
Pro Forma Operating Income	\$84,302,594	\$ 38,680,023	\$ 22,822,245	\$ 153,322		\$ 2,064,832	\$ 562,157	\$ 639,938		\$ 128
Adjusted Net Rate Base ROR	\$2,235,749,719 3.77%	\$ 1,474,121,251 2.62%	\$ 275,139,801 8.29%	\$ 8,716,031 1.76%	\$ 283,375,230 4.99%	\$ 60,984,072 3.39%	\$ 9,563,334 5.88%	\$ 2,125,840 30.10%	\$ 119,102,220 4.30%	\$ 2,62
Jnitized ROR	1.00	0.70	2.20	0.47	1.32	0.90	1.56	7.98	1.14	4
February Income	405	1								
Table 3: Revenue Increase Revenue Requirement w/o SUT	ACE \$ 104,788,395	+								
Revenue Requirement w/ SUT	\$ 111,730,626									
Operating Income Deficiency	\$ 75,106,361									
Proposed ROR	7.13%]								
			MONTHLY GENERAL		ANNUAL GENERAL		TRANSMISSION	TRANSMISSION		DIRECT
	TO-	DE0/DE:	SERVICE	MONTHLY GENERAL	SERVICE	ANNUAL GENERAL	GENERAL SERVICE	GENERAL SERVICE	STREET LIGHTING	DISTRIBUTIO
Table 4: Revenue Allocation Multi-Step Process Step 1 - Exclusion	TOTAL	RESIDENTIAL	SECONDARY	SERVICE PRIMARY	SECONDARY	SERVICE PRIMARY	SUB-TRANSMISSION	TRANSMISSION X	SERVICE	CONNECTIO
Itep 1: Allocated Revenue Requirement	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$
Step 1: Remaining Revenue Requirement	\$ 104,788,395									
Step 2 - UROR Steady State Multiplier										
Proposed System Average Increase										
Annualized Current Delivery Revenues										
Step 2: Allocated Revenue Requirement Step 2: Remaining Revenue Requirement	\$ - \$ 104,788,395									
Step 3 - Under-Earning Rate Classes	\$ 104,766,393	X		X						
fultiplier		1.01		1.01						
ystem Average Increase		20.84%		20.84%						
Annualized Current Delivery Revenues Step 3: Allocated Revenue Requirement	\$ 66,116,397	\$ 311,687,887 \$ 65,616,879		\$ 2,372,769 \$ 499,518						
Step 3: Remaining Revenue Requirement	\$ 38,671,998	* *************************************								
Step 4 - Remaining Rate Classes	6 00.074.000	\$ -	X 10.500.400		X 40.455.000	\$ 2.754.438	X 004 400		X 1044457	X
Step 4: Allocated Revenue Requirement Step 4: Remaining Revenue Requirement	\$ 38,671,998 \$ -	\$ -	\$ 18,532,483	\$ -	\$ 12,455,922	\$ 2,754,438	\$ 661,463		\$ 4,044,157	\$ 22
			MONTHLY GENERAL SERVICE	MONTHLY GENERAL	ANNUAL GENERAL SERVICE	ANNUAL GENERAL	TRANSMISSION GENERAL SERVICE	TRANSMISSION GENERAL SERVICE	STREET LIGHTING	DIRECT
Table 5: Revenue Allocation Summary (\$)	TOTAL	RESIDENTIAL	SECONDARY	SERVICE PRIMARY	SECONDARY	SERVICE PRIMARY	SUB-TRANSMISSION	TRANSMISSION	SERVICE	CONNECTIO
Step 1	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$
Step 2 Step 3	\$ - \$ 66,116,397	\$ - \$ 65,616,879	\$ -	\$ - \$ 499,518	\$ - \$ -	\$ - \$ -	\$ - \$ -	\$ - \$ -	\$ - \$ -	\$ \$
Step 4	\$ 38,671,998	\$ 65,616,679	\$ 18,532,483	\$ 499,516	\$ 12,455,922	\$ 2,754,438	\$ 661,463	s -	\$ 4,044,157	\$ 22
Step 4 Fotal	\$ 104,788,395	\$ 65,616,879	\$ 18,532,483	\$ 499,518	\$ 12,455,922	\$ 2,754,438	\$ 661,463	\$ -	\$ 4,044,157	\$ 22
			MONTHLY GENERAL		ANNUAL GENERAL		TRANSMISSION	TRANSMISSION		DIRECT
			SERVICE	MONTHLY GENERAL	SERVICE	ANNUAL GENERAL	GENERAL SERVICE	GENERAL SERVICE	STREET LIGHTING	DISTRIBUTION
Table 6: Revenue Allocation Summary (%) Step 1	TOTAL 0.00%	RESIDENTIAL 0.00%	SECONDARY 0.00%	SERVICE PRIMARY 0.00%	SECONDARY 0.00%	SERVICE PRIMARY 0.00%	SUB-TRANSMISSION 0.00%	TRANSMISSION 0.00%	SERVICE 0.00%	CONNECTIO 0.00%
Step 2	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Step 3	63.10%	62.62%	0.00%	0.48%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Step 4 Fotal	36.90% 100.00%	0.00% 62.62%	17.69% 17.69%	0.00% 0.48%	11.89% 11.89%	2.63% 2.63%	0.63% 0.63%	0.00% 0.00%	3.86% 3.86%	0.21% 0.21%
otai	100.00%			0.4070	•	2.03/0			3.00 /6	
			MONTHLY GENERAL		ANNUAL GENERAL		TRANSMISSION	TRANSMISSION	0705571	DIRECT
Fable 7: Proposed Revenue Allocation - UROR Analysis	TOTAL	RESIDENTIAL	SERVICE SECONDARY	MONTHLY GENERAL SERVICE PRIMARY	SERVICE SECONDARY	ANNUAL GENERAL SERVICE PRIMARY	GENERAL SERVICE SUB-TRANSMISSION	GENERAL SERVICE TRANSMISSION	STREET LIGHTING SERVICE	DISTRIBUTI
ROR	7.13%	5.81%	13.12%	5.87%	8.14%	6.62%	10.84%	30.10%	6.73%	1
ncremental Income	\$ 75,106,361	\$ 47,030,447	\$ 13,283,029	\$ 358,026	\$ 8,927,696	\$ 1,974,224	\$ 474,099	\$ -	\$ 2,898,622	\$ 16
tevenue Conversion Factor tevenue Requirement	1.3952 \$ 104,788,395	1.3952 \$ 65,616,879	1.3952 \$ 18,532,483	1.3952 \$ 499,518	1.3952 \$ 12,455,922	1.3952 \$ 2,754,438	1.3952 \$ 661,463	1.3952	1.3952 \$ 4,044,157	\$ 22
inal Unitized ROR	1.00	0.82	1.84	0.82	1.14	0.93	1.52	4.22	0.94	Ψ 22
ROR Change		0.12	(0.36)	0.36	(0.18)	0.03	(0.04)	(3.76)	(0.20)	
			MONTHLY GENERAL		ANNUAL GENERAL		TRANSMISSION	TRANSMISSION		DIRECT
			SERVICE	MONTHLY GENERAL	SERVICE	ANNUAL GENERAL	GENERAL SERVICE	GENERAL SERVICE	STREET LIGHTING	DISTRIBUTI
able 8: Rate Schedule Specific Revenue Increase Allocation	TOTAL	RESIDENTIAL	SECONDARY	SERVICE PRIMARY	SECONDARY	SERVICE PRIMARY	SUB-TRANSMISSION	TRANSMISSION	SERVICE	CONNECTION
nnualized Current Delivery Revenues (w/ EDIT and w/o SUT)	\$ 502,734,762 \$ 104,788,395	\$ 311,687,887 \$ 65,616,879	\$ 89,235,950 \$ 18,532,483	\$ 2,372,769 \$ 499,518	\$ 59,976,640 \$ 12,455,922	\$ 13,262,923 \$ 2,754,438	\$ 3,185,017 \$ 661,463	\$ 2,464,167	\$ 19,473,063 \$ 4,044,157	\$ 1,07 \$ 22
evenue Change (\$) roposed Revenue	\$ 607,523,157	\$ 377,304,767	\$ 18,532,483 \$ 107,768,433	\$ 2,872,287	\$ 12,455,922 \$ 72,432,562	\$ 2,754,438 \$ 16,017,361	\$ 3,846,480	\$ 2,464,167	\$ 4,044,157	\$ 1,29
	20.84%	21.05%	20.77%	21.05%	20.77%	20.77%	20.77%	0.00%	20.77%	2
Revenue Change based on Annualized Current Revenue (%)	20.04%									
Revenue Change based on Annualized Current Revenue (%) Service Classification Rate Change as a Percentage of Overall Distribution Change	20.04%	1.01	1.00	1.01	1.00	1.00	1.00		1.00	

Atlantic City Electric Company

Development of Proposed Distribution Rate Rate Design Worksheet

RS & EV-ERR Rate Schedule w/o SUT w/ SUT 332,337,210 Annualized Current Delivery Revenues 311,687,887 \$ Revenue Change \$ 65,616,879 \$ 69,963,998 Total Proposed Revenue 377,304,767 402,301,207

21.05% Proposed Residential Class Increase 21.56% Proposed Customer Charge Increase (Rounding to \$7.60)

Blocks	Normalized Billing Determinants	ı	Current Distribution Rates cluding SUT)	ı	4 Current Distribution Rates (w/o SUT)	(5 = 2 x 4 Calculated Rate Class Revenue under Current stribution Rates (w/o SUT)	1	Proposed Distribution Rates ncluding SUT)	7 oposed Distribution Rates (w/o SUT)	8 = 2 x 7 ecovery under Proposed Distribution Rates (w/o SUT)	R	9 = 2 x 6 Recovery under Proposed stribution Rates including SUT)	Distribution Rate
CUSTOMER	6,031,481	\$	6.25	\$	5.86	\$	35,354,518	\$	7.60	\$ 7.13	\$ 43,004,458	\$	45,839,254	21.6%
SUM 'First 750 KWh SUM '> 750 KWh	1,183,990,699 736,410,419		0.072877 0.085560		0.068349 0.080244		80,924,446 59,092,404			0.084560 0.099276	100,117,727 73,107,664			23.7% 23.7%
WIN	2,093,076,034	\$	0.066324	\$	0.062203	\$	130,195,709	\$	0.082054	\$ 0.076956	\$ 161,074,918	\$	171,745,261	23.7%
TOTAL ENERGY	4,013,477,152					\$	270,212,559				\$ 334,300,309	\$	356,447,482	
						\$	305,567,076	=			\$ 377,304,767		402,286,736	:
	TOTAL REVENUE										\$ -	\$	14,471	

Present Revenues

Unadjusted Present Revenue \$ 305,567,076 CIP Annualization Adjustment 6,120,811 Adjusted Present Revenue 311,687,887

<u>Proposed Increase</u> Proposed Rate Increase w/o SUT 65,616,879 Total Proposed Revenue w/o SUT 377,304,767 Total Proposed Revenue w/ SUT 402,301,207

Atlantic City Electric Company

Development of Proposed Distribution Rate Rate Design Worksheet

Rate Schedule MGS SECONDARY w/o SUT w/ SUT Annualized Current Delivery Revenu \$ 89,235,950 \$ 95,147,832 Revenue Change \$ 18,532,483 \$ 19,760,260 107,768,433 \$ 114,908,092 Total Proposed Revenue

20.77%	Proposed Class Increase
20.77%	Proposed Customer Charge Increase
20.77%	Proposed Demand Charge Increase

	1 2		3	3	4		5 = 2 x 4 Calculated Rate		6	7	F	8 = 2 x 7 Recovery under		9 = 2 x 6 ecovery under	10 = (6-3)/3	j
ВЬОСК	Billing Determinants		Current Distribution Rates cluding SUT)		Current Distribution Rates (w/o SUT)		Class Revenue under Current istribution Rates (w/o SUT)		Proposed Distribution Rates Icluding SUT)	Proposed istribution Rates (w/o SUT)		Proposed Distribution Rates (w/o SUT)		Proposed Distribution Rates ncluding SUT)	Distribution Rate Change %	_
CUSTOMER																
Single Phase Service	500,653	\$	11.90	\$	11.16	\$	5,587,594	\$	14.37	\$ 13.48	\$	6,748,804	\$	7,194,385	20.8%	,
3 Phase Service	179,618	\$	13.84	\$	12.98	\$	2,331,452	\$	16.72	\$ 15.68	\$	2,816,408	\$	3,003,210	20.8%)
DEMAND CHARGE - All kWs																
Summer	2,260,193	\$	3.27	\$	3.07	\$	6,931,611	\$	3.95	\$ 3.70	\$	8,362,713	\$	8,927,762	20.8%)
Winter	3,666,010	\$	2.68	\$	2.51	\$	9,214,449	\$	3.24	\$ 3.04	\$	11,144,670	\$	11,877,872	20.9%)
REACTIVE DEMAND	78,362	\$	0.64	\$	0.60	\$	47,036	\$	0.77	\$ 0.72	\$	56,421	\$	60,339	20.3%)
ENERGY CHARGE																
Summer	565,644,181	\$	0.062158	\$	0.058296	\$	32,974,735	\$	0.064995	\$ 0.060957	\$	34,479,972	\$	36,764,044	4.6%	,
Winter	818,455,557	\$	0.055017	\$	0.051599	\$	42,231,155	\$	0.057528	\$ 0.053954	\$	44,158,951	\$	47,084,111	4.6%)
TOTAL	1 294 000 729	-				•	00 249 022	_			•	107,767,939	\$	114 011 722		
TOTAL	1,384,099,738	=				<u> </u>	99,318,032	=			<u> </u>	101,701,939	Ð	114,911,722		
											\$	(494)	\$	3,630		

TOTAL REVENUE

99,318,032
(10,082,081)
89,235,950

Proposed Increase	
Proposed Rate Increase w/o SUT	\$ 18,532,483
Total Proposed Revenue w/o SUT	\$ 107,768,433
Total Proposed Revenue w/ SUT	\$ 114,908,092

10 = 6/3

 $9 = 2 \times 6$

7

 $8 = 2 \times 7$

6

Atlantic City Electric Company

Development of Proposed Distribution Rate Rate Design Worksheet

Rate Schedule MGS PRIMARY 21.05% Proposed Class Increase w/o SUT w/ SUT \$ Annualized Current Delivery Revenues 2,372,769 \$ 2,529,965 0.00% Proposed Customer Charge Increase \$ 0.00% Proposed Demand Charge Increase Revenue Change 499,518 \$ 532,611 Total Proposed Revenue 2,872,287 \$ 3,062,576

3

2

1

вьоск	Billing Determinants		Current ibution Rates luding SUT)	Current t Distribution Rates Rates			bution Distribution tes Rates			Proposed stribution Rates (w/o SUT)	Recovery under Proposed Distribution Rates (w/o SUT)		Recovery under Proposed Distribution Rates (including SUT)		Distribution Rate Change	
CUSTOMER																
Single Phase Service	951	\$	17.56	\$	16.47	\$	15,665	\$	17.56	\$ 16.47	\$	15,666	\$	16,703	0.0%	
3 Phase Service	911	\$	19.08	\$	17.89	\$	16,309	\$	19.08	\$ 17.89	\$	16,305	\$	17,390	0.0%	
DEMAND CHARGE																
SUM > 3 KW	90,723	\$	1.90	\$	1.78	\$	161,664	\$	1.90	\$ 1.78	\$	161,487	\$	172,374	0.0%	
WIN > 3 KW	167,868	\$	1.49	\$	1.40	\$	234,583	\$	1.49	\$ 1.40	\$	235,016	\$	250,124	0.0%	
REACTIVE DEMAND	127,842	\$	0.47	\$	0.44	\$	56,353	\$	0.47	\$ 0.44	\$	56,251	\$	60,086	0.0%	
ENERGY CHARGE																
SUM < 300KWh	37,584,360	\$	0.048255	\$	0.045257	\$	1,700,946	\$	0.024755	\$ 0.023217	\$	872,596	\$	930,401	-48.7%	
WIN < 300 KWh	67,354,644	\$	0.046750	\$	0.043845	\$	2,953,181	\$	0.023983	\$ 0.022493	\$	1,515,008	\$	1,615,366	-48.7%	
TOTAL	104,939,004	- =				\$	5,138,701	-			\$	2,872,329	\$	3,062,444		
											\$	42	\$	(132)		

 $5 = 2 \times 4$

TOTAL REVENUE											
Present Revenues											
Unadjusted Present Revenue	\$	5,138,701									
CIP Annualization Adjustment	\$	(2,765,932)									
Adjusted Present Revenue	\$	2,372,769									
Proposed Increase											
Proposed Rate Increase w/o SUT	\$	499,518									
Total Proposed Revenue w/o SUT	\$	2,872,287									
Total Proposed Revenue w/ SUT	\$	3,062,576									

10 = (6-3)/3

 $9 = 2 \times 6$

Atlantic City Electric Company
Development of Proposed Distribution Rate Rate Design Worksheet

Rate Schedule	AGS SECONDARY									
		w/o SUT		w/ SUT						
Annualized Current Delivery Revenues	\$	59,976,640	\$	63,950,092						
Revenue Change	\$	12,455,922	\$	13,281,127						
Total Proposed Revenue	\$	72,432,562	\$	77,231,219						

2

3

20.77% Proposed Class Increase 0.00% Proposed Customer Charge Increase 20.25% Proposed Reactive Demand Charge Increase (Demand Weighting)

7

 $8 = 2 \times 7$

6

вьоск	Billing Determinants	istribution Rates Rates Distribution Rates Rates Rates		oposed Distribution Rates (w/o SUT)	ecovery under Proposed Distribution Rates (w/o SUT)	covery under Proposed Distribution Rates cluding SUT)	Distribution Rate Change %				
CUSTOMER	34,914	\$ 193.22	\$	181.21	\$ 6,326,782	\$ 193.22	\$	181.21	\$ 6,326,782	\$ 6,746,100	0.0%
DEMAND CHARGE	4,680,245	\$ 12.44	\$	11.67	\$ 54,604,691	\$ 14.96	\$	14.03	\$ 65,663,842	\$ 70,016,470	20.3%
REACTIVE DEMAND	421,142	\$ 0.94	\$	0.88	\$ 371,277	\$ 1.13	\$	1.06	\$ 446,411	\$ 475,891	20.2%
ENERGY CHARGE	1,562,897,454	-		-	\$ -	-		-	\$ -	\$ -	
TOTAL REVENUE					\$ 61,302,750				\$ 72,437,035	\$ 77,238,461	
									\$ 4,473	\$ 7,242	

 $5 = 2 \times 4$

TOTAL REVENUE

Present Revenues	
Unadjusted Present Revenue	\$ 61,302,750
CIP Annualization Adjustment	\$ (1,326,110)
Adjusted Present Revenue	\$ 59,976,640
Proposed Increase	
Proposed Rate Increase w/o SUT	\$ 12,455,922
Total Proposed Revenue w/o SUT	\$ 72,432,562
Total Proposed Revenue w/ SUT	\$ 77,231,219

<u>Proposed Increase</u> Proposed Rate Increase w/o SUT

Total Proposed Revenue w/o SUT

Total Proposed Revenue w/ SUT

Rate Schedule

Atlantic City Electric Company
Development of Proposed Distribution Rate Rate Design Worksheet

AGS PRIMARY

2,754,438

16,017,361

17,078,511

Annualized Current Delivery Revenues Revenue Change Total Proposed Revenue	\$ \$	13,262,923 2,754,438 16,017,361	\$	w/ SUT 14,141,592 2,936,920 17,078,511	-			11.05% 18.30%	Pro Pro		r Cha Dem	arge Increase and Charge Increase (De					
вьоск	1 De	2 Billing eterminants	Dis	3 Current stribution Rates ncluding SUT)		Current Distribution Rates (w/o SUT)	Ca	5 = 2 x 4 alculated Rate lass Revenue inder Current Distribution Rates (w/o SUT)	ſ	Proposed Distribution Rates cluding SUT)	Pr	7 oposed Distribution Rates (w/o SUT)	Re	8 = 2 x 7 ecovery under Proposed tribution Rates (w/o SUT)	Re	9 = 2 x 6 ecovery under Proposed Distribution Rates ncluding SUT)	10 = (6-3)/3 Distribution Rate Change %
CUSTOMER		1,416	\$	744.15	\$	697.91	\$	988,187	\$	826.34	\$	775.00	\$	1,097,340	\$	1,170,034	11.0%
DEMAND CHARGE		1,343,042	\$	9.86	\$	9.25	\$	12,419,596	\$	11.66	\$	10.94	\$	14,692,880	\$	15,659,870	18.3%
REACTIVE DEMAND		284,066	\$	0.74	\$	0.69	\$	197,148	\$	0.87	\$	0.82	\$	232,934	\$	247,137	17.6%
ENERGY CHARGE		552,682,556	\$	-	\$	-	\$	-		-		-	\$	-	\$	-	
TOTAL REVENUE							\$	13,604,931	=				\$	16,023,154	\$	17,077,041	
TOTAL REVENUE			_										\$	5,793	\$	(1,470)	
Present Revenues Unadjusted Present Revenue CIP Annualization Adjustment Adjusted Present Revenue	\$ \$ \$	13,604,931 (342,008) 13,262,923	-														

10 = 6/3

 $9 = 2 \times 6$

168

Atlantic City Electric Company

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Development of Proposed Distribution Rate Rate Design Worksheet

IGS SUB TRANSMISSION										
	w/o SUT		w/ SUT							
\$	3,185,017	\$	3,396,025							
\$	661,463	\$	705,285							
\$	3,846,480	\$	4,101,310							
	7	w/o SUT \$ 3,185,017 \$ 661,463	w/o SUT \$ 3,185,017 \$ \$ 661,463 \$							

1

2

4,101,310

3

4

20.77%	Proposed Class Increase
0.00%	Proposed Customer Charge Increase
4.43%	Proposed Reactive Demand Charge Increase (Demand Weighting)

7

 $8 = 2 \times 7$

412 \$

6

Calculated Rate Class Revenue Current under Current Recovery under Proposed Recovery under Distribution Distribution Proposed Distribution Distribution Rate Billing Current Distribution Proposed Distribution **Proposed** Rates Change **BLOCK Determinants Distribution Rates** Rates Rates Rates **Distribution Rates** Rates (including SUT) (w/o SUT) (w/o SUT) (including SUT) (w/o SUT) (w/o SUT) (including SUT) % CUSTOMER <5000 KW 337 \$ 131.75 \$ 123.56 \$ 41,614 \$ 131.75 \$ 123.56 \$ 41.613 \$ 44,371 0.0% 30 \$ 4,363.57 \$ 4,092.45 \$ 122,651 \$ 4,363.57 4,092.45 \$ 122,652 \$ 5000 - 9000 KW \$ 130,777 0.0% 31 \$ >9000 KW 7,921.01 \$ 7,428.85 \$ 230,171 \$ 7,921.01 \$ 7,428.85 \$ 230,171 \$ 245,419 0.0% **DEMAND CHARGE** <5000 KW 554,769 \$ 3.84 \$ 3.60 \$ 1,997,947 \$ 4.01 \$ 3.76 \$ 2,085,930 \$ 2,224,622 4.4% 5000 - 9000 KW 215,055 \$ 2.96 \$ 2.78 \$ 597,011 \$ 3.09 \$ 2.90 \$ 623,659 \$ 664,520 4.4% >9000 KW 384,495 \$ 1.50 \$ 1.41 \$ 540,908 \$ 1.57 \$ 1.47 \$ 565,208 \$ 603,658 4.7% REACTIVE DEMAND <5000 KW 205,553 \$ 0.52 \$ 0.49 \$ 100,246 \$ 0.54 \$ 0.51 \$ 104,832 \$ 3.8% 110,998.42 5000 - 9000 KW 53,379 \$ 0.52 \$ 0.49 \$ 26,033 \$ 0.54 \$ 0.51 \$ 27,224 \$ 28,824.93 3.8% >9000 KW 89,420 \$ 0.52 \$ 0.49 \$ 43,609 \$ 0.54 \$ 0.51 \$ 45,604 \$ 48,286.87 3.8% \$ \$ 551,547,682 \$ \$ \$ **ENERGY CHARGE TOTAL REVENUE** 3,846,892 \$ 3,700,190 4,101,477 \$

 $5 = 2 \times 4$

TOTAL REVENUE Present Revenues Unadjusted Present Revenue \$ 3,700,190 CIP Annualization Adjustment (515,173)Adjusted Present Revenue 3,185,017 **Proposed Increase** Proposed Rate Increase w/o SUT 661,463 Total Proposed Revenue w/o SUT 3,846,480

Total Proposed Revenue w/ SUT

10 = (6-3)/3

 $8 = 2 \times 7$ $9 = 2 \times (8+10) 6$

Atlantic City Electric Company

Development of Proposed Distribution Rate

Rate Design Worksheet

Rate Schedule	TGS TRANSMISSION							
		w/o SUT		w/ SUT				
Annualized Current Delivery Revenues	\$	2,464,167	\$	2,627,418				
Revenue Change	\$	-	\$	-				
Total Proposed Revenue	\$	2.464.167	\$	2.627.418				

2

3

0.00% Proposed Class Increase0.00% Proposed Customer Charge Increase0.00% Proposed Reactive Demand Charge Increase

7

6

Calculated Rate Class Revenue Recovery under Recovery under Current under Current **Proposed Proposed Proposed** Distribution Distribution Billing Current Distribution Distribution **Proposed Distribution** Distribution **Distribution Rate BLOCK** Determinants Distribution Rates Rates Rates Rates Rates Rates Rates Change (w/o SUT) % (including SUT) (w/o SUT) (including SUT) (w/o SUT) (w/o SUT) (including SUT) **CUSTOMER** <5000 KW 79 \$ 128.21 \$ 120.24 \$ 9,539 \$ 128.21 \$ 120.24 \$ 9,539 \$ 10,171 0.0% 5000 - 9000 KW 36 \$ 4.246.42 \$ 3.982.57 \$ 144.976 \$ 4,246.42 \$ 3.982.57 \$ 144,976 \$ 154,581 0.0% 18,115.97 >9000 KW 65 \$ 19,316.15 \$ \$ 1,181,796 \$ 19,316.15 \$ 18,115.97 \$ 1,181,796 \$ 1,260,090 0.0% **DEMAND CHARGE** 148,311 \$ <5000 KW 2.98 \$ 2.79 \$ 414,506 \$ 2.79 \$ 2.62 \$ 388,737 \$ 413,788 -6.4% 5000 - 9000 KW 238,653 \$ 2.31 \$ 2.17 \$ 517,034 \$ 2.17 \$ 2.03 \$ 484.892 \$ 517,877 -6.1% 854,087 \$ 0.18 \$ 0.17 144.184 \$ 0.17 \$ 0.16 \$ 135,220 \$ >9000 KW \$ 145.195 -5.6% REACTIVE DEMAND <5000 KW 59.540 \$ 0.50 \$ 0.47 \$ 27.921 \$ 0.50 \$ 0.47 \$ 27.921 \$ 29,770 0.0% 5000 - 9000 KW 66.771 \$ 0.50 \$ 0.47 \$ 31,311 \$ 0.50 \$ 0.47 \$ 31,311 \$ 33,385 0.0% >9000 KW 127,472 \$ 0.50 \$ 0.47 59,776 \$ 0.50 \$ 0.47 \$ 59,776 \$ 63,736 0.0% \$ \$ \$ \$ \$ **ENERGY CHARGE** 527,992,816 \$ **TOTAL REVENUE** 2,531,042 2,464,167 \$ 2,628,592 **TOTAL REVENUE** \$ \$ 1,174

 $5 = 2 \times 4$

Present Revenues

Unadjusted Present Revenue \$ 2,531,042
CIP Annualization Adjustment \$ (66,875)
Adjusted Present Revenue \$ 2,464,167

Proposed Increase

 Proposed Rate Increase w/o SUT
 \$

 Total Proposed Revenue w/o SUT
 \$ 2,464,167

 Total Proposed Revenue w/ SUT
 \$ 2,627,418

amp Code		Street and Private Lighting)		Current Rate	Current Rate		Current Annualized		Proposed Rate	Proposed Rate		Proposed Annualized
_	Watts 103	Type INCANDESCENT	Style Standard	(w/SUT) \$ 833 \$	(w/o SUT) 7.81	Number of Lights	Revenue 89 499	S	(w/o SUT)	(w/ SUT)	Number of Lights	Revenue 111.53
	202	INCANDESCENT		\$ 8.33 \$ \$ 14.35 \$	7.81 13.46	955 \$ 166 \$	89,499 26,807	\$ \$	9.73		955 \$ 166 \$	
10	327	INCANDESCENT	Standard	\$ 19.89 \$	18.65	21 \$	4.701	s	23.25	24.79	21 S	5,85
10	448	INCANDESCENT	Standard	\$ 26.57 \$	24.92	10 \$	2,991	\$	31.06		10 \$	3,72
00	100 175	MERCURY VAPOR MERCURY VAPOR		\$ 13.89 \$ \$ 18.49 \$	13.03 17.34	6,411 \$	1,002,127	s	16.23 \$ 21.61 \$		6,411 \$	
00	1/5 250	MERCURY VAPOR		\$ 18.49 \$ \$ 23.40 \$	17.34	933 \$ 303 \$	194,135 79,789	\$ \$	21.61 \$ 27.35 \$		933 \$ 303 \$	
10	400	MERCURY VAPOR	Standard	\$ 23.40 S	31.55	228 \$	79.769 86,333	S	39.32	41.93	228 \$	
30	700	MERCURY VAPOR	Standard	\$ 53.61 S	50.28	2 \$	1.207	š	62.66	66.81	2 \$	
31	1000	MERCURY VAPOR	Standard	\$ 92.48 \$	86.74	34 \$	35,389	\$	108.09	115.25	34 \$	44,10
0	150	HPS	Retrofit	\$ 16.95 \$	15.90	7.222 \$	1.377.538	s	19.81		7.222 S	
0	360	HPS OH	Retrofit	\$ 31.47 \$	29.52	440 \$	155,855 2,564,040	s	36.78 \$ 17.68 \$		440 \$	194,22
4 5	50 70	HPS OH HPS OH		\$ 15.13 \$ \$ 15.68 \$	14.19 14.70	15,058 \$ 8,418 \$	2,564,040 1.485.077	\$ \$	17.68 \$ 18.32 \$		15,058 \$ 8.418 \$	
6	100	HPS OH		\$ 16.50 \$	15.47	6.631 \$	1,231,284	š	19.28		6.631 \$	
17	150	HPS OH	Cobra Head	\$ 17.94 \$	16.83	4,921 \$	993,733	š	20.97	22.36	4.921 S	1.238.35
18 19	250	HPS OH	Cobra Head	\$ 25.38 \$	23.80	1,672 \$	477,524	\$	29.66 \$	31.62	1,672 \$	595,07
19	400	HPS OH		\$ 29.35 \$	27.52	1,466 \$	484,162	\$	34.30 \$		1,466 \$	
16	150	HPS OH HPS OH	Shoe Box Shoe Box	\$ 21.83 \$ \$ 28.30 \$	20.47 26.54	69 \$ 50 \$	16.949 15.923	s	25.51 S 33.07 S	27.20 35.26	69 S 50 S	
7 8 3	250 400	HPS OH HPS OH		\$ 28.30 \$ \$ 32.68 \$	26.54 30.65		15,923 13,977	\$ \$	33.07 \$			
3	50	HPS OH	Post Top	\$ 16.79 S	15.74	58 \$	10.958	š	19.62	20.92	58 S	13.65
4	100	HPS OH	Post Top	\$ 18.29 \$	17.15	326 \$	67,087	š	21.37	22.79	326 \$	83,60
15	150	HPS OH		\$ 21.49 \$	20.16	24 \$	5,806	\$	25.12		24 \$	7,23
9	150	HPS OH	Flood/Profile	\$ 17.58 \$	16.49	1,009 \$	199,625	s	20.55		1,009 \$	248,76
0	250 400	HPS OH HPS OH	Flood/Profile Flood/Profile	\$ 22.17 \$ \$ 28.31 \$	20.79 26.55	1,731 \$ 2,578 \$	431,862 821,310	\$ \$	25.91 \$ 33.08 \$	27.62 35.28	1,731 \$ 2,578 \$	538,170
1	50/70	HPS OH HPS OH	Decorative 50/70 OH	\$ 28.31 \$ \$ 20.57 \$	26.55 19.30	2,578 \$	821,310 463	\$	24.05 S		2,5/8 \$	
01	100	HPS OH		\$ 23.16 \$	21.72	70 \$	18,248	Š	27.07		70 S	22,740
02	150	HPS OH	Decorative 150 OH	\$ 25.52 \$	23.93	8 \$	2.297	š	29.82	31.80	8 S	2.863
06	400	METAL HALIDE	Flood/Profile	\$ 34.78 \$	32.62	461 \$	180,441	\$	40.65		461 \$	224,860
07	1000	METAL HALIDE	Flood/Profile	\$ 59.22 \$	55.54	416 \$ 932 \$	277.255 243.404	s	69.21 S		416 S	345.505 303.322
1	50 70	HPS UG HPS UG	Cobra Head Cobra Head	\$ 23.21 \$ \$ 23.72 \$	21.76 22.25	932 \$ 435 \$	243,404 116.120	\$ \$	27.12 \$ 27.72 \$		932 \$ 435 \$	303,322
3	100	HPS UG HPS UG	Cobra Head Cobra Head	\$ 23.72 \$ \$ 24.48 \$	22.25	435 \$ 603 \$	166.120	\$	28.61	30.50	603 \$	207.012
1	150	HPS UG	Cobra Head	\$ 26.01 \$	24.39	623 \$	182,354	s	30.40 \$	32.41	623 S	227,243
5	250	HPS UG	Cobra Head	\$ 31.44 S	29.49	388 \$	137,296	\$	36.75 5	39.18	388 \$ 412 \$	171,093
1	400 150	HPS UG	Cobra Head	\$ 35.40 \$ \$ 29.92 \$	33.20 28.06	412 \$ 345 \$	164,139 116.183	s	41.37 S 34.97 S	44.11 37.29	412 \$ 345 \$	204,544 144,783
,	150 250	HPS UG HPS UG	Shoe Box Shoe Box	\$ 29.92 \$ \$ 36.33 \$	28.06 34.07	345 \$ 319 \$	116,183 130.429	ş	34.97 \$ 42.46 \$		345 \$ 319 \$	
2	400	HPS LIG	Shoe Box	\$ 40.74 \$	38.21	330 \$	151,293	s	47.61 5		330 \$	188 536
6	50	HPS UG	Post Top	\$ 20.55 \$	19.28	594 \$	137,398	š	24.02	25.61	594 \$	171.220
7	100	HPS UG	Post Top	\$ 22.02 \$	20.65	2,002 \$	496,098	\$	25.73		2,002 \$	618,220
8	150	HPS UG	Post Top	\$ 30.01 S	28.14	662 S	223.574	s	35.07	37.40	662 S	278.609
3 4	150 250	HPS UG HPS UG	Flood/Profile Flood/Profile	\$ 27.41 \$ \$ 31.99 \$	25.71 30.00	92 \$ 165 \$	28,379 59.399	\$ \$	32.03 \$ 37.38 \$		92 \$ 165 \$	35,365 74,021
15	400	HPS UG	Flood/Profile	\$ 36.40 \$	34.14	375 \$	153.642	3	42.55		375 \$	191.463
15	400	HPS UG	Flood/Profile	\$ 43.03 S	40.35	93 \$	45.033	Š	50.29		93 \$	
16	1000	HPS UG	Flood/Profile	\$ 67.44 \$	63.25	65 \$	49,338	\$	78.83	84.05	65 \$	61.48
1	50/70	HPS UG		\$ 27.37 \$	25.67	88 \$	27,103	\$	31.98	34.10	88 S	33,775
12	100	HPS UG	Decorative 100 UG	\$ 29.92 \$	28.06	262 \$	88,231	\$	34.97		262 \$	
13	150 50	HPS UG		\$ 39.10 S \$ 8.90 \$	36.67 8.35	252 \$ 90 \$	110.892 9.020	S	45.70 S		252 \$ 90 \$	
52	70	LED OH	Cobra Head	\$ 9.20 S	8.63	599 \$	62.049	Š	10.76		90 \$ 599 \$	77.323
53	100	LED OH	Cobra Head	\$ 9.43 \$	8.84	246 \$	26,104	š	11.02	11.75	246 \$	32,530
54	150	LED OH		\$ 9.97 \$	9.35	486 \$	54,556	\$	11.66 \$		486 \$	
5	250	LED OH	Cobra Head	\$ 11.35 \$	10.65	145 \$	18,529	\$	13.27		145 \$	23,090
4	400 150	LED OH LED OH	Cobra Head Decorative 150 OH	\$ 15.40 \$ \$ 20.65 \$	14.45 19.37	8 \$	1,387 930	s	18.00 \$ 24.13 \$	19.19 25.73	8 \$ 4 \$	1,728
58 25	250	LED OH	Mongoose	\$ 20.00 \$ \$ 18.97 \$	19.37	7 \$	1,495	\$	24.13 3	23.65	4 3 7 S	1,156
26	400	LED OH	Mongoose	\$ 21.01 \$	19.70	- \$	1,400	š	24.55 \$		- \$	1,001
27	70	LED OH	Acorn (Granville)	\$ 23.68 \$	22.21	- š	-	š	27.68		- š	-
18	100	LED OH	Acorn (Granville)	\$ 23.68 \$	22.21	- S	-	\$	27.68	29.51	- \$	-
9	150	LED OH	Acorn (Granville)	\$ 23.68 \$	22.21	- s		\$	27.68 \$		- \$	
	100 150	LED OH LED OH	Acorn (Granville) w/ ribs and bands Acorn (Granville) w/ ribs and bands	\$ 27.76 S \$ 27.76 S	26.04 26.04	- s		s s	32.44 5 32.44 5		- S	
6	70	LED OH	Post Top	\$ 11.61 \$	10.89	- S	-	\$	13.57	14.47	- \$	-
57	100	LED OH	Post Top	\$ 12.15 \$	11.39	30 \$	4,101	š	14.20	15.14	30 \$	5,110
i9	100	LED OH		\$ 10.34 S	9.70	- S	-	s	12.08		- s	
0	150	LED OH	Shoe Box	\$ 11.24 \$	10.54	2 \$	253	s	13.13		2 \$	315
1	250 100	LED OH LED OH	Shoe Box Tear Drop	\$ 11.73 \$ \$ 19.10 \$	11.00 17.91	- S		\$	13.71	14.62	- \$ - \$	
	100	LED OH	Tear Drop	\$ 19.10 \$ \$ 19.10 \$	17.91	- \$	-	\$	22.32 5		- \$	
	150	LED OH	Flood/Profile	\$ 17.03 S	15.98	21 \$	4,026	\$	19.91 \$	21.23	21 S	5.017
	250	LED OH	Flood/Profile	\$ 17.73 \$	16.63	52 \$	10,376	\$	20.72	22.09	52 \$	12,930
1	400	LED OH	Flood/Profile	\$ 20.38 \$	19.12	240 \$	55,052	\$	23.82 \$	25.40	240 \$	68,604
12 34	1000	LED OH LED UG		\$ 21.21 S \$ 16.67 S	19.89	85 \$	20.285	S	24.78 5 19.48 5		85 S 2 S	25.279 468
4 5	50 70	LED UG LED UG	Cobra Head Cobra Head	\$ 16.67 \$ \$ 16.97 \$	15.63 15.92	2 \$ 13 \$	375 2,483	S S	19.48 \$ 19.83 \$	20.77	2 S 13 S	3,094
6	100	LED UG		\$ 16.97 \$ \$ 17.20 \$	16.14	13 \$ 46 \$	2,483 8.907	s	20.11		13 3 46 S	11.100
7	150	LED UG	Cobra Head	\$ 17.74 S	16.64	79 \$	15.772	Š	20.73		79 S	19.655
3	250	LED UG	Cobra Head	\$ 19.12 \$	17.93	69 \$	14,847	\$	22.35		69 \$	18,502
1	400 150	LED UG	Cobra Head	\$ 20.02 \$	18.78	12 \$	2,704	ş	23.40	24.95	12 \$	3,370
1	150 250	LED UG	Decorative 150 UG Monggoese	\$ 28.43 \$ \$ 23.61 \$	26.66 22.14	62 \$ - \$	19,834	\$	33.22 \$ 27.59 \$		62 \$ - \$	
3	250 400	LED UG LED UG	Mongoose Mongoose	\$ 23.61 \$ \$ 25.63 \$	22.14 24.04	- S		s s	27.59 S 29.95 S		- S	-
	70	LED UG	Acorn (Granville)	\$ 28.30 \$	26.54	- 3	-	\$	33.08	35.27	- 3	- 1
	100	LED UG	Acorn (Granville)	\$ 28.30 S	26.54	26 \$	8,282	š	33.08 \$	35.27	26 \$	
	150	LED UG	Acorn (Granville)	\$ 28.30 \$	26.54	- \$	-	\$	33.08		- \$	
	100	LED UG	Acorn (Granville) w/ ribs and bands	\$ 31.93 \$	29.95	- ş	-	s	37.32	39.79	- s	-
	150	LED UG	Acorn (Granville) w/ ribs and bands	\$ 31.93 \$ \$ 19.38 \$	29.95 18.17	- \$	5 234	\$	37.32 \$ 22.65 \$		- \$	6.52
19 10	70 100	LED UG	Post Top Post Top	\$ 19.38 \$ \$ 19.92 \$	18.17 18.68	24 \$ 130 \$	5,234 29.147	\$ \$	22.65 \$ 23.28 \$		24 \$ 130 \$	
2	100	LED UG	Shoe Box	S 18.11 S	16.99	17 \$	3.466	s	21.17	22.57	17 S	4.319
73	150	LED UG	Shoe Box	\$ 19.01 \$	17.83	35 \$	7,489	s	22.22	23.69	35 \$	9,333
74	250	LED UG	Shoe Box	\$ 19.50 \$	18.29	11 \$	2,415	š	22.80 \$	24.31	11 S	3,009
75	100	LED UG	Tear Drop	\$ 26.85 \$	25.18	15 \$	4,533	s	31.38		15 \$	
376	150	LED UG	Tear Drop	\$ 26.85 S	25.18	- S	837	S	31.38 5 28.97 5	33.46	- S	
43 44	150 250	LED UG		\$ 24.79 \$ \$ 25.49 \$	23.25 23.91	3 \$ 29 \$	837 8 321	\$ \$	28.97 \$ 29.80 \$		3 \$ 29 \$	
		LED UG		\$ 28.16 \$	26.41	121 \$	38,345	\$	32.91		121 \$	47,784
4 5	400		Flood/Profile	\$ 28.98 \$	27.18	106 \$	34.574	š	33.87		106 S	43.085

	ile CSL (C	ontributed Street Lighting)			urrent		Current			Current		Proposed	P	roposed		Proposed
Lamp					Rate		Rate			Annualized		Rate		Rate		Annualized
Code	Watts	Type	Style		/ SUT)		(w/o SUT)	Number of Lights		Revenue	_	(w/o SUT)		w/ SUT)	Number of Lights	Revenue
201	50	HPS	All	\$	6.67		6.25	12,957		972,273	\$	7.79		8.31	12,957 \$	
202	70	HPS	All	S	7.23		6.78	5.871		477.998	s	8.45		9.02	5.871 \$	
203	100	HPS	All	\$	8.09		7.59	7,235		658,708	\$	9.45		10.08	7,235 \$	
204	150	HPS	All	\$	9.59		8.99	5,246		566,008	\$	11.20		11.95	5,246 \$	
205	250	HPS	All	\$	13.02		12.21		\$	100,076	\$	15.22		16.22	683 \$	
206	400	HPS	All	\$	17.17		16.10	507		97,962	\$	20.07		21.39	507 \$	
271	1000	MH	Flood	\$	13.02		12.21	10		1,465	\$	15.22		16.22	10 \$	
286	175	MH	Flood	\$	12.30		11.54			6,231	\$	14.38		15.33	45 \$	
308	175	MH	Decorative - Two Lights	\$	41.25		38.69	211		97,955	\$	48.21		51.40	211 \$	
309	175	MH	Decorative	\$	29.17		27.35			26,260	\$	34.09		36.35	80 \$	
377	50	LED	Cobra Head	S	3.51		3.29	809		31.985	S	4.11		4.38	809 \$	
378	70	LED	Cobra Head	\$	3.51		3.29	403		15,933	\$	4.11		4.38	403 \$	
379	100	LED	Cobra Head	\$	3.51		3.29			65,669	\$	4.11		4.38	1,661 \$	
380	150	LED	Cobra Head	\$	3.51	\$	3.29	1,624	\$	64,206	\$	4.11	\$	4.38	1,624 \$	80,012
381	250	LED	Cobra Head	\$	3.51	\$	3.29	336	\$	13,284	\$	4.11	\$	4.38	336 \$	16,554
404	400	LED	Cobra Head	\$	3.51	\$	3.29	11	\$	435	\$	4.11	\$	4.38	11 \$	542
384	150	LED	Post Top	\$	3.51	\$	3.29	175	\$	6,919	\$	4.11	\$	4.38	175 \$	
382	70	LED	Colonial Post Top	\$	3.51	\$	3.29	16	\$	633	\$	4.11	\$	4.38	16 \$	
383	100	LED	Colonial Post Top	S	3.51	S	3.29	123	S	4.863	S	4.11	S	4.38	123 \$	6.060
405	250	LED	Mongoose	\$	3.51	\$	3.29		\$		\$	4.11	\$	4.38	- \$	
406	400	LED	Mongoose	\$	3.51	\$	3.29		\$		\$	4.11	\$	4.38	- \$	
407	70	LED	Acorn (Granville)	\$	3.51	\$	3.29		\$		\$	4.11	\$	4.38	- \$	
408	100	LED	Acorn (Granville)	s	3.51	S	3.29		S		S	4.11	S	4.38	- 9	-
409	150	LED	Acorn (Granville)	\$	3.51	\$	3.29		\$		\$	4.11	\$	4.38	- \$	
	100	LED	Acorn (Granville) w/ ribs and bands	\$	3.51	\$	3.29		\$		\$	4.10	\$	4.37	- \$	
	150	LED	Acorn (Granville) w/ ribs and bands	\$	3.51	\$	3.29		\$		\$	4.10	\$	4.37	- \$	
385	100	LED	Shoe Box	s	3.51	S	3.29		S	-	s	4.11	S	4.38	- S	
386	150	LED	Shoe Box	\$	3.51	\$	3.29		\$		\$	4.11	\$	4.38	- \$	-
387	250	LED	Shoe Box	\$	3.51	\$	3.29	17	\$	672	\$	4.11	\$	4.38	17 \$	838
388	100	LED	Tear Drop	\$	3.51	\$	3.29		\$		\$	4.11	\$	4.38	- \$	
389	150	LED	Tear Drop	s	3.51	S	3.29	31	s	1.226	s	4.11	S	4.38	31 5	1.527
347	150	LED	Flood	s	3.51	S	3.29	19	s	751	s	4.11	S	4.38	19 5	936
348	250	LED	Flood	s	3.51	s	3.29	17	Ś	672	Ś	4.11	s	4.38	17 \$	838
349	400	LED	Flood	\$	3.51	\$	3.29	60	\$	2,372	\$	4.11	\$	4.38	60 \$	2,956
338	1000	LED	Flood	s	3.51	s	3.29	15	s	593	s	4.11	s	4.38	15 \$	739
								38.162		3.215.150					38.162 \$	

DDC		Rate	Rate	- 4	Annualized	Rate		Annu	alized		Rate	Α	nnualized
		(w/SUT)	(w/o SUT)		Revenue	(w/o SUT)		Revenue	(w/o SUT)		(w/ SUT)	- 1	Revenue
Service and Demand (per day per connection)	3,973,698	######## S	0.153793	\$	611,127	5	0.185733	\$	738,047	\$	0.198038	\$	786,943
Energy (ner day for each kW of effective load)	628.026	nununun S	0.740763	S	465.219		0.894604	S	561.835	S	0.953872	S	599.057
				S	1 076 345			S	1 299 881			S	1 386 000

Atlantic City Electric Base Rate Case New LED Streetlight Offerings

Line No.	Lamp Style	Watts (Equivalent)	Lumens	Monthly Distribution Charge ^{1,2}	Tariff CLE Lamp Price ^{3,4}
(A)	(B)	(C)	(D)	(E)	(F)
	Rate Schedu	le SPL (Street		Lighting)	
1	Acorn (Granville) w/ Ribs and Bands		8.000	\$ 27.76	\$1,955.21
2	Acorn (Granville) w/ Ribs and Bands		10,000	\$ 27.76	\$1,955.21
-	Tiesti (Granvine) w Tres and Bands	120	10,000	Ψ 27.770	Ψ1,>55.21
		Undergro	ound_		
3	Acorn (Granville) w/ Ribs and Bands	100	8,000	\$ 31.93	\$1,955.21
4	Acorn (Granville) w/ Ribs and Bands	150	10,000	\$ 31.93	\$1,955.21
	,		*		,
	Rate Schedul	e CSL (Contri	buted Street	Lighting)	
5	Acorn (Granville) w/ Ribs and Bands		8,000	\$ 3.51	\$1,955.21

Notes

150

10,000

\$

3.51

\$1,955.21

Acorn (Granville) w/ Ribs and Bands

Rates shown in this schedule are subject to the approved rate increase in this docket.

Monthly Distribution Charge is based on a 15 year revenue requirement net present value calculation at the Company's Requested Cost of Capital. This will be updated upon final approval of rates.

To be added to Tariff Section III, Rate Schedule CLE, Sheet No. 7a

Includes loaders for High Use, Low Value (HULV), Stores Handling and Labor

Atlantic City Electric Company
Development of Proposed Distribution Rate
Rate Design Worksheet Stand By Rate

					Distribution
	Dema	nd Rates (\$/kW)	Stand	lby Rates (\$/kW)	Standby
Rate Schedule		Distribution		Distribution	Factor
MGS Secondary	\$	3.51	\$	0.53	0.15
MGS Primary	\$	1.63	\$	0.24	0.15
AGS Secondary	\$	14.96	\$	2.24	0.15
AGS Primary	\$	11.66	\$	1.75	0.15
TGS - Sub Transmission	\$	-	\$	-	0.15
TGS Transmission	\$	-	\$	-	0.15

Atlantic City Electric Development of Proposed Distribution Rates Annual Distribution Revenues with CIP Test Year: 5+7 Ending June 2023

	Residential	MGSS	MGSP	AGSS	AGSP	TGST	TGS	SPL/CSL	DDC	Total
5 Month Actual Revenue July - November 2022 \$	149,476,431 \$	46,380,059 \$	2,253,293 \$	24,344,265 \$	5,578,620 \$	1,434,856 \$	1,012,057 \$	7,988,820 \$	243,086 \$	238,711,487
7 Month Forecast Revenue December 2022 - June 2023 \$	147,385,188 \$	52,406,457 \$	2,888,717 \$	33,880,165 \$	7,329,533 \$	2,114,906 \$	1,314,434 \$	10,767,088 \$	816,069 \$	258,902,556
5+7me June 2023 Revenues w/ IIP Revenues, Veteran's Law,										
and EDGE Credits = \$	296,861,619 \$	98,786,516 \$	5,142,010 \$	58,224,430 \$	12,908,152 \$	3,549,762 \$	2,326,491 \$	18,755,908 \$	1,059,155 \$	497,614,043
Add: CIP Revenue Annualization \$	4,780,947 \$	(11,005,928) \$	(2,832,686) \$	(1,301,150) \$	(277,687) \$	(545,458) \$	(45,440) \$	- \$	- \$	(11,227,402)
5+7me June 2023 Revenues w/ CIP Annualization Adj = \$	301,642,566 \$	87,780,588 \$	2,309,324 \$	56,923,280 \$	12,630,465 \$	3,004,304 \$	2,281,051 \$	18,755,908 \$	1,059,155 \$	486,386,641
D.										
Remove:										
IIP Revenue (Removal) \$	(5,012,451) \$	(1,692,066) \$	(84,544) \$	(1,084,709) \$	(213,233) \$	(66,948) \$	(43,329) \$	(266,256) \$	(3,168) \$	(8,466,703)
CIP IIP Revenue Annualization (Removal) \$	55,790 \$	216,095 \$	46,634 \$	34,071 \$	4,576 \$	8,294 \$	(5,372) \$	- \$	- \$	360,089
EDGE Credits (Removal) \$	- \$	165 \$	- \$	17,589 \$	- \$	- \$	- \$	- \$	- \$	17,754
EDIT Credits \$	(15,001,982) \$	(2,931,169) \$	(101,354) \$	(4,086,409) \$	(841,115) \$	(239,367) \$	(231,816) \$	(983,411) \$	(20,359) \$	(24,436,982)
Annualized Revenue Total = \$	311,687,887 \$	89,235,950 \$	2,372,769 \$	59,976,640 \$	13,262,923 \$	3,185,017 \$	2,464,167 \$	19,473,063 \$	1,076,345 \$	502,734,762

Atlantic City Electric Development of Proposed Distribution Rates 5+7me June 2023

July 2022 - June 2023 Customer Counts

	Actual/Forecast (a/f)	RES	MGSS	MGSP	AGSS	AGSP	TGST	TGS	SPL/CSL	DDC	TOTAL
Jul-22	(a)	501,579	56,692	142	2,916	117	36	12	6,040	1,063	568,597
Aug-22	(a)	501,762	56,717	148	2,914	117	35	14	6,028	1,064	568,799
Sep-22	(a)	501,866	56,645	154	2,908	118	34	15	6,006	1,064	568,810
Oct-22	(a)	501,761	56,590	160	2,899	118	34	16	5,992	1,064	568,634
Nov-22	(a)	502,039	56,608	159	2,895	119	35	14	5,997	1,067	568,933
Dec-22	(f)	501,957	56,738	136	2,924	117	37	14	5,846	1,072	568,842
Jan-23	(f)	503,134	56,663	160	2,907	118	31	16	5,797	1,076	569,904
Feb-23	(f)	503,354	56,681	160	2,908	118	31	16	5,798	1,076	570,143
Mar-23	(f)	503,481	56,683	160	2,908	118	31	16	5,797	1,076	570,272
Apr-23	(f)	503,251	56,733	161	2,911	118	31	16	6,103	1,076	570,401
May-23	(f)	503,465	56,765	161	2,912	118	31	16	6,106	1,077	570,651
Jun-23	(f)	503,831	56,756	161	2,911	118	31	16	6,105	1,076	571,005
		6,031,481	680,271	1,863	34,914	1,416	398	181	71,616	12,852	6,834,990

July 2022 - June 2023 Demands

	Actual/Forecast (a/f)	RES	MGSS	MGSP	AGSS	AGSP	TGST	TGS	SPL/CSL	DDC	TOTAL
Jul-22	(a)	-	558,558	23,142	400,707	106,347	92,607	116,646	-	1,828	1,299,835
Aug-22	(a)	-	599,294	23,148	402,136	119,184	99,482	120,192	-	1,829	1,365,264
Sep-22	(a)	-	589,140	27,093	398,749	121,741	105,557	124,926	-	1,827	1,369,033
Oct-22	(a)	-	523,566	28,377	383,155	116,923	95,182	127,185	-	1,828	1,276,216
Nov-22	(a)	-	476,071	26,800	357,414	104,242	89,585	98,858	-	1,827	1,154,797
Dec-22	(f)	-	515,501	26,011	410,582	134,307	112,063	84,585	-	1,614	1,284,664
Jan-23	(f)	-	433,820	16,440	411,664	107,585	90,288	86,683	-	1,588	1,148,069
Feb-23	(f)	-	418,096	17,429	389,266	100,015	72,748	138,131	-	1,622	1,137,306
Mar-23	(f)	-	406,060	21,362	379,537	105,175	73,833	117,690	-	1,465	1,105,122
Apr-23	(f)	-	440,664	16,540	389,887	109,537	105,783	65,370	-	1,483	1,129,263
May-23	(f)	-	452,232	14,909	378,283	103,694	105,486	73,163	-	1,426	1,129,192
Jun-23	(f)		513,201	17,341	378,866	114,291	111,706	87,623	-	1,620	1,224,648
		-	5,926,203	258,592	4,680,245	1,343,042	1,154,319	1,241,051	-	19,957	14,623,408

July 2022 - June 2023 Reactive Demands

	Actual/Forecast (a/f)	RES	MGSS	MGSP	AGSS	AGSP	TGST	TGS	SPL/CSL	DDC	TOTAL
Jul-22	(a)	-	9,010	4,968	45,302	26,327	19,612	15,655	-	-	120,875
Aug-22	(a)	-	9,267	4,971	43,892	30,882	21,776	16,588	-	-	127,376
Sep-22	(a)	-	11,454	4,838	46,620	33,270	20,850	19,602	-	-	136,634
Oct-22	(a)	-	9,969	4,903	41,594	30,676	20,517	23,243	-	-	130,901
Nov-22	(a)	-	9,389	4,586	37,733	25,325	18,164	17,974	-	-	113,171
Dec-22	(f)	-	4,098	8,716	28,582	18,975	33,916	20,646	-	-	114,933
Jan-23	(f)	-	4,169	17,620	29,812	20,656	37,147	24,191	-	-	133,594
Feb-23	(f)	-	4,212	15,124	29,497	19,404	34,992	22,916	-	-	126,145
Mar-23	(f)	-	4,054	15,644	28,597	19,268	34,773	22,632	-	-	124,968
Apr-23	(f)	-	4,075	15,180	28,669	19,159	34,399	22,719	-	-	124,200
May-23	(f)	-	4,045	14,085	28,213	18,421	33,152	21,904	-	-	119,820
Jun-23	(f)	-	4,620	17,208	32,633	21,702	39,054	25,713	-	-	140,930
	(f)	-	78,362	127,842	421,142	284,066	348,352	253,783	-	-	1,513,548

Atlantic City Electric Development of Proposed Distribution Rates Rate Class Allocation of Weather Normalization Adjustment

July 2022 - June 2023 Sales - Weather Normalized

	Actual/Forecast (a/f)	RES	MGSS	MGSP	AGSS	AGSP	TGST	TGS	SPL/CSL	DDC	TOTAL
Jul-22	(a)	475,306,007	143,316,536	6,497,095	151,413,220	46,275,357	49,083,084	45,896,698	4,440,206	1,226,687	923,454,890
Aug-22	(a)	529,842,336	154,442,384	10,447,604	152,516,689	54,495,468	54,531,818	38,840,370	4,870,013	1,290,801	1,001,277,483
Sep-22	(a)	475,686,452	152,329,499	10,711,091	157,092,780	55,084,182	55,834,418	36,911,614	4,512,616	1,256,349	949,419,001
Oct-22	(a)	273,710,508	105,828,003	9,139,642	129,447,510	50,838,972	48,955,761	65,434,485	6,416,657	1,216,967	690,988,505
Nov-22	(a)	220,236,632	95,167,990	9,163,404	114,059,147	43,569,888	43,576,791	37,846,283	6,178,932	1,184,821	570,983,888
Dec-22	(f)	286,521,166	102,998,272	4,866,452	119,305,639	41,401,051	40,817,778	38,648,147	6,657,848	1,137,568	642,353,921
Jan-23	(f)	370,303,346	106,665,462	9,156,181	124,961,775	44,016,736	43,805,816	44,449,616	7,495,511	1,220,712	752,075,154
Feb-23	(f)	333,021,306	104,561,229	8,979,564	122,615,726	43,274,235	42,942,859	43,800,915	6,266,586	1,173,575	706,635,993
Mar-23	(f)	290,232,796	101,900,916	8,746,853	119,369,905	42,039,962	41,848,989	42,444,863	6,125,746	1,144,231	653,854,261
Apr-23	(f)	251,936,576	101,906,013	8,757,214	119,670,643	42,353,442	41,854,096	43,011,599	5,466,311	1,129,671	616,085,565
May-23	(f)	208,269,905	99,427,672	8,545,334	116,792,794	41,357,770	40,836,543	42,027,863	4,645,856	1,087,626	562,991,364
Jun-23	(f)	298,410,121	115,555,762	9,928,570	135,651,626	47,975,494	47,459,729	48,680,363	4,602,956	1,247,152	709,511,774
	_	4.013.477.152	1,384,099,738	104,939,004	1.562.897.454	552,682,556	551,547,682	527,992,816	67,679,238	14.316.159	8,779,631,800

July 2022 - June 2023 - As Billed

	Actual/Forecast (a/f)	RES	MGSS	MGSP	AGSS	AGSP	TGST	TGS	SPL/CSL	DDC	TOTAL	Residential Average kWh
Jul-22	(a)	456,316,877	141,753,724	6,443,673	149,559,212	45,737,561	48,542,187	45,629,658	4,440,206	1,226,687	899,649,785	910
Aug-22	(a)	575,178,832	158,173,593	10,575,148	156,943,127	55,779,455	55,823,208	39,477,927	4,870,013	1,290,801	1,058,112,104	1,146
Sep-22	(a)	490,324,337	153,534,202	10,752,271	158,521,953	55,498,746	56,251,372	37,117,463	4,512,616	1,256,349	967,769,309	977
Oct-22	(a)	258,595,211	105,189,136	9,112,420	128,190,178	50,377,775	48,487,679	65,177,062	6,416,657	1,216,967	672,763,085	515
Nov-22	(a)	214,568,608	93,953,281	9,128,598	113,234,993	43,450,576	43,461,576	37,822,129	6,178,932	1,184,821	562,983,514	427
Dec-22	(f)	286,521,166	102,998,272	4,866,452	119,305,639	41,401,051	40,817,778	38,648,147	6,657,848	1,137,568	642,353,921	571
Jan-23	(f)	370,303,346	106,665,462	9,156,181	124,961,775	44,016,736	43,805,816	44,449,616	7,495,511	1,220,712	752,075,154	736
Feb-23	(f)	333,021,306	104,561,229	8,979,564	122,615,726	43,274,235	42,942,859	43,800,915	6,266,586	1,173,575	706,635,993	662
Mar-23	(f)	290,232,796	101,900,916	8,746,853	119,369,905	42,039,962	41,848,989	42,444,863	6,125,746	1,144,231	653,854,261	576
Apr-23	(f)	251,936,576	101,906,013	8,757,214	119,670,643	42,353,442	41,854,096	43,011,599	5,466,311	1,129,671	616,085,565	501
May-23	(f)	208,269,905	99,427,672	8,545,334	116,792,794	41,357,770	40,836,543	42,027,863	4,645,856	1,087,626	562,991,364	414
Jun-23	(f)	298,410,121	115,555,762	9,928,570	135,651,626	47,975,494	47,459,729	48,680,363	4,602,956	1,247,152	709,511,774	592
	_	4.033.670.082	1 385 610 262	104 992 278	1 564 817 571	553 262 802	552 131 932	528 287 605	67 670 238	14 316 150	8 804 785 830	660

Allocation of Weather Normalization Effect to Grouped Rate Classes

	Actual/Forecast (a/f)	RES	MGSS	MGSP	AGSS	AGSP	TGST	TGS	SPL/CSL	DDC	TOTAL
Jul-22	(a)	18,989,130	1,562,812	53,422	1,854,008	537,796	540,897	267,040	-	-	23,805,105
Aug-22	(a)	(45,336,496)	(3,731,209)	(127,544)	(4,426,438)	(1,283,987)	(1,291,390)	(637,557)	-	-	(56,834,621)
Sep-22	(a)	(14,637,885)	(1,204,703)	(41,180)	(1,429,173)	(414,564)	(416,954)	(205,849)	-	-	(18,350,308)
Oct-22	(a)	15,115,297	638,867	27,222	1,257,332	461,197	468,082	257,423	-	-	18,225,420
Nov-22	(a)	5,668,024	1,214,709	34,806	824,154	119,312	115,215	24,154	-	-	8,000,374
Dec-22	(f)	-	-	-	-	-	-	-	-	-	-
Jan-23	(f)	-	-	-	-	-	-	-	-	-	-
Feb-23	(f)	-	-	-	-	-	-	-	-	-	-
Mar-23	(f)	-	-	-	-	-	-	-	-	-	-
Apr-23	(f)	-	-	-	-	-	-	-	-	-	-
May-23	(f)	-	-	-	-	-	-	-	-	-	-
Jun-23	(f)	-	-	-	-	-	-	-	-	-	
	_	(20.201.030)	(1.519.524)	(53.274)	(1.920.117)	(580.246)	(584 150)	(204.780)			(25 154 030)

Weather Normalization Effect

					weatt	ier Normalization E	лест				
											Total
		RES	MGSS	MGSP	AGSS	AGSP	TGST	TGS	SPL/CSL	DDC	ACE
		Effect	Effect	Effect	Effect	Effect	Effect	Effect	Effect	Effect	Effect
		(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)
Jul-22	(a)	18,989	1,563	53	1,854	538	541	267	0	0	23,805
Aug-22	(a)	(45,336)	(3,731)	(128)	(4,426)	(1,284)	(1,291)	(638)	0	0	(56,835)
Sep-22	(a)	(14,638)	(1,205)	(41)	(1,429)	(415)	(417)	(206)	0	0	(18,350)
Oct-22	(a)	15,115	639	27	1,257	461	468	257	0	0	18,225
Nov-22	(a)	5,668	1,215	35	824	119	115	24	0	0	8,000
Dec-22	(f)	0	0	0	0	0	0	0	0	0	0
Jan-23	(f)	0	0	0	0	0	0	0	0	0	0
Feb-23	(f)	0	0	0	0	0	0	0	0	0	0
Mar-23	(f)	0	0	0	0	0	0	0	0	0	0
Apr-23	(f)	0	0	0	0	0	0	0	0	0	0
May-23	(f)	0	0	0	0	0	0	0	0	0	0
Jun-23	(f)	0	0	0	0	0	0	0	0	0	0
Total		(20,202)	(1,520)	(53)	(1,920)	(580)	(584)	(295)	0	0	(25,154)

The total Weather Normalization Effect is the adjustment required to convert actual sales to weather normalized sales. If degree days are above normal, the weather normalization effect must be negative to remove the extra sales caused by the excess of degree days.

Atlantic City Electric Company Development of One-Time Gross Receipts Tax Reserve Regulatory Liability Allocation

Regulatory Liability (excludes SUT) Regulatory Liability (including SUT)	\$ \$	(994,337) (1,060,212)														•		. 5
<u>Docket No. ER20120746 Revenue Allocation</u> Proposed Annualized Distribution Revenue Revenue Allocation %		Total 68,834,688 100.0%	R 37,226,512 61.26%	Secor \$81,89 17.4	ndary 5,149	Pr \$1,6	MGS rimary 647,641 .35%	\$60	AGS econdary 0,263,122 12.85%	\$1:	AGS Primary 2,792,347 2.73%	\$3,	TGS ubtrans 128,671 0.67%	TGS Trans ,154,311 0.46%	\$19	Street Lighting 9,154,884 4.09%	Con \$ 5	ect Dist. inection 72,050 .12%
Allocation of Regulatory Liability	\$	(994,337)	\$ (609,170)	\$ (17	3,689)	\$	(3,494)	\$	(127,810)	\$	(27,131)	\$	(6,636)	\$ (4,569)	\$	(40,625)	\$	(1,213)
Count of Contracts as of September 2022 Installations with no meters to be excluded			 501,866	5	6,645		154		2,908		118		34	15				1,064
Credit per Customer*			\$ (1.21)	\$	(3.07)	\$	(22.69)	\$	(43.95)	\$	(229.92)	\$	(195.16)	\$ (304.60)			\$	(1.14)
Number of Lamps as of September 2022																111,745		
Credit per Lamp*															\$	(0.36)		

^{*} For actual credits paid, customer and light counts may be different then amounts shown here. When these credits are processed the most recent available data will be utilized.

^{**}For illustrative purposes only, actual one-time refund issued to customers by rate class will be based on actuals at that point in time.

^{***} Credits will include SUT

Schedule (MTN)-8

ATLANTIC CITY ELECTRIC COMPANY RESIDENTIAL SERVICE ("RS") 8 WINTER MONTHS (October Through May)

Present Rates vs. Proposed Rates

Monthly	F	resent		Present	F	Present		New		New	New		Diffe	_			Total	
<u>Usage</u>	<u>D</u>	elivery	5	Supply+T		<u>Total</u>		<u> Delivery</u>	5	Supply+T	<u>Total</u>		<u>Delivery</u>	5	Supply+T	D	<u>ifference</u>	
(kWh)		(\$)		(\$)		(\$)		(\$)		(\$)	(\$)		(\$)		(\$)		(\$)	(%)
0	\$	6.25	\$	-	\$	6.25	\$	7.60	\$	-	\$ 7.60	9			-	\$	1.35	21.60%
25	\$	8.40	\$	2.79	\$	11.19	\$	10.14	\$	2.79	\$ 12.93	5		\$	-	\$	1.74	15.55%
50	\$	10.55	\$	5.58	\$	16.13	\$	12.69	\$	5.58	\$ 18.27	9		\$	-	\$	2.14	13.27%
75	\$	12.70	\$	8.38	\$	21.08	\$	15.23	\$	8.38	\$ 23.61	9		\$	-	\$	2.53	12.00%
100	\$	14.85	\$	11.17	\$	26.02	\$	17.78	\$	11.17	\$ 28.95	9		\$	-	\$	2.93	11.26%
150	\$	19.16	\$	16.75	\$	35.91	\$	22.87	\$	16.75	\$ 39.62		3.71	\$	-	\$	3.71	10.33%
200	\$	23.46	\$	22.33	\$	45.79	\$	27.95	\$	22.33	\$ 50.28		4.49	\$	-	\$	4.49	9.81%
250	\$	27.76	\$	27.92	\$	55.68	\$	33.04	\$	27.92	\$ 60.96		5.28	\$	-	\$	5.28	9.48%
300	\$	32.06	\$	33.50	\$	65.56	\$	38.13	\$	33.50	\$ 71.63	5	6.07	\$	-	\$	6.07	9.26%
350	\$	36.36	\$	39.08	\$	75.44	\$	43.22	\$	39.08	\$ 82.30	5	6.86	\$	-	\$	6.86	9.09%
400	\$	40.67	\$	44.67	\$	85.34	\$	48.31	\$	44.67	\$ 92.98	5	7.64	\$	-	\$	7.64	8.95%
450	\$	44.97	\$	50.25	\$	95.22	\$	53.40	\$	50.25	\$ 103.65	9	8.43	\$	-	\$	8.43	8.85%
500	\$	49.27	\$	55.83	\$	105.10	\$	58.48	\$	55.83	\$ 114.31	5	9.21	\$	-	\$	9.21	8.76%
600	\$	57.87	\$	67.00	\$	124.87	\$	68.66	\$	67.00	\$ 135.66	9	10.79	\$	-	\$	10.79	8.64%
650	\$	62.17	\$	72.58	\$	134.75	\$	73.75	\$	72.58	\$ 146.33	9	11.58	\$	-	\$	11.58	8.59%
669	\$	63.81	\$	74.71	\$	138.52	\$	75.68	\$	74.71	\$ 150.39		11.87	\$	-	\$	11.87	8.57%
700	\$	66.48	\$	78.17	\$	144.65	\$	78.84	\$	78.17	\$ 157.01	9	12.36	\$	-	\$	12.36	8.54%
750	\$	70.78	\$	83.75	\$	154.53	\$	83.93	\$	83.75	\$ 167.68	9	13.15	\$	-	\$	13.15	8.51%
800	\$	75.08	\$	89.33	\$	164.41	\$	89.01	\$	89.33	\$ 178.34	9	13.93	\$	-	\$	13.93	8.47%
900	\$	83.68	\$	100.50	\$	184.18	\$	99.19	\$	100.50	\$ 199.69	9	15.51	\$	-	\$	15.51	8.42%
1000	\$	92.29	\$	111.67	\$	203.96	\$	109.37	\$	111.67	\$ 221.04		17.08	\$	-	\$	17.08	8.37%
1200	\$	109.50	\$	134.00	\$	243.50	\$	129.72	\$	134.00	\$ 263.72	9	20.22	\$	-	\$	20.22	8.30%
1500	\$	135.31	\$	167.50	\$	302.81	\$	160.25	\$	167.50	\$ 327.75	5	24.94	\$	-	\$	24.94	8.24%
2000	\$	178.33	\$	223.34	\$	401.67	\$	211.14	\$	223.34	\$ 434.48		32.81	\$	-	\$	32.81	8.17%
2500	\$	221.35	\$	279.17	\$	500.52	\$	262.02	\$	279.17	\$ 541.19	5	40.67	\$	-	\$	40.67	8.13%
3000	\$	264.36	\$	335.00	\$	599.36	\$	312.90	\$	335.00	\$ 647.90	9	48.54	\$	-	\$	48.54	8.10%
3500	\$	307.38	\$	390.84	\$	698.22	\$	363.79	\$	390.84	\$ 754.63	9	56.41	\$	-	\$	56.41	8.08%
4000	\$	350.40	\$	446.67	\$	797.07	\$	414.67	\$	446.67	\$ 861.34	5	64.27	\$	-	\$	64.27	8.06%

ATLANTIC CITY ELECTRIC COMPANY RESIDENTIAL SERVICE ("RS") 4 SUMMER MONTHS (June Through September)

Present Rates vs. Proposed Rates

Monthly	F	Present		Present	F	Present			New		New	New		Diffe	renc	<u>:e</u>		<u>Total</u>
<u>Usage</u>	<u></u>	Delivery	5	Supply+T		Total		D	<u>Delivery</u>	9	Supply+T	<u>Total</u>		Delivery	<u>S</u>	Supply+T	<u>Di</u>	fference
(kWh)		(\$)		(\$)		(\$)			(\$)		(\$)	(\$)		(\$)		(\$)	(\$)	(%)
0	\$	6.25	\$	-	\$	6.25	(\$	7.60	\$	-	\$ 7.60	;	1.35	\$	-	\$ 1.35	21.60%
25	\$	8.56	\$	2.66	\$	11.22		\$	10.35	\$	2.66	\$ 13.01		1.79	\$	-	\$ 1.79	15.95%
50	\$	10.88	\$	5.32	\$	16.20	(\$	13.09	\$	5.32	\$ 18.41		2.21	\$	-	\$ 2.21	13.64%
75	\$	13.19	\$	7.98	\$	21.17	(\$	15.84	\$	7.98	\$ 23.82	;	2.65	\$	-	\$ 2.65	12.52%
100	\$	15.51	\$	10.65	\$	26.16		\$	18.59	\$	10.65	\$ 29.24		3.08	\$	-	\$ 3.08	11.77%
150	\$	20.14	\$	15.97	\$	36.11	(\$	24.08	\$	15.97	\$ 40.05	;	3.94	\$	-	\$ 3.94	10.91%
200	\$	24.77	\$	21.29	\$	46.06	(\$	29.58	\$	21.29	\$ 50.87	;	4.81	\$	-	\$ 4.81	10.44%
250	\$	29.40	\$	26.61	\$	56.01	(\$	35.07	\$	26.61	\$ 61.68	;	5.67	\$	-	\$ 5.67	10.12%
300	\$	34.03	\$	31.94	\$	65.97	(\$	40.56	\$	31.94	\$ 72.50	;	6.53	\$	-	\$ 6.53	9.90%
350	\$	38.66	\$	37.26	\$	75.92	(\$	46.06	\$	37.26	\$ 83.32	;	7.40	\$	-	\$ 7.40	9.75%
400	\$	43.29	\$	42.58	\$	85.87	(\$	51.55	\$	42.58	\$ 94.13	;	8.26	\$	-	\$ 8.26	9.62%
450	\$	47.92	\$	47.90	\$	95.82	(\$	57.04	\$	47.90	\$ 104.94	;	9.12	\$	-	\$ 9.12	9.52%
500	\$	52.55	\$	53.23	\$	105.78	(\$	62.54	\$	53.23	\$ 115.77	;	9.99	\$	-	\$ 9.99	9.44%
600	\$	61.80	\$	63.87	\$	125.67	(\$	73.53	\$	63.87	\$ 137.40	;	11.73	\$	-	\$ 11.73	9.33%
650	\$	66.43	\$	69.19	\$	135.62	(\$	79.02	\$	69.19	\$ 148.21	;	12.59	\$	-	\$ 12.59	9.28%
669	\$	68.19	\$	71.22	\$	139.41	;	\$	81.11	\$	71.22	\$ 152.33	;	12.92	\$	-	\$ 12.92	9.27%
700	\$	71.06	\$	74.52	\$	145.58	,	\$	84.51	\$	74.52	\$ 159.03	;	13.45	\$	-	\$ 13.45	9.24%
750	\$	75.69	\$	79.84	\$	155.53	(\$	90.01	\$	79.84	\$ 169.85	;	14.32	\$	-	\$ 14.32	9.21%
800	\$	80.96	\$	85.66	\$	166.62	(\$	96.29	\$	85.66	\$ 181.95	;	15.33	\$	-	\$ 15.33	9.20%
900	\$	91.48	\$	97.31	\$	188.79	,	\$	108.84	\$	97.31	\$ 206.15	;	17.36	\$	-	\$ 17.36	9.20%
1000	\$	102.01	\$	108.96	\$	210.97	(\$	121.40	\$	108.96	\$ 230.36	;	19.39	\$	-	\$ 19.39	9.19%
1200	\$	123.07	\$	132.25	\$	255.32	(\$	146.51	\$	132.25	\$ 278.76	;	23.44	\$	-	\$ 23.44	9.18%
1500	\$	154.65	\$	167.19	\$	321.84	(\$	184.18	\$	167.19	\$ 351.37	;	29.53	\$	-	\$ 29.53	9.18%
2000	\$	207.29	\$	225.43	\$	432.72	(\$	246.97	\$	225.43	\$ 472.40	;	39.68	\$	-	\$ 39.68	9.17%
2500	\$	259.92	\$	283.67	\$	543.59	,	\$	309.75	\$	283.67	\$ 593.42	:	49.83	\$	-	\$ 49.83	9.17%
3000	\$	312.56	\$	341.90	\$	654.46	(\$	372.53	\$	341.90	\$ 714.43	;	59.97	\$	-	\$ 59.97	9.16%
3500	\$	365.20	\$	400.14	\$	765.34	,	\$	435.32	\$	400.14	\$ 835.46	;	70.12	\$	-	\$ 70.12	9.16%
4000	\$	417.83	\$	458.37	\$	876.20		\$	498.10	\$	458.37	\$ 956.47		80.27	\$	-	\$ 80.27	9.16%

ATLANTIC CITY ELECTRIC COMPANY RESIDENTIAL SERVICE ("RS") Annual Average

Present Rates vs. Proposed Rates

Monthly	F	Present		Present	F	Present	New		New	New	Differ	enc	<u>e</u>		<u>Total</u>
Usage	<u></u>	elivery	5	Supply+T		<u>Total</u>	Delivery	5	Supply+T	<u>Total</u>	Delivery	S	Supply+T	Di	<u>ifference</u>
(kWh)		(\$)		(\$)		(\$)	(\$)		(\$)	(\$)	(\$)		(\$)	(\$)	(%)
0	\$	6.25	\$	-	\$	6.25	\$ 7.60	\$	-	\$ 7.60	\$ 1.35	\$	-	\$ 1.35	21.60%
25	\$	8.45	\$	2.75	\$	11.20	\$ 10.21	\$	2.75	\$ 12.96	\$ 1.76	\$	-	\$ 1.76	15.71%
50	\$	10.66	\$	5.49	\$	16.15	\$ 12.82	\$	5.49	\$ 18.31	\$ 2.16	\$	-	\$ 2.16	13.37%
75	\$	12.86	\$	8.25	\$	21.11	\$ 15.43	\$	8.25	\$ 23.68	\$ 2.57	\$	-	\$ 2.57	12.17%
100	\$	15.07	\$	11.00	\$	26.07	\$ 18.05	\$	11.00	\$ 29.05	\$ 2.98	\$	-	\$ 2.98	11.43%
150	\$	19.49	\$	16.49	\$	35.98	\$ 23.27	\$	16.49	\$ 39.76	\$ 3.78	\$	-	\$ 3.78	10.51%
200	\$	23.90	\$	21.98	\$	45.88	\$ 28.49	\$	21.98	\$ 50.47	\$ 4.59	\$	-	\$ 4.59	10.00%
250	\$	28.31	\$	27.48	\$	55.79	\$ 33.72	\$	27.48	\$ 61.20	\$ 5.41	\$	-	\$ 5.41	9.70%
300	\$	32.72	\$	32.98	\$	65.70	\$ 38.94	\$	32.98	\$ 71.92	\$ 6.22	\$	-	\$ 6.22	9.47%
350	\$	37.13	\$	38.47	\$	75.60	\$ 44.17	\$	38.47	\$ 82.64	\$ 7.04	\$	-	\$ 7.04	9.31%
400	\$	41.54	\$	43.97	\$	85.51	\$ 49.39	\$	43.97	\$ 93.36	\$ 7.85	\$	-	\$ 7.85	9.18%
450	\$	45.95	\$	49.47	\$	95.42	\$ 54.61	\$	49.47	\$ 104.08	\$ 8.66	\$	-	\$ 8.66	9.08%
500	\$	50.36	\$	54.96	\$	105.32	\$ 59.83	\$	54.96	\$ 114.79	\$ 9.47	\$	-	\$ 9.47	8.99%
600	\$	59.18	\$	65.96	\$	125.14	\$ 70.28	\$	65.96	\$ 136.24	\$ 11.10	\$	-	\$ 11.10	8.87%
650	\$	63.59	\$	71.45	\$	135.04	\$ 75.51	\$	71.45	\$ 146.96	\$ 11.92	\$	-	\$ 11.92	8.83%
669	\$	65.27	\$	73.55	\$	138.82	\$ 77.49	\$	73.55	\$ 151.04	\$ 12.22	\$	-	\$ 12.22	8.80%
700	\$	68.01	\$	76.95	\$	144.96	\$ 80.73	\$	76.95	\$ 157.68	\$ 12.72	\$	-	\$ 12.72	8.77%
750	\$	72.42	\$	82.45	\$	154.87	\$ 85.96	\$	82.45	\$ 168.41	\$ 13.54	\$	-	\$ 13.54	8.74%
800	\$	77.04	\$	88.11	\$	165.15	\$ 91.44	\$	88.11	\$ 179.55	\$ 14.40	\$	-	\$ 14.40	8.72%
900	\$	86.28	\$	99.44	\$	185.72	\$ 102.41	\$	99.44	\$ 201.85	\$ 16.13	\$	-	\$ 16.13	8.69%
1000	\$	95.53	\$	110.77	\$	206.30	\$ 113.38	\$	110.77	\$ 224.15	\$ 17.85	\$	-	\$ 17.85	8.65%
1200	\$	114.02	\$	133.42	\$	247.44	\$ 135.32	\$	133.42	\$ 268.74	\$ 21.30	\$	-	\$ 21.30	8.61%
1500	\$	141.76	\$	167.40	\$	309.16	\$ 168.23	\$	167.40	\$ 335.63	\$ 26.47	\$	-	\$ 26.47	8.56%
2000	\$	187.98	\$	224.04	\$	412.02	\$ 223.08	\$	224.04	\$ 447.12	\$ 35.10	\$	-	\$ 35.10	8.52%
2500	\$	234.21	\$	280.67	\$	514.88	\$ 277.93	\$	280.67	\$ 558.60	\$ 43.72	\$	-	\$ 43.72	8.49%
3000	\$	280.43	\$	337.30	\$	617.73	\$ 332.78	\$	337.30	\$ 670.08	\$ 52.35	\$	-	\$ 52.35	8.47%
3500	\$	326.65	\$	393.94	\$	720.59	\$ 387.63	\$	393.94	\$ 781.57	\$ 60.98	\$	-	\$ 60.98	8.46%
4000	\$	372.88	\$	450.57	\$	823.45	\$ 442.48	\$	450.57	\$ 893.05	\$ 69.60	\$	-	\$ 69.60	8.45%

ATLANTIC CITY ELECTRIC COMPANY MONTHLY GENERAL SERVICE SECONDARY ("MGS Secondary") 8 WINTER MONTHS (October Through May)

								Prop	oosed Rates								
	Load	_				Present	Present	Present			New	New	New	Difference	Difference	Total	Total
Demand (kW)	Factor (%)	Energy (kWh)	Dict kW	Trans kW D Demand	D Energy	Distribution (\$)	BGS and Other Charges (\$)	<u>Total</u> (\$)	D Demand	D Energy	Distribution (\$)	BGS and Other Charges (\$)	Total (\$)	Distribution (\$)	BGS and Other Charges (\$)	Difference (\$)	Difference (%)
5	20	730	5.00	2 \$ 13.60	- 37		\$ 77.34			\$ 42.79			\$ 150.90	\$ 7.10		\$ 7.10	4.9%
5	30	1,095	5.00	2 \$ 13.60			\$ 109.91			\$ 64.19		\$ 109.91		\$ 8.02		\$ 8.02	4.1%
5	40	1,460	5.00	2 \$ 13.60	\$ 81.92	\$ 107.42	\$ 142.48	\$ 249.90	\$ 16.40	\$ 85.59	\$ 116.36	\$ 142.48	\$ 258.84	\$ 8.94	\$ -	\$ 8.94	3.6%
5	50	1,825	5.00				\$ 175.04					\$ 175.04			\$ -	\$ 9.85	3.3%
5	60	2,190	5.00	2 \$ 13.60		Ψ	\$ 207.61		*	Ψ .20.00	\$ 159.15		\$ 366.77	Ψ	\$ -	\$ 10.77	3.0%
5	70	2,555	5.00	2 \$ 13.60			\$ 240.18 \$ 272.75				\$ 180.55	\$ 240.18		\$ 11.69	\$ -	\$ 11.69	2.9%
5 10	80 20	2,920 1.460	5.00 10.00	2 \$ 13.60 7 \$ 27.20		Ψ 100.00	\$ 272.75 \$ 172.98			+		\$ 272.75 \$ 172.98	\$ 474.70 \$ 305.74	\$ 12.60 \$ 11.74	\$ -	\$ 12.60 \$ 11.74	2.7% 4.0%
10	30	2,190	10.00	7 \$ 27.20			\$ 238.11				\$ 175.55		\$ 413.67		\$ -	\$ 13.57	3.4%
10	40	2,920	10.00	7 \$ 27.20			\$ 303.25			\$ 171.18		\$ 303.25		\$ 15.40	\$ -	\$ 15.40	3.0%
10	50	3,650	10.00				\$ 368.39				\$ 261.14		\$ 629.53		\$ -	\$ 17.24	2.8%
10	60	4,380	10.00	7 \$ 27.20	\$ 245.77	\$ 284.87	\$ 433.53	\$ 718.40	\$ 32.80	\$ 256.77	\$ 303.94	\$ 433.53	\$ 737.47	\$ 19.07	\$ -	\$ 19.07	2.7%
10	70	5,110	10.00	7 \$ 27.20	\$ 286.73	\$ 325.83	\$ 498.67	\$ 824.50	\$ 32.80	\$ 299.56	\$ 346.73	\$ 498.67	\$ 845.40	\$ 20.90	\$ -	\$ 20.90	2.5%
10	80	5,840	10.00	7 \$ 27.20			\$ 563.80			\$ 342.36			\$ 953.33	\$ 22.73	\$ -	\$ 22.73	2.4%
20	20	2,920	20.00				\$ 364.25				\$ 251.15		\$ 615.40	Ψ 21.00	\$ -	\$ 21.00	3.5%
20	30	4,380	20.00	17 \$ 54.40			\$ 494.53				\$ 336.74		\$ 831.27	\$ 24.67	\$ -	\$ 24.67	3.1%
20 20	40 50	5,840 7.300	20.00 20.00	17 \$ 54.40 17 \$ 54.40			\$ 624.80 \$ 755.08			\$ 342.36 \$ 427.95	\$ 422.33 \$ 507.92		\$ 1,047.13 \$ 1,263.00	\$ 28.33 \$ 32.00	\$ -	\$ 28.33 \$ 32.00	2.8%
20	60	8.760	20.00	17 \$ 54.40			\$ 885.35				\$ 593.51		\$ 1,478.86		\$ -	\$ 35.67	2.5%
20	70	10,220	20.00	17 \$ 54.40			\$ 1,015.63						\$ 1,694.73	\$ 39.33	\$ -	\$ 39.33	2.4%
20	80	11.680	20.00	17 \$ 54.40			\$ 1,145,91				\$ 764.69		\$ 1.910.59		\$ -	\$ 43.00	2.3%
30	20	4,380	30.00	27 \$ 81.60	\$ 245.77	\$ 339.27	\$ 555.53	\$ 894.80	\$ 98.40	\$ 256.77	\$ 369.54	\$ 555.53	\$ 925.07	\$ 30.27	\$ -	\$ 30.27	3.4%
30	30	6,570	30.00	27 \$ 81.60	\$ 368.66	\$ 462.16	\$ 750.94	\$ 1,213.10	\$ 98.40	\$ 385.15	\$ 497.92	\$ 750.94	\$ 1,248.86	\$ 35.77	\$ -	\$ 35.77	2.9%
30	40	8,760	30.00	27 \$ 81.60			\$ 946.35				\$ 626.31		\$ 1,572.66	\$ 41.27	\$ -	\$ 41.27	2.7%
30	50	10,950	30.00					\$ 1,849.69		\$ 641.92			\$ 1,896.46		\$ -	\$ 46.77	2.5%
30	60	13,140	30.00	27 \$ 81.60				\$ 2,167.99			\$ 883.08		\$ 2,220.26	Ψ 02.20	\$ -	\$ 52.26	2.4%
30 30	70 80	15,330 17,520	30.00 30.00					\$ 2,486.29 \$ 2,804.59		\$ 898.69 \$ 1,027.07	\$ 1,011.46 \$ 1,139.84		\$ 2,544.06 \$ 2,867.85	\$ 57.76 \$ 63.26	\$ -	\$ 57.76 \$ 63.26	2.3% 2.3%
50	20	7.300	50.00					\$ 1,495.60					\$ 2,007.05		\$ -	\$ 48.80	3.3%
50	30	10.950	50.00					\$ 2.026.09			\$ 820.29		\$ 2.084.06		\$ -	\$ 57.97	2.9%
50	40	14,600	50.00				\$ 1,589.46				\$ 1.034.27		\$ 2.623.72	\$ 67.13	\$ -	\$ 67.13	2.6%
50	50	18,250	50.00	47 \$ 136.00	\$ 1,024.04	\$ 1,171.94	\$ 1,915.15	\$ 3,087.09	\$ 164.00	\$ 1,069.87	\$ 1,248.24	\$ 1,915.15	\$ 3,163.39	\$ 76.30	\$ -	\$ 76.30	2.5%
50	60	21,900	50.00	47 \$ 136.00	\$ 1,228.85	\$ 1,376.75	\$ 2,240.84	\$ 3,617.59	\$ 164.00	\$ 1,283.84	\$ 1,462.21	\$ 2,240.84	\$ 3,703.05	\$ 85.46	\$ -	\$ 85.46	2.4%
50	70	25,550	50.00			.,	\$ 2,566.53			\$ 1,497.82			\$ 4,242.71	Ψ 000	\$ -	\$ 94.63	2.3%
50	80	29,200	50.00	47 \$ 136.00		.,		\$ 4,678.59		\$ 1,711.79			\$ 4,782.38	\$ 103.79	\$ -	\$ 103.79	2.2%
75	30	16,425	75.00	72 \$ 204.00		.,	\$ 1,904.80			\$ 962.88	. ,		\$ 3,128.06		\$ -	\$ 85.71	2.8%
75 75	40 50	21,900 27,375	75.00 75.00	72 \$ 204.00 72 \$ 204.00		.,		\$ 3,838.09 \$ 4.633.84		,	\$ 1,544.21 \$ 1.865.17		\$ 3,937.55 \$ 4,747.05	,	\$ - \$ -	\$ 99.46 \$ 113.21	2.6%
75	60	32.850	75.00	72 \$ 204.00		\$ 2.059.18	-,	\$ 5,429.58		\$ 1,925.77	. ,		\$ 5,556.54	\$ 126.96	¢ -	\$ 126.96	2.3%
75	70	38.325	75.00	72 \$ 204.00			\$ 3.858.94			\$ 2,246.73			\$ 6.366.04	\$ 140.70	\$ -	\$ 140.70	2.3%
75	80	43,800	75.00	72 \$ 204.00				\$ 7,021.08			\$ 2,828.06		\$ 7,175.53	\$ 154.45	\$ -	\$ 154.45	2.2%
75	90	49,275	75.00	72 \$ 204.00	\$ 2,764.92	\$ 2,980.82	\$ 4,836.01	\$ 7,816.83	\$ 246.00	\$ 2,888.65	\$ 3,149.02	\$ 4,836.01	\$ 7,985.03	\$ 168.20	\$ -	\$ 168.20	2.2%
100	30	21,900	100.00	97 \$ 272.00				\$ 4,058.59			\$ 1,626.21		\$ 4,172.05	\$ 113.46	\$ -	\$ 113.46	2.8%
100	40	29,200	100.00	97 \$ 272.00				\$ 5,119.59		\$ 1,711.79			\$ 5,251.38	\$ 131.79		\$ 131.79	2.6%
100	50	36,500	100.00	97 \$ 272.00		-,	\$ 3,848.60				\$ 2,482.11		\$ 6,330.70	\$ 150.12		\$ 150.12	2.4%
100 100	60	43,800	100.00	97 \$ 272.00				\$ 7,241.58			\$ 2,910.06		\$ 7,410.03	\$ 168.45	\$ - \$ -	\$ 168.45 \$ 186.78	2.3%
100	70 80	51,100 58,400	100.00 100.00	97 \$ 272.00 97 \$ 272.00		,	-,	\$ 8,302.58 \$ 9,363.57		\$ 2,995.64 \$ 3,423.58	\$ 3,338.01 \$ 3,765.95		\$ 8,489.36 \$ 9,568.69	\$ 186.78 \$ 205.11	Ψ .	\$ 186.78 \$ 205.11	2.2% 2.2%
100	90	65.700	100.00	97 \$ 272.00				\$ 10.424.57			\$ 4.193.90		\$ 10.648.01	\$ 223.44	\$ -	\$ 223.44	2.1%
200	30	43,800	200.00	197 \$ 544.00				\$ 8,123.58		,	\$ 3,238.06		\$ 8,348.03	\$ 224.45	\$ -	\$ 224.45	2.8%
200	40	58,400	200.00	197 \$ 544.00				\$ 10,245.57			\$ 4,093.95		\$ 10,506.69	\$ 261.11		\$ 261.11	2.5%
200	50	73,000	200.00	197 \$ 544.00	\$ 4,096.18	\$ 4,652.08	\$ 7,715.49	\$ 12,367.57			\$ 4,949.85	\$ 7,715.49	\$ 12,665.34	\$ 297.77	\$ -	\$ 297.77	2.4%
200	60	87,600	200.00	197 \$ 544.00		,	\$ 9,018.25			\$ 5,135.37			\$ 14,823.99		\$ -	\$ 334.43	2.3%
200	70	102,200	200.00	197 \$ 544.00				\$ 16,611.55		\$ 5,991.27			\$ 16,982.65	\$ 371.09		\$ 371.09	2.2%
200 200	80 90	116,800 131,400	200.00 200.00	197 \$ 544.00 197 \$ 544.00		Ψ 1,100.10		\$ 18,733.55 \$ 20.855.54			\$ 7,517.54 \$ 8.373.43		\$ 19,141.30 \$ 21,299.95	\$ 407.75 \$ 444.42		\$ 407.75 \$ 444.42	2.2%
200	90	131,400	200.00	197 \$ 544.00	φ 1,313.12	φ 1,929.02	ψ 12,926.52	φ 20,000.54	\$ 000.00	φ 1,103.06	φ 0,3/3.43	12,926.52	φ Z1,Z99.95	\$ 444.4Z	φ -	φ 444.42	2.170

ATLANTIC CITY ELECTRIC COMPANY MONTHLY GENERAL SERVICE SECONDARY ("MGS Secondary") 4 SUMMER MONTHS (June Through September)

										Prop	osed Rates								
_		Load	_					Present	Present	Present			New	New	New	Difference	Difference	Total	Total
	emand		Energy (IdA/Ib)	Diet I/M	Trans kW I	D Domond	D Energy	Distribution (\$)	BGS and Other Charges	Total	D Demand	D Energy	Distribution (\$)	BGS and Other Charges (\$)	Total (\$)	Distribution (\$)	BGS and Other Charges (\$)	Difference (\$)	Difference
	(kW) 5 [(%) 20	(kWh) 730	5.00	1 rans kw 1			(+/	\$ 79.63	(\$) \$ 154.25			\$ 82.57	\$ 79.63	\$ 162.19	\$ 7.94		\$ 7.94	(%) 5.1%
	5	30	1,095	5.00					\$ 112.96			\$ 72.37			\$ 219.65	\$ 8.98		\$ 8.98	4.3%
	5	40	1,460	5.00					\$ 146.29	\$ 267.09			\$ 130.81			\$ 10.01		\$ 10.01	3.7%
	5	50	1,825	5.00					\$ 179.63	\$ 323.51			\$ 154.93		\$ 334.56	\$ 11.05		\$ 11.05	3.4%
	5	60	2,190	5.00	2		\$ 138.52	\$ 166.97	\$ 212.96	\$ 379.94	\$ 19.95		\$ 179.06	\$ 212.96	\$ 392.02	\$ 12.08	\$ -	\$ 12.08	3.2%
	5	70	2,555	5.00	2	\$ 16.55	\$ 161.61	\$ 190.06	\$ 246.30	\$ 436.36	\$ 19.95	\$ 168.86	\$ 203.18	\$ 246.30	\$ 449.48	\$ 13.12	\$ -	\$ 13.12	3.0%
	5	80	2,920	5.00			Ψ .σσ	Ψ 2.00	\$ 279.63	\$ 492.78		\$ 192.98	\$ 227.30	\$ 279.63	\$ 506.93	\$ 14.15		\$ 14.15	2.9%
	10	20	1,460	10.00		\$ 33.10			\$ 178.69				\$ 150.76		\$ 329.46	\$ 13.41		\$ 13.41	4.2%
	10	30	2,190	10.00		\$ 33.10			\$ 245.36	\$ 428.89		\$ 144.74			\$ 444.37	\$ 15.48		\$ 15.48	3.6%
	10	40	2,920	10.00		\$ 33.10			\$ 312.03	\$ 541.73			\$ 247.25	\$ 312.03	\$ 559.28	\$ 17.55		\$ 17.55	3.2%
	10	50	3,650	10.00		\$ 33.10			\$ 378.70				\$ 295.50		\$ 674.19	\$ 19.63	•	\$ 19.63	3.0% 2.8%
	10 10	60 70	4,380 5.110	10.00 10.00		\$ 33.10 \$ 33.10			\$ 445.36 \$ 512.03	\$ 767.41 \$ 880.25			\$ 343.74 \$ 391.99	\$ 445.36 \$ 512.03	\$ 789.11 \$ 904.02	\$ 21.70 \$ 23.77		\$ 21.70 \$ 23.77	2.8%
	10	80	5,110	10.00		\$ 33.10			\$ 578.70				\$ 440.24		\$ 1.018.93	\$ 25.84		\$ 25.84	2.6%
	20	20	2.920	20.00			\$ 184.70		\$ 376.83				\$ 287.15		\$ 663.98	\$ 24.35		\$ 24.35	3.8%
	20	30	4.380	20.00			\$ 277.05		\$ 510.16				\$ 383.64		\$ 893.81	\$ 28.50		\$ 28.50	3.3%
	20	40	5.840	20.00			\$ 369.40			\$ 1.091.00			\$ 480.14		\$ 1.123.63	\$ 32.64	•	\$ 32.64	3.0%
	20	50	7,300	20.00	17		\$ 461.75		\$ 776.83				\$ 576.63		\$ 1,353.46	\$ 36.78	\$ -	\$ 36.78	2.8%
	20	60	8,760	20.00	17	\$ 66.20	\$ 554.10	\$ 632.20		\$ 1,542.36	\$ 79.80	\$ 578.95	\$ 673.12	\$ 910.17	\$ 1,583.29	\$ 40.92	\$ -	\$ 40.92	2.7%
	20	70	10,220	20.00	17	\$ 66.20	\$ 646.45	\$ 724.55	\$ 1,043.50	\$ 1,768.05	\$ 79.80	\$ 675.44	\$ 769.61		\$ 1,813.11	\$ 45.06	\$ -	\$ 45.06	2.5%
	20	80	11,680	20.00	17	\$ 66.20				\$ 1,993.73	\$ 79.80	\$ 771.93	\$ 866.10	\$ 1,176.84	\$ 2,042.94	\$ 49.21	\$ -	\$ 49.21	2.5%
	30	20	4,380	30.00			\$ 277.05			\$ 963.21	\$ 119.70		\$ 423.54		\$ 998.51	\$ 35.30		\$ 35.30	3.7%
	30	30	6,570	30.00	27		Ψ			\$ 1,301.74	\$ 119.70		\$ 568.28		\$ 1,343.25	\$ 41.51		\$ 41.51	3.2%
	30	40	8,760	30.00	27		Ψ 0010		\$ 974.97		\$ 119.70		\$ 713.02		\$ 1,687.99	\$ 47.72	•	\$ 47.72	2.9%
	30	50	10,950	30.00		\$ 99.30				\$ 1,978.79	\$ 119.70		\$ 857.76		\$ 2,032.72	\$ 53.94	*	\$ 53.94	2.7%
	30	60	13,140 15.330	30.00	27		\$ 831.14 \$ 969.67	Ψ 0.2.0.		\$ 2,317.31	\$ 119.70				\$ 2,377.46	\$ 60.15 \$ 66.36		\$ 60.15 \$ 66.36	2.6%
	30 30	70 80	17,520	30.00 30.00		\$ 99.30	\$ 969.67 \$ 1,108.19	Ψ 1,000.01		\$ 2,655.84 \$ 2,994.37			\$ 1,147.23 \$ 1,291.97		\$ 2,722.20 \$ 3,066.94	\$ 66.36 \$ 72.57		\$ 66.36 \$ 72.57	2.5% 2.4%
	50	20	7.300	50.00		\$ 165.50				\$ 1,610.38	\$ 199.50		\$ 696.33		\$ 1.667.56	\$ 72.57		\$ 57.18	3.6%
	50	30	10.950	50.00		\$ 165.50				\$ 2,174.59	\$ 199.50		\$ 937.56		\$ 2,242.12	\$ 67.54		\$ 67.54	3.1%
	50	40	14.600	50.00		\$ 165.50				\$ 2,738.80	\$ 199.50		\$ 1.178.78		\$ 2,816.69	\$ 77.89	•	\$ 77.89	2.8%
	50	50	18.250	50.00				. ,	\$ 1,971.24	. ,		\$ 1,206.14			\$ 3,391.25	\$ 88.25		\$ 88.25	2.7%
	50	60	21,900	50.00	47	\$ 165.50	\$ 1,385.24	\$ 1,562.64	\$ 2,304.58	\$ 3,867.22			\$ 1,661.24		\$ 3,965.82	\$ 98.60	\$ -	\$ 98.60	2.5%
	50	70	25,550	50.00	47	\$ 165.50	\$ 1,616.11	\$ 1,793.51	\$ 2,637.91	\$ 4,431.43	\$ 199.50	\$ 1,688.60	\$ 1,902.47	\$ 2,637.91	\$ 4,540.38	\$ 108.96	\$ -	\$ 108.96	2.5%
	50	80	29,200	50.00	47	\$ 165.50	\$ 1,846.99	\$ 2,024.39	\$ 2,971.25	\$ 4,995.64	\$ 199.50	\$ 1,929.83	\$ 2,143.70	\$ 2,971.25	\$ 5,114.95	\$ 119.31	\$ -	\$ 119.31	2.4%
	75	30	16,425	75.00				+ -,=	\$ 1,966.57		\$ 299.25		\$ 1,399.15		\$ 3,365.72	\$ 100.07		\$ 100.07	3.1%
	75	40	21,900	75.00			\$ 1,385.24	+ .,	\$ 2,466.58	\$ 4,111.97			\$ 1,760.99		\$ 4,227.57	\$ 115.60	•	\$ 115.60	2.8%
	75	50	27,375	75.00			\$ 1,731.55		\$ 2,966.58	. ,			\$ 2,122.83		\$ 5,089.42	\$ 131.13	•	\$ 131.13	2.6%
	75	60	32,850 38.325	75.00 75.00			\$ 2,077.86	Ψ 2,000.01	\$ 3,466.59 \$ 3.966.59				\$ 2,484.68		\$ 5,951.26	\$ 146.67		\$ 146.67 \$ 162.20	2.5% 2.4%
	75 75	70 80	43,800	75.00 75.00			\$ 2,424.17 \$ 2,770.48			\$ 6,650.91 \$ 7,497.23			\$ 2,846.52 \$ 3,208.36		\$ 6,813.11 \$ 7,674.96	\$ 162.20 \$ 177.73		\$ 162.20 \$ 177.73	2.4%
	75	90	49,275	75.00				,	\$ 4,466.60						\$ 8.536.80	\$ 177.73		\$ 177.73	2.3%
	100	30	21,900	100.00			,		\$ 2,628.58	\$ 4,356.72			\$ 1,860.74		\$ 4,489.32	\$ 132.60		\$ 132.60	3.0%
	100	40	29,200	100.00			\$ 1.846.99			\$ 5,485.14			\$ 2,343,20		\$ 5,638.45	\$ 153.31		\$ 153.31	2.8%
	100	50	36.500	100.00			. ,	. ,	\$ 3,961.92				\$ 2.825.66		\$ 6,787.58	\$ 174.02		\$ 174.02	2.6%
	100	60	43,800	100.00	97	\$ 331.00	\$ 2,770.48	\$ 3,113.38	\$ 4,628.60	\$ 7,741.98	\$ 399.00	\$ 2,894.74	\$ 3,308.11	\$ 4,628.60	\$ 7,936.71	\$ 194.73	\$ -	\$ 194.73	2.5%
	100	70	51,100	100.00	97	\$ 331.00	\$ 3,232.23	\$ 3,575.13	\$ 5,295.27	\$ 8,870.40	\$ 399.00	\$ 3,377.20	\$ 3,790.57	\$ 5,295.27	\$ 9,085.84	\$ 215.44	\$ -	\$ 215.44	2.4%
	100	80	58,400	100.00	97	\$ 331.00	\$ 3,693.98	\$ 4,036.88	\$ 5,961.94	\$ 9,998.82	\$ 399.00	\$ 3,859.66	\$ 4,273.03	\$ 5,961.94	\$ 10,234.97	\$ 236.15	\$ -	\$ 236.15	2.4%
	100	90	65,700	100.00			Ψ 1,100.72	.,		\$ 11,127.23			\$ 4,755.48		\$ 11,384.10	\$ 256.86		\$ 256.86	2.3%
	200	30	43,800	200.00			+ -,	+ -,		\$ 8,720.98			\$ 3,707.11		\$ 8,983.71	\$ 262.73		\$ 262.73	3.0%
	200	40	58,400	200.00			φ 0,000.00		\$ 6,609.94		\$ 798.00		\$ 4,672.03		\$ 11,281.97	\$ 304.15		\$ 304.15	2.8%
	200	50	73,000	200.00			\$ 4,617.47	,		\$ 13,234.65		\$ 4,824.57			\$ 13,580.23	\$ 345.57	•	\$ 345.57	2.6%
	200 200	60 70	87,600 102,200	200.00 200.00			,- :-:	,	\$ 9,276.63 \$ 10,609.98				\$ 6,601.85		\$ 15,878.48	\$ 386.99 \$ 428.41		\$ 386.99 \$ 428.41	2.5%
	200	80	102,200	200.00			\$ 6,464.46 \$ 7,387.95			\$ 17,748.33 \$ 20,005.17			\$ 7,566.77 \$ 8,531.68		\$ 18,176.74 \$ 20,475.00	\$ 428.41 \$ 469.83		\$ 428.41 \$ 469.83	2.4% 2.3%
	200	90	131,400	200.00			\$ 8.311.44			\$ 20,003.17			\$ 9,496.60		\$ 20,473.00	\$ 511.25		\$ 511.25	2.3%

ATLANTIC CITY ELECTRIC COMPANY MONTHLY GENERAL SERVICE SECONDARY ("MGS Secondary") Annual Average

									Prop	posed Rates								
	Load	_					Present	Present	Present			New	New	New	Difference	Difference	Total	Total
(kW)	Factor (%)	Energy (kWh)	Diet I/M	Tropo k/M	D Demand	D Energy	Distribution (\$)	BGS and Other Charges (\$)	Total (\$)	D Demand	D Energy	Distribution (\$)	BGS and Other Charges (\$)	Total (\$)	Distribution (\$)	BGS and Other Charges (\$)	Difference (\$)	Difference (%)
5	20	730	5.00	2			(+/	\$ 78.10				\$ 76.57	\$ 78.10	\$ 154.67	\$ 7.38	\$ -	\$ 7.38	5.0%
5	30	1.095	5.00					\$ 110.92		\$ 17.58				\$ 209.80			\$ 8.34	4.1%
5	40	1,460	5.00	2	\$ 14.58	\$ 85.40	\$ 111.88	\$ 143.75	\$ 255.63	\$ 17.58	\$ 89.22	\$ 121.18	\$ 143.75	\$ 264.93	\$ 9.29	\$ -	\$ 9.29	3.6%
5	50	1,825	5.00	2	\$ 14.58	\$ 106.75	\$ 133.23	\$ 176.57	\$ 309.80	\$ 17.58	\$ 111.53	\$ 143.48	\$ 176.57	\$ 320.06	\$ 10.25	\$ -	\$ 10.25	3.3%
5	60	2,190	5.00	2		\$ 128.10		\$ 209.40	\$ 363.98			\$ 165.79		\$ 375.18		\$ -	\$ 11.21	3.1%
5	70	2,555	5.00	2		\$ 149.45		\$ 242.22	\$ 418.15			\$ 188.09		\$ 430.31	\$ 12.16		\$ 12.16	2.9%
5	80 20	2,920 1,460	5.00 10.00			\$ 170.80 \$ 85.40		\$ 275.04 \$ 174.88	\$ 472.33 \$ 301.35			\$ 210.40 \$ 138.76		\$ 485.44 \$ 313.64			\$ 13.12 \$ 12.29	2.8% 4.1%
10 10	30	2,190	10.00		\$ 29.17			\$ 174.88 \$ 240.53	\$ 301.35 \$ 409.69	\$ 35.17 \$ 35.17				\$ 313.64 \$ 423.90	\$ 12.29 \$ 14.21		\$ 12.29	4.1% 3.5%
10	40	2,130	10.00	7				\$ 306.18	\$ 518.04	\$ 35.17		\$ 227.98		\$ 534.16			\$ 16.12	3.1%
10	50	3,650	10.00		\$ 29.17			\$ 371.83	\$ 626.39	\$ 35.17		\$ 272.60		\$ 644.42	\$ 18.03	\$ -	\$ 18.03	2.9%
10	60	4,380	10.00	7	\$ 29.17	\$ 256.20	\$ 297.26	\$ 437.47	\$ 734.74	\$ 35.17	\$ 267.67	\$ 317.21	\$ 437.47	\$ 754.68	\$ 19.94	\$ -	\$ 19.94	2.7%
10	70	5,110	10.00		\$ 29.17			\$ 503.12		\$ 35.17		\$ 361.82		\$ 864.94	\$ 21.86	\$ -	\$ 21.86	2.6%
10	80	5,840	10.00	7				\$ 568.77	\$ 951.43	\$ 35.17		\$ 406.43		\$ 975.20	\$ 23.77	\$ -	\$ 23.77	2.5%
20	20	2,920	20.00		\$ 58.33			\$ 368.44	\$ 609.48	\$ 70.33		\$ 263.15	\$ 368.44		\$ 22.12		\$ 22.12	3.6%
20 20	30 40	4,380 5,840	20.00 20.00	17 17		\$ 256.20 \$ 341.60		\$ 499.74 \$ 631.03	\$ 826.17 \$ 1.042.86	\$ 70.33 \$ 70.33		\$ 352.37 \$ 441.60	\$ 499.74 \$ 631.03	\$ 852.11 \$ 1.072.63	\$ 25.94 \$ 29.77	\$ - \$ -	\$ 25.94 \$ 29.77	3.1% 2.9%
20	50	7.300	20.00	17		\$ 426.99		\$ 762.33	\$ 1,042.00			\$ 530.82		\$ 1,072.03	\$ 33.59	\$ -	\$ 33.59	2.7%
20	60	8.760	20.00	17				\$ 893.63	\$ 1,476,25	\$ 70.33		\$ 620.04		\$ 1,513.67	\$ 37.42	*	\$ 37.42	2.5%
20	70	10,220	20.00	17		\$ 597.79	\$ 668.02	\$ 1,024.92	\$ 1,692.95	\$ 70.33	\$ 624.56	\$ 709.27	\$ 1,024.92	\$ 1,734.19	\$ 41.24	\$ -	\$ 41.24	2.4%
20	80	11,680	20.00	17	\$ 58.33	\$ 683.19	\$ 753.42	\$ 1,156.22	\$ 1,909.64	\$ 70.33	\$ 713.79	\$ 798.49	\$ 1,156.22	\$ 1,954.71	\$ 45.07	\$ -	\$ 45.07	2.4%
30	20	4,380	30.00					\$ 562.01		\$ 105.50				\$ 949.55		•	\$ 31.94	3.5%
30	30	6,570	30.00			\$ 384.29		\$ 758.95	\$ 1,242.64	\$ 105.50		\$ 521.38		\$ 1,280.32	\$ 37.68	\$ -	\$ 37.68	3.0%
30 30	40 50	8,760 10,950	30.00 30.00			\$ 512.39 \$ 640.49		\$ 955.89 \$ 1.152.84	\$ 1,567.69 \$ 1.892.73	\$ 105.50 \$ 105.50		\$ 655.21 \$ 789.05		\$ 1,611.10 \$ 1,941.88	\$ 43.42 \$ 49.16		\$ 43.42 \$ 49.16	2.8% 2.6%
30	60	13,140	30.00						\$ 1,892.73	\$ 105.50		\$ 789.05 \$ 922.88		\$ 1,941.88	\$ 54.89	\$ -	\$ 54.89	2.5%
30	70	15,330	30.00						\$ 2,542.81	\$ 105.50		\$ 1.056.72		\$ 2,603.44	\$ 60.63	\$ -	\$ 60.63	2.4%
30	80	17.520	30.00		\$ 87.50				\$ 2.867.85		\$ 1.070.68	. ,		\$ 2,934.22	\$ 66.37	\$ -	\$ 66.37	2.3%
50	20	7,300	50.00	47	\$ 145.83	\$ 426.99	\$ 584.73	\$ 949.13	\$ 1,533.86	\$ 175.83	\$ 446.12	\$ 636.32	\$ 949.13	\$ 1,585.45	\$ 51.59	\$ -	\$ 51.59	3.4%
50	30	10,950	50.00	47	\$ 145.83	\$ 640.49		\$ 1,277.37	\$ 2,075.59	\$ 175.83	\$ 669.18	\$ 859.38		\$ 2,136.75	\$ 61.16	\$ -	\$ 61.16	2.9%
50	40	14,600	50.00			+		\$ 1,605.61	\$ 2,617.33	\$ 175.83		\$ 1,082.44		\$ 2,688.05	\$ 70.72	•	\$ 70.72	2.7%
50	50	18,250 21,900	50.00		\$ 145.83			\$ 1,933.85	\$ 3,159.06	\$ 175.83		\$ 1,305.50		\$ 3,239.34	\$ 80.28	\$ -	\$ 80.28	2.5% 2.4%
50 50	60 70	25,550	50.00 50.00		\$ 145.83 \$ 145.83			\$ 2,262.08 \$ 2,590.32	\$ 3,700.80 \$ 4.242.53	\$ 175.83 \$ 175.93		\$ 1,528.56 \$ 1.751.61		\$ 3,790.64 \$ 4.341.94			\$ 89.84 \$ 99.40	2.4%
50	80	29,200	50.00		\$ 145.83			\$ 2,918.56				\$ 1,731.67		\$ 4.893.23	\$ 108.96	•	\$ 108.96	2.3%
75	30	16,425	75.00			. ,	. ,	\$ 1.925.39	\$ 3.116.78			\$ 1,281.88		\$ 3.207.28	\$ 90.50	\$ -	\$ 90.50	2.9%
75	40	21,900	75.00	72	\$ 218.75	\$ 1,280.98	\$ 1,511.63	\$ 2,417.75	\$ 3,929.38	\$ 263.75	\$ 1,338.35	\$ 1,616.47	\$ 2,417.75	\$ 4,034.22	\$ 104.84	\$ -	\$ 104.84	2.7%
75	50	27,375	75.00	72	\$ 218.75	\$ 1,601.23	\$ 1,831.88	\$ 2,910.11	\$ 4,741.99	\$ 263.75	\$ 1,672.94	\$ 1,951.06	\$ 2,910.11	\$ 4,861.17	\$ 119.18	\$ -	\$ 119.18	2.5%
75	60	32,850	75.00			\$ 1,921.47			\$ 5,554.59	\$ 263.75		\$ 2,285.65		\$ 5,688.11	\$ 133.53		\$ 133.53	2.4%
75	70	38,325	75.00			,	-,	\$ 3,894.82	\$ 6,367.19	\$ 263.75		\$ 2,620.24		\$ 6,515.06		\$ -	\$ 147.87	2.3%
75 75	80 90	43,800 49,275	75.00 75.00		\$ 218.75 \$ 218.75	\$ 2,561.96		\$ 4,387.18 \$ 4,879.54	\$ 7,179.80 \$ 7.992.40	\$ 263.75 \$ 263.75	\$ 2,676.71	\$ 2,954.83 \$ 3.289.41		\$ 7,342.01 \$ 8,168.95	\$ 162.21 \$ 176.55	\$ - \$ -	\$ 162.21 \$ 176.55	2.3%
100	30	21,900	100.00		\$ 291.67		,	\$ 4,879.54 \$ 2,573.42		\$ 263.75 \$ 351.67		\$ 1,704.39		\$ 4,277.81	\$ 176.55	-	\$ 176.55	2.2%
100	40	29,200	100.00		\$ 291.67			\$ 3,229.89	\$ 5.241.44			\$ 2.150.51		\$ 5.380.40	\$ 138.96		\$ 138.96	2.7%
100	50	36,500	100.00		\$ 291.67	. ,		\$ 3,886.37	\$ 6,324.91	\$ 351.67		\$ 2,596.62	,	\$ 6,483.00	\$ 158.09	\$ -	\$ 158.09	2.5%
100	60	43,800	100.00	97	\$ 291.67	\$ 2,561.96	\$ 2,865.53	\$ 4,542.85	\$ 7,408.38	\$ 351.67	\$ 2,676.71	\$ 3,042.74	\$ 4,542.85	\$ 7,585.59	\$ 177.21	\$ -	\$ 177.21	2.4%
100	70	51,100	100.00		\$ 291.67			\$ 5,199.32	\$ 8,491.85			\$ 3,488.86		\$ 8,688.18			\$ 196.33	2.3%
100	80	58,400	100.00		\$ 291.67			\$ 5,855.80	\$ 9,575.32	\$ 351.67		\$ 3,934.98		\$ 9,790.78	\$ 215.46		\$ 215.46	2.3%
100	90	65,700	100.00		\$ 291.67		.,	\$ 6,512.28	\$ 10,658.79	\$ 351.67		\$ 4,381.10		\$ 10,893.37	\$ 234.58		\$ 234.58	2.2%
200 200	30 40	43,800 58,400	200.00 200.00		\$ 583.33 \$ 583.33	\$ 2,561.96	1	\$ 5,165.51 \$ 6.478.47	\$ 8,322.71 \$ 10.489.65	\$ 703.33 \$ 703.33	\$ 2,676.71	\$ 3,394.41 \$ 4.286.64		\$ 8,559.92 \$ 10,765.11	\$ 237.21 \$ 275.46		\$ 237.21 \$ 275.46	2.9% 2.6%
200	50	73,000	200.00		\$ 583.33				\$ 10,489.65		\$ 4,461,18			\$ 10,765.11	\$ 275.46		\$ 275.46	2.5%
200	60	87.600	200.00		\$ 583.33			\$ 9.104.38	\$ 14.823.54		\$ 5,353.41			\$ 15,175.49			\$ 351.95	2.4%
200	70	102,200	200.00			\$ 5,977.92			\$ 16,990.48		\$ 6,245.65			\$ 17,380.68	\$ 390.20	•	\$ 390.20	2.3%
200	80	116,800	200.00	197	\$ 583.33	\$ 6,831.90	\$ 7,427.14	\$ 11,730.28	\$ 19,157.42	\$ 703.33	\$ 7,137.88	\$ 7,855.58	\$ 11,730.28	\$ 19,585.87	\$ 428.45	\$ -	\$ 428.45	2.2%
200	90	131,400	200.00	197	\$ 583.33	\$ 7,685.89	\$ 8,281.13	\$ 13,043.24	\$ 21,324.36	\$ 703.33	\$ 8,030.12	\$ 8,747.82	\$ 13,043.24	\$ 21,791.06	\$ 466.69	\$ -	\$ 466.69	2.2%

ATLANTIC CITY ELECTRIC COMPANY MONTHLY GENERAL SERVICE PRIMARY ("MGS Primary") 8 WINTER MONTHS (October Through May)

Present Rates

vs.
Proposed Rates

								Pro	posed Rates								
	Load					Present	Present	Present			New	New	New	Difference	Difference	Total	Total
	Factor					Distribution	BGS and Other Charges	Total			Distribution	BGS and Other Charges	<u>Total</u>	Distribution	BGS and Other Charges	<u>Difference</u>	<u>Difference</u>
(kW)	(%)	(kWh)		Trans kW D Demand		(\$)	(\$)	(\$)		D Energy	(\$)	(\$)	(\$)	(\$)	(\$)	(\$)	(%)
5	20	730	5.00		\$ 34.68	\$ 59.84	\$ 49.08	\$ 108.92	\$ 7.60	\$ 18.06	\$ 43.22	\$ 49.08	\$ 92.30	\$ (16.62)		\$ (16.62)	-15.3%
5	30	1,095	5.00		\$ 52.02	\$ 77.18	\$ 70.34	\$ 147.52		\$ 27.09	\$ 52.25	\$ 70.34		\$ (24.93)		\$ (24.93)	-16.9%
5	40	1,460	5.00		\$ 69.36	\$ 94.52	\$ 91.60	\$ 186.12	\$ 7.60	\$ 36.12	\$ 61.28	\$ 91.60	\$ 152.88	\$ (33.24)		\$ (33.24)	-17.9%
5	50	1,825	5.00		\$ 86.70	\$ 111.86	\$ 112.86	\$ 224.72	\$ 7.60	\$ 45.15		\$ 112.86		\$ (41.55)		\$ (41.55)	-18.5%
5 5	60 70	2,190 2.555	5.00 5.00		\$ 104.04 \$ 121.38	\$ 129.20 \$ 146.54	\$ 134.11 \$ 155.37	\$ 263.32 \$ 301.92	\$ 7.60 \$ 7.60	\$ 54.18 \$ 63.21	\$ 79.34 \$ 88.37	\$ 134.11 \$ 155.37	\$ 213.46 \$ 243.75	\$ (49.86) \$ (58.17)		\$ (49.86) \$ (58.17)	-18.9% -19.3%
5	80	2,555	5.00		\$ 138.72	\$ 163.88	\$ 176.63			\$ 72.24	\$ 97.40	\$ 176.63	\$ 274.04	\$ (66.48)		\$ (56.48)	-19.5%
10	20	1,460	10.00		\$ 69.36	\$ 102.12	\$ 108.00	\$ 210.12	\$ 7.60 \$ 15.20	\$ 72.24	\$ 68.88	\$ 176.03	\$ 176.88	\$ (33.24)		\$ (33.24)	-15.8%
10	30	2,190	10.00		\$ 104.04	\$ 136.80		\$ 287.32	\$ 15.20	\$ 54.18	\$ 86.94	\$ 150.51	\$ 237.46	\$ (33.24)		\$ (33.24)	-17.4%
10	40	2,920	10.00		\$ 138.72	\$ 171.48	\$ 193.03	\$ 364.52	\$ 15.20	\$ 72.24	\$ 105.00	\$ 193.03		\$ (66.48)	•	\$ (66.48)	-18.2%
10	50	3,650	10.00		\$ 173.40	\$ 206.16	\$ 235.55	\$ 441.71	\$ 15.20	\$ 90.30	\$ 123.06	\$ 235.55	\$ 358.62	\$ (83.10)		\$ (83.10)	-18.8%
10	60	4.380	10.00		\$ 208.09	\$ 240.85	\$ 278.07	\$ 518.91	\$ 15.20	\$ 108.37	\$ 141.13	\$ 278.07	\$ 419.19	\$ (99.72)		\$ (99.72)	-19.2%
10	70	5,110	10.00		\$ 242.77	\$ 275.53	\$ 320.59	\$ 596.11	\$ 15.20	\$ 126.43	\$ 159.19	\$ 320.59	\$ 479.77	\$ (116.34)		\$ (116.34)	-19.5%
10	80	5,840	10.00		\$ 277.45	\$ 310.21	\$ 363.10	\$ 673.31	\$ 15.20	\$ 144.49	\$ 177.25	\$ 363.10		\$ (132.96)		\$ (132.96)	-19.7%
20	20	2.920	20.00		\$ 138.72	\$ 186.68	\$ 225.83	\$ 412.52	\$ 30.40	\$ 72.24	\$ 120.20	\$ 225.83	\$ 346.04	\$ (66.48)		\$ (66.48)	-16.1%
20	30	4.380	20.00		\$ 208.09	\$ 256.05	\$ 310.87	\$ 566.91	\$ 30.40	\$ 108.37	\$ 156.33	\$ 310.87	\$ 467.19	\$ (99.72)		\$ (99.72)	-17.6%
20	40	5,840	20.00	17 \$ 30.40	\$ 277.45	\$ 325.41	\$ 395.90	\$ 721.31	\$ 30.40	\$ 144.49	\$ 192.45	\$ 395.90	\$ 588.35	\$ (132.96)	\$ -	\$ (132.96)	-18.4%
20	50	7,300	20.00	17 \$ 30.40	\$ 346.81	\$ 394.77	\$ 480.94	\$ 875.71	\$ 30.40	\$ 180.61	\$ 228.57	\$ 480.94	\$ 709.51	\$ (166.20)	\$ -	\$ (166.20)	-19.0%
20	60	8,760	20.00	17 \$ 30.40	\$ 416.17	\$ 464.13	\$ 565.98	\$ 1,030.11	\$ 30.40	\$ 216.73	\$ 264.69	\$ 565.98	\$ 830.67	\$ (199.44)	\$ -	\$ (199.44)	-19.4%
20	70	10,220	20.00	17 \$ 30.40	\$ 485.53	\$ 533.49	\$ 651.01	\$ 1,184.51	\$ 30.40	\$ 252.85	\$ 300.81	\$ 651.01	\$ 951.83	\$ (232.68)	\$ -	\$ (232.68)	-19.6%
20	80	11,680	20.00	17 \$ 30.40	\$ 554.89	\$ 602.85	\$ 736.05	\$ 1,338.90	\$ 30.40	\$ 288.97	\$ 336.93	\$ 736.05	\$ 1,072.98	\$ (265.92)	\$ -	\$ (265.92)	-19.9%
30	20	4,380	30.00	27 \$ 45.60	\$ 208.09	\$ 271.25	\$ 343.67	\$ 614.91	\$ 45.60	\$ 108.37	\$ 171.53	\$ 343.67	\$ 515.19	\$ (99.72)	\$ -	\$ (99.72)	-16.2%
30	30	6,570	30.00	27 \$ 45.60	\$ 312.13	\$ 375.29	\$ 471.22	\$ 846.51	\$ 45.60	\$ 162.55	\$ 225.71	\$ 471.22	\$ 696.93	\$ (149.58)	\$ -	\$ (149.58)	-17.7%
30	40	8,760	30.00	27 \$ 45.60	\$ 416.17		\$ 598.78	\$ 1,078.11	\$ 45.60	\$ 216.73	\$ 279.89	\$ 598.78	\$ 878.67	\$ (199.44)		\$ (199.44)	-18.5%
30	50	10,950	30.00		\$ 520.21	\$ 583.37	\$ 726.33	\$ 1,309.70	\$ 45.60	\$ 270.91	\$ 334.07	\$ 726.33	\$ 1,060.41	\$ (249.30)		\$ (249.30)	-19.0%
30	60	13,140	30.00		\$ 624.26	\$ 687.42	\$ 853.89	\$ 1,541.30	\$ 45.60	\$ 325.10	\$ 388.26	\$ 853.89	\$ 1,242.14	\$ (299.16)		\$ (299.16)	-19.4%
30	70	15,330	30.00		\$ 728.30	\$ 791.46	\$ 981.44	\$ 1,772.90	\$ 45.60	\$ 379.28	\$ 442.44	\$ 981.44	\$ 1,423.88	\$ (349.02)		\$ (349.02)	-19.7%
30	80	17,520	30.00		\$ 832.34	\$ 895.50	\$ 1,108.99	\$ 2,004.50	\$ 45.60	\$ 433.46	\$ 496.62	\$ 1,108.99	\$ 1,605.62	\$ (398.88)		\$ (398.88)	-19.9%
50	20	7,300	50.00		\$ 346.81	\$ 440.37		\$ 1,019.71	\$ 76.00	\$ 180.61		\$ 579.34	\$ 853.51	\$ (166.20)		\$ (166.20)	-16.3%
50	30 40	10,950	50.00		\$ 520.21	\$ 613.77	\$ 791.93	\$ 1,405.70	\$ 76.00	\$ 270.91	\$ 364.47	\$ 791.93	\$ 1,156.41	\$ (249.30)		\$ (249.30)	-17.7%
50	50	14,600 18,250	50.00 50.00		\$ 693.62 \$ 867.02	\$ 787.18 \$ 960.58	\$ 1,004.52	\$ 1,791.70	\$ 76.00 \$ 76.00	\$ 361.22 \$ 451.52	\$ 454.78 \$ 545.08	\$ 1,004.52 \$ 1,217.11		\$ (332.40) \$ (415.50)		\$ (332.40)	-18.6%
50 50	60	21,900	50.00					\$ 2,177.69 \$ 2,563.69	\$ 76.00	\$ 451.52	\$ 635.39		\$ 1,762.20	+ ()		\$ (415.50) \$ (498.60)	-19.1% -19.4%
50	70	25,550	50.00		\$ 1,040.43 \$ 1,213.83	\$ 1,133.99 \$ 1,307.39	Ψ .,.200	\$ 2,563.69	\$ 76.00	\$ 632.13	\$ 725.69	\$ 1,429.70 \$ 1,642.29	\$ 2,065.09 \$ 2,367.99	\$ (498.60) \$ (581.70)		\$ (498.60)	-19.4%
50	80	29,200	50.00			\$ 1,480.79	\$ 1.854.88	\$ 3,335.68	\$ 76.00	\$ 722.44	\$ 816.00	\$ 1,854.88	\$ 2,670.88	\$ (664.80)		\$ (664.80)	-19.9%
75	30	16.425	75.00		\$ 780.32	\$ 911.88	*	\$ 2,104.70	\$ 114.00	\$ 406.37	\$ 537.93	\$ 1,192.82		\$ (373.95)	•	\$ (373.95)	-17.8%
75	40	21.900	75.00			\$ 1.171.99			\$ 114.00	\$ 541.83	\$ 673.39	\$ 1,511.70		\$ (498.60)		\$ (498.60)	-18.6%
75	50	27,375	75.00		\$ 1,300.53	\$ 1,432.09		\$ 3,262.68	\$ 114.00	\$ 677.28	\$ 808.84	\$ 1,830.59	\$ 2,639.43	\$ (623.25)		\$ (623.25)	-19.1%
75	60	32.850	75.00			\$ 1,692.20		\$ 3,841.67	\$ 114.00	\$ 812.74	\$ 944.30	\$ 2,149.48		\$ (747.90)		\$ (747.90)	-19.5%
75	70	38,325	75.00			\$ 1,952.30		\$ 4,420.67	\$ 114.00	\$ 948.20	\$ 1,079.76	\$ 2,468.36	\$ 3,548.12	\$ (872.55)		\$ (872.55)	-19.7%
75	80	43,800	75.00			\$ 2,212.41		\$ 4,999.66	\$ 114.00	\$ 1,083.66	\$ 1,215.22	\$ 2,787.25		\$ (997.19)		\$ (997.19)	-19.9%
75	90	49,275	75.00	72 \$ 114.00		\$ 2,472.52		\$ 5,578.65		\$ 1,219.11	\$ 1,350.67	\$ 3,106.13		\$ (1,121.84)		\$ (1,121.84)	-20.1%
100	30	21,900	100.00	97 \$ 152.00	\$ 1,040.43	\$ 1,209.99			\$ 152.00	\$ 541.83	\$ 711.39	\$ 1,593.70	\$ 2,305.09	\$ (498.60)	\$ -	\$ (498.60)	-17.8%
100	40	29,200	100.00	97 \$ 152.00	\$ 1,387.23	\$ 1,556.79	\$ 2,018.88	\$ 3,575.68	\$ 152.00	\$ 722.44	\$ 892.00	\$ 2,018.88	\$ 2,910.88	\$ (664.80)	\$ -	\$ (664.80)	-18.6%
100	50	36,500	100.00	97 \$ 152.00	\$ 1,734.04	\$ 1,903.60	\$ 2,444.07	\$ 4,347.67	\$ 152.00	\$ 903.05	\$ 1,072.61	\$ 2,444.07	\$ 3,516.67	\$ (831.00)	\$ -	\$ (831.00)	-19.1%
100	60	43,800	100.00	97 \$ 152.00		\$ 2,250.41		\$ 5,119.66	\$ 152.00	\$ 1,083.66	\$ 1,253.22	\$ 2,869.25	\$ 4,122.46	\$ (997.19)		\$ (997.19)	-19.5%
100	70	51,100	100.00		-,	\$ 2,597.22		\$ 5,891.65	\$ 152.00	\$ 1,264.27	\$ 1,433.83	\$ 3,294.43	\$ 4,728.25	\$ (1,163.39)		\$ (1,163.39)	-19.7%
100	80	58,400	100.00	97 \$ 152.00		\$ 2,944.03		\$ 6,663.64	\$ 152.00	\$ 1,444.87	\$ 1,614.43	\$ 3,719.61	\$ 5,334.04	\$ (1,329.59)	•	\$ (1,329.59)	-20.0%
100	90	65,700	100.00			\$ 3,290.84		\$ 7,435.63	\$ 152.00	\$ 1,625.48	\$ 1,795.04	\$ 4,144.79	\$ 5,939.83	\$ (1,495.79)		\$ (1,495.79)	-20.1%
200	30	43,800	200.00		\$ 2,080.85	\$ 2,402.41	\$ 3,197.25	\$ 5,599.66	\$ 304.00	\$ 1,083.66	\$ 1,405.22	\$ 3,197.25	\$ 4,602.46	\$ (997.19)		\$ (997.19)	-17.8%
200	40	58,400	200.00		T =,	\$ 3,096.03		\$ 7,143.64	\$ 304.00	\$ 1,444.87	\$ 1,766.43	\$ 4,047.61	\$ 5,814.04	\$ (1,329.59)		\$ (1,329.59)	-18.6%
200	50	73,000	200.00		\$ 3,468.08	\$ 3,789.64		\$ 8,687.62	\$ 304.00	\$ 1,806.09	\$ 2,127.65	\$ 4,897.97	\$ 7,025.63	\$ (1,661.99)		\$ (1,661.99)	-19.1%
200	60	87,600	200.00		Ψ 1,1010	\$ 4,483.26		\$ 10,231.60	\$ 304.00	\$ 2,167.31	\$ 2,488.87	\$ 5,748.33		\$ (1,994.39)		\$ (1,994.39)	-19.5%
200	70	102,200	200.00	197 \$ 304.00		\$ 5,176.88		\$ 11,775.57	\$ 304.00	\$ 2,528.53	\$ 2,850.09		\$ 9,448.79	\$ (2,326.79)		\$ (2,326.79)	-19.8%
200	80	116,800	200.00	197 \$ 304.00		\$ 5,870.49		\$ 13,319.55		\$ 2,889.75			\$ 10,660.37	\$ (2,659.19)		\$ (2,659.19)	-20.0%
200	90	131,400	200.00	197 \$ 304.00	\$ 6,242.55	\$ 6,564.11	\$ 8,299.42	\$ 14,863.53	\$ 304.00	\$ 3,250.97	\$ 3,572.53	\$ 8,299.42	\$ 11,871.95	\$ (2,991.58)	\$ -	\$ (2,991.58)	-20.1%

ATLANTIC CITY ELECTRIC COMPANY MONTHLY GENERAL SERVICE PRIMARY ("MGS Primary") 4 SUMMER MONTHS (June Through September)

								Pro	posed Rates								
_	Loa					Present	Present	Present			New	New	New	Difference	Difference	Total	Total
Demar (kW)	d Facto (%)		Diet I/M	Trans kW D Demand	D Energy	Distribution (\$)	BGS and Other Charges (\$)	Total (\$)	D Demand	D Energy	Distribution (\$)	BGS and Other Charges (\$)	Total (\$)	Distribution (\$)	BGS and Other Charges (\$)	Difference (\$)	Difference (%)
5	20	730	5.00		\$ 35.78	\$ 62.99	\$ 51.28	\$ 114.27			\$ 45.83	\$ 51.28	\$ 97.12	\$ (17.16)	(4)	\$ (17.16)	-15.0%
5	30	1,095	5.00		\$ 53.67					\$ 27.94		\$ 73.30		\$ (25.73)		\$ (25.73)	-16.7%
5	40	1,460	5.00		\$ 71.56	\$ 98.77	\$ 95.31	\$ 194.08				\$ 95.31	\$ 159.77	\$ (34.31)		\$ (34.31)	-17.7%
5	50	1.825	5.00		\$ 89.45	\$ 116.66		\$ 233.98				\$ 117.32	\$ 191.09	\$ (42.89)		\$ (42.89)	-18.3%
5	60	2,190	5.00	2 \$ 9.65	\$ 107.34	\$ 134.55	\$ 139.33	\$ 273.88	\$ 9.65	\$ 55.87	\$ 83.08	\$ 139.33	\$ 222.41	\$ (51.47)	\$ -	\$ (51.47)	-18.8%
5	70	2,555	5.00	2 \$ 9.65	\$ 125.23	\$ 152.44	\$ 161.34	\$ 313.78	\$ 9.65	\$ 65.19	\$ 92.40	\$ 161.34	\$ 253.74	\$ (60.04)	\$ -	\$ (60.04)	-19.1%
5	80	2,920	5.00		\$ 143.12	\$ 170.33	\$ 183.35	\$ 353.68	Ψ 0.00			\$ 183.35	\$ 285.06	\$ (68.62)		\$ (68.62)	-19.4%
10	20	1,460	10.00		\$ 71.56	\$ 108.42						\$ 113.46	\$ 187.57	\$ (34.31)		\$ (34.31)	-15.5%
10	30	2,190	10.00		\$ 107.34	\$ 144.20	\$ 157.48	\$ 301.68					\$ 250.21	\$ (51.47)		\$ (51.47)	-17.1%
10 10	40 50	2,920 3.650	10.00		\$ 143.12 \$ 178.90	\$ 179.98 \$ 215.76	\$ 201.50 \$ 245.53				\$ 111.36 \$ 129.98		\$ 312.86 \$ 375.51	\$ (68.62) \$ (85.78)		\$ (68.62) \$ (85.78)	-18.0% -18.6%
10	60	4.380	10.00 10.00		\$ 178.90 \$ 214.68	\$ 251.54		\$ 461.28 \$ 541.09				\$ 245.53 \$ 289.55	\$ 375.51 \$ 438.16	\$ (102.93)	•	\$ (85.78) \$ (102.93)	-19.0%
10	70	5,110	10.00		\$ 250.46	\$ 287.32		\$ 620.89			\$ 167.23	\$ 333.57	\$ 500.81	\$ (102.93)		\$ (102.93)	-19.3%
10	80	5.840	10.00		\$ 286.24	\$ 323.10		\$ 700.69			\$ 185.86	\$ 377.60	\$ 563.45	\$ (120.09)		\$ (120.03)	-19.6%
20	20	2,920	20.00		\$ 143.12	\$ 199.28	\$ 237.80	\$ 437.08			\$ 130.66	\$ 237.80	\$ 368.46	\$ (68.62)		\$ (68.62)	-15.7%
20	30	4.380	20.00	17 \$ 38.60		\$ 270.84	\$ 325.85	\$ 596.69				\$ 325.85	\$ 493.76	\$ (102.93)		\$ (102.93)	-17.3%
20	40	5,840	20.00	17 \$ 38.60	\$ 286.24	\$ 342.40	\$ 413.90	\$ 756.29	\$ 38.60	\$ 149.00	\$ 205.16	\$ 413.90	\$ 619.05	\$ (137.24)	\$ -	\$ (137.24)	-18.1%
20	50	7,300	20.00	17 \$ 38.60	\$ 357.79	\$ 413.95	\$ 501.94	\$ 915.90	\$ 38.60	\$ 186.24	\$ 242.40	\$ 501.94	\$ 744.35	\$ (171.55)	\$ -	\$ (171.55)	-18.7%
20	60	8,760	20.00	17 \$ 38.60	\$ 429.35	\$ 485.51	\$ 589.99	\$ 1,075.50	\$ 38.60	\$ 223.49	\$ 279.65	\$ 589.99	\$ 869.64	\$ (205.86)	\$ -	\$ (205.86)	-19.1%
20	70	10,220	20.00		\$ 500.91	\$ 557.07		\$ 1,235.11	\$ 38.60		\$ 316.90	\$ 678.04	\$ 994.94	\$ (240.17)		\$ (240.17)	-19.4%
20	80	11,680	20.00		\$ 572.47	\$ 628.63	\$ 766.08	\$ 1,394.72					\$ 1,120.24	\$ (274.48)		\$ (274.48)	-19.7%
30	20	4,380	30.00	27 \$ 57.90		\$ 290.14						\$ 362.15		\$ (102.93)		\$ (102.93)	-15.8%
30	30	6,570	30.00		\$ 322.02	\$ 397.48		\$ 891.70			\$ 243.08	\$ 494.22	\$ 737.30	\$ (154.40)		\$ (154.40)	-17.3%
30	40	8,760	30.00		\$ 429.35	\$ 504.81	\$ 626.29	\$ 1,131.10			\$ 298.95	\$ 626.29	\$ 925.24	\$ (205.86)		\$ (205.86)	-18.2%
30 30	50 60	10,950 13,140	30.00 30.00	27 \$ 57.90 27 \$ 57.90		\$ 612.15 \$ 719.49		\$ 1,370.51 \$ 1,609.92			\$ 354.83 \$ 410.70		\$ 1,113.19 \$ 1,301.13	\$ (257.33) \$ (308.79)		\$ (257.33) \$ (308.79)	-18.8% -19.2%
30	70	15,330	30.00	27 \$ 57.90			φ 000.10	\$ 1,849.33					\$ 1,489.08	\$ (360.26)		\$ (360.26)	-19.5%
30	80	17,520	30.00		\$ 858.71			\$ 2,088.74					\$ 1,677.02	\$ (411.72)		\$ (300.20)	-19.7%
50	20	7.300	50.00		\$ 357.79	\$ 471.85		\$ 1.082.70			\$ 300.30	\$ 610.84	\$ 911.15	\$ (171.55)		\$ (171.55)	-15.8%
50	30	10,950	50.00		\$ 536.69	\$ 650.75	\$ 830.96	\$ 1,481.71			\$ 393.43		\$ 1,224.39	\$ (257.33)		\$ (257.33)	-17.4%
50	40	14,600	50.00	47 \$ 96.50	\$ 715.59	\$ 829.65	\$ 1,051.08	\$ 1,880.73	\$ 96.50	\$ 372.49	\$ 486.55	\$ 1,051.08	\$ 1,537.63	\$ (343.10)	\$ -	\$ (343.10)	-18.2%
50	50	18,250	50.00	47 \$ 96.50	\$ 894.49	\$ 1,008.55	\$ 1,271.19	\$ 2,279.74	\$ 96.50	\$ 465.61	\$ 579.67	\$ 1,271.19	\$ 1,850.87	\$ (428.88)	\$ -	\$ (428.88)	-18.8%
50	60	21,900	50.00	47 \$ 96.50		\$ 1,187.44		\$ 2,678.76					\$ 2,164.11	\$ (514.65)		\$ (514.65)	-19.2%
50	70	25,550	50.00		Ψ .,ΣοΣ.Σο	\$ 1,366.34		\$ 3,077.77			\$ 765.92		\$ 2,477.35	\$ (600.43)		\$ (600.43)	-19.5%
50	80	29,200	50.00		Ψ 1,101110	\$ 1,545.24		\$ 3,476.78			\$ 859.04		\$ 2,790.58	\$ (686.20)		\$ (686.20)	-19.7%
75	30	16,425	75.00		\$ 805.04	\$ 967.35		\$ 2,219.23			\$ 581.36		\$ 1,833.25	\$ (385.99)		\$ (385.99)	-17.4%
75 75	40 50	21,900 27,375	75.00	72 \$ 144.75	. ,	\$ 1,235.69		\$ 2,817.76			\$ 721.04		\$ 2,303.11	\$ (514.65)	•	\$ (514.65)	-18.3%
75	60	32.850	75.00 75.00	72 \$ 144.75 72 \$ 144.75		\$ 1,504.04 \$ 1,772.39		\$ 3,416.28 \$ 4.014.80			\$ 860.73 \$ 1.000.41		\$ 2,772.97 \$ 3.242.82	\$ (643.31) \$ (771.98)	•	\$ (643.31) \$ (771.98)	-18.8% -19.2%
75	70	38,325	75.00	72 \$ 144.75		\$ 2,040.73		\$ 4,613.32			\$ 1,140.10		\$ 3,712.68	\$ (900.64)		\$ (900.64)	-19.5%
75	80	43,800	75.00	72 \$ 144.75		\$ 2,309.08		\$ 5,211.84	\$ 144.75		\$ 1,279.78		\$ 4,182.54	\$ (1,029.30)		\$ (1,029.30)	-19.7%
75	90	49,275	75.00	72 \$ 144.75		\$ 2,577.43		\$ 5.810.36			\$ 1,419,46	\$ 3,232,94	\$ 4,652,40	\$ (1,157,96)		\$ (1,157,96)	-19.9%
100	30	21,900	100.00	97 \$ 193.00	\$ 1,073.38	\$ 1,283.94	\$ 1,672.81	\$ 2,956.76	\$ 193.00	\$ 558.73	\$ 769.29	\$ 1,672.81	\$ 2,442.11	\$ (514.65)	\$ -	\$ (514.65)	-17.4%
100	40	29,200	100.00	97 \$ 193.00	\$ 1,431.18	\$ 1,641.74	\$ 2,113.05	\$ 3,754.78	\$ 193.00	\$ 744.98	\$ 955.54	\$ 2,113.05	\$ 3,068.58	\$ (686.20)	\$ -	\$ (686.20)	-18.3%
100	50	36,500	100.00	97 \$ 193.00	\$ 1,788.97	\$ 1,999.53	\$ 2,553.28	\$ 4,552.81	\$ 193.00	\$ 931.22	\$ 1,141.78	\$ 2,553.28	\$ 3,695.06	\$ (857.75)	\$ -	\$ (857.75)	-18.8%
100	60	43,800	100.00	97 \$ 193.00		\$ 2,357.33		\$ 5,350.84			\$ 1,328.03	\$ 2,993.51	\$ 4,321.54	\$ (1,029.30)		\$ (1,029.30)	-19.2%
100	70	51,100	100.00	97 \$ 193.00		\$ 2,715.12		\$ 6,148.87					\$ 4,948.02	\$ (1,200.85)		\$ (1,200.85)	-19.5%
100	80	58,400	100.00		Ψ 2,002.00	\$ 3,072.92		\$ 6,946.90			\$ 1,700.52		\$ 5,574.50	\$ (1,372.40)		\$ (1,372.40)	-19.8%
100	90 30	65,700	100.00	97 \$ 193.00		\$ 3,430.71		\$ 7,744.93			.,		\$ 6,200.98	\$ (1,543.95)		\$ (1,543.95)	-19.9%
200 200	40	43,800 58,400	200.00 200.00	197 \$ 386.00 197 \$ 386.00		\$ 2,550.33 \$ 3,265.92	\$ 3,356.51 \$ 4,236.98	\$ 5,906.84 \$ 7,502.90			\$ 1,521.03 \$ 1,893.52		\$ 4,877.54 \$ 6,130.50	\$ (1,029.30) \$ (1,372.40)	\$ -	\$ (1,029.30) \$ (1,372.40)	-17.4% -18.3%
200	50	73.000	200.00	197 \$ 386.00		\$ 3,265.92		\$ 7,502.90			\$ 1,893.52 \$ 2,266.01		\$ 6,130.50	\$ (1,372.40) \$ (1,715.50)	*	\$ (1,372.40)	-18.9%
200	60	87,600	200.00	197 \$ 386.00				\$ 10,695.01			. ,		\$ 8,636.41	\$ (2,058.60)		\$ (2,058.60)	-19.2%
200	70	102,200	200.00	197 \$ 386.00		\$ 5.412.69		\$ 12,291.07			\$ 3,010.99	\$ 6,878.38	\$ 9,889.37	\$ (2,401.70)		\$ (2,401.70)	-19.5%
200	80	116,800	200.00	197 \$ 386.00				\$ 13,887.13		\$ 2,979.92			\$ 11,142.33	\$ (2,744.80)		\$ (2,744.80)	-19.8%
200	90		200.00	197 \$ 386.00				\$ 15,483.19			\$ 3,755.97		\$ 12,395.29	\$ (3,087.90)		\$ (3,087.90)	-19.9%

ATLANTIC CITY ELECTRIC COMPANY MONTHLY GENERAL SERVICE PRIMARY ("MGS Primary") Annual Average

Demail Factor Energy New Demail	71.32 \$ 124.54 92.83 \$ 155.17 114.34 \$ 155.81 135.85 \$ 216.44 157.36 \$ 247.08 178.87 \$ 277.71 109.82 \$ 180.44 152.84 \$ 241.71 152.84 \$ 241.71 195.86 \$ 302.98 238.88 \$ 364.25 281.90 \$ 425.52 364.78 \$ 367.94 5 367.94 \$ 548.05 5 229.82 \$ 335.51	Distribution BGS and C	- - - - - - - - - -	Total Difference (\$) \$ (16.80) \$ (25.20) \$ (33.60) \$ (42.00) \$ (50.39) \$ (58.79) \$ (67.19) \$ (67.19) \$ (67.19) \$ (67.19) \$ (67.19) \$ (67.19) \$ (67.19) \$ (67.19) \$ (67.19) \$ (67.19) \$ (67.19) \$ (67.19) \$ (67.19) \$ (67.19)	Total <u>Difference</u> (%) -15.2% -16.8% -17.8% -18.4% -18.9% -19.5% -19.5% -15.7% -17.3% -18.2%
(kW) (%) (kWh) Dist kW Trans kW D Demand D Energy (\$) 5 20 730 5.00 2 8.28 \$ 3.505 \$ 60.89 \$ 49.81 \$ 110.70 \$ 8.28 \$ 18.25 \$ 44.09 \$ 5 30 1,095 5.00 2 8.28 \$ 52.57 \$ 78.41 \$ 71.32 \$ 149.74 \$ 8.28 \$ 27.37 \$ 53.22 \$ 5 40 1,460 5.00 2 8.28 \$ 70.09 \$ 95.94 \$ 92.83 \$ 188.77 \$ 8.28 \$ 36.50 \$ 62.34 \$ 5 5 1,4825 5.00 2 8.28 \$ 76.22 \$ 113.46 \$ 113.46 \$ 114.34 \$ 227.80 \$ 8.28 \$ 45.62 \$ 71.47 \$ 8.28 \$ 45.62 \$ 71.47 \$ 60.24 \$ 60.24 \$ 60.24 \$ 60.24 \$ 60.24 \$ 80.59 \$ 8.28 \$ 44.09 \$ 82.8 \$ 45.62 \$ 71.47 \$ 60.24 \$ 60.24 \$ 80.59 \$ 80.59	(\$) (\$) (\$) 49.81 \$ 93.91 71.32 \$ 124.54 92.83 \$ 155.17 5 114.34 \$ 185.81 135.85 \$ 216.44 157.36 \$ 247.08 178.87 \$ 277.71 109.82 \$ 180.44 152.84 \$ 241.71 195.86 \$ 302.98 238.88 \$ 364.25 241.90 \$ 425.52 324.92 \$ 486.78 367.94 \$ 548.05 5 229.82 \$ 335.51	(\$) \$ \$ (16.80) \$ \$ (25.20) \$ \$ (33.60) \$ \$ \$ (42.00) \$ \$ (50.39) \$ \$ (50.39) \$ \$ (50.39) \$ \$ (67.19) \$ \$ (33.60) \$ \$ (50.39) \$ \$ (67.19) \$ \$ (33.90) \$ \$ (67.19) \$ \$ (83.99) \$ \$ (100.79) \$ \$ (100.79) \$ \$ (117.59) \$	(\$) - - - - - - - - - - - - - - - - - - -	\$ (16.80) \$ (25.20) \$ (33.60) \$ (42.00) \$ (50.39) \$ (58.79) \$ (67.19) \$ (50.39) \$ (67.19)	-15.2% -16.8% -17.8% -18.4% -18.9% -19.2% -19.5% -15.7% -17.3%
5 20 730 5.00 2 8.28 \$ 3.505 \$ 60.89 \$ 49.81 \$ 110.70 \$ 8.28 \$ 110.70 \$ 8.28 \$ 140.09 \$ 50.00 2 \$ 8.28 \$ 52.57 \$ 78.41 \$ 71.32 \$ 149.74 \$ 8.28 \$ 27.37 \$ 53.22 \$ 52.23 \$ 50.00 \$ 8.28 \$ 70.09 \$ 95.94 \$ 92.83 \$ 188.77 \$ 8.28 \$ 36.50 \$ 62.24 \$ 62.24 \$ 50.00 \$ 8.28 \$ 70.09 \$ 95.94 \$ 92.83 \$ 188.77 \$ 8.28 \$ 36.50 \$ 62.24 \$ 62.24 \$ 71.47 \$ 8.28 \$ 36.50 \$ 62.24 \$ 71.47 \$ 8.28 \$ 46.62 \$ 71.47 \$ 8.28 \$ 45.62 \$ 71.47 \$ 8.28 \$ 45.62 \$ 71.47 \$ 8.28 \$ 66.84 \$ 82.8 \$ 66.84 \$ 82.8 \$ 65.75 \$ 80.59 \$ 57.00 \$ 8.28 \$ 66.84 \$ 82.8 \$ 66.84 \$ 82.8 \$ 66.84 \$ 82.8 \$ 66.84 \$ 82.8 \$ 63.87 \$ 80.91 \$ 82.8 \$ 63.87 \$ 80.71 \$ 80.91 \$ 82.8 <	\$ 49.81 \$ 93.91 \$ 71.32 \$ 124.54 \$ 92.83 \$ 155.17 \$ 144.54 \$ 185.81 \$ 155.17 \$ 145.81 \$ 124.54 \$ 185.81 \$ 157.36 \$ 247.08 \$ 178.87 \$ 277.71 \$ 109.82 \$ 180.44 \$ 152.84 \$ 241.71 \$ 195.86 \$ 302.98 \$ 238.88 \$ 364.25 \$ 281.90 \$ 425.52 \$ 324.92 \$ 486.78 \$ 367.94 \$ 548.05 \$ 229.82 \$ 335.51	\$ (16.80) \$ (25.20) \$ (25.		\$ (16.80) \$ (25.20) \$ (33.60) \$ (42.00) \$ (50.39) \$ (67.19) \$ (33.60) \$ (50.39) \$ (67.19)	-15.2% -16.8% -17.8% -18.4% -18.9% -19.2% -19.5% -15.7% -17.3%
5 30 1,095 5,00 2 \$ 8,28 \$ 70.09 \$ 95.94 \$ 92.83 \$ 149.74 \$ 8,28 \$ 27.37 \$ 53.22 \$ 5 5 40 1,460 5,00 2 \$ 8,28 \$ 70.09 \$ 95.94 \$ 92.83 \$ 188.77 \$ 8,28 \$ 36.50 \$ 62.34 \$ 62.34 \$ 60 \$ 2,190 5,00 2 \$ 8,28 \$ 113.46 \$ 113.46 \$ 114.34 \$ 227.80 \$ 8,28 \$ 45.62 \$ 71.47 \$ 80.59 \$ 60 2,190 5,00 2 \$ 8,28 \$ 105.14 \$ 130.98 \$ 135.85 \$ 266.84 \$ 8.28 \$ 45.62 \$ 71.47 \$ 80.59 \$ 82.8 \$ 60.59 \$ 80.59 \$ 82.8 \$ 60.59 \$ 80.59 \$ 82.8 \$ 63.87 \$ 80.59 \$ 80.59 \$ 82.8 \$ 63.87 \$ 80.59 \$ 82.8 \$ 63.87 \$ 80.59 \$ 82.8 \$ 60.59 \$ 82.8 \$ 60.59 \$ 80.59 \$ 82.8 \$ 60.59 \$ 80.59 \$ 82.8 \$ 80.59 \$ 80.59 \$ 82.8 \$ 60.59 \$ 80.59 <td>71.32 \$ 124.54 92.83 \$ 155.17 114.34 \$ 185.81 138.85 \$ 216.44 157.36 \$ 247.08 178.87 \$ 277.71 109.82 \$ 180.44 152.84 \$ 241.71 195.86 \$ 302.98 238.88 \$ 364.25 281.90 \$ 425.52 34.92 \$ 486.78 367.94 \$ 548.05 5 229.82 \$ 335.51</td> <td>\$\ (25.20) \$\ (33.60) \$\ (42.00) \$\ (50.39) \$\ (67.19) \$\ (67.19) \$\ (67.19) \$\ (63.39) \$\ (67.19) \$\ (63.39) \$\ (67.19) \$\ (60.39) \$\ (67.19) \$\ (60.39) \$\ (67.19) \$\ (100.79) \$\ (100.79) \$\ (117.59) \$\ (117.59) \$\ \$\ (117.59) \$\ \$\ (117.59) \$\ \$\ (117.59) \$\ \$\ (117.59) \$\ \$\ (117.59) \$\ \$\ (117.59) \$\ \$\ (117.59) \$\ \$\ (117.59) \$\ \$\ (117.59) \$\ (11</td> <td>- - - - - - - - - -</td> <td>\$ (25.20) \$ (33.60) \$ (42.00) \$ (50.39) \$ (67.19) \$ (33.60) \$ (50.39) \$ (67.19)</td> <td>-16.8% -17.8% -18.4% -18.9% -19.2% -19.5% -15.7% -17.3%</td>	71.32 \$ 124.54 92.83 \$ 155.17 114.34 \$ 185.81 138.85 \$ 216.44 157.36 \$ 247.08 178.87 \$ 277.71 109.82 \$ 180.44 152.84 \$ 241.71 195.86 \$ 302.98 238.88 \$ 364.25 281.90 \$ 425.52 34.92 \$ 486.78 367.94 \$ 548.05 5 229.82 \$ 335.51	\$\ (25.20) \$\ (33.60) \$\ (42.00) \$\ (50.39) \$\ (67.19) \$\ (67.19) \$\ (67.19) \$\ (63.39) \$\ (67.19) \$\ (63.39) \$\ (67.19) \$\ (60.39) \$\ (67.19) \$\ (60.39) \$\ (67.19) \$\ (100.79) \$\ (100.79) \$\ (117.59) \$\ (117.59) \$\ \$\ (117.59) \$\ \$\ (117.59) \$\ \$\ (117.59) \$\ \$\ (117.59) \$\ \$\ (117.59) \$\ \$\ (117.59) \$\ \$\ (117.59) \$\ \$\ (117.59) \$\ \$\ (117.59) \$\ (11	- - - - - - - - - -	\$ (25.20) \$ (33.60) \$ (42.00) \$ (50.39) \$ (67.19) \$ (33.60) \$ (50.39) \$ (67.19)	-16.8% -17.8% -18.4% -18.9% -19.2% -19.5% -15.7% -17.3%
5 50 1,825 5,00 2 \$ 8,28 \$ 87,62 \$ 113,46 \$ 114,34 \$ 227,80 \$ 8,28 \$ 45,62 \$ 71,47 \$ 5 60 2,190 5,00 2 \$ 8,28 \$ 105,14 \$ 130,98 \$ 133,85 \$ 266,84 \$ 8,28 \$ 45,62 \$ 71,47 \$ 80,59 \$ 8,28 \$ 45,62 \$ 71,47 \$ 80,59 \$ 8,28 \$ 45,62 \$ 71,47 \$ 80,59	114.34 \$ 185.81 135.85 \$ 216.44 157.36 \$ 247.08 178.87 \$ 247.08 178.87 \$ 277.71 5 109.82 \$ 180.44 152.84 \$ 241.71 \$ 195.66 \$ 302.98 \$ 364.25 \$ 281.90 \$ 425.52 \$ 324.92 \$ 486.78 \$ 367.94 \$ 548.05 \$ 367.94 \$ 548.05 \$ 229.82 \$ 335.51	\$ (42.00) \$ \$ (50.39) \$ \$ (67.19) \$ \$ (50.39) \$ \$ (67.19) \$ \$ (50.39) \$ \$ (67.19) \$ \$ (33.60) \$ \$ (67.19) \$ \$ (30.07) \$ \$ (100.79) \$ \$ (110.79) \$ \$ (110.79) \$ \$ (117.59) \$ \$ \$ (117.59) \$ \$ \$ (117.59) \$ \$ (117.59) \$ \$ (117.59) \$ \$ (117.59) \$ \$ (117.59) \$ \$ (117.59) \$ \$ (117.59) \$ \$ (117.59) \$ \$ (117.59) \$ \$ (117.59)	- - - - - - -	\$ (42.00) \$ (50.39) \$ (58.79) \$ (67.19) \$ (33.60) \$ (50.39) \$ (67.19)	-18.4% -18.9% -19.2% -19.5% -15.7% -17.3%
5 60 2,190 5,00 2 \$ 8.28 \$ 105,14 \$ 130,98 \$ 135,85 \$ 266,84 \$ 8.28 \$ 64,75 \$ 80,59 \$ 5 5 70 2,555 5,00 2 \$ 8.28 \$ 122,66 \$ 166,03 \$ 157,36 \$ 305,87 \$ 8.28 \$ 63,87 \$ 89,71 \$ 82,8 \$ 73,00 \$ 98,84 \$ 10,00 \$ 178,87 \$ 344,90 \$ 8.28 \$ 73,00 \$ 98,84 \$ 70,62 \$ 10,00 \$ 16,57 \$ 105,14 \$ 10,00 \$ 10,00 \$ 16,57 \$ 105,14 \$ 10,00 \$ 10,00 \$ 16,57 \$ 105,14 \$ 139,27 \$ 152,84 \$ 292,10 \$ 16,57 \$ 54,75 \$ 88,87 \$ 88,87 \$ 88,87 \$ 90,62 \$ 70,62 \$ 10,00 \$ 16,57 \$ 105,14 \$ 139,27 \$ 152,84 \$ 292,10 \$ 16,57 \$ 54,75 \$ 88,87 \$ 88,87 \$ 88,87 \$ 10,00 \$ 16,57 \$ 10,00 \$ 17,524 \$ 209,36 \$ 195,86 \$ 370,17 \$ 16,57 \$ 10,752,44 \$ 209,36 \$ 238,88 \$ 448,24 \$	135.85 \$ 216.44 157.36 \$ 247.08 178.87 \$ 277.71 109.82 \$ 180.44 152.84 \$ 241.71 195.86 \$ 302.98 238.88 \$ 364.25 281.90 \$ 425.52 324.92 \$ 486.78 367.94 \$ 548.05 5 229.82 \$ 353.51	\$ (50.39) \$ (58.79) \$ (58.79) \$ (58.79) \$ (58.79) \$ (50.39) \$ \$ (67.19) \$ \$ (67.19) \$ \$ (67.19) \$ \$ (67.19) \$ \$ (100.79) \$ \$ (110.79) \$ \$ (111.759) \$	- - - - - -	\$ (50.39) \$ (58.79) \$ (67.19) \$ (33.60) \$ (50.39) \$ (67.19)	-18.9% -19.2% -19.5% -15.7% -17.3%
5 70 2,555 5.00 2 \$ 8.28 \$ 122.66 \$ 148.51 \$ 157.36 \$ 305.87 \$ 8.28 \$ 63.87 \$ 89.71 \$ 89.71 \$ 157.36 \$ 305.87 \$ 8.28 \$ 63.87 \$ 89.71 \$ 89.71 \$ 157.36 \$ 305.87 \$ 8.28 \$ 63.87 \$ 89.71 \$ 89.71 \$ 157.36 \$ 305.87 \$ 8.28 \$ 63.87 \$ 89.71 \$ 89.71 \$ 10.22 \$ 10.22 \$ 10.22 \$ 10.22 \$ 10.22 \$ 10.42	157.36 \$ 247.08 178.87 \$ 277.71 109.82 \$ 180.44 152.84 \$ 241.71 195.86 \$ 302.98 238.88 \$ 364.25 6 281.90 \$ 425.52 349.22 \$ 486.78 367.94 \$ 548.05 229.82 \$ 335.51	\$ (58.79) \$ \$ (67.19) \$ \$ (33.60) \$ \$ (50.39) \$ \$ (67.19) \$ \$ (83.99) \$ \$ (100.79) \$ \$ (117.59) \$	- - - - -	\$ (58.79) \$ (67.19) \$ (33.60) \$ (50.39) \$ (67.19)	-19.2% -19.5% -15.7% -17.3%
5 80 2.920 5.00 2 \$ 8.28 \$ 140.19 \$ 166.03 \$ 178.87 \$ 344.90 \$ 8.28 \$ 73.00 \$ 98.84 \$ 10 20 1,460 10.00 7 \$ 16.57 \$ 70.09 \$ 104.22 \$ 109.82 \$ 214.04 \$ 16.57 \$ 36.50 \$ 70.62<	178.87 \$ 277.71 109.82 \$ 180.44 5 152.84 \$ 241.71 195.86 \$ 302.98 238.88 \$ 364.25 5 281.90 \$ 425.52 5 324.92 \$ 486.78 367.94 \$ 548.05 5 229.82 \$ 335.51	\$ (67.19) \$ \$ (33.60) \$ \$ (50.39) \$ \$ (67.19) \$ \$ (83.99) \$ \$ (100.79) \$ \$ (117.59) \$	-	\$ (67.19) \$ (33.60) \$ (50.39) \$ (67.19)	-19.5% -15.7% -17.3%
10 20 1,460 10.00 7 \$ 16.57 \$ 70.09 \$ 104.22 \$ 109.82 \$ 214.04 \$ 16.57 \$ 36.50 \$ 70.62 \$ 10 30 2,190 10.00 7 \$ 16.57 \$ 105.14 \$ 139.27 \$ 152.84 \$ 292.10 \$ 16.57 \$ 36.50 \$ 70.62 \$ 88.87 \$ 10 40 2,920 10.00 7 \$ 16.57 \$ 140.19 \$ 174.31 \$ 195.86 \$ 370.17 \$ 16.57 \$ 73.00 \$ 107.12 \$ 10.00 7 \$ 16.57 \$ 140.19 \$ 174.31 \$ 298.88 \$ 448.24 \$ 16.57 \$ 91.24 \$ 125.37 \$ 10 \$ 60 4,380 10.00 7 \$ 16.57 \$ 210.28 \$ 244.41 \$ 281.90 \$ 562.30 \$ 16.57 \$ 109.49 \$ 143.62 \$ 10 7 5,110 10.00 7 \$ 16.57 \$ 245.33 \$ 279.46 \$ 324.92 \$ 604.37 \$ 16.57 \$ 145.99 \$ 180.12 \$ 10 8 682.44 \$ 16.57 \$ 145.99 \$ 180.12 \$ 10 8 682.44 \$ 16.57 \$ 145.99 </td <td>109.82 \$ 180.44 152.84 \$ 241.71 195.86 \$ 302.98 5 238.88 \$ 364.25 5 281.90 \$ 425.52 6 324.92 \$ 486.78 367.94 \$ 548.05 5 229.82 \$ 335.51</td> <td>\$ (33.60) \$ \$ (50.39) \$ \$ (67.19) \$ \$ (83.99) \$ \$ (100.79) \$ \$ (117.59) \$</td> <td>- - -</td> <td>\$ (33.60) \$ (50.39) \$ (67.19)</td> <td>-15.7% -17.3%</td>	109.82 \$ 180.44 152.84 \$ 241.71 195.86 \$ 302.98 5 238.88 \$ 364.25 5 281.90 \$ 425.52 6 324.92 \$ 486.78 367.94 \$ 548.05 5 229.82 \$ 335.51	\$ (33.60) \$ \$ (50.39) \$ \$ (67.19) \$ \$ (83.99) \$ \$ (100.79) \$ \$ (117.59) \$	- - -	\$ (33.60) \$ (50.39) \$ (67.19)	-15.7% -17.3%
10 30 2,190 10.00 7 \$ 16.57 \$ 105.14 \$ 139.27 \$ 152.84 \$ 292.10 \$ 16.57 \$ 54.75 \$ 88.87 \$ 10.00 10 40 2,920 10.00 7 \$ 16.57 \$ 175.24 \$ 209.36 \$ 238.88 \$ 448.24 \$ 16.57 \$ 73.00 \$ 107.12 \$ 16.57 \$ 175.24 \$ 209.36 \$ 238.88 \$ 448.24 \$ 16.57 \$ 10.24 \$ 10.00 \$ 16.57 \$ 10.57 \$ 10.00 \$ 16.57 \$ 10.57 \$ 245.37 \$ 244.41 \$ 281.90 \$ 526.30 \$ 16.57 \$ 10.94 \$ 143.62 \$ 10.00 \$ 10.00 7 \$ 16.57 \$ 245.33 \$ 279.46 \$ 324.92 \$ 604.37 \$ 16.57 \$ 127.74 \$ 161.87 10 80 5,840 10.00 7 \$ 16.57 \$ 245.33 \$ 314.50 \$ 367.94 \$ 682.44 \$ 16.57 \$ 145.99 \$ 180.12 \$ 180.12	5 152.84 \$ 241.71 195.86 \$ 302.98 5 238.88 \$ 364.25 281.90 \$ 425.52 5 324.92 \$ 486.78 6 367.94 \$ 548.05 5 229.82 \$ 353.51	\$ (50.39) \$ \$ (67.19) \$ \$ (83.99) \$ \$ (100.79) \$ \$ (117.59) \$	- - -	\$ (50.39) \$ (67.19)	-17.3%
10 40 2.920 10.00 7 \$ 16.57 \$ 140.19 \$ 174.31 \$ 195.86 \$ 370.17 \$ 16.57 \$ 73.00 \$ 107.12 \$ 10.71 \$ 16.57 \$ 16.57 \$ 175.24 \$ 209.36 \$ 238.88 \$ 448.24 \$ 16.57 \$ 91.24 \$ 125.37 \$ 10.00 \$ 16.57 \$ 10.24 \$ 125.37 \$ 125.37 \$ 10.00 \$ 16.57 \$ 210.28 \$ 244.41 \$ 281.90 \$ 526.30 \$ 16.57 \$ 10.49 \$ 143.62 \$ 143.62 \$ 143.62 \$ 10.00 \$ 16.57 \$ 245.33 \$ 279.46 \$ 324.92 \$ 604.37 \$ 16.57 \$ 127.74 \$ 161.87 \$ 10.00 \$ 314.50 \$ 367.94 \$ 682.44 \$ 16.57 \$ 145.99 \$ 810.12 \$ 10.00 \$ 10.00 \$ 10.57 \$ 200.38 \$ 314.50 \$ 367.94 \$ 682.44 \$ 16.57 \$ 145.99 \$ 810.12 \$ 10.00 \$ 10.00 \$ 10.00 \$ 10.00 \$ 10.00 \$ 10.00 \$ 10.00 \$ 10.00 \$ 10.00 \$ 10.00 \$ 10.00 \$ 10.00 \$ 10.00 \$ 10.00 \$ 10.00 \$ 10.00	195.86 \$ 302.98 238.88 \$ 364.25 5 281.90 \$ 425.52 6 324.92 \$ 486.78 367.94 \$ 548.05 5 229.82 \$ 353.51	\$ (67.19) \$ \$ (83.99) \$ \$ (100.79) \$ \$ (117.59) \$	-	\$ (67.19)	
10 60 4,380 10.00 7 \$ 16.57 \$ 240.28 \$ 244.41 \$ 281.90 \$ 526.30 \$ 16.57 \$ 109.49 \$ 143.62 \$ 10 70 5,110 10.00 7 \$ 16.57 \$ 245.33 \$ 279.46 \$ 324.92 \$ 604.37 \$ 16.57 \$ 127.74 \$ 161.87 \$ 10 80 5,840 10.00 7 \$ 16.57 \$ 280.38 \$ 314.50 \$ 367.94 \$ 682.44 \$ 16.57 \$ 145.99 \$ 180.12 \$	281.90 \$ 425.52 324.92 \$ 486.78 6 367.94 \$ 548.05 5 229.82 \$ 353.51	\$ (100.79) \$ \$ (117.59) \$		\$ (83.00)	
10 70 5,110 10.00 7 \$ 16.57 \$ 245.33 \$ 279.46 \$ 324.92 \$ 604.37 \$ 16.57 \$ 127.74 \$ 161.87 \$ 10 80 5,840 10.00 7 \$ 16.57 \$ 280.38 \$ 314.50 \$ 367.94 \$ 682.44 \$ 16.57 \$ 145.99 \$ 180.12 \$	324.92 \$ 486.78 367.94 \$ 548.05 229.82 \$ 353.51	\$ (117.59) \$	-		-18.7%
10 80 5,840 10.00 7 \$ 16.57 \$ 280.38 \$ 314.50 \$ 367.94 \$ 682.44 \$ 16.57 \$ 145.99 \$ 180.12 \$	367.94 \$ 548.05 5 229.82 \$ 353.51			\$ (100.79)	-19.2%
	229.82 \$ 353.51	¢ (12/120) ¢	-	\$ (117.59)	-19.5%
1 20 20 2,920 20,00 17 \$ 33,13 \$ 140,19 \$ 190,88 \$ 229,82 \$ 420,70 \$ 33.13 \$ 73.00 \$ 123.69 \$				\$ (134.39)	-19.7%
		\$ (67.19) \$		\$ (67.19)	-16.0%
20 30 4,380 20,00 17 \$ 33.13 \$ 210.28 \$ 260.98 \$ 315.86 \$ 576.84 \$ 33.13 \$ 109.49 \$ 160.19 \$ 20 40 5,840 20,00 17 \$ 33.13 \$ 209.38 \$ 331.07 \$ 401.90 \$ 732.97 \$ 33.13 \$ 145.99 \$ 196.68		\$ (100.79) \$ \$ (134.39) \$		\$ (100.79) \$ (134.39)	-17.5% -18.3%
20 40 5,040 20,00 17 \$ 33.13 \$ 350.47 \$ 401.16 \$ 487.94 \$ 889.11 \$ 33.13 \$ 182.49 \$ 233.18 \$		\$ (167.98) \$		\$ (167.98)	-18.9%
20 60 8.760 20.00 17 \$ 33.13 \$ 420.56 \$ 471.26 \$ 573.98 \$ 1.045.24 \$ 33.13 \$ 218.99 \$ 269.68 \$	573.98 \$ 843.66	\$ (201.58) \$	_	\$ (201.58)	-19.3%
20 70 10,220 20.00 17 \$ 33.13 \$ 490.66 \$ 541.35 \$ 660.02 \$ 1,201.37 \$ 33.13 \$ 255.48 \$ 306.18 \$		\$ (235.18) \$	-	\$ (235.18)	-19.6%
20 80 11,680 20.00 17 \$ 33.13 \$ 560.75 \$ 611.45 \$ 746.06 \$ 1,357.51 \$ 33.13 \$ 291.98 \$ 342.67 \$	746.06 \$ 1,088.74	\$ (268.77) \$	-	\$ (268.77)	-19.8%
30 20 4,380 30.00 27 \$ 49.70 \$ 210.28 \$ 277.54 \$ 349.83 \$ 627.37 \$ 49.70 \$ 109.49 \$ 176.75 \$		\$ (100.79) \$	-	\$ (100.79)	-16.1%
30 30 6,570 30.00 27 \$ 49.70 \$ 315.42 \$ 382.68 \$ 478.89 \$ 861.57 \$ 49.70 \$ 164.24 \$ 231.50 \$		\$ (151.18) \$		\$ (151.18)	-17.5%
30 40 8,760 30.00 27 \$ 49.70 \$ 420.56 \$ 487.82 \$ 607.95 \$ 1,095.77 \$ 49.70 \$ 218.99 \$ 286.25 \$		\$ (201.58) \$		\$ (201.58)	-18.4%
30 50 10,950 30.00 27 \$ 49.70 \$ 525.71 \$ 592.97 \$ 737.01 \$ 1,329.97 \$ 49.70 \$ 273.73 \$ 340.99 \$,	\$ (251.97) \$		\$ (251.97)	-18.9%
30 60 13,140 30,00 27 \$ 49,70 \$ 630,85 \$ 698,11 \$ 866,07 \$ 1,564,17 \$ 49,70 \$ 328,48 \$ 395,74 \$ 30 70 15,330 30,00 27 \$ 49,70 \$ 735,99 \$ 803,25 \$ 995,13 \$ 1,798,38 \$ 49,70 \$ 383,22 \$ 450,48		\$ (302.37) \$ \$ (352.76) \$		\$ (302.37) \$ (352.76)	-19.3% -19.6%
30 80 17.520 30.00 27 \$ 49.70 \$ 841.13 \$ 908.39 \$ 1.124.19 \$ 2.032.58 \$ 49.70 \$ 437.97 \$ 505.23		\$ (403.16) \$		\$ (403.16)	-19.8%
50 20 7.300 50.00 47 \$ 82.83 \$ 350.47 \$ 450.86 \$ 589.84 \$ 1.040.71 \$ 82.83 \$ 182.49 \$ 282.88 \$		\$ (167.98) \$		\$ (167.98)	-16.1%
50 30 10,950 50.00 47 \$ 82.83 \$ 525.71 \$ 626.10 \$ 804.94 \$ 1,431.04 \$ 82.83 \$ 273.73 \$ 374.13 \$	804.94 \$ 1,179.07	\$ (251.97) \$	-	\$ (251.97)	-17.6%
50 40 14,600 50.00 47 \$ 82.83 \$ 700.94 \$ 801.33 \$ 1,020.04 \$ 1,821.38 \$ 82.83 \$ 364.98 \$ 465.37 \$	1,020.04 \$ 1,485.41	\$ (335.97) \$	-	\$ (335.97)	-18.4%
50 50 18,250 50.00 47 \$ 82.83 \$ 876.18 \$ 976.57 \$ 1,235.14 \$ 2,211.71 \$ 82.83 \$ 456.22 \$ 556.61 \$	1,235.14 \$ 1,791.75	\$ (419.96) \$	-	\$ (419.96)	-19.0%
50 60 21,900 50.00 47 \$ 82.83 \$ 1,051.41 \$ 1,151.81 \$ 1,450.24 \$ 2,602.04 \$ 82.83 \$ 547.46 \$ 647.86 \$, + =,	\$ (503.95) \$		\$ (503.95)	-19.4%
50 70 25,550 50.00 47 \$ 82,83 \$ 1,226,65 \$ 1,327,04 \$ 1,665,34 \$ 2,992,38 \$ 82,83 \$ 638,71 \$ 739,10 \$ 50 80 29,200 50,00 47 \$ 82,83 \$ 1,401,88 \$ 1,502,28 \$ 1,880,44 \$ 3,382,71 \$ 82,83 \$ 729,95 \$ 830,34		\$ (587.94) \$ \$ (671.93) \$		\$ (587.94) \$ (671.93)	-19.6% -19.9%
50 80 29,200 50.00 47 \$ 82.83 \$ 1,401.88 \$ 1,502.28 \$ 1,880.44 \$ 3,382.71 \$ 82.83 \$ 729.95 \$ 830.34 \$ 75.00 72 \$ 124.25 \$ 788.56 \$ 930.37 \$ 121.251 \$ 2,142.88 \$ 124.25 \$ 410.60 \$ 552.41 \$		\$ (671.93) \$ \$ (377.96) \$		\$ (671.93) \$ (377.96)	-17.6%
75 40 21,900 75.00 72 \$124.25 \$ 1,051.41 \$ 1,193.22 \$ 1,535.16 \$ 2,728.38 \$ 124.25 \$ \$47.46 \$ 689.27 \$		\$ (503.95) \$		\$ (503.95)	-18.5%
75 50 27,375 75.00 72 \$124.25 \$ 1,314.26 \$ 1,456.07 \$ 1,857.81 \$ 3,313.88 \$ 124.25 \$ 684.33 \$ 826.14 \$		\$ (629.94) \$	-	\$ (629.94)	-19.0%
75 60 32,850 75.00 72 \$124.25 \$ 1,577.12 \$ 1,718.93 \$ 2,180.45 \$ 3,899.38 \$ 124.25 \$ 821.20 \$ 963.01 \$		\$ (755.92) \$	-	\$ (755.92)	-19.4%
75 70 38,325 75.00 72 \$124.25 \$ 1,839.97 \$ 1,981.78 \$ 2,503.10 \$ 4,484.88 \$ 124.25 \$ 958.06 \$ 1,099.87 \$	_,	\$ (881.91) \$	-	\$ (881.91)	-19.7%
75 80 43,800 75.00 72 \$124.25 \$ 2,102.82 \$ 2,244.63 \$ 2,825.75 \$ 5,070.39 \$ 124.25 \$ 1,094.93 \$ 1,236.74 \$	_, , ,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,	\$ (1,007.90) \$		\$ (1,007.90)	-19.9%
75 90 49,275 75,00 72 \$124,25 \$ 2,565,68 \$ 2,507.49 \$ 3,148.40 \$ 5,655.89 \$ 124.25 \$ 1,231.79 \$ 1,373.60 \$		\$ (1,133.88) \$		\$ (1,133.88)	-20.0%
100 30 21,900 100.00 97 \$165.67 \$ 1,051.41 \$ 1,234.64 \$ 1,620.07 \$ 2,854.71 \$ 165.67 \$ 547.46 \$ 730.69 \$ 100 40 29,200 100.00 97 \$165.67 \$ 1,401.88 \$ 1,585.11 \$ 2,050.27 \$ 3,635.38 \$ 165.67 \$ 729.95 \$ 913.18	1,620.07 \$ 2,350.76	\$ (503.95) \$		\$ (503.95)	-17.7% -18.5%
100 40 29,200 100.00 97 \$165.67 \$ 1,401.88 \$ 1,585.11 \$ 2,050.27 \$ 3,635.38 \$ 165.67 \$ 729.95 \$ 913.18 \$ 100 50 36.500 100.00 97 \$165.67 \$ 1,782.35 \$ 1,935.58 \$ 2,480.47 \$ 4,416.05 \$ 165.67 \$ 912.44 \$ 1,095.67	\$ 2,050.27 \$ 2,963.45 \$ 2,480.47 \$ 3,576.14	\$ (671.93) \$ \$ (839.91) \$		\$ (671.93) \$ (839.91)	-18.5% -19.0%
100 50 50,500 100.00 97 \$165.67 \$1,752.53 \$1,253.56 \$2,910.67 \$5,196.72 \$165.67 \$1,095.07 \$1,095	1 11 11 11 11	\$ (1,007.90) \$	-	\$ (1,007.90)	-19.4%
100 70 51,100 100.00 97 \$165.67 \$ 2,453.29 \$ 2,656.52 \$ 3,340.87 \$ 5,977.39 \$ 165.67 \$ 1,7741 \$ 1,460.64 \$		\$ (1,175.88) \$		\$ (1,175.88)	-19.7%
100 80 58,400 100.00 97 \$165.67 \$ 2,803.76 \$ 2,986.99 \$ 3,771.07 \$ 6,758.06 \$ 165.67 \$ 1,459.90 \$ 1,643.13 \$		\$ (1,343.86) \$		\$ (1,343.86)	-19.9%
100 90 65,700 100.00 97 \$165.67 \$ 3,154.24 \$ 3,337.46 \$ 4,201.27 \$ 7,538.73 \$ 165.67 \$ 1,642.39 \$ 1,825.62 \$,,	\$ (1,511.84) \$	-	\$ (1,511.84)	-20.1%
200 30 43,800 200.00 197 \$331.33 \$ 2,102.82 \$ 2,451.72 \$ 3,250.34 \$ 5,702.05 \$ 331.33 \$ 1,094.93 \$ 1,443.82 \$	-,	\$ (1,007.90) \$	-	\$ (1,007.90)	-17.7%
200 40 58,400 200.00 197 \$331.33 \$ 2,803.76 \$ 3,152.66 \$ 4,110.73 \$ 7,263.39 \$ 331.33 \$ 1,459.90 \$ 1,808.80 \$	1,110.70 \$ 0,010.00	\$ (1,343.86) \$		\$ (1,343.86)	-18.5%
200 50 73,000 200,00 197 \$331,33 \$3,504,71 \$3,853,60 \$4,971,13 \$8,824,73 \$331,33 \$1,824,88 \$2,173,77 \$		\$ (1,679.83) \$		\$ (1,679.83)	-19.0%
200 60 87,600 200.00 197 \$331.33 \$ 4,205.65 \$ 4,554.54 \$ 5,831.53 \$ 10,386.07 \$ 331.33 \$ 2,189.85 \$ 2,538.75 \$ 200 70 102.200 200.00 197 \$331.33 \$ 4,906.59 \$ 5,255.48 \$ 6,891.93 \$11.947.41 \$ 331.33 \$ 2,554.83 \$ 2,903.72		\$ (2,015.79) \$ \$ (2,351.76) \$		\$ (2,015.79) \$ (2,351.76)	-19.4% -19.7%
200 80 118,800 200.00 197 \$31:33 \$ 1,900.09 \$ 0,250.40 \$ 0,091:35 \$ 11,947.41 \$ 351:35 \$ 2,905.65 \$ 2,905.72 \$ 200 80 118,800 200.00 197 \$331:33 \$ 5,607.55 \$ 5,956.42 \$ 7,552.32 \$ 13,508.75 \$ 331:33 \$ 2,919.81 \$ 3,268.70 \$		\$ (2,687.72) \$		\$ (2,687.72)	-19.7%
200 90 131,400 200.00 197 \$331.33 \$ 6.308.47 \$ 6.657.36 \$ 8.412.72 \$ 15.070.08 \$ 331.33 \$ 3.284.78 \$ 3.633.67 \$		\$ (3.023.69) \$		\$ (3.023.69)	-20.1%

ATLANTIC CITY ELECTRIC COMPANY ANNUAL GENERAL SERVICE SECONDARY ("AGS Secondary") 8 WINTER MONTHS (October Through May)

Present Rates

vs. Proposed Rates

	Proposed Rates																	
	Load	_					Present	Present	Present			New	New	New	Difference	Difference	Total	Total
Demand (kW)	(%)	Energy (kWh)	Metered kW Bi	llod kW	D Demand	D Energy	Distribution (\$)	BGS and Other Charges (\$)	<u>Total</u> (\$)	D Demand	D Energy	Distribution (\$)	BGS and Other Charges (\$)	Total (\$)	Distribution BG (\$)	S and Other Charges (\$)	Difference (\$)	Difference (%)
25	20	3,650	25	25 \$		\$ (10.17)		\$ 482.38		\$ 380.00	\$ (10.17)	\$ 563.05	\$ 482.38 5		\$ 63.00 \$	(\$)	\$ 63.00	6.4%
25	30	5,475	25	25 \$		\$ (15.25)					\$ (15.25)		\$ 652.82		\$ 63.00 \$	-	\$ 63.00	5.5%
25	40	7,300	25	25 \$	317.00	\$ (20.33)	\$ 489.89	\$ 823.26	\$ 1,313.15	\$ 380.00	\$ (20.33)	\$ 552.89	\$ 823.26 \$	1,376.15	\$ 63.00 \$	-	\$ 63.00	4.8%
25	50	9,125	25	25 \$		\$ (25.41)		\$ 993.70			\$ (25.41)		\$ 993.70		\$ 63.00 \$	-	\$ 63.00	4.3%
25	60	10,950	25	25 \$		\$ (30.50)		\$ 1,164.14			\$ (30.50)	\$ 542.72	\$ 1,164.14		\$ 63.00 \$	-	\$ 63.00	3.8%
25	70 80	12,775 14,600	25	25 \$		\$ (35.58)					\$ (35.58) \$ (40.66)	\$ 537.64	\$ 1,334.58 \$ \$ 1,505.02 \$.,	\$ 63.00 \$ \$ 63.00 \$	-	\$ 63.00 \$ 63.00	3.5%
25 50	20	7.300	25 50	25 \$ 50 \$		\$ (40.66) \$ (20.33)		\$ 1,505.02 \$ 964.76			\$ (40.66) \$ (20.33)	\$ 532.56 \$ 932.89	\$ 1,505.02 \$ \$ 964.76 \$		\$ 63.00 \$ \$ 126.00 \$		\$ 126.00	3.2% 7.1%
50	30	10.950	50	50 \$		\$ (30.50)					\$ (20.55)	\$ 922.72			\$ 126.00 \$		\$ 126.00	6.0%
50	40	14.600	50	50 \$		\$ (40.66)		\$ 1.646.52		\$ 760.00	\$ (40.66)	\$ 912.56	\$ 1.646.52		\$ 126.00 \$	_	\$ 126.00	5.2%
50	50	18,250	50	50 \$	634.00	\$ (50.83)	\$ 776.39	\$ 1,987.40	\$ 2,763.80	\$ 760.00	\$ (50.83)	\$ 902.39	\$ 1,987.40	2,889.80	\$ 126.00 \$	-	\$ 126.00	4.6%
50	60	21,900	50	50 \$	634.00	\$ (60.99)	\$ 766.23	\$ 2,328.28	\$ 3,094.51	\$ 760.00	\$ (60.99)	\$ 892.23	\$ 2,328.28 \$		\$ 126.00 \$	-	\$ 126.00	4.1%
50	70	25,550	50	50 \$		\$ (71.16)		\$ 2,669.17			\$ (71.16)		\$ 2,669.17		\$ 126.00 \$	-	\$ 126.00	3.7%
50	80	29,200	50	50 \$		\$ (81.32)		\$ 3,010.05		Ψ 100.00	\$ (81.32)	\$ 871.90	\$ 3,010.05		\$ 126.00 \$	-	\$ 126.00	3.4%
100 100	20 30	14,600 21,900	100 100	100 \$ 100 \$	1,200.00	\$ (40.66) \$ (60.99)		\$ 1,929.52 \$ 2,611.28		* .,	\$ (40.66) \$ (60.99)	\$ 1,672.56 \$ 1,652.23	\$ 1,929.52 \$ \$ 2,611.28 \$		\$ 252.00 \$ \$ 252.00 \$	-	\$ 252.00 \$ 252.00	7.5% 6.3%
100	40	29,200	100		,	\$ (81.32)		\$ 2,011.20		* .,			\$ 3,293,05		\$ 252.00 \$ \$ 252.00 \$	-	\$ 252.00	5.4%
100	50	36.500	100	100 \$				\$ 3,974.81			\$ (101.65)	\$ 1,611.57	\$ 3.974.81		\$ 252.00 \$	_	\$ 252.00	4.7%
100	60	43,800	100			\$ (121.98)		\$ 4,656.57			\$ (121.98)	\$ 1,591.24			\$ 252.00 \$	-	\$ 252.00	4.2%
100	70	51,100	100	100 \$	1,268.00	\$ (142.31)	\$ 1,318.91	\$ 5,338.33	\$ 6,657.24	\$ 1,520.00	\$ (142.31)	\$ 1,570.91	\$ 5,338.33	6,909.24	\$ 252.00 \$	-	\$ 252.00	3.8%
100	80	58,400	100			\$ (162.64)	\$ 1,298.58	\$ 6,020.09		\$ 1,520.00	\$ (162.64)	\$ 1,550.58	\$ 6,020.09		\$ 252.00 \$	-	\$ 252.00	3.4%
300	20	43,800	300	300 \$			\$ 3,875.24	\$ 5,788.57		Ψ 1,000.00	\$ (121.98)	\$ 4,631.24	\$ 5,788.57		\$ 756.00 \$	-	\$ 756.00	7.8%
300	30	65,700	300		-,	\$ (182.97)		\$ 7,833.85				\$ 4,570.25		12,404.10	\$ 756.00 \$	-	\$ 756.00	6.5%
300 300	40 50	87,600 109,500	300 300		.,	\$ (243.97) \$ (304.96)			\$ 13,632.39 \$ 15,616.69		\$ (243.97) \$ (304.96)	\$ 4,509.25 \$ 4,448.26		\$ 14,388.39 \$ 16,372.69	\$ 756.00 \$ \$ 756.00 \$	-	\$ 756.00 \$ 756.00	5.5% 4.8%
300	60	131,400	300			\$ (365.95)			\$ 17,600.98	1 /111111	\$ (365.95)	\$ 4,446.26	\$ 13,969.71		\$ 756.00 \$		\$ 756.00	4.3%
300	70	153,300	300			\$ (426.94)			\$ 19,585.27			\$ 4,326.28		20,341.27	\$ 756.00 \$	_	\$ 756.00	3.9%
300	80	175,200	300			\$ (487.93)			\$ 21,569.57			\$ 4,265.29		22,325.57	\$ 756.00 \$	-	\$ 756.00	3.5%
500	20	73,000	500			\$ (203.31)			\$ 15,977.53			\$ 7,589.92		17,237.53	\$ 1,260.00 \$	-	\$ 1,260.00	7.9%
500	30	109,500	500			\$ (304.96)			\$ 19,284.69			\$ 7,488.26		20,544.69	\$ 1,260.00 \$	-	\$ 1,260.00	6.5%
500	40	146,000	500			\$ (406.61)			\$ 22,591.84	+ .,		\$ 7,386.61	\$ 16,465.23		\$ 1,260.00 \$	-	\$ 1,260.00	5.6%
500 500	50 60	182,500 219,000	500 500		0,010.00	\$ (508.26) \$ (609.92)	\$ 6,024.96 \$ 5,923.31		\$ 25,899.00 \$ 29,206.15	Ψ 1,000.00	\$ (508.26) \$ (609.92)	\$ 7,284.96 \$ 7,183.31		\$ 27,159.00 \$ 30,466.15	\$ 1,260.00 \$ \$ 1,260.00 \$	-	\$ 1,260.00 \$ 1,260.00	4.9% 4.3%
500	70	255,500	500		.,	\$ (609.92)			\$ 29,206.15			\$ 7,163.31		30,466.15	\$ 1,260.00 \$	-	\$ 1,260.00	3.9%
500	80	292.000	500		.,	\$ (813.22)			\$ 35,820.46		\$ (813.22)	\$ 6,980.00		37.080.46	\$ 1,260.00 \$	_	\$ 1,260.00	3.5%
750	30	164.250	750		.,	\$ (457.44)			\$ 28.830.42			\$ 11.135.78		30,720,42	\$ 1.890.00 \$	-	\$ 1,890.00	6.6%
750	40	219,000	750	750 \$	9,510.00	\$ (609.92)	\$ 9,093.31	\$ 24,697.85	\$ 33,791.15	\$ 11,400.00	\$ (609.92)	\$ 10,983.31	\$ 24,697.85	35,681.15	\$ 1,890.00 \$	-	\$ 1,890.00	5.6%
750	50	273,750	750			\$ (762.39)			\$ 38,751.89	\$ 11,400.00				\$ 40,641.89	\$ 1,890.00 \$	-	\$ 1,890.00	4.9%
750	60	328,500	750			\$ (914.87)			\$ 43,712.62			\$ 10,678.35	\$ 34,924.27		\$ 1,890.00 \$	-	\$ 1,890.00	
750	70	383,250	750 750			\$ (1,067.35)			\$ 48,673.35		\$ (1,067.35)			50,563.35	\$ 1,890.00 \$	-	\$ 1,890.00	3.9%
750 750	80 90	438,000 492,750	750 750			\$ (1,219.83) \$ (1,372.31)			\$ 53,634.09 \$ 58,594.82	\$ 11,400.00 \$ 11,400.00		\$ 10,373.39		\$ 55,524.09 \$ 60,484.82	\$ 1,890.00 \$ \$ 1,890.00 \$	-	\$ 1,890.00 \$ 1,890.00	3.5% 3.2%
1000	30	219.000	1.000			\$ (609.92)			\$ 38,376.15		\$ (609.92)			\$ 40.896.15	\$ 2,520.00 \$	-	\$ 2,520.00	6.6%
1000	40	292,000	1,000			\$ (813.22)			\$ 44,990.46			\$ 14,783.31	\$ 32,930.46		\$ 2,520.00 \$		\$ 2,520.00	5.6%
1000	50	365,000	1,000	1,000 \$	12,680.00	\$ (1,016.53)		\$ 39,748.08	\$ 51,604.78	\$ 15,200.00			\$ 39,748.08	54,124.78	\$ 2,520.00 \$		\$ 2,520.00	4.9%
1000	60	438,000	1,000	1,000 \$	12,680.00	\$ (1,219.83)	\$ 11,653.39	\$ 46,565.70	\$ 58,219.09	\$ 15,200.00	\$ (1,219.83)	\$ 14,173.39	\$ 46,565.70	60,739.09	\$ 2,520.00 \$	-	\$ 2,520.00	4.3%
1000	70	511,000	1,000			\$ (1,423.14)			\$ 64,833.40			\$ 13,970.09		67,353.40	\$ 2,520.00 \$	-	\$ 2,520.00	3.9%
1000	80	584,000	1,000			\$ (1,626.44)			\$ 71,447.71			\$ 13,766.78		73,967.71	\$ 2,520.00 \$	-	\$ 2,520.00	
1000	90	657,000	1,000			\$ (1,829.75)			\$ 78,062.02		\$ (1,829.75)		\$ 67,018.54 \$		\$ 2,520.00 \$	-	\$ 2,520.00	3.2%
2000 2000	30 40	438,000 584.000	2,000 2.000			\$ (1,219.83) \$ (1,626.44)			\$ 76,559.09 \$ 89.787.71	\$ 30,400.00 \$ 30,400.00		\$ 29,373.39 \$ 28.966.78	\$ 52,225.70 \$ \$ 65.860.93 \$	\$ 81,599.09 \$ 94.827.71	\$ 5,040.00 \$ \$ 5.040.00 \$	-	\$ 5,040.00 \$ 5.040.00	6.6% 5.6%
2000	50	730,000	2,000			\$ (2,033.05)			\$ 103,016.33			\$ 28,966.78	\$ 79,496,16		\$ 5,040.00 \$ \$ 5,040.00 \$	-	\$ 5,040.00	
2000	60	876.000	2,000			\$ (2,439.66)			\$ 116.244.95	\$ 30,400.00			\$ 93.131.39		\$ 5,040.00 \$		\$ 5,040.00	4.3%
2000		1,022,000	2,000			\$ (2,846.27)			\$ 129,473.57			\$ 27,746.95	\$ 106,766.62		\$ 5,040.00 \$	-	\$ 5,040.00	3.9%
2000	80	1,168,000	2,000			\$ (3,252.88)			\$ 142,702.20	\$ 30,400.00					\$ 5,040.00 \$	-	\$ 5,040.00	3.5%
2000	90	1,314,000	2,000	2,000 \$	25,360.00	\$ (3,659.49)	\$ 21,893.73	\$ 134,037.09	\$ 155,930.82	\$ 30,400.00	\$ (3,659.49)	\$ 26,933.73	\$ 134,037.09	\$ 160,970.82	\$ 5,040.00 \$	-	\$ 5,040.00	3.2%

ATLANTIC CITY ELECTRIC COMPANY ANNUAL GENERAL SERVICE SECONDARY ("AGS Secondary") 4 SUMMER MONTHS (June Through September)

Present Rates

										posed Rates								
	Load						Present	Present	Present			New	New	New	Difference	Difference	Total	Total
Demand		Energy					Distribution	BGS and Other Charges	Total			Distribution	BGS and Other Charges	Total		GS and Other Charges	Difference	Difference
(kW)	20	(kWh) 3.650	Metered kW B 25			D Energy \$ (10.17) 5	(\$)	\$ 490.59	\$ 990.65	D Demand	D Energy \$ (10.17)	(\$) © 563.05	(\$) \$ 490.59 \$	(\$) 1,053.65	(\$) \$ 63.00 \$	(\$)	\$ 63.00	(%) 6.4%
25 25	30	5,475	25 25	25 \$ 25 \$		\$ (10.17) \$ \$ (15.25) \$			\$ 990.65	*	+ ()	\$ 563.05 \$ 557.97			\$ 63.00 \$ \$ 63.00 \$		\$ 63.00	5.4%
25	40	7,300	25	25 \$ 25 \$		\$ (20.33) \$		\$ 839.69	\$ 1,329.58		\$ (20.33)		\$ 839.69 \$		\$ 63.00 \$		\$ 63.00	4.7%
25	50	9.125	25	25 \$		\$ (25.41) \$		\$ 1,014.23	\$ 1,499.04	*			\$ 1,014.23 \$		\$ 63.00 \$		\$ 63.00	4.2%
25	60	10.950	25	25 \$		\$ (30.50)			\$ 1,668.50		\$ (30.50)		\$ 1,188.78 \$		\$ 63.00 \$	-	\$ 63.00	3.8%
25	70	12,775	25	25 \$		\$ (35.58) \$		\$ 1,363.33	\$ 1,837.97		\$ (35.58)	\$ 537.64	\$ 1,363.33 \$		\$ 63.00 \$	-	\$ 63.00	3.4%
25	80	14,600	25	25 \$	317.00	\$ (40.66) \$	469.56	\$ 1,537.87	\$ 2,007.43	\$ 380.00	\$ (40.66)	\$ 532.56	\$ 1,537.87 \$	2,070.43	\$ 63.00 \$	-	\$ 63.00	3.1%
50	20	7,300	50	50 \$	634.00	\$ (20.33) \$		\$ 981.19	\$ 1,788.08	\$ 760.00	\$ (20.33)		\$ 981.19 \$		\$ 126.00 \$	-	\$ 126.00	7.0%
50	30	10,950	50	50 \$		\$ (30.50)			\$ 2,127.00		\$ (30.50)	\$ 922.72			\$ 126.00 \$	-	\$ 126.00	5.9%
50	40	14,600	50	50 \$	001.00	\$ (40.66) \$, , , , , ,	\$ 1,679.37	\$ 2,465.93	Ψ .00.00	\$ (40.66)	\$ 912.56	\$ 1,679.37 \$		\$ 126.00 \$	-	\$ 126.00	5.1%
50	50	18,250	50	50 \$		\$ (50.83) \$		\$ 2,028.47			\$ (50.83)		\$ 2,028.47 \$		\$ 126.00 \$	-	\$ 126.00	4.5%
50 50	60 70	21,900 25,550	50 50	50 \$ 50 \$	001.00	\$ (60.99) \$ \$ (71.16) \$		\$ 2,377.56 \$ 2,726.65	\$ 3,143.79 \$ 3,482.72	Ψ 100.00	\$ (60.99) \$ (71.16)	002.20	\$ 2,377.56 \$ \$ 2,726.65 \$.,	\$ 126.00 \$ \$ 126.00 \$	-	\$ 126.00 \$ 126.00	4.0% 3.6%
50	80	29,200	50	50 \$ 50 \$		\$ (81.32)		\$ 2,720.05	\$ 3,821.64	*	\$ (81.32)		\$ 3.075.75		\$ 126.00 \$ \$ 126.00 \$		\$ 126.00	3.3%
100	20	14,600	100	100 \$		\$ (40.66) \$		\$ 1,962.37	\$ 3.382.93	*		\$ 1.672.56	\$ 1.962.37 \$	- ,	\$ 252.00 \$		\$ 252.00	7.4%
100	30	21.900	100	100 \$		\$ (60.99)		\$ 2,660,56	\$ 4.060.79	* .,			\$ 2,660,56 \$		\$ 252.00 \$		\$ 252.00	6.2%
100	40	29,200	100	100 \$		\$ (81.32) \$		\$ 3,358,75	\$ 4,738.64			\$ 1,631.90	\$ 3,358,75 \$,	\$ 252.00 \$	-	\$ 252.00	5.3%
100	50	36,500	100	100 \$	1,268.00	\$ (101.65) \$	1,359.57	\$ 4,056.93	\$ 5,416.50	\$ 1,520.00	\$ (101.65)	\$ 1,611.57	\$ 4,056.93 \$	5,668.50	\$ 252.00 \$	-	\$ 252.00	4.7%
100	60	43,800	100	100 \$		\$ (121.98) \$		\$ 4,755.12	\$ 6,094.36			\$ 1,591.24	\$ 4,755.12 \$		\$ 252.00 \$	-	\$ 252.00	4.1%
100	70	51,100	100			\$ (142.31) \$			\$ 6,772.21				\$ 5,453.31 \$		\$ 252.00 \$	-	\$ 252.00	3.7%
100	80	58,400	100	100 \$		\$ (162.64) \$		\$ 6,151.49	\$ 7,450.07			\$ 1,550.58	\$ 6,151.49 \$		\$ 252.00 \$	-	\$ 252.00	3.4%
300	20	43,800	300	300 \$		\$ (121.98) \$		\$ 5,887.12	\$ 9,762.36				\$ 5,887.12 \$		\$ 756.00 \$	-	\$ 756.00	7.7%
300 300	30 40	65,700 87,600	300 300	300 \$		\$ (182.97) \$ \$ (243.97) \$			\$ 11,795.92 \$ 13,829.49			\$ 4,570.25 \$ 4,509.25		12,551.92 14,585,49	\$ 756.00 \$ \$ 756.00 \$	-	\$ 756.00 \$ 756.00	6.4% 5.5%
300	50	109.500	300	300 \$		\$ (304.96) \$			\$ 15,863.06				\$ 10,076.24 \$ \$ 12,170.80 \$		\$ 756.00 \$ \$ 756.00 \$		\$ 756.00	4.8%
300	60	131,400	300			\$ (365.95) \$			\$ 17.896.63	4 .,				18,652,63	\$ 756.00 \$ \$ 756.00 \$		\$ 756.00	4.2%
300	70	153,300	300	300 \$		\$ (426.94) \$			\$ 19,930.20	4 .,		\$ 4,326.28		20,686,20	\$ 756.00 \$	-	\$ 756.00	3.8%
300	80	175,200	300	300 \$	3,804.00	\$ (487.93) \$			\$ 21,963.77	\$ 4,560.00			\$ 18,454.48 \$	22,719.77	\$ 756.00 \$	-	\$ 756.00	3.4%
500	20	73,000	500	500 \$	6,340.00	\$ (203.31) \$	6,329.92	\$ 9,811.87	\$ 16,141.78	\$ 7,600.00	\$ (203.31)	\$ 7,589.92	\$ 9,811.87 \$	17,401.78	\$ 1,260.00 \$	-	\$ 1,260.00	7.8%
500	30	109,500	500	500 \$	6,340.00	\$ (304.96) \$	6,228.26		\$ 19,531.06	\$ 7,600.00	\$ (304.96)	\$ 7,488.26	\$ 13,302.80 \$	20,791.06	\$ 1,260.00 \$	-	\$ 1,260.00	6.5%
500	40	146,000	500	500 \$		\$ (406.61)			\$ 22,920.34			\$ 7,386.61		24,180.34	\$ 1,260.00 \$	-	\$ 1,260.00	5.5%
500	50	182,500	500	500 \$		\$ (508.26) \$,		\$ 26,309.62			\$ 7,284.96		27,569.62	\$ 1,260.00 \$	-	\$ 1,260.00	4.8%
500 500	60 70	219,000 255,500	500			\$ (609.92) \$ \$ (711.57) \$			\$ 29,698.90 \$ 33.088.18			.,	\$ 23,775.60 \$	30,958.90	\$ 1,260.00 \$ \$ 1,260.00 \$	-	\$ 1,260.00	4.2% 3.8%
500	80	292,000	500 500	500 \$ 500 \$		\$ (711.57) \$ \$ (813.22) \$			\$ 33,088.18			\$ 7,081.65 \$ 6.980.00		34,348.18	\$ 1,260.00 \$	-	\$ 1,260.00 \$ 1,260.00	3.8%
750	30	164,250	750	750 \$		\$ (457.44) \$			\$ 29,199.98			\$ 11,135.78	\$ 19,954.20 \$		\$ 1,890.00 \$		\$ 1,890.00	6.5%
750	40	219,000	750			\$ (609.92)			\$ 34,283.90				\$ 25,190.60 \$		\$ 1,890.00 \$		\$ 1.890.00	5.5%
750	50	273,750	750			\$ (762.39)			\$ 39,367.82			\$ 10.830.83		41,257,82	\$ 1.890.00 \$	-	\$ 1,890.00	4.8%
750	60	328,500	750			\$ (914.87)			\$ 44,451.74		\$ (914.87)			46,341.74	\$ 1,890.00 \$	-	\$ 1,890.00	4.3%
750	70	383,250	750			\$ (1,067.35) \$		\$ 40,899.80	\$ 49,535.67	\$ 11,400.00			\$ 40,899.80 \$	51,425.67	\$ 1,890.00 \$	-	\$ 1,890.00	3.8%
750	80	438,000	750			\$ (1,219.83) \$			\$ 54,619.59	\$ 11,400.00			\$ 46,136.20 \$		\$ 1,890.00 \$	-	\$ 1,890.00	3.5%
750	90	492,750	750			\$ (1,372.31) \$			\$ 59,703.51	\$ 11,400.00				61,593.51	\$ 1,890.00 \$	-	\$ 1,890.00	3.2%
1000	30	219,000	1,000			\$ (609.92) \$			\$ 38,868.90		\$ (609.92)			41,388.90	\$ 2,520.00 \$	-	\$ 2,520.00	6.5%
1000 1000	40 50	292,000 365,000	1,000			\$ (813.22) \$			\$ 45,647.46 \$ 52,426.03			\$ 14,580.00	\$ 33,587.46 \$ \$ 40,569.33 \$		\$ 2,520.00 \$ \$ 2,520.00 \$	-	\$ 2,520.00 \$ 2,520.00	5.5% 4.8%
1000	60	438,000	1,000 1,000			\$ (1,016.53) \$ \$ (1,219.83) \$			\$ 52,426.03	\$ 15,200.00 \$ 15,200.00	\$ (1,016.53)			61,724.59	\$ 2,520.00 \$	-	\$ 2,520.00	4.8%
1000	70	511,000	1,000			\$ (1,423.14)			\$ 65,983.15		\$ (1,423.14)			68,503.15	\$ 2,520.00 \$		\$ 2,520.00	3.8%
1000	80	584,000	1,000			\$ (1,626.44) \$			\$ 72,761.71		\$ (1,626.44)		\$ 61,514.93		\$ 2,520.00 \$	-	\$ 2,520.00	3.5%
1000	90	657,000	1,000			\$ (1,829.75)			\$ 79,540.27		\$ (1,829.75)		\$ 68,496.79 \$		\$ 2,520.00 \$	-	\$ 2,520.00	3.2%
2000	30	438,000	2,000	2,000 \$	25,360.00	\$ (1,219.83) \$	24,333.39		\$ 77,544.59		\$ (1,219.83)		\$ 53,211.20 \$	82,584.59	\$ 5,040.00 \$	-	\$ 5,040.00	6.5%
2000	40	584,000	2,000			\$ (1,626.44) \$			\$ 91,101.71		\$ (1,626.44)			96,141.71	\$ 5,040.00 \$	-	\$ 5,040.00	5.5%
2000	50	730,000	2,000			\$ (2,033.05) \$			\$ 104,658.83		\$ (2,033.05)		\$ 81,138.66 \$		\$ 5,040.00 \$	-	\$ 5,040.00	4.8%
2000	60	876,000	2,000			\$ (2,439.66) \$		\$ 95,102.39	\$ 118,215.95			\$ 28,153.56		123,255.95	\$ 5,040.00 \$	-	\$ 5,040.00	4.3%
2000 2000	70	1,022,000	2,000			\$ (2,846.27) \$			\$ 131,773.07	\$ 30,400.00			\$ 109,066.12 \$		\$ 5,040.00 \$	-	\$ 5,040.00	3.8% 3.5%
2000	80 90	1,168,000	2,000			\$ (3,252.88) \$ \$ (3,659.49) \$			\$ 145,330.20 \$ 158.887.32	\$ 30,400.00 \$ 30,400.00			\$ 123,029.86 \$ \$ 136,993.59 \$		\$ 5,040.00 \$ \$ 5.040.00 \$	-	\$ 5,040.00 \$ 5.040.00	3.5%
2000	90	1,314,000	2,000	2,000 \$	20,300.00	φ (3,009.49) Ş	p 21,093.73	φ 130,993.59	φ 100,001.32	a 30,400.00	φ (3,009.49)	φ 20,933./3	φ 130,993.59 \$	103,921.32	\$ 5,040.0U \$	-	φ 5,040.00	3.2%

ATLANTIC CITY ELECTRIC COMPANY ANNUAL GENERAL SERVICE SECONDARY ("AGS Secondary") Annual Average

										Pro	posed Rates								
		Load						Present	Present	Present			New	New	New	Difference	Difference	Total	Total
	and F		Energy (kWh)	Metered kW B	Silled IAM D.	Damand	D Energy	<u>Distribution</u>	BGS and Other Charges	<u>Total</u> (\$)	D Demand	D Energy	<u>Distribution</u>	BGS and Other Charges	Total (\$)		GS and Other Charges	<u>Difference</u>	Difference
(k)		20	3.650	25.00	22 \$		\$ (10.17) \$	(\$) 500.05	\$ 485.12			\$ (10.17)	(\$) \$ 563.05	\$ 485.12 \$		(\$) \$ 63.00 \$	(\$)	\$ 63.00	(%) 6.4%
2		30	5,475	25.00	22 \$		\$ (15.25)		\$ 656.93				\$ 557.97			\$ 63.00 \$		\$ 63.00	5.5%
2		40	7.300	25.00	22 \$		\$ (20.33) \$		\$ 828.74			\$ (20.33)		\$ 828.74 \$		\$ 63.00 \$		\$ 63.00	4.8%
2		50	9,125	25.00	22 \$		\$ (25.41)		\$ 1,000.55					\$ 1,000.55 \$		\$ 63.00 \$	-	\$ 63.00	4.2%
2	5	60	10,950	25.00	22 \$	317.00	\$ (30.50) \$		\$ 1,172.35	\$ 1,652.08	\$ 380.00	\$ (30.50)	\$ 542.72	\$ 1,172.35 \$	1,715.08	\$ 63.00 \$	-	\$ 63.00	3.8%
2		70	12,775	25.00	22 \$		\$ (35.58) \$		\$ 1,344.16			\$ (35.58)	\$ 537.64	\$ 1,344.16 \$		\$ 63.00 \$	-	\$ 63.00	3.5%
2		80	14,600	25.00	22 \$		\$ (40.66)		\$ 1,515.97			\$ (40.66)		\$ 1,515.97 \$		\$ 63.00 \$	-	\$ 63.00	3.2%
50		20	7,300	50.00	47 \$	634.00			\$ 970.24			\$ (20.33)		\$ 970.24 \$		\$ 126.00 \$	-	\$ 126.00	7.1%
50		30 40	10,950	50.00	47 \$		\$ (30.50) \$ \$ (40.66) \$					\$ (30.50) \$ (40.66)	\$ 922.72			\$ 126.00 \$ \$ 126.00 \$	-	\$ 126.00	6.0%
50		50	14,600 18,250	50.00 50.00	47 \$ 47 \$		\$ (40.66) \$ \$ (50.83) \$		\$ 1,657.47 \$ 2,001.09	\$ 2,444.03 \$ 2,777.49		\$ (40.66) \$ (50.83)	\$ 912.56 \$ 902.39	\$ 1,657.47 \$ \$ 2,001.09 \$		\$ 126.00 \$ \$ 126.00 \$	-	\$ 126.00 \$ 126.00	5.2% 4.5%
5		60	21.900	50.00	47 S		\$ (60.99)		\$ 2,344.71			\$ (60.99)		\$ 2,344.71 \$		\$ 126.00 \$		\$ 126.00	4.1%
50		70	25,550	50.00	47 S		\$ (71.16)		\$ 2,688,33	\$ 3,444.39	,	\$ (71.16)		\$ 2.688.33 \$.,	\$ 126.00 \$	-	\$ 126.00	3.7%
50		80	29,200	50.00	47 \$		\$ (81.32)		\$ 3,031.95	\$ 3,777.84		\$ (81.32)		\$ 3,031.95 \$		\$ 126.00 \$	-	\$ 126.00	3.3%
10	0	20	14,600	100.00	97 \$	1,268.00	\$ (40.66) \$	1,420.56	\$ 1,940.47	\$ 3,361.03	\$ 1,520.00	\$ (40.66)	\$ 1,672.56	\$ 1,940.47 \$	3,613.03	\$ 252.00 \$	-	\$ 252.00	7.5%
10		30	21,900	100.00		.,	\$ (60.99) \$,	\$ 2,627.71		+ .,		· .,	\$ 2,627.71 \$		\$ 252.00 \$	-	\$ 252.00	6.3%
10		40	29,200	100.00		1,268.00	\$ (81.32)	,0.0.00	\$ 3,314.95	\$ 4,694.84	Ψ 1,020.00		\$ 1,631.90	\$ 3,314.95 \$		\$ 252.00 \$	-	\$ 252.00	5.4%
10		50	36,500	100.00			\$ (101.65) \$		\$ 4,002.18					\$ 4,002.18 \$		\$ 252.00 \$	-	\$ 252.00	4.7%
10		60 70	43,800 51,100	100.00 100.00			\$ (121.98) \$ \$ (142.31) \$		\$ 4,689.42 \$ 5,376.66				\$ 1,591.24 \$ 1,570.91	\$ 4,689.42 \$ 5,376.66 \$.,	\$ 252.00 \$ \$ 252.00 \$	-	\$ 252.00 \$ 252.00	4.2% 3.8%
10		80	58,400	100.00			\$ (142.51) \$		\$ 5,376.66 \$ 6.063.89	\$ 7.362.47			\$ 1,570.51	\$ 5,376.66 \$ \$ 6.063.89 \$.,.	\$ 252.00 \$ \$ 252.00 \$	-	\$ 252.00	3.4%
30		20	43,800	300.00			\$ (121.98)		\$ 5,821.42				1 /11111	\$ 5,821.42 \$		\$ 756.00 \$		\$ 756.00	7.8%
30		30	65,700	300.00			\$ (182.97) \$			\$ 11,697.37			\$ 4,570.25	\$ 7,883.13 \$		\$ 756.00 \$		\$ 756.00	6.5%
30		40	87,600	300.00	297 \$		\$ (243.97) \$			\$ 13,698.09			\$ 4,509.25		14,454.09	\$ 756.00 \$	-	\$ 756.00	5.5%
30	0	50	109,500	300.00	297 \$	3,804.00	\$ (304.96) \$	3,692.26	\$ 12,006.55	\$ 15,698.81	\$ 4,560.00	\$ (304.96)	\$ 4,448.26	\$ 12,006.55 \$	16,454.81	\$ 756.00 \$	-	\$ 756.00	4.8%
30		60	131,400	300.00	297 \$		\$ (365.95) \$			\$ 17,699.53					18,455.53	\$ 756.00 \$	-	\$ 756.00	4.3%
30		70	153,300	300.00	297 \$		\$ (426.94) \$			\$ 19,700.25	+ .,		4 .,	\$ 16,129.97 \$		\$ 756.00 \$	-	\$ 756.00	3.8%
30		80	175,200	300.00			\$ (487.93) \$		\$ 18,191.68				\$ 4,265.29	\$ 18,191.68 \$		\$ 756.00 \$	-	\$ 756.00	3.5%
50 50		20 30	73,000 109,500	500.00 500.00	497 \$ 497 \$		\$ (203.31) \$ \$ (304.96) \$			\$ 16,032.28 \$ 19,366.81			\$ 7,589.92 \$ 7,488.26		17,292.28 20,626.81	\$ 1,260.00 \$ \$ 1,260.00 \$	-	\$ 1,260.00 \$ 1,260.00	7.9% 6.5%
50		40	146.000	500.00			\$ (304.96) \$			\$ 22,701.34	+ .,		\$ 7,466.26	\$ 15,136.55 \$ \$ 16,574.73 \$		\$ 1,260.00 \$ \$ 1.260.00 \$	-	\$ 1,260.00	5.6%
50		50	182,500	500.00	497 \$		\$ (508.26) \$			\$ 26,035.87			\$ 7.284.96	\$ 20.010.92 \$		\$ 1,260.00 \$		\$ 1,260.00	4.8%
50		60	219.000	500.00	497 \$		\$ (609.92) \$			\$ 29,370,40				\$ 23.447.10 \$		\$ 1,260,00 \$	-	\$ 1,260.00	4.3%
50	0	70	255,500	500.00	497 \$	6,340.00	\$ (711.57) \$	5,821.65	\$ 26,883.28	\$ 32,704.93	\$ 7,600.00	\$ (711.57)	\$ 7,081.65	\$ 26,883.28 \$	33,964.93	\$ 1,260.00 \$	-	\$ 1,260.00	3.9%
50		80	292,000	500.00			\$ (813.22) \$			\$ 36,039.46			\$ 6,980.00	\$ 30,319.46 \$		\$ 1,260.00 \$	-	\$ 1,260.00	3.5%
75		30	164,250	750.00			\$ (457.44) \$		\$ 19,707.82				\$ 11,135.78	\$ 19,707.82 \$		\$ 1,890.00 \$	-	\$ 1,890.00	6.5%
75		40	219,000	750.00	747 \$		\$ (609.92)			\$ 33,955.40			\$ 10,983.31	\$ 24,862.10 \$		\$ 1,890.00 \$	-	\$ 1,890.00	5.6%
75		50	273,750	750.00	747 \$		\$ (762.39) \$	-,		\$ 38,957.20	\$ 11,400.00		\$ 10,830.83		40,847.20	\$ 1,890.00 \$	-	\$ 1,890.00	4.9%
75 75		60 70	328,500 383,250	750.00 750.00	747 \$ 747 \$		\$ (914.87) \$ \$ (1,067.35) \$			\$ 43,958.99 \$ 48,960.79	\$ 11,400.00 \$ 11,400.00	\$ (914.87)			45,848.99 50,850.79	\$ 1,890.00 \$ \$ 1,890.00 \$	-	\$ 1,890.00 \$ 1,890.00	4.3% 3.9%
75		80	438.000	750.00			\$ (1,219.83)			\$ 53,962.59	\$ 11,400.00			\$ 45,479.20 \$		\$ 1,890.00 \$		\$ 1,890.00	3.5%
75		90	492,750	750.00	747 \$		\$ (1,372,31) \$.,		\$ 58,964.38	\$ 11,400.00			\$ 50.633.47 \$		\$ 1,890.00 \$		\$ 1.890.00	3.2%
1,0		30	219,000	1,000.00	997 \$ 1		\$ (609.92)			\$ 38,540.40		\$ (609.92)		\$ 26,277.10 \$		\$ 2,520.00 \$	-	\$ 2,520.00	6.5%
1,0	00	40	292,000	1,000.00	997 \$ 1	2,680.00	\$ (813.22) \$	12,060.00	\$ 33,149.46	\$ 45,209.46	\$ 15,200.00	\$ (813.22)	\$ 14,580.00	\$ 33,149.46 \$	47,729.46	\$ 2,520.00 \$	-	\$ 2,520.00	5.6%
1,0		50	365,000	1,000.00	997 \$ 1	2,680.00	\$ (1,016.53) \$	11,856.70	\$ 40,021.83	\$ 51,878.53	\$ 15,200.00	\$ (1,016.53)	\$ 14,376.70	\$ 40,021.83 \$		\$ 2,520.00 \$	-	\$ 2,520.00	4.9%
1,0		60	438,000	1,000.00	997 \$ 1				\$ 46,894.20			\$ (1,219.83)			61,067.59	\$ 2,520.00 \$	-	\$ 2,520.00	4.3%
1,0		70	511,000	1,000.00			\$ (1,423.14) \$			\$ 65,216.65		\$ (1,423.14)			67,736.65	\$ 2,520.00 \$	-	\$ 2,520.00	3.9%
1,0		80 90	584,000	1,000.00	997 \$ 1		\$ (1,626.44) \$		\$ 60,638.93 \$ 67,511.29			\$ (1,626.44)		\$ 60,638.93 \$		\$ 2,520.00 \$ \$ 2,520.00 \$	-	\$ 2,520.00	3.5%
1,0		30	657,000 438,000	1,000.00 2,000.00	1997 \$ 1		\$ (1,829.75) \$ \$ (1,219.83) \$			\$ 78,554.77 \$ 76,887.59		\$ (1,829.75) \$ (1,219.83)		\$ 67,511.29 \$ \$ 52,554.20 \$	81,074.77	\$ 2,520.00 \$ \$ 5,040.00 \$	-	\$ 2,520.00 \$ 5,040.00	3.2% 6.6%
2,0		40	584,000	2,000.00	1997 \$ 2		\$ (1,626.44) \$		\$ 52,554.20			\$ (1,626.44)			95,265.71	\$ 5,040.00 \$ \$ 5,040.00 \$		\$ 5,040.00	5.6%
2,0		50	730,000	2,000.00	1997 \$ 2		\$ (2,033.05) \$			\$ 103,563.83		\$ (2,033.05)		\$ 80,043.66 \$		\$ 5,040.00 \$	-	\$ 5,040.00	4.9%
2,0		60	876,000	2,000.00	1997 \$ 2		\$ (2,439.66)		\$ 93,788.39	\$ 116,901.95			\$ 28,153.56		121,941.95	\$ 5,040.00 \$	-	\$ 5,040.00	4.3%
2,0	00		1,022,000	2,000.00	1997 \$ 2	25,360.00	\$ (2,846.27) \$	22,706.95	\$ 107,533.12	\$ 130,240.07	\$ 30,400.00	\$ (2,846.27)	\$ 27,746.95	\$ 107,533.12 \$	135,280.07	\$ 5,040.00 \$	-	\$ 5,040.00	3.9%
2,0			1,168,000	2,000.00			\$ (3,252.88) \$			\$ 143,578.20	\$ 30,400.00			\$ 121,277.86 \$		\$ 5,040.00 \$	-	\$ 5,040.00	3.5%
2,0	00	90	1,314,000	2,000.00	1997 \$ 2	25,360.00	\$ (3,659.49) \$	21,893.73	\$ 135,022.59	\$ 156,916.32	\$ 30,400.00	\$ (3,659.49)	\$ 26,933.73	\$ 135,022.59 \$	161,956.32	\$ 5,040.00 \$	-	\$ 5,040.00	3.2%

ATLANTIC CITY ELECTRIC COMPANY ANNUAL GENERAL SERVICE PRIMARY ("AGS Primary") 8 WINTER MONTHS (October Through May)

Present Rates

ronocad	Rates	

	Proposed Rates Proposed Rates Proposed Rates Proposed Rates Proposed Rates Proposed Rates Proposed Rates																	
_	Load	_					Present	Present	Present			New	New	New	Difference	Difference	Total	Total
Demano (kW)	Factor (%)	(kWh)	Metered kW Bi	llod kW D	Demand	D Energy	Distribution (\$)	BGS and Other Charges (\$)	<u>Total</u> (\$)	D Demand	D Energy	Distribution (\$)	BGS and Other Charges (\$)	Total (\$)	Distribution BC (\$)	GS and Other Charges (\$)	Difference (\$)	Difference (%)
25	20	3,650	25	25 \$		\$ (5.92) \$		\$ 464.64				\$ 1,115.67		\$ 1,580.32	\$ 126.69 \$	(\$)	\$ 126.69	8.7%
25	30	5.475	25	25 \$	250.75							\$ 1,112.72		\$ 1,739.06	\$ 126.69 \$	_	\$ 126.69	7.9%
25	40	7,300	25	25 \$	250.75			\$ 788.04						\$ 1,897.79	\$ 126.69 \$	-	\$ 126.69	7.2%
25	50	9,125	25	25 \$		\$ (14.79) \$		\$ 949.73						\$ 2,056.53	\$ 126.69 \$	-	\$ 126.69	6.6%
25	60	10,950	25	25 \$		\$ (17.75) \$		\$ 1,111.43				\$ 1,103.84		\$ 2,215.27	\$ 126.69 \$	-	\$ 126.69	6.1%
25	70	12,775	25	25 \$	250.75			\$ 1,273.13				\$ 1,100.88		\$ 2,374.01	\$ 126.69 \$	-	\$ 126.69	5.6%
25 50	80 20	14,600 7.300	25 50	25 \$ 50 \$		\$ (23.67) \$ \$ (11.83) \$		\$ 1,434.82 \$ 929.29				\$ 1,097.92 \$ 1,405.01		\$ 2,532.75 \$ 2,334.29	\$ 126.69 \$ \$ 171.19 \$	-	\$ 126.69 \$ 171.19	5.3% 7.9%
50	30	10.950	50	50 \$ 50 \$		\$ (17.75) \$		\$ 1.252.68						\$ 2,554.29	\$ 171.19 \$		\$ 171.19	6.9%
50	40	14,600	50	50 \$		\$ (23.67) \$		\$ 1,576.07				\$ 1,393.17		\$ 2,969.25	\$ 171.19 \$	_	\$ 171.19	6.1%
50	50	18,250	50	50 \$		\$ (29.58) \$		\$ 1,899.47						\$ 3,286.73	\$ 171.19 \$	-	\$ 171.19	
50	60	21,900	50	50 \$	501.50	\$ (35.50) \$	1,210.15	\$ 2,222.86	\$ 3,433.01	\$ 590.50	\$ (35.50)	\$ 1,381.34	\$ 2,222.86	\$ 3,604.20	\$ 171.19 \$	-	\$ 171.19	5.0%
50	70	25,550	50	50 \$		\$ (41.42) \$			\$ 3,750.49					\$ 3,921.68	\$ 171.19 \$	-	\$ 171.19	4.6%
50	80	29,200	50	50 \$		\$ (47.33) \$		\$ 2,869.65				\$ 1,369.51		\$ 4,239.16	\$ 171.19 \$	-	\$ 171.19	4.2%
100 100	20 30	14,600 21,900	100			\$ (23.67) \$		\$ 1,858.57						\$ 3,842.25	\$ 260.19 \$		\$ 260.19 \$ 260.19	7.3%
100	40	29,200	100 100			\$ (35.50) \$ \$ (47.33) \$		\$ 2,505.36 \$ 3.152.15				Ψ 1,011.01		\$ 4,477.20 \$ 5.112.16	\$ 260.19 \$ \$ 260.19 \$		\$ 260.19 \$ 260.19	6.2% 5.4%
100	50	36.500	100			\$ (59.17) \$		\$ 3,152.15				\$ 1,960.01		\$ 5,747.11	\$ 260.19 \$ \$ 260.19 \$	-	\$ 260.19	4.7%
100	60	43.800	100			\$ (71.00) \$			\$ 6,121.87			\$ 1,936.34		\$ 6,382.06	\$ 260.19 \$	_	\$ 260.19	4.3%
100	70	51,100	100			\$ (82.83) \$		\$ 5,092.51						\$ 7,017.02	\$ 260.19 \$	-	\$ 260.19	3.9%
100	80	58,400	100	100 \$	1,003.00	\$ (94.67) \$	1,652.48	\$ 5,739.30	\$ 7,391.78	\$ 1,181.00	\$ (94.67)	\$ 1,912.67	\$ 5,739.30	\$ 7,651.97	\$ 260.19 \$	-	\$ 260.19	3.5%
300	20	43,800	300			\$ (71.00) \$			\$ 9,257.87			\$ 4,298.34		\$ 9,874.06	\$ 616.19 \$	-	\$ 616.19	6.7%
300	30	65,700	300			\$ (106.50) \$			\$ 11,162.74			\$ 4,262.84		\$ 11,778.93	\$ 616.19 \$	-	\$ 616.19	5.5%
300 300	40 50	87,600 109,500	300			\$ (142.00) \$			\$ 13,067.60			\$ 4,227.34		\$ 13,683.79	\$ 616.19 \$	-	\$ 616.19 \$ 616.19	4.7%
300	60	131,400	300 300			\$ (177.50) \$ \$ (213.00) \$			\$ 14,972.46 \$ 16,877.32			\$ 4,191.84 \$ 4,156.34	\$ 11,396.81 \$ 13,337.17		\$ 616.19 \$ \$ 616.19 \$		\$ 616.19 \$ 616.19	4.1% 3.7%
300	70	153,300	300			\$ (248.50) \$			\$ 18,782.18			\$ 4,120.84	\$ 15,277.53		\$ 616.19 \$	_	\$ 616.19	3.3%
300	80	175,200	300			\$ (284.00) \$			\$ 20,687.05				\$ 17,217.90		\$ 616.19 \$	_	\$ 616.19	
500	20	73,000	500			\$ (118.33) \$	5,640.82		\$ 14,933.69			\$ 6,613.01		\$ 15,905.88	\$ 972.19 \$	-	\$ 972.19	6.5%
500	30	109,500	500			\$ (177.50) \$			\$ 18,108.46		\$ (177.50)			\$ 19,080.65	\$ 972.19 \$		\$ 972.19	5.4%
500	40	146,000	500			\$ (236.67) \$			\$ 21,283.23			\$ 6,494.67	\$ 15,760.75		\$ 972.19 \$	-	\$ 972.19	4.6%
500	50	182,500	500			\$ (295.83) \$			\$ 24,458.00					\$ 25,430.19	\$ 972.19 \$	-	\$ 972.19	4.0%
500 500	60 70	219,000 255,500	500 500			\$ (355.00) \$ \$ (414.17) \$			\$ 27,632.77 \$ 30.807.54			\$ 6,376.34 \$ 6.317.17	\$ 22,228.62 \$ 25,462.56		\$ 972.19 \$ \$ 972.19 \$	-	\$ 972.19 \$ 972.19	3.5% 3.2%
500	80	292,000	500			\$ (473.33) \$			\$ 33,982.31			\$ 6,258.01	\$ 28,696.49		\$ 972.19 \$	-	\$ 972.19	2.9%
750	30	164.250	750			\$ (266.25) \$			\$ 26,790.62			\$ 9.417.59	\$ 18.790.21		\$ 1.417.19 \$		\$ 1.417.19	5.3%
750	40	219,000	750			\$ (355.00) \$			\$ 31,552.77			\$ 9,328.84	\$ 23,641.12		\$ 1,417.19 \$	-	\$ 1,417.19	4.5%
750	50	273,750	750	750 \$	7,522.50	\$ (443.75) \$	7,822.90	\$ 28,492.02	\$ 36,314.93	\$ 8,857.50	\$ (443.75)	\$ 9,240.09	\$ 28,492.02	\$ 37,732.12	\$ 1,417.19 \$	-	\$ 1,417.19	3.9%
750	60	328,500	750			\$ (532.50) \$			\$ 41,077.08				\$ 33,342.93		\$ 1,417.19 \$	-	\$ 1,417.19	3.5%
750	70	383,250	750			\$ (621.25) \$			\$ 45,839.24			\$ 9,062.59	\$ 38,193.83		\$ 1,417.19 \$	-	\$ 1,417.19	3.1%
750	80	438,000	750			\$ (710.00) \$			\$ 50,601.39			\$ 8,973.84	\$ 43,044.74		\$ 1,417.19 \$		\$ 1,417.19	2.8%
750 1000	90 30	492,750 219,000	750 1.000	1.000 \$		\$ (798.75) \$ \$ (355.00) \$			\$ 55,363.55 \$ 35,472.77			\$ 8,885.09 \$ 12,281.34	\$ 47,895.64 \$ 25,053.62		\$ 1,417.19 \$ \$ 1,862.19 \$		\$ 1,417.19 \$ 1.862.19	2.6% 5.2%
1000	40	292,000	1,000	1,000 \$		\$ (355.00) \$			\$ 35,472.77 \$ 41,822.31			\$ 12,281.34	\$ 25,053.62 \$ 31,521.49		\$ 1,862.19 \$ \$ 1,862.19 \$		\$ 1,862.19	5.2% 4.5%
1000	50	365,000	1,000			\$ (591.67) \$			\$ 48.171.85			\$ 12,044.68	\$ 37,989.37		\$ 1.862.19 \$		\$ 1,862.19	3.9%
1000	60	438,000	1,000			\$ (710.00) \$			\$ 54,521.39				\$ 44,457.24		\$ 1,862.19 \$		\$ 1,862.19	3.4%
1000	70	511,000	1,000	1,000 \$		\$ (828.33) \$		\$ 50,925.11	\$ 60,870.93		\$ (828.33)	\$ 11,808.01	\$ 50,925.11	\$ 62,733.12	\$ 1,862.19 \$	-	\$ 1,862.19	3.1%
1000	80	584,000	1,000	1,000 \$		\$ (946.66) \$			\$ 67,220.47			\$ 11,689.68	\$ 57,392.98		\$ 1,862.19 \$	-	\$ 1,862.19	2.8%
1000	90	657,000	1,000			\$ (1,065.00) \$			\$ 73,570.01	\$ 11,810.00			\$ 63,860.86		\$ 1,862.19 \$	-	\$ 1,862.19	2.5%
2000	30	438,000	2,000			\$ (710.00) \$			\$ 70,201.39	\$ 23,620.00			\$ 50,107.24		\$ 3,642.19 \$	-	\$ 3,642.19	5.2%
2000 2000	40 50	584,000 730,000	2,000 2.000			\$ (946.66) \$ \$ (1.183.33) \$			\$ 82,900.47 \$ 95,599.55		\$ (946.66) \$ (1.183.33)		\$ 63,042.98 \$ 75,978.73		\$ 3,642.19 \$ \$ 3.642.19 \$	-	\$ 3,642.19 \$ 3.642.19	4.4% 3.8%
2000	60	876.000	2,000			\$ (1,163.33) \$			\$ 108.298.63	\$ 23,620.00			\$ 75,976.73 \$ 88.914.48		\$ 3,642.19 \$ \$ 3.642.19 \$	-	\$ 3,642.19	3.4%
2000		1.022.000	2,000			\$ (1,656.66) \$			\$ 120,997.71		\$ (1,420.00)		\$ 101.850.22		\$ 3,642.19 \$		\$ 3,642.19	3.0%
2000		1,168,000	2,000			\$ (1,893.33) \$			\$ 133,696.79	\$ 23,620.00			\$ 114,785.97		\$ 3,642.19 \$	-	\$ 3,642.19	2.7%
2000		1,314,000	2,000			\$ (2,129.99) \$			\$ 146,395.87	\$ 23,620.00			\$ 127,721.71		\$ 3,642.19 \$	-	\$ 3,642.19	2.5%

ATLANTIC CITY ELECTRIC COMPANY ANNUAL GENERAL SERVICE PRIMARY ("AGS Primary") 4 SUMMER MONTHS (June Through September)

									Pro	posed Rates								
	Load						Present	Present	Present	•		New	New	New	Difference	Difference	Total	Total
Demand		Energy					Distribution	BGS and Other Charges	Total			Distribution	BGS and Other Charges	Total		BGS and Other Charges		Difference
(kW)	(%)	(kWh)	Metered kW B		D Demand	D Energy	(\$)	(\$)	(\$)	D Demand	D Energy	(\$)	(\$)	(\$)	(\$)	(\$)	(\$)	(%)
25 25	20 30	3,650 5,475	25 25	25 \$ 25 \$	250.75 250.75	+ ()	\$ 988.98 \$ 986.03	\$ 472.31 \$ 637.84	\$ 1,461.30 \$ 1,623.87	\$ 295.25 \$ 295.25		\$ 1,115.67 \$ 1.112.72	\$ 472.31 \$ 637.84	\$ 1,587.99 \$ 1,750.56	\$ 126.69 \$ 126.69	*	\$ 126.69 \$ 126.69	8.7% 7.8%
25	40	7.300	25 25	25 \$				\$ 803.37						\$ 1,750.56		\$ - \$ -	\$ 126.69	7.0%
25	50	9,125	25	25 \$				\$ 968.91	\$ 1,949.01			\$ 1,106.80		\$ 2,075.70		\$ - \$ -	\$ 126.69	6.5%
25	60	10.950	25	25 \$			\$ 977.15		\$ 2,111.59			\$ 1,103.84		\$ 2,238.28		\$ -	\$ 126.69	6.0%
25	70	12,775	25	25 \$			\$ 974.19	\$ 1,299.97						\$ 2,400.85		\$ -	\$ 126.69	5.6%
25	80	14,600	25	25 \$			\$ 971.23	\$ 1,465.50	\$ 2,436.73	\$ 295.25	\$ (23.67)	\$ 1,097.92	\$ 1,465.50	\$ 2,563.42	\$ 126.69	\$ -	\$ 126.69	5.2%
50	20	7,300	50	50 \$			\$ 1,233.82			\$ 590.50				\$ 2,349.63	\$ 171.19	\$ -	\$ 171.19	7.9%
50	30	10,950	50	50 \$			\$ 1,227.90	\$ 1,275.69				\$ 1,399.09		\$ 2,674.78		\$ -	\$ 171.19	6.8%
50	40	14,600	50	50 \$			\$ 1,221.98	\$ 1,606.75					\$ 1,606.75	\$ 2,999.92	\$ 171.19		\$ 171.19	6.1%
50	50	18,250	50	50 \$		φ (20.00)	\$ 1,216.07	\$ 1,937.81			\$ (29.58)	\$ 1,387.26		\$ 3,325.07		\$ -	\$ 171.19	5.4%
50 50	60 70	21,900 25,550	50 50	50 \$ 50 \$			\$ 1,210.15 \$ 1,204.23	\$ 2,268.87 \$ 2,599.94			\$ (35.50) \$ (41.42)			\$ 3,650.21 \$ 3,975.36	\$ 171.19 \$ 171.19		\$ 171.19 \$ 171.19	4.9% 4.5%
50	80	29,200	50	50 \$			\$ 1,204.23	\$ 2,599.94				\$ 1,375.42		\$ 4.300.51	\$ 171.19	Ÿ	\$ 171.19	4.1%
100	20	14,600	100	100 \$			\$ 1,723,48	\$ 1.889.25				\$ 1,983.67		\$ 3.872.92	\$ 260.19	*	\$ 260.19	7.2%
100	30	21,900	100	100 \$			\$ 1,711.65	\$ 2.551.37				\$ 1.971.84		\$ 4.523.21	·	\$ -	\$ 260.19	6.1%
100	40	29,200	100	100 \$			\$ 1,699.82	\$ 3.213.50			\$ (47.33)	\$ 1,960.01		\$ 5,173.51	\$ 260.19		\$ 260.19	5.3%
100	50	36,500	100	100 \$	1,003.00		\$ 1,687.98	\$ 3,875.62		\$ 1,181.00	\$ (59.17)	\$ 1,948.17	\$ 3,875.62	\$ 5,823.80	\$ 260.19	\$ -	\$ 260.19	4.7%
100	60	43,800	100	100 \$	1,003.00	\$ (71.00)	\$ 1,676.15	\$ 4,537.75	\$ 6,213.90	\$ 1,181.00	\$ (71.00)	\$ 1,936.34	\$ 4,537.75	\$ 6,474.09	\$ 260.19	\$ -	\$ 260.19	4.2%
100	70	51,100	100	100 \$			\$ 1,664.32	\$ 5,199.87		\$ 1,181.00		\$ 1,924.51		\$ 7,124.38	\$ 260.19		\$ 260.19	3.8%
100	80	58,400	100	100 \$			\$ 1,652.48	\$ 5,862.00				\$ 1,912.67		\$ 7,774.67	\$ 260.19		\$ 260.19	3.5%
300	20	43,800	300	300 \$			\$ 3,682.15		\$ 9,349.90			\$ 4,298.34		\$ 9,966.09	\$ 616.19		\$ 616.19	6.6%
300	30 40	65,700	300	300 \$		\$ (106.50)			\$ 11,300.77			\$ 4,262.84		\$ 11,916.96	\$ 616.19 \$ 616.19		\$ 616.19	5.5%
300 300	40 50	87,600 109,500	300 300	300 \$		+ (,	\$ 3,611.15 \$ 3.575.65		\$ 13,251.65 \$ 15,202.52		\$ (142.00) \$ (177.50)	\$ 4,227.34 \$ 4,191.84	\$ 9,640.50 \$ 11,626.87	\$ 13,867.84	\$ 616.19 \$ 616.19		\$ 616.19 \$ 616.19	4.6% 4.1%
300	60	131,400	300	300 \$			\$ 3,540.15		\$ 17,153.39			\$ 4,156.34	\$ 13,613.24			\$ - \$	\$ 616.19	3.6%
300	70	153,300	300	300 \$		\$ (248.50)			\$ 19,104.27	+ -,		\$ 4,120.84	\$ 15,599.62		\$ 616.19		\$ 616.19	3.2%
300	80	175,200	300	300 \$			\$ 3,469,15		\$ 21,055.14		\$ (284.00)	\$ 4.085.34	\$ 17.585.99			\$ -	\$ 616.19	2.9%
500	20	73,000	500	500 \$	5,015.00	\$ (118.33)	\$ 5,640.82		\$ 15,087.06	\$ 5,905.00	\$ (118.33)	\$ 6,613.01	\$ 9,446.25	\$ 16,059.25	\$ 972.19	\$ -	\$ 972.19	6.4%
500	30	109,500	500	500 \$	5,015.00	\$ (177.50)	\$ 5,581.65	\$ 12,756.87	\$ 18,338.52	\$ 5,905.00	\$ (177.50)	\$ 6,553.84	\$ 12,756.87	\$ 19,310.71	\$ 972.19	\$ -	\$ 972.19	5.3%
500	40	146,000	500	500 \$			\$ 5,522.48		\$ 21,589.98			\$ 6,494.67	\$ 16,067.49			\$ -	\$ 972.19	4.5%
500	50	182,500	500	500 \$			\$ 5,463.32		\$ 24,841.43				\$ 19,378.12		\$ 972.19		\$ 972.19	3.9%
500	60	219,000	500	500 \$		+ ()	\$ 5,404.15		\$ 28,092.89			\$ 6,376.34	\$ 22,688.74		\$ 972.19		\$ 972.19	3.5%
500	70	255,500	500	500 \$		\$ (414.17)			\$ 31,344.35				\$ 25,999.36		\$ 972.19		\$ 972.19	3.1%
500 750	80 30	292,000 164,250	500 750	500 \$ 750 \$		+ ()	\$ 5,285.82 \$ 8,000.40		\$ 34,595.80 \$ 27,135.70		\$ (473.33) \$ (266.25)	\$ 6,258.01 \$ 9,417.59	\$ 29,309.98 \$ 19,135.30	\$ 35,567.99	\$ 972.19 \$ 1,417.19		\$ 972.19 \$ 1,417.19	2.8% 5.2%
750	40	219.000	750 750	750 \$			\$ 7.911.65		\$ 32,012.89		\$ (355.00)		\$ 24.101.24		\$ 1,417.19		\$ 1,417.19	4.4%
750	50	273,750	750			\$ (443.75)			\$ 36,890.07	+ -,		\$ 9.240.09	\$ 29,067.17		\$ 1,417.19		\$ 1,417.19	3.8%
750	60	328,500	750	750 \$			\$ 7,734,15		\$ 41.767.26		\$ (532.50)		\$ 34.033.11			\$ -	\$ 1,417,19	3.4%
750	70	383,250	750	750 \$		\$ (621.25)	\$ 7,645.40	\$ 38,999.04	\$ 46,644.44	\$ 8,857.50		\$ 9,062.59	\$ 38,999.04	\$ 48,061.63	\$ 1,417.19	\$ -	\$ 1,417.19	3.0%
750	80	438,000	750	750 \$	7,522.50	\$ (710.00)	\$ 7,556.65	\$ 43,964.98	\$ 51,521.63	\$ 8,857.50	\$ (710.00)	\$ 8,973.84	\$ 43,964.98	\$ 52,938.82	\$ 1,417.19	\$ -	\$ 1,417.19	2.8%
750	90	492,750	750				\$ 7,467.90		\$ 56,398.81	\$ 8,857.50		\$ 8,885.09	\$ 48,930.91		\$ 1,417.19	\$ -	\$ 1,417.19	2.5%
1000	30	219,000	1,000				\$ 10,419.15		\$ 35,932.89		\$ (355.00)		\$ 25,513.74			\$ -	\$ 1,862.19	5.2%
1000	40	292,000	1,000			\$ (473.33)			\$ 42,435.80		\$ (473.33)		\$ 32,134.98		\$ 1,862.19		\$ 1,862.19	4.4%
1000	50	365,000	1,000			\$ (591.67)			\$ 48,938.72	\$ 11,810.00			\$ 38,756.23		\$ 1,862.19		\$ 1,862.19	3.8%
1000 1000	60 70	438,000 511,000	1,000 1,000		10,030.00		\$ 10,064.15 \$ 9,945.82		\$ 55,441.63 \$ 61,944.54		\$ (710.00) \$ (828.33)		\$ 45,377.48 \$ 51,998.72		\$ 1,862.19 \$ 1,862.19	\$ - \$ -	\$ 1,862.19 \$ 1,862.19	3.4% 3.0%
1000	80	584,000	1,000				\$ 9,827.49		\$ 68,447.45		\$ (946.66)		\$ 58,619.97			\$ - \$ -	\$ 1,862.19	2.7%
1000	90	657,000	1,000			\$ (1,065.00)			\$ 74,950.37	\$ 11,810.00			\$ 65,241.21		\$ 1,862.19		\$ 1,862.19	2.5%
2000	30	438,000	2,000			\$ (710.00)			\$ 71,121.63			\$ 23,736.34	\$ 51,027.48		\$ 3,642.19		\$ 3,642.19	5.1%
2000	40	584,000	2,000			\$ (946.66)			\$ 84,127.45				\$ 64,269.97		\$ 3,642.19	\$ -	\$ 3,642.19	4.3%
2000	50	730,000	2,000	2,000 \$	20,060.00	\$ (1,183.33)	\$ 19,620.82		\$ 97,133.28	\$ 23,620.00			\$ 77,512.46			\$ -	\$ 3,642.19	3.7%
2000	60	876,000	2,000			\$ (1,420.00)			\$ 110,139.11			\$ 23,026.34	\$ 90,754.95		\$ 3,642.19	Ÿ	\$ 3,642.19	3.3%
2000	70	1,022,000	2,000			\$ (1,656.66)			\$ 123,144.93			\$ 22,789.68	\$ 103,997.44			\$ -	\$ 3,642.19	3.0%
2000		1,168,000	2,000				\$ 18,910.82		\$ 136,150.76	\$ 23,620.00			\$ 117,239.94		\$ 3,642.19		\$ 3,642.19	2.7%
2000	90	1,314,000	2,000	2,000 \$	20,060.00	\$ (2,129.99)	\$ 18,674.16	\$ 130,482.43	\$ 149,156.58	\$ 23,620.00	\$ (2,129.99)	\$ 22,316.35	\$ 130,482.43	\$ 152,798.77	\$ 3,642.19	\$ -	\$ 3,642.19	2.4%

ATLANTIC CITY ELECTRIC COMPANY ANNUAL GENERAL SERVICE PRIMARY ("AGS Primary") Annual Average

										Pre	posed Rates								
	Lo	ad						Present	Present	Present			New	New	New	Difference	Difference	Total	Total
	nd Fac		ergy					Distribution	BGS and Other Charges	Total			Distribution	BGS and Other Charges	Total		BGS and Other Charges		Difference
(kW				red kW I		D Demand	D Energy	(\$)	(\$)	(\$)	D Demand	D Energy	(\$)	(\$)	(\$)	(\$)	(\$)	(\$)	(%)
25 25	31		650 475	25.00 25.00	22 \$ 22 \$	250.75 250.75	\$ (5.92) \$ (8.87)		\$ 467.20 \$ 630.17		\$ 295.25 \$ 295.25		\$ 1,115.67 \$ 1,112.72		\$ 1,582.87 \$ 1.742.89	\$ 126.69 \$ 126.69	\$ - \$ -	\$ 126.69 \$ 126.69	8.7% 7.8%
25	41		300	25.00	22 \$					\$ 1,016.20			\$ 1,112.72		\$ 1,742.89		\$ - \$	\$ 126.69	7.0%
25	5		125	25.00	22 \$		\$ (14.79)		\$ 956.12				\$ 1,106.80		\$ 2,062.92		\$ - \$ -	\$ 126.69	
25	6		.950	25.00	22 \$				\$ 1,119.10				\$ 1,103.84		\$ 2,222.94		\$ -	\$ 126.69	6.0%
25	7		775	25.00	22 \$								\$ 1,100.88		\$ 2,382.96		\$ -	\$ 126.69	5.6%
25	8		600	25.00	22 \$				\$ 1,445.05			\$ (23.67)	\$ 1,097.92		\$ 2,542.97	\$ 126.69	\$ -	\$ 126.69	5.2%
50	2		300	50.00	47 \$					\$ 2,168.22					\$ 2,339.41	\$ 171.19		\$ 171.19	
50	3		,950	50.00	47 \$				\$ 1,260.35				\$ 1,399.09		\$ 2,659.44	\$ 171.19		\$ 171.19	6.9%
50	41		,600	50.00	47 \$				\$ 1,586.30						\$ 2,979.47	\$ 171.19		\$ 171.19	
50 50	51 61		,250 .900	50.00	47 \$ 47 \$		\$ (29.58)		\$ 1,912.25 \$ 2,238.20			\$ (29.58) \$ (35.50)	\$ 1,387.26		\$ 3,299.51 \$ 3.619.54	\$ 171.19 \$ 171.19	\$ -	\$ 171.19 \$ 171.19	
50	7		.550	50.00 50.00	47 \$		\$ (35.50) \$ (41.42)		\$ 2,238.20 \$ 2,564.15		*	\$ (35.50)			\$ 3,619.54 \$ 3,939.57		\$ - \$	\$ 171.19	
50	8		.200	50.00	47 \$		\$ (47.33)		\$ 2,890.10		*		\$ 1,369.51		\$ 4.259.61	\$ 171.19	Ψ	\$ 171.19	4.2%
100	2		.600	100.00	97 \$		\$ (23.67)		\$ 1.868.80				\$ 1,983.67		\$ 3.852.47	\$ 260.19		\$ 260.19	
100	3	0 21	900	100.00	97 \$	1,003.00	\$ (35.50)	\$ 1,711.65	\$ 2,520.70	\$ 4,232.35	\$ 1,181.00		\$ 1,971.84	\$ 2,520.70	\$ 4,492.54	\$ 260.19	\$ -	\$ 260.19	6.1%
100	4	0 29	200	100.00	97 \$	1,003.00	\$ (47.33)	\$ 1,699.82	\$ 3,172.60	\$ 4,872.42	\$ 1,181.00	\$ (47.33)	\$ 1,960.01	\$ 3,172.60	\$ 5,132.61	\$ 260.19	\$ -	\$ 260.19	5.3%
100	5		,500	100.00	97 \$		\$ (59.17)		\$ 3,824.50		\$ 1,181.00	\$ (59.17)	\$ 1,948.17		\$ 5,772.67		\$ -	\$ 260.19	4.7%
100	6		,800	100.00	97 \$					\$ 6,152.55					\$ 6,412.74	\$ 260.19		\$ 260.19	
100	7		,100	100.00	97 \$		\$ (82.83)		\$ 5,128.30				\$ 1,924.51		\$ 7,052.81	\$ 260.19		\$ 260.19	
100	20		400	100.00	97 \$		\$ (94.67)		\$ 5,780.20				\$ 1,912.67		\$ 7,692.87	\$ 260.19 \$ 616.19	\$ - \$ -	\$ 260.19 \$ 616.19	
300 300	31		,800 ,700	300.00	297 \$ 297 \$		\$ (71.00) \$ (106.50)		\$ 5,606.40	\$ 9,288.55 \$ 11,208.75			\$ 4,298.34 \$ 4,262.84		\$ 9,904.74 \$ 11,824.94	\$ 616.19 \$ 616.19		\$ 616.19 \$ 616.19	6.6% 5.5%
300	41		.600	300.00	297 \$		\$ (142.00)			\$ 13,128.95		\$ (100.50)	\$ 4,227.34		\$ 13,745.14		\$ - \$ -	\$ 616.19	4.7%
300	5		0.500	300.00			\$ (177.50)			\$ 15,049.15			\$ 4,191.84		\$ 15,665.34	\$ 616.19		\$ 616.19	
300	6		.400	300.00			\$ (213.00)			\$ 16,969.35			\$ 4,156.34		\$ 17.585.54	\$ 616.19		\$ 616.19	
300	7	0 153	3,300	300.00	297 \$	3,009.00	\$ (248.50)	\$ 3,504.65	\$ 15,384.89	\$ 18,889.55	\$ 3,543.00	\$ (248.50)	\$ 4,120.84	\$ 15,384.89	\$ 19,505.74	\$ 616.19	\$ -	\$ 616.19	3.3%
300	8		,200	300.00	297 \$		\$ (284.00)			\$ 20,809.74		\$ (284.00)	\$ 4,085.34		\$ 21,425.93		\$ -	\$ 616.19	
500	2		,000	500.00	497 \$		\$ (118.33)			\$ 14,984.81			\$ 6,613.01		\$ 15,957.00	\$ 972.19		\$ 972.19	6.5%
500	31		,500	500.00	497 \$		\$ (177.50)			\$ 18,185.15		\$ (177.50)			\$ 19,157.34	\$ 972.19		\$ 972.19	
500 500	41 51		5,000 2,500	500.00 500.00	497 \$		\$ (236.67) \$ (295.83)			\$ 21,385.48 \$ 24,585.81			\$ 6,494.67 \$ 6,435.51	\$ 15,862.99 \$ 19,122.49	\$ 22,357.67 \$ 25.558.00	\$ 972.19 \$ 972.19	\$ -	\$ 972.19 \$ 972.19	4.5% 4.0%
500	6		1.000	500.00			\$ (295.03)			\$ 24,565.61			\$ 6,376.34		\$ 25,556.00	\$ 972.19		\$ 972.19	
500	7		5.500	500.00			\$ (414.17)			\$ 30,986.48			\$ 6,317.17		\$ 31.958.67	\$ 972.19		\$ 972.19	
500	8		2.000	500.00	497 \$		\$ (473.33)			\$ 34.186.81		\$ (473.33)	\$ 6,258.01		\$ 35,159.00		\$ -	\$ 972.19	2.8%
750	3		,250	750.00			\$ (266.25)			\$ 26,905.64		\$ (266.25)			\$ 28,322.83	\$ 1,417.19	\$ -	\$ 1,417.19	5.3%
750	4	0 219	,000	750.00	747 \$	7,522.50	\$ (355.00)	\$ 7,911.65	\$ 23,794.49	\$ 31,706.14	\$ 8,857.50	\$ (355.00)	\$ 9,328.84	\$ 23,794.49	\$ 33,123.33	\$ 1,417.19	\$ -	\$ 1,417.19	4.5%
750	5		3,750	750.00	747 \$	7,522.50	\$ (443.75)		\$ 28,683.74	\$ 36,506.64	\$ 8,857.50	\$ (443.75)	\$ 9,240.09	\$ 28,683.74	\$ 37,923.83	\$ 1,417.19	\$ -	\$ 1,417.19	3.9%
750	6			750.00	747 \$		\$ (532.50)			\$ 41,307.14		\$ (532.50)			\$ 42,724.33		\$ -	\$ 1,417.19	3.4%
750	7		3,250	750.00			\$ (621.25)			\$ 46,107.64			\$ 9,062.59		\$ 47,524.83	\$ 1,417.19		\$ 1,417.19	3.1%
750	81		3,000	750.00			\$ (710.00)			\$ 50,908.14		\$ (710.00)			\$ 52,325.33	\$ 1,417.19		\$ 1,417.19	2.8%
750 1,000	91		2,750 0,000 1	750.00 1,000.00			\$ (798.75) \$ (355.00)			\$ 55,708.63 \$ 35,626.14		\$ (798.75) \$ (355.00)	\$ 8,885.09 \$ 12,281.34		\$ 57,125.82 \$ 37,488.33	\$ 1,417.19 \$ 1,862.19	\$ - \$ -	\$ 1,417.19 \$ 1,862.19	2.5% 5.2%
1,00				1,000.00			\$ (473.33)			\$ 42,026.81		\$ (473.33)		\$ 25,206.99		\$ 1,862.19		\$ 1,862.19	4.4%
1,00				1,000.00			\$ (591.67)			\$ 48,427.47	\$ 11,810.00				\$ 50,289.66	\$ 1,862.19		\$ 1,862.19	3.8%
1,00				1,000.00			\$ (710.00)			\$ 54,828.14		\$ (710.00)		\$ 44,763.98			\$ -	\$ 1,862.19	3.4%
1,00	7	0 511	,000 1	1,000.00	997 \$	10,030.00	\$ (828.33)	\$ 9,945.82	\$ 51,282.98	\$ 61,228.80	\$ 11,810.00	\$ (828.33)	\$ 11,808.01	\$ 51,282.98	\$ 63,090.99	\$ 1,862.19	\$ -	\$ 1,862.19	
1,00				00.000,1			\$ (946.66)			\$ 67,629.46		\$ (946.66)		\$ 57,801.98			\$ -	\$ 1,862.19	2.8%
1,000				00.000,1			\$ (1,065.00)			\$ 74,030.13					\$ 75,892.32	\$ 1,862.19		\$ 1,862.19	
2,000				2,000.00			\$ (710.00)			\$ 70,508.14			\$ 23,736.34		\$ 74,150.33		\$ -	\$ 3,642.19	5.2%
2,000				2,000.00				\$ 19,857.49		\$ 83,309.46			\$ 23,499.68		\$ 86,951.65	\$ 3,642.19		\$ 3,642.19	
2,000				2,000.00			\$ (1,183.33) \$ (1,420.00)			\$ 96,110.79 \$ 108,912.12			\$ 23,263.01	\$ 76,489.97 \$ 89,527.97			\$ - \$ -	\$ 3,642.19 \$ 3.642.19	3.8% 3.3%
2,000				2.000.00				\$ 19,147.49		\$ 121,713.45			\$ 22,789.68	\$ 102,565.96			\$ - \$	\$ 3,642.19	3.0%
2,00				2,000.00				\$ 18,910.82		\$ 134,514.78	\$ 23,620.00			\$ 115,603.96		\$ 3,642.19	*	\$ 3,642.19	2.7%
2,00	9	0 1,31	4,000 2	2,000.00	1997 \$	20,060.00	\$ (2,129.99)	\$ 18,674.16	\$ 128,641.95	\$ 147,316.11	\$ 23,620.00	\$ (2,129.99)	\$ 22,316.35	\$ 128,641.95	\$ 150,958.30	\$ 3,642.19	\$ -	\$ 3,642.19	2.5%

IN THE MATTER OF THE PETITION OF ATLANTIC CITY ELECTRIC COMPANY FOR APPROVAL OF AMENDMENTS TO ITS TARIFF TO PROVIDE FOR AN INCREASE IN RATES AND CHARGES FOR ELECTRIC SERVICE PURSUANT TO N.J.S.A. 48:2-21 AND N.J.S.A. 48:2-21.1, AND FOR OTHER APPROPRIATE RELIEF (2/2023)

STATE OF NEW JERSEY BOARD OF PUBLIC UTILITIES

CERTIFICATION OF SERVICE

CYNTHIA L.M. HOLLAND, of full age, certifies as follows:

- 1. I am an attorney at law of the State of New Jersey and am Assistant General Counsel to Atlantic City Electric Company, the Petitioner in the within matter, with which I am familiar.
- 2. I hereby certify that, on February 15, 20023, I caused the within Petition and the supporting testimony, schedules, and exhibits thereto, to be filed with the New Jersey Board of Public Utilities (the "Board") through its eFiling Portal. I also caused an electronic copy to be sent to the Board Secretary's office at board.secretary@bpu.state.nj.us.
- 3. I further certify that, on February 15, 2023, I caused a complete copy of the Petition and the supporting testimony, schedules, and exhibits thereto, to be sent by electronic mail to each of the parties listed in the attached Service List.
- 4. Consistent with the Order issued by the Board in connection with *In the Matter of the New Jersey Board of Public Utilities' Response to the COVID-19 Pandemic for a Temporary Waiver of Requirements for Certain Non-Essential Obligations*, BPU Docket No. EO20030254, Order dated March 19, 2020, only electronic copies of this Petition have been served on persons on the service list.

5. I further and finally 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.

Dated: February 15, 2023

CYNTHIA L.M. HOLLAND

An Attorney at Law of the State of New Jersey

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I/M/O the Petition of Atlantic City Electric Company for Approval of Amendments to Its Tariff to Provide for an Increase in Rates and Charges for Electric Service Pursuant to *N.J.S.A.* 48:2-21 and *N.J.S.A.* 48:2-21.1, and for Other Appropriate Relief (2023) BPU Docket No. ER23020091

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• Does Not Receive Discovery