IN THE MATTER OF THE PROVISION OF BASIC GENERATION SERVICE FOR THE PERIOD BEGINNING JUNE 1, 2027	STATE OF NEW JERSEY BOARD OF PUBLIC UTILITIES BPU DOCKET NO. ER26040105

ATLANTIC CITY ELECTRIC COMPANY

BASIC GENERATION SERVICE COMMENCING JUNE 1, 2027

COMPANY-SPECIFIC ADDENDUM FILING

Proposal Dated July 1, 2026

ATLANTIC CITY ELECTRIC COMPANY'S
COMPANY-SPECIFIC ADDENDUM

The following contains the company-specific material (referred to herein as the "Addendum") of Atlantic City Electric Company ("ACE" or the "Company") for the joint compliance filing made with the New Jersey Board of Public Utilities (the "Board" or "BPU") on this date by the Electric Distribution Companies (the "EDCs") in this docket. Capitalized terms used herein shall have the meanings defined in the joint filing.

As described in the generic section of this filing, two (2) different methods will be utilized for the pricing of Basic Generation Service ("BGS") to customers: (1) residential and small commercial energy pricing, and (2) variable hourly energy pricing. The residential and small commercial energy pricing, formerly referred to as "Basic Generation Service–Fixed Price" or "BGS-FP", is now termed "Basic Generation Service–Residential Small Commercial Pricing" or "BGS-RSCP". The variable hourly energy pricing service is termed "Basic Generation Service – Commercial and Industrial Energy Pricing" or "BGS- CIEP." BGS-RSCP will be available to all residential and small commercial customers, specifically those customers taking service on Rate Schedules RS, EV-ERR, MGS (Secondary, Secondary Electric Vehicle Charging, and Primary), AGS (Secondary and Primary), DDC, SPL, and CSL. These rate classes comprise the vast majority of ACE's customers and approximately 94% of the usage on the ACE electric system. As described in detail later in this filing, BGS-RSCP commercial or industrial customers can opt in to BGS-CIEP.

BGS-CIEP will continue to be the only default supply option available to customers taking service under ACE's Rate Schedule TGS (Transmission General Service). Pursuant to the Board's Decision on June 18, 2012, in BPU Docket No. ER12020150, changing the BGS-CIEP required customer capacity peak load share ("PLS") to 500 kW or greater effective June 1, 2013,

BGS-CIEP will be the only default supply option available to customers on Rate Schedules MGS Secondary, MGS Secondary Electric Vehicle Charging, MGS Primary, AGS Secondary or AGS Primary with an annual PLS for generation capacity equal to or greater than 500 kW as of November 1 of the year prior to the BGS auction. There are an estimated 192 eligible CIEP customers representing approximately 6% of the usage on the ACE electric system, whose only default supply option is BGS-CIEP. As described in detail later in this filing, BGS-CIEP will also be available to any commercial or industrial customer on a voluntary basis, regardless of such customer's regular Rate Schedule.

A. CONTINGENCY PLANS

While not every contingency can be anticipated, ACE can anticipate four (4) areas of concern:

a) an insufficient number of bids to provide for a fully subscribed Auction Volume either for the BGS-RSCP auction or the BGS-CIEP auction;

b) a default by a winning bidder prior to June 2027;

c) a default during the June 1, 2027 - May 31, 2028 supply period, under the BGS-CIEP contracts entered into for 12 months; and/or

d) a default during the June 1, 2027 - May 31, 2030 supply period, under the BGS-RSCP contracts entered into for 36 months.

1. Insufficient Number of Bids in Auction

To ensure that the auction process achieves the best price for customers, there must be a sufficient degree of competition in the auction. To ensure a sufficient degree of competition, the volume of BGS-RSCP and BGS-CIEP Load purchased at each auction will be finally decided after the first round of bids are received. Provided that there are sufficient bids at the starting prices, the auctions will be held for 100% of BGS-RSCP and BGS-CIEP Loads.

It is possible that the number of initial bids will not result in a competitive auction for 100% of the BGS-RSCP or BGS-CIEP Load. This determination will be made by the Auction Manager in consultation with the EDCs and the Board Advisor.

In the event that the Auction Volume is reduced to less than 100% of BGS-RSCP or BGS-CIEP Load, ACE, at its option, will implement a Contingency Plan for the remaining tranches. Under the Plan, ACE will purchase necessary services (including, but not limited to, network transmission, capacity, energy and ancillary services, and any required Renewable Portfolio Standards ("RPS") Renewable Energy Certificate) for the remaining tranches through PJM-administered markets until May 31, 2028. Any unsubscribed tranches for the period after May 31, 2028, may be included in a subsequent auction or treated pursuant to the provisions of part 4 of the Contingency Plan described below. This Contingency Plan will alert bidders that, in order to secure BGS-RSCP and BGS-CIEP prices from New Jersey BGS customers for their supply, it will be necessary to bid in the auctions.

Since the Contingency Plan calls for the purchase of BGS supply in PJM-administered markets, it is considered a prominent feature of the auction proposal because it provides bidders a strong incentive to participate in the auction process. If bidders were to believe that a less than fully subscribed auction would lead to a negotiation or a secondary market in which ACE, on behalf of its customers, would seek to acquire BGS supplies, the incentive to participate in the auctions and the incentive to offer the best deal in the auctions would be subsequently diminished.

2. Defaults Prior to June 1, 2027

If a winning bidder defaults prior to the beginning of the BGS service, then, at ACE's option, the open tranches may first be offered to the other winning bidders or will be filled as provided in part 3, below. Additional costs incurred by ACE in implementing the Contingency Plan will be assessed against the defaulting supplier's credit security.

3. Defaults During the June 1, 2027 - May 31, 2028 Supply Period

If a default occurs during the June 1, 2027 - May 31, 2028 period, for those contracts entered into for 12 months, at ACE's option, the tranches supplied by the defaulting supplier may be offered to the other winning bidders, may be bid out or may be procured from PJM-administered markets. Additional costs incurred by ACE in implementing this part of the Contingency Plan will be assessed against the defaulting suppliers' credit security.

If circumstances are such that it is not practical to find another such supplier, ACE proposes to utilize a process similar to the "flexible portfolio approach" for BGS wholesale supply, as previously described in ACE's filing in BPU Docket No. EM00080604, as noted in the Board's November 29, 2000 Order in that docket. This approach relies on a combination of competitive sources for BGS power, including Requests for Proposal(s), broker markets, capacity costs based on the PJM Reliability Pricing Model ("RPM"), and the PJM spot energy market.

4. Defaults During the June 1, 2027 - May 31, 2030 Supply Period

If a default occurs during the June 1, 2027 - May 31, 2030 period, for those contracts entered into for 36 months, at ACE's option, the tranches supplied by the defaulting supplier may be offered to the other winning bidders, may be bid out or may be procured from PJM-administered markets. Among the options for bidding out the tranches, ACE may include such tranches in the next BGS procurement. Additional costs incurred by ACE in implementing this part of the Contingency Plan will be assessed against the defaulting suppliers' credit security.

If circumstances are such that it is not practical to find another such supplier, ACE proposes to utilize a process similar to the "flexible portfolio approach" for BGS wholesale supply, as previously described in the Company's filing in BPU Docket No. EM00080604, as noted in the Board's November 29, 2000 Order in that docket. This approach relies on a combination of competitive sources for BGS power, including requests for proposal, broker markets, capacity costs based on the PJM RPM, and the PJM spot energy market.

B. ACCOUNTING AND COST RECOVERY

The accounting and cost recovery that ACE will use for its BGS service is summarized in this Section. These provisions are intended to be applicable to ACE only. Each EDC will provide these individual BGS cost recovery methodologies.

ACE's BGS accounting will account for BGS-RSCP revenues and BGS-CIEP revenues individually as follows:

1. BGS-RSCP and BGS-CIEP revenues will be tracked using established accounting procedures and recorded separately as BGS-RSCP revenue and BGS-CIEP revenue; and
2. as previously established for ACE, uncollectible revenues are recovered through a component of ACE's Societal Benefits Charge.

ACE will account for BGS-RSCP and BGS-CIEP costs individually as the sum of the following:

1. all payments made for the provision of BGS-RSCP and BGS CIEP service, including CIEP Standby Fee payments; and
2. any administrative costs associated with the provision of BGS-RSCP and BGS-CIEP service:

a. Administrative costs are defined as commonly-incurred or directly-incurred. *Commonly-incurred costs* are costs shared among all of the New Jersey EDCs. *Directly-incurred costs* are costs specifically incurred by each EDC, individually.

Commonly-incurred costs include, but are not limited to, the following:

- preparing and conducting the annual auction, which include all pre-auction development work, developing and printing materials, developing and maintaining the BGS auction website, conducting information sessions for prospective bidders, as well as other consulting services provided by the Auction Manager;
- oversight of the auction process on behalf of the BPU, as performed by the Board's consultant;
- outside counsel legal costs associated with the prosecution and/or defense of BGS patent claims; and
- facility costs associated with viewing the annual auction in real time, which include, but are not limited to, costs for physical space and equipment/media connections.

Directly-incurred costs for ACE include, but are not limited to, the following:

- labor costs and expenses associated with employees who are considered incremental to the BGS process;
- system and software costs related to tracking BGS costs and invoicing;
- power procurement residual costs; and
- other administrative fees incurred in connection with the BGS process, including, but not limited to, fees/licenses, costs associated with public hearings, postage, and information technology support and programming changes necessitated by BPU directives.

The commonly-incurred cost estimates for each BGS Auction cycle are paid for by the winning bidders of the auction at the start of each Energy Year ("EY") through the Tranche Fee. The difference between the estimated commonly-incurred costs and the actual commonly-incurred costs and all the directly-incurred costs are paid through the BGS Reconciliation Charges.

3. any cost for procurement of capacity, energy, ancillary service, transmission, RPS compliance, and other expenses related to the Contingency Plan, and any payments to the winners of a subsequent bid process to cover defaults made under the Contingency Plan, less any payments recovered from defaulting bidders. In the event that implementation of the Contingency Plan is required for BGS CIEP load, CIEP Standby Fee payments will be tracked separately.

BGS-RSCP and BGS-CIEP rates will be subject to deferred accounting since there will be differences between the BGS costs (as defined above) and BGS-related revenues. Adjustment type charges (also subject to deferred accounting) are necessary in order to balance out the difference between the amount paid to the BGS-RSCP and BGS-CIEP supplier(s) for BGS-RSCP and BGS-CIEP supply, and the revenue from customers for BGS-RSCP and BGS-CIEP services. ACE calculates the reconciliation charges ("RC"), including interest on a quarterly basis. The RC, including interest, will be calculated quarterly for BGS-RSCP and BGS-CIEP on a cent per kWh basis, and the respective rates will be applied to all BGS-RSCP and BGS-CIEP kWh. These charges will be combined with the fixed, seasonally-differentiated BGS-RSCP and hourly BGS-CIEP charges for billing; although they will be published in ACE's Rider BGS as separate BGS-RSCPRC and BGS-CIEPRC rates that will be revised quarterly.

The following table summarizes ACE's quarterly reconciliation schedule:

Reconciliation for the Months of:	**Quarterly Rate in Effect:**
January – March	June 1– August 31
April – June	September 1– November 30
July – September	December 1– February 28
October – December	March 1– May 31

A BGS deferral/credit will be determined individually for the BGS-RSCP and BGS-CIEP rates as the difference between recorded BGS-RSCP or BGS-CIEP revenue and the total BGS-RSCP or BGS-CIEP cost. The individual BGS deferrals will be accounted for in the following manner:

1. If individual BGS costs, as defined above, are higher than individual BGS recorded revenue, the difference will be charged on a monthly basis to the cost deferral to be reconciled and recovered from customers, with interest, on a quarterly basis through the BGS-RSCPRC and/or the BGS-CIEPRC.
2. If individual BGS costs, as defined above, are lower than individual BGS recorded revenue, the difference will be credited monthly, to the cost deferral to be reconciled and returned to customers, with interest, on a quarterly basis through the BGS-RSCPRC and/or BGS-CIEPRC.

A separate deferred balance will be maintained individually for the BGS-RSCPRC and BGS-CIEPRC rates to ensure full recovery and reconciliation of all the costs associated with the provision of BGS service.

In the event the Contingency Plan is required to be implemented to serve BGS-CIEP load, the difference between CIEP Standby Fee revenues and CIEP Standby Fee payments made to winning BGS-CIEP auction bidders will be maintained in a separate deferred balance account. Interest on this account will be accrued monthly, using the same methodology and interest rate as used for the BGS-RSCP and BGS-CIEP deferred balances. Any debit/credit balance in this account at the end of the BGS period of June 1, 2027 through May 31, 2028 will be applied as a $/kWh adjustment to the CIEP Standby Fee for the next BGS-CIEP annual period. In this manner, the mechanism to reconcile any CIEP Standby Fee deferred balance is applied, to the greatest

extent practicable, to all BGS-CIEP eligible customers who paid the CIEP Standby Fee, and not only to those taking BGS-CIEP service.

With the exception of any adjustment to the CIEP Standby Fee which may be required, ACE will follow the following schedule for the quarterly reconciliation of its BGS-RSCP and BGS- CIEP rates:

1. For BGS-RSCPRC and BGS-CIEPRC rates effective June 1, the actual data for the months of January through March will be used.
2. For BGS-RSCPRC and BGS-CIEPRC rates effective September 1, the actual data for the months of April through June will be used.
3. For BGS-RSCPRC and BGS-CIEPRC rates effective December 1, the actual data for the months of July through September will be used.
4. For BGS-RSCPRC and BGS-CIEPRC rates effective March 1, the actual data for the months of October through December will be used.

ACE will file BGS-RSCPRC and BGS-CIEPRC rates with the Board at least 30 days in advance of the date upon which they are requested to be effective. The BGS Reconciliation Rate will be capped at two cents per kWh. The filed rates will become effective 30 days after filing, absent a determination of manifest error by the Board. To minimize volatility in the quarterly reconciliation charge or credit, ACE may propose an adjustment to the reconciliation rate based on forecasted sales and revenues. The purpose of such adjustment is to mitigate the impact of temporary seasonal sales fluctuations on the accumulated reconcilable balance and avoid setting a charge or credit rate that does not reasonably reflect expected cost recovery. This may include variances attributable to seasonal fluctuations that are expected to reverse in subsequent periods.

C. DESCRIPTION OF BGS TARIFF SHEETS

This Section describes the proposed tariff sheets needed to implement ACE's BGS proposal. The proposed tariff sheets for Tariff Rider Basic Generation Service ("Rider BGS") are included as **Attachment 1**. Rider BGS provides the rates, terms, and conditions for customers being served under the BGS-RSCP or BGS-CIEP pricing mechanisms.

1. BGS-RSCP

BGS-RSCP will be available to all customers served on Rate Schedules RS, EV-ERR, DDC, SPL, and CSL. BGS-RSCP is also available to customers with a PLS of less than 500 kW who are served under Rate Schedules MGS Secondary, MGS Secondary Electric Vehicle Charging, MGS Primary, AGS Secondary, and AGS Primary. On any meter reading date, and with prior requisite notice, a customer taking supply service under BGS-RSCP may switch to third-party supply service, and a customer taking third-party supply service may switch to BGS-RSCP supply service.

As indicated on the proposed tariff sheets, BGS-RSCP is made up of two components: (1) the BGS Supply Charges and (2) the BGS Reconciliation Charge. Additionally, each BGS customer is subject to transmission charges as discussed below.

a. BGS Supply Charges

The values of the BGS Supply charges applicable to Rate Schedules RS, EV-ERR, MGS Secondary, MGS Secondary Electric Vehicle Charging, MGS Primary, AGS Secondary, AGS Primary, DDC, SPL, and CSL include the costs related to energy, generation capacity, RPS, ancillary services, and administration. This is a continuation of the currently approved methodology for recovering all electric supply service costs in the kilowatt-hour charges for these Rate Schedules.

Typically, the generation capacity costs used in the development of the BGS-RSCP rates would have been based on the average of the relevant wholesale market prices for capacity from the Base Residual Auctions ("BRA") under the RPM applicable to load served in the ACE zone for the following three years (i.e. average of 2027/2028, 2028/2029, and 2029/2030). Given recent delays in conducting the BRAs, expected capacity prices for future years may no longer be known, resulting in the need for Capacity Proxy prices (i.e. capacity price estimates) within BGS auction contracts. The contract supplements with Capacity Proxy prices for the applicable delivery years with delayed BRAs are later adjusted to the actual BRA price once known. PJM issued a schedule of upcoming BRAs, and the recently conducted BRA produced a preliminary price paid for capacity of $333.69 per MW-day for the 2027/2028 Delivery Year for the ACE Zone. Due to the delays of the BRAs, contracts from the 2025 and 2026 BGS auctions contained supplements with Capacity Proxy Prices.

Previously, with the delays of the BRAs for the 2026/2027, 2027/2028, and 2028/2029 Delivery Years, a Capacity Proxy Price of $270.35 per MW-Day was used in place of the 2026/2027 and 2027/2028 BRA values in the 2025 contracts. A Capacity Proxy Price of $333.69 per MW-Day was used in place for the 2028/2029 BRA in the 2026 contracts.

Given the continued delay in the schedule of BRAs for the 2028/2029 Delivery Year and 2029/2030 Delivery Year, a Capacity Proxy Price of $333.69 per MW-Day has been used in place of the prices paid for capacity for 2028/2029 Delivery Year and 2029/2030 Delivery Year.

For EY 2029, if Supplement A to the BGS-RSCP Supplier Master Agreement is approved by the BPU, and if the BRA for the 2028/2029 Delivery has not occurred at least five (5) business days prior to the BGS-RSCP Auction, payments to BGS-RSCP suppliers will be adjusted for the difference between the "Zonal Capacity Price," which is the price paid by BGS-RSCP Suppliers

for Capacity in the Company's PJM zone, as may be determined under the RPM or its successor or otherwise, and the Capacity Proxy Price for the 2028/2029 Delivery Year.

For EY 2030, if Supplement B to the BGS-RSCP Supplier Master Agreement is approved by the BPU and if the BRA for the 2029/2030 Delivery has not occurred at least five (5) business days prior to the BGS-RSCP Auction, payments to BGS-RSCP suppliers will be adjusted for the capacity price difference between the Zonal Capacity Price, which is the price paid by BGS-RSCP Suppliers for Capacity in the Company's PJM zone, as may be determined under the RPM or its successor or otherwise, and the Capacity Proxy Price for the 2029/2030 Delivery Year.

ACE will file new tariff sheets for EY 2029 and 2030, reflecting the impact of this price adjustment in a manner similar to **Attachment 4**, page 1 – Development of Capacity Proxy Price True Up - $/MWh. The rate design spreadsheets include the formulas that will be used to reflect the impact of payments made pursuant to the Supplements. However, the spreadsheets do not provide a value for the EY 2029 and 2030 true-ups as the actual values are not known at this time. **Attachment 4**, pages 2 and 3 provide illustrative examples of how the Capacity Proxy Price True Up will be calculated for EY 2029 and EY 2030 respectively and prospectively.

The Supplements to the SMAs signed by BGS-RSCP Suppliers in February 2025 and February 2026 are still in effect for approximately two-thirds of the load for EY 2028 (the year beginning June 1, 2026). Payments to BGS-RSCP suppliers that executed the Supplements to the SMAs approved by the BPU on November 21, 2024 and November 21, 2025 will be adjusted for the price difference between the price paid by BGS-RSCP Suppliers for Capacity in the Company's PJM Zone and the Capacity Proxy Price for the 2027/2028 Delivery Year. Upon the conclusion of the Third Incremental RPM Auction, or the RPM's successor or otherwise, the price paid by BGS-RSCP Suppliers for Capacity in the Company's PJM Zone will be known. At that

time, ACE will file new tariff sheets reflecting the impact of the Supplements. The rate design spreadsheets include the formulas that will be used to reflect the impact of payments made pursuant to the Supplements executed by BGS-RSCP Suppliers in February 2025 and February 2026. The value of the recently conducted BRA that was made available in December 2025 is used as an approximation for the price paid by BGS-RSCP Suppliers for Capacity in the Company's PJM Zone for the 2027/2028 Delivery Year ($333.69 per MW-Day).

The specific values that will be utilized for the BGS Supply Charges will be calculated as the tranche-weighted average of the winning BGS-RSCP bid prices for the ACE zone, adjusted for the seasonal payment factors for ACE's Atlantic Electric zone, adjusted by the appropriate factor (multiplier and constant, if applicable) as shown on Table No. 14 of the Development of Post Transition Period BGS Cost and Bid Factor Tables, included in **Attachment 2**.

It is the intent of ACE that the factors in the tables will be applied to the tranche-weighted average of the winning BGS-RSCP bid prices adjusted for the seasonal payment factors. For the period beginning June 1, 2027, the pricing will be based on the 36-month auction price, the 36-month price from the auction held in February 2026, and the 36-month price from the auction held in February 2025. The tables will be updated annually prior to future BGS auctions and will be utilized to develop customer charges for a related annual period in a similar manner as described above. The updates will reflect then current factors such as updated futures prices, factors based on 12-month data, and any changes in the customer groups and loads eligible for the BGS-RSCP class.

b. BGS Reconciliation Charge

This is the implementation of the BGS Reconciliation Charge for BGS-RSCP as explained in the Accounting and Cost Recovery section of this Addendum.

c. Transmission Charges

Transmission service will continue to be billed under the rates, terms, and conditions of the customer's applicable Rate Schedule as set forth in the ACE Tariff for Electric Service. The transmission charges applicable to ACE's BGS-RSCP customers are based on the annual transmission rate for network service for the ACE zone, as stated in PJM's Open Access Transmission Tariff ("OATT"). As part of a settlement approved by the Federal Energy Regulatory Commission ("FERC") on August 9, 2004, certain transmission owners in PJM, including ACE, agreed to re-examine their existing rates and propose a method (such as a formula rate) to harmonize new and existing transmission investments by January 31, 2005, with such new rate(s) (if any) to go into effect June 1, 2005. The objective of the formula rate filing is to establish a just and reasonable method for determining the transmission revenue requirements for the affected transmission pricing zones which would reflect both existing and new investment on a current basis. The formula rate tracks increases and decreases in costs such that no under-recovery nor over-recovery of actual costs will occur. The formula rate protocols include provisions for an annual update to the rate based on current levels of costs and reconciliation of prior period costs and revenues. Pursuant to the protocols established in the settlement, the Company will file updates to the formula rate at FERC on or about May 15 of each year to be effective on June 1 of that same year. The Company will make corresponding filings with the Board each year seeking approval of the formula rates on a retail level.

In addition to the formula rate protocols described above, the transmission charge may change from time to time as FERC approves other changes in the PJM OATT and related charges. The transmission cost component of the BGS-RSCP charges to customers will change from time to time as FERC approves changes in the Network Integration Transmission Service rates for the ACE zone in the PJM OATT or FERC approves other network transmission-related charges in the PJM OATT.

ACE will provide the basis for any transmission cost adjustment, and will file supporting documentation from the OATT, as well as any rate translation spreadsheets used.

2. BGS-CIEP

BGS-CIEP will be the only default supply option available to customers served on Rate Schedule TGS (Transmission General Service), and to customers served on Rate Schedules MGS Secondary, MGS Secondary Electric Vehicle Charging, MGS Primary, AGS Secondary, and AGS Primary with a PLS of 500 kW and higher as of November 1 of the year prior to the BGS auctions. Additionally, BGS-CIEP is available on a voluntary basis to any commercial or industrial customer taking service under the MGS or AGS Rate Schedules. To be eligible for BGS-CIEP, the customer will need to notify ACE of its choice no later than the second working day of a given year and must commit to having BGS-CIEP as its default supply service option for a 12-month period commencing June 1 of that year. All commercial and industrial customers taking service under the MGS or AGS Rate Schedules will be notified of their option to switch to BGS-CIEP through the Company's website and tariffs. Customers who elected BGS-CIEP in a prior procurement period and who are eligible to receive BGS-RSCP service may return to BGS-RSCP if they notify ACE of their intent to return to BGS-RSCP default service no later than the second working day of January. Such election will be effective on June 1 of that year.

The charges for BGS-CIEP are comprised of three segments: (1) BGS Energy Charges, (2) BGS Capacity Charges, and (3) BGS Reconciliation Charges. Transmission service will continue to be billed under the rates, terms, and conditions of the customer's applicable Rate Schedule as set forth in the ACE Tariff for Electric Service. The transmission charges applicable to ACE's BGS-CIEP customers are based on the annual transmission rate for network service for the ACE zone, as stated in PJM's OATT. As part of a settlement approved by FERC on August 9, 2004, certain transmission owners in PJM, including ACE, agreed to re-examine their existing rates and propose a method (such as a formula rate) to harmonize new and existing transmission investments by January 31, 2005, with such new rate (if any) to go into effect June 1, 2005. The objective of the formula rate filing is to establish a just and reasonable method for determining the transmission revenue requirements for the affected transmission pricing zones which would reflect both existing and new investment on a current basis. The formula rate tracks increases and decreases in costs such that no under- and no over-recovery of actual costs will occur. The formula rate protocols include provisions for an annual update to the rate based on current levels of costs, and reconciliation of prior period costs and revenues. Pursuant to the protocols established in the settlement, the Company will file updates to the formula rate at FERC on or about May 15 of each year, to be effective on June 1 of that year. The Company will make corresponding filings with the Board each year seeking approval of the formula rates on a retail level.

In addition to the formula rate protocols described above, the transmission charge may change from time to time as FERC approves other changes in the PJM OATT and related charges. The transmission cost component of the BGS-CIEP charges to customers will change from time to time as FERC approves changes in the Network Integration Transmission Service rates for

the ACE zone in the PJM OATT or FERC approves other network transmission-related charges in the PJM OATT.

ACE will provide the basis for any transmission cost adjustment, and will file supporting documentation from the OATT, as well as any rate translation spreadsheets used.

a. BGS Energy Charge

One of the primary components of this charge will be the actual real time PJM load-weighted average Residual Metered Load Aggregate Locational Marginal Price ("LMP"), of energy for ACE's Atlantic Electric Transmission Zone. An estimate of the Ancillary Service cost for the ACE zone expressed on a dollar per MWh basis and administrative costs will be added to this charge. This sum will then be adjusted for losses for service according to the Rate Schedule for which this service is applicable.

b. BGS Capacity Charges

These charges will recover the costs associated with generation capacity. Effective with the supply period beginning June 1, 2009, the BGS Capacity Charge is based on the results of the BGS-CIEP auction process. This charge, Sales and Use Tax ("SUT"), and the Board Revenue Assessment will be applied to the customer's share of the PJM zonal capacity obligation.

D. ACE's BGS EV 2 Cents Program

ACE seeks the Board's approval to recover implementation and ongoing costs associated with ACE's BGS EV 2 Cents Program. Additionally, the Company proposes to terminate the BGS EV 2 Cents Program as of May 31, 2027, and instead make available to EV customers a revised Residential TOU (whole house) rate as outlined in the ACE Proposal to Revise the existing BGS Residential Time-of-Use section.

1. Background

On November 9, 2022, the Board ordered, in BPU Docket No. ER22030127 ("The November 2022 Order"), all EDC's to create a "BGS Time-of-Use ('TOU') rate" for electric vehicle ("EV") customers on the residential supply side to take effect June 1, 2023.

On April 6, 2023, ACE filed a petition, in BPU Docket No. ER23040209, to comply with the November 2022 Order. At the time, ACE did not have sufficient data from its AMI program or Smart Energy Network to create a TOU rate specifically tailored to the energy usage habits of its customers. The petition included the following details regarding ACE's BGS EV 2 Cents Program:

- ACE proposed to allow eligible customers to receive a net off-peak BGS energy credit exclusively for their EV usage. According to the proposed tariff, once approved by ACE, a customer would receive an off-bill credit issued twice a year by check.
- To be eligible, a customer must install or utilize approved smart charging equipment and network technology and agree to share the data with ACE. The Company proposed that, if the customer's on-peak usage is higher than off-peak usage for the billing period, no credit for the corresponding billing period will be provided.
- ACE requested that all costs associated with the proposed Tariff (including, but not limited to, the cost of the credits to customers, customer education and outreach, and the implementation costs of upgrading systems) flow through the Company's periodic BGS reconciliation charge filings

On May 24, 2023, the BPU issued its Order in Docket No. ER23040209 ("The May 2023 Order"), approving ACE's proposed BGS EV 2 Cents Program, recognizing its potential to support electric vehicle adoption and enhance customer engagement. The BPU did not approve ACE's cost recovery proposal at that time—due to the implementation costs not being finalized—but it did authorize ACE to defer the costs associated with implementing the BGS EV 2 Cents Program until the program was fully implemented. At that point, the Board directed ACE to file a petition to recover the deferred costs, which may include a proposal to recover through the BGS Reconciliation filing.

2. BGS EV TOU Program Cost Recovery

ACE seeks approval to recover costs incurred implementing and maintaining the BGS EV 2 Cents Program. The Board, pursuant to the May 2023 Order, authorized ACE to defer the costs associated with implementing the BGS EV TOU rate option until fully implemented and file a petition at such time to recover costs. As the BGS EV 2 Cents Program is now fully implemented, ACE submits that it may now recover those costs.

The Company is proposing to recover all costs associated with the BGS EV 2 Cents Program (including, but not limited to, the cost of the credits to customers, implementation costs of updating ACE's systems, and on-going administration costs) through the BGS Reconciliation Rate, which is applicable to all BGS-RSCP customers. ACE believes that recovery through the BGS Reconciliation is the appropriate cost recovery mechanism for costs related to BGS-RSCP, because the costs incurred were both reasonable and necessary to implement a TOU program as directed by the Board in the November 2022 Order.

To minimize the impact on customer bills, ACE proposes to amortize the accumulated costs over 24 months. ACE also proposes future ongoing costs incurred in this program to be recovered through the BGS Reconciliation. The following table summarizes the costs the Company incurred from the start of program implementation in September 2023 through May 2026 as related to the BGS EV 2 Cents Program:

BGS EV 2 Cents Program Costs *September 2023 - May 2026*	
Internal Implementation	$0
External Implementation	$336,385
Internal Program Management	$168,323
External Program Management	$916,772
Credit Disbursement Costs	$117,109
Total Program Costs	$1,538,588

3. Termination of the BGS EV 2 Cents Program

ACE also proposes the termination of the BGS EV 2 Cents Program as of May 31, 2027, because the program is not cost-effective. Administrative expenses significantly outweigh the customer credit benefits by a ratio of approximately 13:1. This means that for every dollar in benefits received by participating customers, the program incurs roughly 13 dollars in total costs. A major driver of these expenses is the reliance on a third-party vendor to collect EV charger usage data and process credits; a service that, while costly, is essential to the program's operation and cannot be avoided under the current structure. Offering a revised whole house TOU rate option can deliver comparable bill savings to customers, while eliminating the need for costly third-party data services and avoiding the burden of subsidizing these expenses across the broader ratepayer base.

Thus, in lieu of the BGS EV 2 Cents Program, ACE proposes a revised BGS Residential (whole house) TOU rate available to Residential EV customers as detailed below. As noted above, the company previously did not have sufficient data from its AMI program and the Smart Energy Network to support the implementation of a TOU program in 2023. Beginning May of 2024, however, the Company began collecting this usage data and now has over a year of information to leverage in the implementation of a revised TOU program.

4. Revisions to the Existing BGS Residential Time-of-Use ('TOU')

ACE proposes revising the existing BGS Residential TOU rate by adjusting the peak period to be 4:00 P.M. to 9:00 P.M., Monday through Friday and thereby aligning it with the pending Residential Distribution TOU petition offering (Docket No. ER25070444). In that matter, the Company selected the peak hours of 4:00 P.M. to 9:00 P.M. because, based on a monthly residential and total system load profile analysis, that is the period during which electricity demand consistently reached its highest levels. ACE proposes that these changes take effect on June 1, 2027.

Currently, the BGS Residential TOU rate is available to residential customers, including EV customers, but its 12-hour peak window significantly limits participation due to the difficulty in avoiding peak hours and higher rates. By shortening the peak period to a 5-hour window, ACE aims to make the rate more accessible and attractive to residential customers, especially to EV customers. The TOU rate design is structured to be revenue-neutral; meaning that a typical residential customer would pay approximately the same total amount under the TOU rate as they would under the standard rate, assuming their usage patterns are similar to the average residential customer. However, customers who shift a portion of their on-peak usage to off-peaks hours can benefit from lower energy costs due to the reduced off-peak TOU rates. In particular, EV

customers often have greater control over when they charge their vehicles and can easily take advantage of off-peak pricing. By doing so, they can realize meaningful bill savings as compated to the average customer's on-peak to off-peak usage ratio.

Adjusting the BGS TOU rate to be identical to the pending Residential Distribution TOU offering allows simultaneous participation in both the distribution and BGS supply portions, maximizing potential savings. The Company is planning to market both offerings to customers. This dual participation opportunity also supports the goal of broadening adoption of TOU rates, facilitated by the roll out of AMI meters company wide. Customers are more likely to engage with and respond to larger time-based pricing signals, enabling them to make informed decisions that help manage their energy costs. Further, aligning peak periods for distribution and supply will encourage greater participation by customers.

This approach also promotes a more comprehensive energy management approach, encouraging customers to shift whole-house electricity usage—not just EV charging—during off-peak periods. This approach helps reduce system strain during peak demand hours and supports a more balanced and efficient grid, resulting in a more effective approach to reduce long-term costs which can be passed on to rate payers.

Importantly, this proposal offers EV customers a revenue-neutral alternative to the higher cost BGS EV 2 Cents Program no longer requiring other rate payers to subsidize the cost. By leveraging existing AMI data and billing mechanisms, it eliminates the need for third-party involvement and does not impose additional costs on the customers, making it a more practical solution. Additionally, this does not represent a step back from EV affordability or managed charging because the transition to whole-house TOU provides comparable off-peak savings without the need for individualized device-level data collection and aligns directly with the Board's

vision that managed charging and networked EV infrastructure are foundational to New Jersey's strategy for mitigating rising rates.

E. BGS RATE DESIGN METHODOLOGY

1. ACE BGS-RSCP Pricing Spreadsheet

The resulting charge for each BGS-RSCP rate element (*i.e.,* Rate RS summer charge, winter charge, etc.) for the non-hourly BGS-RSCP supply service will be based on factors applied to the tranche-weighted average of the BGS-RSCP winning bid prices adjusted for the seasonal payment factors. The rate class specific factors have been developed based on the ratios of the estimated underlying market costs of each rate element (for each rate class) to the overall BGS-RSCP cost. The tables included in **Attachment 2** and described below present all of the input data, intermediate calculations, and the final results in the calculation of these factors.

Table No. 1 (% Usage During PJM On-Peak Period) contains the percentage of on-peak load, by month, for each applicable Rate Schedule. The on-peak period as used in this table (referred to as PJM periods) is defined as the 16-hour period from 7:00 A.M. to 11:00 P.M., Monday through Friday. All remaining weekday hours and all hours on weekends and holidays recognized by the National Electric Reliability Council (also known as NERC) are considered the off-peak period. This is consistent with the time periods used in the forwards market for trading of bulk power. The values in this table for each month are based on the most recent available settlement data for current ACE customers.

Table No. 2 (% Usage During ACE On-Peak Billing Period) contains the percentage of on- peak load, by month, for each applicable Rate Schedule based on the definitions of time periods as contained in ACE's delivery Rate Schedules. These percentages are based on usage history for the RS TOU BGS customers for the most recent period. This table reflects ACE's proposed

TOU On-Peak hours of 4:00 P.M. to 9:00 P.M.

Table No. 3 (Class Usage @ Customer) contains the billing month sales forecasted for the period of June 2027 through May 2028, with migration adjustments. The values in Table No. 3 will be updated in January 2027 to better reflect forecasts for the June 1 delivery year.

Table No. 4 (Forward Prices – Energy Only @ Bulk System) contains the forward prices for energy, by time period and month, for the BGS analysis period. These values are the energy on- peak forwards as of June 1, 2026, for the PJM West trading hub for the period of June 2027 to May 2028, as utilized in BGS market-to-market calculations, and the historical ratio of actual off-peak to on-peak PJM LMPs for the prior summer and winter periods. An adjustment of the forward prices contained in Table No. 4 must be made to correct for the pricing differential between the PJM West trading hub and the ACE zone where the BGS supply will be utilized.

Table No. 5 (Zone-Hub Basis Differential) contains an estimate of the average zone-hub basis differential factors, by month and time period, which, when multiplied by the prices at the PJM West trading hub, will result in costs for power delivered into the ACE zone.

Table No. 6 (Losses) contains the factors utilized for average system losses by Rate Schedule and voltage level. Loss factors are developed by including losses at the 500kV transmission level as well as losses at lower transmission and distribution voltage levels currently approved for use by the Board.

Table No. 7 (Summary of Average BGS Energy Unit Costs @ Customer – PJM Time Periods) is the calculation of the energy costs by rate, time period, and season. These values are the seasonal and time period average costs per Megawatt hour ("MWh") as measured at the customer billing meter (from Table No. 3), based on the forwards prices (from Table No. 4), corrected for zone-hub basis differential (from Table No. 5), losses (from Table No. 6), and

monthly time period weights (from Table No. 1). These average costs do not include the costs associated with Ancillary Services, RPS compliance or Generation Obligation costs, which will be considered in subsequent calculations.

Table No. 8 (Summary of Average BGS Energy Costs @ Customer – PJM Time Periods) indicates the total value, in thousands of dollars, of the average BGS energy costs. These are the results of the multiplication of the unit costs from Table No. 7, the monthly time period weights from Table No. 1, and the total sales to customers from Table No. 3. Since the end result of these calculations are to be utilized in the development of retail BGS rates, the rates utilizing time of day pricing must be developed based upon the time periods as defined for billing.

Table No. 9 (Summary of Average BGS Energy Unit Costs @ Customer – ACE Time Periods) shows the result of the corrections for the RS-TOU-BGS rate. These values are calculated based on the assumption that the MWhs included in the PJM on-peak time period and not included in the ACE on-peak time periods are at the average of the on- and off-peak PJM prices.

Table No. 10 (Generation Obligations and Costs and Other Adjustments) includes the values necessary for the inclusion of the costs of the Generation Capacity obligations. The top portion of Table No. 10 shows the total generation obligations with a migration adjustment, by applicable Rate Schedule, that are currently being utilized in the year 2026. Table No. 10 will be updated in January 2027, similar to Table No. 3. The middle portion of this table shows the number of summer and winter days and months that are used in this analysis. The bottom portion of this table shows the seasonally differentiated average market price of generation capacity, using the relevant RPM auction result for Delivery Year 2027/2028, the Capacity Proxy Price for Delivery Year 2028/2029, and the Capacity Proxy Price for Delivery Year 2029/2030. The Capacity Proxy Price will be replaced with the Zonal Capacity Prices, which are the prices

paid by BGS-RSCP Suppliers for Capacity for the 2028/2029 and the 2029/2030 Delivery Years when available as may be determined through the RPM or its successor or otherwise.

Table No. 11 (Ancillary Services and RPS) contains an estimate of the effects of the costs of ancillary services and RPS. The values of $2.00 per MWh and $16.14 per MWh are used, respectively. Since the actual costs are a complex combination of many factors, an estimate of the overall annual average value, expressed on a dollar per MWh basis, is used as a reasonable and practical alternative.

Table No. 12 (Summary of Obligation Costs Expressed as $/MWh @ Customer) shows the result of the allocation of the generation costs, on a per MWh basis, to all Rate Schedules. For RS TOU BGS, the per MWh Generation Capacity Obligation Costs are based on the on-peak usage only.

Table No. 13 (Summary of BGS Unit Costs @ Customer) is the result of the inclusion of the generation capacity, Ancillary Services, and RPS costs to the energy only costs shown in Table No. 9. This table shows the total estimated costs for BGS, based on the assumptions utilized in the above tables, and the average per unit cost, as measured at the customer meters or the bulk system meters.

Table No. 14 (Ratio of BGS Unit Costs @ Customer to Average Cost @ transmission nodes) indicates the ratio of the individual rate element costs from Table No. 13 to the overall cost as measured at the transmission nodes, plus constants, where applicable.

Table No. 15 (Summary of Total BGS Costs by Season) shows the calculation of the total BGS Costs, utilizing the total customer usage from Table No. 3 and the BGS unit costs from Table No. 13. The lower left portion of the table indicates the relative percentage of total costs by season for all Rate Schedules, while the center shows the calculation of the overall average

seasonal unit costs on a dollar per MWh basis. The ratio of these overall average seasonal costs to the overall total cost, shown in the lower right-hand portion of Table No. 15, are the seasonal payment ratios upon which payments to the winning bidders are based. The final section summarizes some of the most important assumptions utilized in the above calculations.

Table No. 16 (Retail Rates Charged to BGS-RSCP Customers), shows the calculation of retail rates to be charged to the BGS-RSCP customers for their BGS services. This table utilizes the information computed in Table No. 14 (Ratio of BGS Unit Costs) and applies the applicable ratios for each rate class to the BGS average price which, in turn, is based on the weighted average winning bids. The upper left portion of this table provides the BGS average price.

Table No. 17 (Retail Rates Charged to BGS-RSCP Customers Including Revenue Assessment and SUT), shows the BGS-RSCP customer rates inclusive of the BPU and Division of Rate Counsel revenue assessments, as well as SUT. This table utilizes the information provided in Table No. 16 and applies the applicable revenue assessment factor and SUT rate to derive the tax effected BGS-RSCP customer's rates.

The second spreadsheet used in the calculation of the final BGS-RSCP rates is included as **Attachment 3** and is titled "Calculation of June 2027 to May 2028 BGS-RSCP Rates." The tables in this spreadsheet calculate the weighted average winning bid price and convert it into the final BGS-RSCP rates that are charged to customers. An explanation of each of the six tables, labeled as Tables A through F, is as follows:

Table A (Auction Results) contains the results of the 2025/2026 BGS auction, the results of the 2026/2027 BGS auction, and the results of the current auction. The Capacity Proxy Price True Up cost in $ per MWh will be used to reflect the impact of payments made pursuant to the Supplements executed by BGS Suppliers in February 2025. Upon conclusion of

the Third Incremental RPM Auction through the RPM or its successor or otherwise, the price paid by BGS-RSCP Suppliers for Capacity in the Company's PJM Zone will be known. The Capacity Proxy Price True-Up will then be determined by the price difference between the price paid by BGS-RSCP Suppliers for Capacity in the Company's PJM Zone and the Capacity Proxy Price for the 2027/2028 Delivery Year. The value of $329.43 per MW-Day is used as an approximation of the price paid by BGS-RSCP Suppliers for Capacity in the Company's PJM Zone for 2027/2028. From these values, the weighted average annual bid price (shown on line 13) is calculated. All of the formulas used in this table are shown in the right-hand column of this table, under the heading "Notes".

Table B (Ratio of BGS Unit Costs @ Customer to Average Cost @ transmission nodes) is a repeat of the values shown in Table No. 14 from **Attachment 2**, the bid factors calculated based on current market conditions.

Table C (Preliminary Resulting BGS Rates) contains the preliminary customer BGS-RSCP rates as the product of the weighted average bid price (from Table A) and the Bid Factors from Table B.

Table D (Revenue Recovery Calculations) contains a comparison of the total anticipated rate revenue billed to customers based on the preliminary BGS-RSCP rates developed in Table C and the anticipated total season payments to BGS suppliers, based on the data in Table A. The calculation of the kWh Rate Adjustment Factors are also provided in this table, which are equal to the seasonal dollar differences between the anticipated billed revenue and supplier payments, divided by the total anticipated seasonal billed BGS-RSCP energy-related charges.

Table E (Final Resulting BGS Rates) contains the final adjusted BGS-RSCP rates, which are equal to the preliminary BGS–RSCP rates shown in Table C, times the seasonal kWh Rate Adjustment Factors that were developed in Table D.

Table F (Spreadsheet Error Checking) contains a comparison of the total anticipated rate revenue billed to customers based on the final BGS-RSCP rates developed in Table E, and the anticipated total season payments to BGS suppliers, based on the data in Table A.

E. CONCLUSION

In connection with the approval of this filing, the Company respectfully requests that the Board determine as follows:

1. it is necessary and in the public interest for the electric public utilities to secure service for the BGS-RSCP and BGS-CIEP customers, as approved herein, for the period June 1, 2027 to May 31, 2030;
2. the Company's proposed accounting for BGS is approved for purposes of accounting and BGS cost recovery;
3. the proposed BGS Contingency Plan is approved, and there will exist a presumption of prudence with respect to the BGS Auction Plan method and the costs incurred for BGS service under the Auction Plan and the related Contingency Plan;
4. the Company may recover costs incurred to implement and maintain the BGS EV 2 Cents program and terminate the program at the end of the current BGS year in May 2027;
5. approve the implementation of the revised BGS Residential (whole house) TOU rate revision of peak and off-peak hours; and
6. the Company's Rate Design Methodology and Tariff Sheets are approved.

Attachment 1

Clean

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**.**

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**.**

RIDER (BGS)
Basic Generation Service (BGS)

Basic Generation Service (BGS) will be arranged for any customer taking service under Electric Rate Schedules RS, EV-ERR, 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 Through September	October Through May
RS and EV-ERR		$ x.xxxxxx
<=750 kwhs summer	$ x.xxxxxx	
> 750 kwh summer	$ x.xxxxxx	
RS TOU BGS Option		
On Peak (See Note 1)	$ x.xxxxxx	$ x.xxxxxx
Off Peak (See Note 1)	$ x.xxxxxx	$ x.xxxxxx
MGS-Secondary and MGS-SEVC	$ x.xxxxxx	$ x.xxxxxx
MGS-Primary	$ x.xxxxxx	$ x.xxxxxx
AGS-Secondary	$ x.xxxxxx	$ x.xxxxxx
AGS-Primary	$ x.xxxxxx	$ x.xxxxxx
DDC	$ x.xxxxxx	$ x.xxxxxx
SPL/CSL	$ x.xxxxxx	$ x.xxxxxx

Note 1: On Peak hours are considered to be 4:00 PM to 9:00 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.

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 September 1, December 1, and March 1 of each year.

Rate Schedule	Charge ($ per kWh)
RS and EV-ERR	$ 0.000000
MGS Secondary, MGS-SEVC, AGS Secondary, SPL/CSL, DDC	$ 0.000000
MGS Primary, AGS Primary	$ 0.000000

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
Charge per kilowatt of Generation Obligation ($ per kW per day)	$ x.xxxxxx	$ x.xxxxxx

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	$ x.xxxxxx
Service taken at Primary Voltage	$ x.xxxxxx
Service taken at Sub-Transmission Voltage	$ x.xxxxxx
Service taken at Transmission Voltage	$ x.xxxxxx

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.

RIDER (BGS) continued
Basic Generation Service (BGS)

BGS Reconciliation Charge:

	Charge ($ per kWh)
Service taken at Secondary Voltage	$ 0.000000
Service taken at Primary Voltage	$ 0.000000
Service taken at Sub-Transmission Voltage	$ 0.000000
Service taken at Transmission Voltage	$ 0.000000

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, September 1, December1, and March 1 of each year.

CIEP Standby Fee $ x.xxxxxx 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.

RIDER (BGS) continued
Basic Generation Service (BGS)

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							
	RS	MGS Secondary And MGS-SEVC	MGS Primary	AGS Secondary	AGS Primary	TGS	SPL/ CSL	DDC
VEPCo	0.000421	0.000302	0.000166	0.000226	0.000189	0.000162	-	0.000132
TrAILCo	0.000295	0.000160	0.000131	0.000133	0.000124	0.000097	-	0.000085
PSE&G	0.001382	0.000989	0.000547	0.000742	0.000622	0.000532	-	0.000437
PPL	0.000106	0.000076	0.000042	0.000057	0.000047	0.000041	-	0.000033
PECO	0.000220	0.000118	0.000098	0.000099	0.000092	0.000071	-	0.000064
Pepco	0.000021	0.000012	0.000010	0.000010	0.000009	0.000006	-	0.000006
MAIT	0.000042	0.000030	0.000016	0.000022	0.000018	0.000016	-	0.000013
JCP&L	0.000003	0.000002	0.000001	0.000002	0.000001	0.000001	-	0.000001
EL05-121	0.000019	0.000014	0.000007	0.000010	0.000009	0.000007	-	0.000006
Delmarva	0.000011	0.000005	0.000004	0.000004	0.000004	0.000003	-	0.000003
BG&E	0.000047	0.000026	0.000021	0.000021	0.000020	0.000015	-	0.000014
AEP-East	0.000062	0.000044	0.000025	0.000033	0.000028	0.000023	-	0.000019
Silver Run	0.000290	0.000208	0.000114	0.000156	0.000130	0.000112	-	0.000092
NIPSCO	0.000003	0.000002	0.000001	0.000001	0.000001	0.000001	-	0.000001
CW Edison	-	-	-	-	-	-	-	-
ER18-680 & Form 715	-	-	-	-	-	-	-	-
SFC	0.000004	0.000003	0.000002	0.000002	0.000002	0.000002	-	0.000001
Duquesne	0.000002	0.000001	0.000001	0.000001	0.000001	0.000001	-	-
Transource	0.000044	0.000031	0.000017	0.000023	0.000019	0.000017	-	0.000014
NextEra	0.000007	0.000004	0.000003	0.000003	0.000003	0.000002	-	0.000002
Total	**0.002979**	**0.002027**	**0.001206**	**0.001545**	**0.001319**	**0.001109**	**-**	**0.000923**

Date of Issue: **Effective Date:**

Issued by:

Attachment 1

Redlined

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**.**

~~**ELECTRIC VEHICLE BASIC GENERATION SERVICE CUSTOMERS ONLY**~~
~~Electric Vehicle Basic Generation Service ("BGS") Customers Only: Based upon the following eligibility criteria, Atlantic City Electric Company ("ACE") residential customers who receive their electric supply through BGS may elect to receive a net off-peak BGS energy credit exclusively for their electric vehicle usage. This option, upon ACE approval into the program, will be issued twice a year as an off-bill credit directly to the customer by check, after the entire usage has been billed at the RS rate.~~

~~A customer eligible for participation under this special provision must be an ACE Residential customer taking service under the RS rate schedule, install or utilize ACE approved smart charging equipment and network technology, and agree to share the Electric Vehicle Charging Data with ACE in a manner specified by ACE. In order for the customer to receive a credit, data must be available to ACE and the proper services must be in place to make this rate available. If data is not available for any reason, a customer may not receive a credit for the period that ACE does or did not have access to the required data.~~

~~The electric vehicle credit will be calculated by ACE's program administration team twice a year using the electric vehicle usage off-peak minus the on-peak electric vehicle usage multiplied by $.02/kWh (ex. (off-peak kWh – on-peak kWh)*.02) for the corresponding billing period. If the customer's on-peak usage is higher than off-peak usage for the billing period, no credit for the corresponding billing period will be provided. BGS on-peak hours are 8:00 A.M. to 8:00 P.M., Monday through Friday. All other hours are considered off-peak hours.~~

~~This solution will fall under the ACE EVsmart umbrella of programs.~~

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.

~~**ELECTRIC VEHICLE BASIC GENERATION SERVICE CUSTOMERS ONLY**~~
~~Electric Vehicle Basic Generation Service ("BGS") Customers Only: Based upon the following eligibility criteria, Atlantic City Electric Company ("ACE") EV-ERR customers who receive their electric supply through BGS may elect to receive a net off-peak BGS energy credit exclusively for their electric vehicle usage. This option, upon ACE approval into the program, will be issued twice a year as an off-bill credit directly to the customer by check, after the entire usage has been billed at the EV-ERR rate.~~

~~A customer eligible for participation under this special provision must be an ACE EV-ERR customer taking service under the EV-ERR rate schedule, install or utilize ACE approved smart charging equipment and network technology, and agree to share the Electric Vehicle Charging Data with ACE in a manner specified by ACE. In order for the customer to receive a credit, data must be available to ACE and the proper services must be in place to make this rate available. If data is not available for any reason, a customer may not receive a credit for the period that ACE does or did not have access to the required data.~~

~~The electric vehicle credit will be calculated by ACE's program administration team twice a year using the electric vehicle usage off-peak minus the on-peak electric vehicle usage multiplied by $.02/kWh (ex. (off-peak kWh – on-peak kWh)*.02) for the corresponding billing period. If the customer's on-peak usage is higher than off-peak usage for the billing period, no credit for the corresponding billing period will be provided. BGS on-peak hours are 8:00 A.M. to 8:00 P.M., Monday through Friday. All other hours are considered off-peak hours.~~

~~This solution will fall under the ACE EVsmart umbrella of programs.~~

RIDER (BGS)
Basic Generation Service (BGS)

Basic Generation Service (BGS) will be arranged for any customer taking service under Electric Rate Schedules RS, EV-ERR, 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 Through September	October Through May
RS and EV-ERR		$ ~~0.140672~~x.xxxxxx
<=750 kwhs summer	$ ~~0.130325~~x.xxxxxx	
> 750 kwh summer	$ ~~0.140300~~x.xxxxxx	
RS TOU BGS Option		
On Peak (See Note 1)	~~$ 0.178886~~$ x.xxxxxx	$ ~~0.182154~~x.xxxxxx
Off Peak (See Note 1)	$ ~~0.078425~~x.xxxxxx	$ ~~0.081821~~x.xxxxxx
MGS-Secondary and MGS-SEVC	$ ~~0.119776~~x.xxxxxx	$ ~~0.113017~~x.xxxxxx
MGS-Primary	$ ~~0.121591~~ x.xxxxxx	$ ~~0.115532~~x.xxxxxx
AGS-Secondary	$ ~~0.113943~~ x.xxxxxx	$ ~~0.107304~~x.xxxxxx
AGS-Primary	$ ~~0.112257~~ x.xxxxxx	$ ~~0.105590~~x.xxxxxx
DDC	$ ~~0.106813~~ x.xxxxxx	$ ~~0.099876~~x.xxxxxx
SPL/CSL	$ ~~0.083091~~ x.xxxxxx	$ ~~0.083078~~x.xxxxxx

Note 1: On Peak hours are considered to be ~~84~~:00 ~~AM~~PM to ~~89~~: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.

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 September 1, December 1, and March 1 of each year.

Rate Schedule	Charge ($ per kWh)
RS and EV-ERR	$ 0.000000
MGS Secondary, MGS-SEVC, AGS Secondary, SPL/CSL, DDC	$ 0.000000
MGS Primary, AGS Primary	$ 0.000000

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
Charge per kilowatt of Generation Obligation ($ per kW per day)	~~$0.720087~~$ x.xxxxxx	$ ~~0.720087~~ x.xxxxxx

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	$ ~~0.002255~~ x.xxxxxx
Service taken at Primary Voltage	$ ~~0.002209~~ x.xxxxxx
Service taken at Sub-Transmission Voltage	$ ~~0.002179~~ x.xxxxxx
Service taken at Transmission Voltage	$ ~~0.002153~~ x.xxxxxx

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.

RIDER (BGS) continued
Basic Generation Service (BGS)

BGS Reconciliation Charge:

	Charge ($ per kWh)
Service taken at Secondary Voltage	$ 0.000000
Service taken at Primary Voltage	$ 0.000000
Service taken at Sub-Transmission Voltage	$ 0.000000
Service taken at Transmission Voltage	$ 0.000000

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, September 1, December1, and March 1 of each year.

CIEP Standby Fee ~~0.000160~~ $ x.xxxxxx 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.

RIDER (BGS) continued
Basic Generation Service (BGS)

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							
	RS	MGS Secondary And MGS-SEVC	MGS Primary	AGS Secondary	AGS Primary	TGS	SPL/ CSL	DDC
VEPCo	0.000421	0.000302	0.000166	0.000226	0.000189	0.000162	-	0.000132
TrAILCo	0.000295	0.000160	0.000131	0.000133	0.000124	0.000097	-	0.000085
PSE&G	0.001382	0.000989	0.000547	0.000742	0.000622	0.000532	-	0.000437
PPL	0.000106	0.000076	0.000042	0.000057	0.000047	0.000041	-	0.000033
PECO	0.000220	0.000118	0.000098	0.000099	0.000092	0.000071	-	0.000064
Pepco	0.000021	0.000012	0.000010	0.000010	0.000009	0.000006	-	0.000006
MAIT	0.000042	0.000030	0.000016	0.000022	0.000018	0.000016	-	0.000013
JCP&L	0.000003	0.000002	0.000001	0.000002	0.000001	0.000001	-	0.000001
EL05-121	0.000019	0.000014	0.000007	0.000010	0.000009	0.000007	-	0.000006
Delmarva	0.000011	0.000005	0.000004	0.000004	0.000004	0.000003	-	0.000003
BG&E	0.000047	0.000026	0.000021	0.000021	0.000020	0.000015	-	0.000014
AEP-East	0.000062	0.000044	0.000025	0.000033	0.000028	0.000023	-	0.000019
Silver Run	0.000290	0.000208	0.000114	0.000156	0.000130	0.000112	-	0.000092
NIPSCO	0.000003	0.000002	0.000001	0.000001	0.000001	0.000001	-	0.000001
CW Edison	-	-	-	-	-	-	-	-
ER18-680 & Form 715	-	-	-	-	-	-	-	-
SFC	0.000004	0.000003	0.000002	0.000002	0.000002	0.000002	-	0.000001
Duquesne	0.000002	0.000001	0.000001	0.000001	0.000001	0.000001	-	-
Transource	0.000044	0.000031	0.000017	0.000023	0.000019	0.000017	-	0.000014
NextEra	0.000007	0.000004	0.000003	0.000003	0.000003	0.000002	-	0.000002
Total	**0.002979**	**0.002027**	**0.001206**	**0.001545**	**0.001319**	**0.001109**	**-**	**0.000923**

Attachment 2

Table #1 **% usage during PJM On-Peak period**
(data rounded to nearest %)

On-Peak periods defined as the 16 hr PJM Trading period, adj for NERC holidays

	RS / EV-ERR	RS TOU - BGS	MGS - SEC / SEVC	MGS - PRI	AGS - SEC	AGS - PRI	SPL/CSL	DDC
January	51.27%	51.35%	54.97%	54.63%	55.03%	52.42%	38.94%	50.96%
February	49.87%	50.07%	54.55%	54.31%	54.94%	52.98%	36.87%	50.99%
March	48.05%	48.88%	54.78%	55.46%	55.51%	52.65%	33.76%	51.08%
April	51.45%	53.78%	59.65%	60.99%	59.32%	57.51%	32.20%	55.33%
May	51.41%	51.27%	56.04%	56.51%	56.76%	54.54%	26.74%	50.94%
June	57.16%	56.87%	59.34%	58.40%	57.90%	54.84%	26.71%	52.47%
July	59.12%	59.21%	60.39%	60.00%	58.63%	55.99%	26.86%	53.35%
August	54.63%	54.52%	57.45%	57.06%	56.11%	53.72%	28.23%	50.76%
September	54.10%	55.18%	58.68%	58.88%	58.42%	55.31%	32.87%	52.57%
October	55.19%	57.15%	60.92%	60.74%	60.56%	57.78%	39.43%	55.65%
November	44.61%	45.29%	49.98%	48.76%	50.06%	48.41%	33.98%	45.17%
December	53.98%	54.19%	57.49%	56.93%	57.61%	55.52%	41.57%	53.29%

Table #2 **% Usage During ACECO On-Peak Billing Period**

	RS TOU - BGS
January	18.25%
February	18.09%
March	17.37%
April	20.25%
May	20.41%
June	23.53%
July	24.96%
August	22.36%
September	22.68%
October	21.02%
November	16.21%
December	19.14%

Table #3 **Class Usage @ customer**
calendar month sales forecasted for period
in MWh

		RS / EV-ERR	RS TOU - BGS	MGS - SEC / SEVC	MGS - PRI	AGS - SEC	AGS - PRI	SPL/CSL	DDC	Total
	Jan-28	354,844	155	86,022	5,992	84,232	27,336	5,766	932	565,279
	Feb-28	320,008	139	81,404	5,576	80,304	25,543	4,909	868	518,752
	Mar-28	274,720	120	78,332	5,448	76,565	25,130	4,683	835	465,833
	Apr-28	235,949	103	76,747	4,751	75,665	24,086	4,252	812	422,365
	May-28	197,555	86	75,617	5,898	74,557	23,209	3,680	782	381,384
	Jun-27	287,416	125	88,307	6,572	86,934	26,838	3,683	901	500,776
	Jul-27	435,895	190	100,149	7,575	98,209	32,139	3,815	1,014	678,985
	Aug-27	491,487	214	104,597	7,961	102,455	32,155	4,060	1,054	743,982
	Sep-27	432,613	188	104,881	7,831	102,759	33,458	4,569	1,074	687,372
	Oct-27	243,024	106	84,011	6,267	82,514	27,413	4,520	884	448,740
	Nov-27	227,291	99	81,581	4,784	80,218	22,756	5,002	870	422,600
	Dec-27	275,270	120	76,884	4,921	75,026	24,511	5,168	834	462,735
Total		3,776,072	1,644	1,038,532	73,575	1,019,439	324,574	54,108	10,859	6,298,802

Table #4 **Forwards Prices - Energy Only @ bulk system**
($/MWH)

	On-Peak	Off/On Pk LMP ratio	Off-Peak
Jan-28	101.55	0.800	81.27
Feb-28	90.60	0.800	72.51
Mar-28	61.65	0.800	49.34
Apr-28	61.95	0.800	49.58
May-28	61.15	0.800	48.94
Jun-27	67.30	0.549	36.95
Jul-27	97.00	0.549	53.25
Aug-27	80.50	0.549	44.19
Sep-27	68.95	0.549	37.85
Oct-27	67.15	0.800	53.74
Nov-27	67.30	0.800	53.86
Dec-27	76.80	0.800	61.46

Table #5 **Zone-Hub Basis Differential** **'Based on 3 Year Average**

	On-Peak	Off-Peak
	80%	84%
	80%	84%
	80%	84%
	80%	84%
	80%	84%
	79%	82%
	79%	82%
	79%	82%
	79%	82%
	80%	84%
	80%	84%
	80%	84%

Table #6 **Losses**

	RS / EV-ERR	RS TOU - BGS	MGS - SEC / SEVC	MGS - PRI	AGS - SEC	AGS - PRI	SPL/CSL	DDC
Delivery Loss Factor	6.7721%	6.7721%	6.7721%	4.8389%	6.7721%	4.8389%	6.7721%	6.7721%
Loss Factors + EHV Losses =	7.1684%	7.1684%	7.1684%	5.2435%	7.1684%	5.2435%	7.1684%	7.1684%
Expansion Factor =	1.07722	1.07722	1.07722	1.05534	1.07722	1.05534	1.07722	1.07722
Marginal Loss Factor (w/ EHV Losses) =	1.6424%	1.6424%	1.6424%	1.6424%	1.6424%	1.6424%	1.6424%	1.6424%
Loss Factor w/o Marginal Loss =	5.6183%	5.6183%	5.6183%	3.6612%	5.6183%	3.6612%	5.6183%	5.6183%
Expansion Factor w/o Marginal Loss =	1.05953	1.05953	1.05953	1.03800	1.05953	1.03800	1.05953	1.05953

Table #7 **Summary of Average BGS Energy Unit Costs @ customer - PJM Time Periods**
based on Forwards @ PJM West - corrected for congestion & losses
in $/MWh

	RS / EV-ERR	RS TOU - BGS	MGS - SEC / SEVC	MGS - PRI	AGS - SEC	AGS - PRI	SPL/CSL	DDC
Summer - all hrs	$ 54.72	$ 54.78	$ 54.91	$ 53.74	$ 54.54	$ 52.76	$ 45.88	$ 52.95
On Peak	$ 67.64	$ 67.61	$ 66.75	$ 65.45	$ 66.68	$ 65.48	$ 65.77	$ 66.67
Off Peak	$ 38.20	$ 38.22	$ 37.91	$ 37.18	$ 37.96	$ 37.23	$ 37.80	$ 37.92
Winter - all hrs	$ 60.14	$ 60.21	$ 59.15	$ 57.95	$ 59.16	$ 57.83	$ 57.87	$ 58.81
On Peak	$ 65.46	$ 65.35	$ 63.59	$ 62.21	$ 63.58	$ 62.37	$ 65.43	$ 63.77
Off Peak	$ 54.65	$ 54.75	$ 53.50	$ 52.49	$ 53.50	$ 52.51	$ 53.65	$ 53.52
Annual	$ 57.78	$ 57.84	$ 57.53	$ 56.24	$ 57.40	$ 55.89	$ 54.30	$ 56.63

System Average Cost @ customer - (limited to classes shown above) = $ 57.53

Table #8 **Summary of Average BGS Energy Costs @ customer - PJM Time Periods**
based on Forwards prices corrected for congestion & losses
in $1000

		RS / EV-ERR	RS TOU - BGS	MGS - SEC / SEVC	MGS - PRI	AGS - SEC	AGS - PRI	SPL/CSL	DDC
Summer - all hrs		$ 90,152	$ 39	$ 21,849	$ 1,609	$ 21,292	$ 6,573	$ 740	$ 214
	PJM on pk	$ 62,537	$ 27	$ 15,653	$ 1,148	$ 15,031	$ 4,485	$ 306	$ 141
	PJM off pk	$ 27,616	$ 12	$ 6,195	$ 461	$ 6,260	$ 2,088	$ 434	$ 73
Winter - all hrs		$ 128,018	$ 56	$ 37,894	$ 2,529	$ 37,219	$ 11,566	$ 2,198	$ 401
	PJM on pk	$ 70,737	$ 31	$ 22,825	$ 1,524	$ 22,478	$ 6,740	$ 891	$ 225
	PJM off pk	$ 57,280	$ 25	$ 15,069	$ 1,005	$ 14,741	$ 4,826	$ 1,307	$ 176
Annual		$ 218,170	$ 95	$ 59,743	$ 4,138	$ 58,511	$ 18,139	$ 2,938	$ 615

System Total $ 362,348

Table #9 **Summary of Average BGS Energy Unit Costs @ customer - ACECO Time Periods**

based on Forwards prices corrected for congestion & losses - ACECO billing time periods
in $/MWh

	RS / EV-ERR	RS TOU - BGS	MGS - SEC / SEVC	MGS - PRI	AGS - SEC	AGS - PRI	SPL/CSL	DDC
Summer - all hrs	$ 54.72	$ 54.78	$ 54.91	$ 53.74	$ 54.54	$ 52.76	$ 45.88	$ 52.95
ACECO On pk		$ 88.39						
ACECO Off pk		$ 44.55						
Winter - all hrs	$ 60.14	$ 60.21	$ 59.15	$ 57.95	$ 59.16	$ 57.83	$ 57.87	$ 58.81
ACECO On pk		$ 74.60						
ACECO Off pk		$ 56.89						
Annual Average	$ 57.78	$ 57.84	$ 57.53	$ 56.24	$ 57.40	$ 55.89	$ 54.30	$ 56.63
System Average	$ 57.53							

Table #10 **Generation Obligations and Costs and Other Adjustments**

obligations - values effective June 2026; costs are market estimates

in MW	RS / EV-ERR	RS TOU - BGS	MGS - SEC / SEVC	MGS - PRI	AGS - SEC	AGS - PRI	SPL/CSL	DDC	Total
Gen Load - MW	1,382.0	0.5	248.1	7.5	179.5	57.4	0.0	1.2	1,876.2
Gen Obl - MW	1,299.3	0.4	233.2	7.1	168.8	54.0	0.0	1.1	1,763.9

Final Zonal RPM Scaling Factor 1.01189
PJM June 1, 2026 Forecast Pool Requirement 0.92910

# of Months and Days used in this analysis

# of summer days =	122	# of summer months =	4
# of winter days =	244	# of winter months =	8
		total # months =	12

Generation Capacity Cost		Base Capacity			
	Summer	$333.69	$/MW/day	Summer Total	$ 71,810,683
	Winter	$333.69	$/MW/day	Winter Total	$ 143,621,365
				Annual Total	$ 215,432,048

Residential Inversion Determination

---------- Rate RS / EV-ERR ----------

	Charges	% usage		
Block 1 (0-750 kWh/m)	5.480200	65.51%	SUM 'First 750 KWh	1,126,672,254
Block 2 (>750 kWh/m)	6.345400	34.49%	SUM '> 750 KWh	593,172,470
Calculated inversion =	0.865200		WIN	2,173,208,357
				3,893,053,081

Table #11 **Ancillary Services & Renewable Power Cost (forecasted overall annual average)**

Ancillary Services	$ 2.00
Renewable Power Cost	$ 16.14
Total Ancillary Services & Renewable Power Costs	$ 18.14

Table #12 **Summary of Obligation Costs expressed as $/MWh @ customer**

	RS / EV-ERR	RS TOU - BGS	MGS - SEC / SEVC	MGS - PRI	AGS - SEC	AGS - PRI	SPL/CSL	DDC
Generation Obl -								
per annual MWh	$ 42.02	$ 151.58	$ 27.43	$ 11.74	$ 20.22	$ 20.32	$ 0.00	$ 12.93
recovery per summer MWh	$ 32.11	$ 102.98	$ 23.86	$ 9.62	$ 17.60	$ 17.64	$ 0.00	$ 11.58
recovery per winter MWh	$ 49.70	$ 198.40	$ 29.65	$ 13.19	$ 21.84	$ 21.98	$ 0.00	$ 13.73

Table #13 **Summary of BGS Unit Costs @ customer**

Includes energy, Generation capacity obligations, Ancillary Services, and Renewable Power Costs - unadjusted for billing vs. PJM time period differences.
in $/MWh

		RS / EV-ERR	RS TOU - BGS	MGS - SEC / SEVC	MGS - PRI	AGS - SEC	AGS - PRI	SPL/CSL	DDC
Summer - all hrs		$ 106.37	$ 177.30	$ 98.31	$ 82.50	$ 91.69	$ 89.54	$ 65.42	$ 84.07
	On-Peak		$ 210.91						
	Off-Peak		$ 64.09						
	Block 1 (0-750 kWh/m)	$ 103.39							
	Block 2 (>750 kWh/m)	$ 112.04							
Winter - all hrs		$ 129.38	$ 278.15	$ 108.34	$ 90.28	$ 100.55	$ 98.96	$ 77.42	$ 92.09
	On-Peak		$ 292.55						
	Off-Peak		$ 76.43						
Annual		$ 119.34	$ 108.83	$ 104.50	$ 87.12	$ 97.15	$ 95.35	$ 73.84	$ 89.10

Grand Total Cost in $1000 = $ 700,706

Average cost for rates shown (@ customer) = $ 111.24
Average costs for rates shown (@ transmission nodes) = $ 105.13

Table #14 **Ratio of BGS Unit Costs @ customer to Average Cost @ transmission nodes (rounded to 3 decimal places)**

Includes energy, Generation capacity obligations, Ancillary Services, and Renewable Power Costs - unadjusted for billing vs. PJM time period differences.

		RS / EV-ERR	RS TOU - BGS	MGS - SEC / SEVC	MGS - PRI	AGS - SEC	AGS - PRI	SPL/CSL	DDC
Summer - all hrs			**1.687**	**0.935**	**0.785**	**0.872**	**0.852**	**0.622**	**0.800**
	On-Peak		**2.006**						
	Off-Peak		**0.610**						
	All usage Multiplier	**1.012**							
	Constant	**$ (2.98)**		for Block 1 (0-750 kWh/m) usage					
	Constant	**$ 5.67**		for Block 2 (>750 kWh/m) usage					
Winter - all hrs		**1.231**	**2.646**	**1.031**	**0.859**	**0.956**	**0.941**	**0.736**	**0.876**
	On-Peak		**2.783**						
	Off-Peak		**0.727**						
Annual		**1.135**	**1.035**	**0.994**	**0.829**	**0.924**	**0.907**	**0.702**	**0.848**

Table #15 **Summary of Total BGS Costs by Season**

	RS / EV-ERR	RS TOU - BGS	MGS - SEC / SEVC	MGS - PRI	AGS - SEC	AGS - PRI	SPL/CSL	DDC
Total Costs by Rate - in $1000								
Summer	$ 175,239	$ 127	$ 39,120	$ 2,470	$ 35,790	$ 11,156	$ 1,055	$ 340
Winter	$ 275,402	$ 258	$ 69,403	$ 3,940	$ 63,253	$ 19,790	$ 2,940	$ 628
Total	$ 450,641	$ 385	$ 108,523	$ 6,410	$ 99,043	$ 30,947	$ 3,995	$ 968
% of Annual Total $ by Rate								
Summer	39%	33%	36%	39%	36%	36%	26%	35%
Winter	61%	67%	64%	61%	64%	64%	74%	65%

Total Costs - in $1000

Summer	$ 265,297
Winter	$ 435,614
Total	$ 700,912

% of Annual Total $

		If total $ were split on a per MWh basis (on bulk system MWhs):				
Summer	38%	$ 96.01	per MWh @ trans nodes	Ratio to BGS Cost	>>> Summer	**1.0000**
Winter	62%	$ 111.64	per MWh @ trans nodes	(rounded to 4 decimal places)	Winter	**1.0000**

Assumptions:

Gen Cost =	$333.69	per MW-day	summer
=	$333.69	per MW-day	winter
Ancillary Services =	$ 2.00	per MWH	
Renewable Power Cost =	$ 16.14	per MWH	

Energy Prices = Quotes for the period June 1, 2027 to May 31, 2028 - corrected for hub-zone basis differential.
Usage patterns = forecasted energy use by class, on/off % from class load profiles
Obligations = class totals as of June 2026
Losses = existing approved loss factors
PJM Time Periods = PJM trading time periods - 7 AM to 11 PM weekdays, local time, x NERC holidays
- New Year's, Memorial, 4th of July, Labor Day, Thanksgiving & Christmas

Table #16 **Retail Rates Charged to BGS RSCP (Previously "FP") Customers**

Includes energy, Generation Obligations, Ancillary Services, and Renewable Power Costs
in $/MWh

BGS Avg. Price >>>>>>>>>>>	**$ 113.988**

		RS / EV-ERR	RS TOU - BGS	MGS - SEC / SEVC	MGS - PRI	AGS - SEC	AGS - PRI	SPL/CSL	DDC
Summer - all hrs			$ 210.560	$ 116.701	$ 97.979	$ 108.837	$ 106.341	$ 77.634	$ 99.851
	On-Peak		$ 250.376						
	Off-Peak		$ 76.136						
	Block 1 (0-750 kWh/m)	$ 123.044							
	Block 2 (>750 kWh/m)	$ 132.517							
Winter - all hrs		$ 132.140	$ 284.031	$ 110.671	$ 92.208	$ 102.621	$ 101.010	$ 79.005	$ 94.033
	On-Peak		$ 298.737						
	Off-Peak		$ 78.039						
Annual		$ 129.376	$ 117.978	$ 113.304	$ 94.496	$ 105.325	$ 103.387	$ 80.020	$ 96.662

Table #17 **Retail Rates Charged to BGS RSCP Customers including Revenue Assessment and SUT**

Includes energy, Generation Obligations, Ancillary Services, and Renewable Power Costs
in $/kWh

Revenue Assessment Factor (BPU, RC Assessments) 1.002471931

		RS / EV-ERR	RS TOU - BGS	MGS - SEC / SEVC	MGS - PRI	AGS - SEC	AGS - PRI	SPL/CSL	DDC
Summer - all hrs				$ 0.124740	$ 0.104728	$ 0.116335	$ 0.113666	$ 0.082982	$ 0.106729
	On-Peak		$ 0.267623						
	Off-Peak		$ 0.081381						
	Block 1 (0-750 kWh/m)	$ 0.131520							
	Block 2 (>750 kWh/m)	$ 0.141646							
Winter - all hrs		$ 0.141243		$ 0.118295	$ 0.098560	$ 0.109690	$ 0.107969	$ 0.084447	$ 0.100511
	On-Peak		$ 0.319316						
	Off-Peak		$ 0.083415						
Annual		$ 0.138289	$ 0.126105	$ 0.121109	$ 0.101005	$ 0.112580	$ 0.110509	$ 0.085532	$ 0.103320

Attachment 3

Atlantic City Electric Company
Calculation of June 2027 to May 2028 BGS-RSCP Rates
based on results of February 2027 BGS RSCP Auction

Table A **Auction Results**

line #	Payment Identifier >>	*remaining portion of 36 month bid - 2025/26 filing*	*remaining portion of 36 month bid - 2026/27 filing*	*36 month bid - 2027/28 filing*	*Notes:*
1	Winning Bid - in $/MWh	$ 110.50	$ 112.75	$ 112.75	winning Bids
1A	Capacity Proxy Price True-Up - in $/MWh	$ 6.14			entered after 2027 BGS Auction
1B					
1C	Total - in $/Mwh	$ 116.64	$ 112.75	$ 112.75	= line 1 + line 1A - line 1B
2	# of Tranches for Bid	7	8	7	from then current Bid
3	Total # of Tranches	22	22	22	from then current Bid
	Payment Factors				
4	Summer	1.0000	1.0000	1.0000	from then current Bid Factor Spreadsheet
5	Winter	1.0000	1.0000	1.0000	from then current Bid Factor Spreadsheet
	Applicable Customer Usage @ bulk system - in MWh				
6	Summer MWh	2,763,222			from current Bid Factor Spreadsheet
7	Winter MWh	3,901,961			
	Total Payment to Suppliers - in $1000				
8	Summer	$ 102,551	$ 113,292	$ 99,131	= (1 + 1A) * (2)/(3) * (4) * (6) / 1000
9	Winter	$ 144,812	$ 159,980	$ 139,983	= (1 + 1A) * (2)/(3) * (5) * (7) / 1000
10	Total	$ 247,363	$ 273,273	$ 239,113	
	Average Payment to Suppliers - in $/MWh				
11	Summer	$ 113.99			= sum(line 8) / (6) - rounded to 2 decimal places
12	Winter	$ 113.99			= sum(line 9) / (7) - rounded to 2 decimal places
13	Total weighted average	**$ 113.99**	<<< used in calculation of Customer Rates		= sum(line 10) / [(6) + (7)] rounded to 2 decimal places
	Reconciliation of amounts - in $1000				
14	Weighted avg * Total MWh =	$ 759,751			= (13) * [(6)+(7)] / 1000
15	Total Payment to Suppliers =	$ 759,749			= sum (line 10)
16	Difference =	$ 2			= line (14) - line (15)

Atlantic City Electric Company
Calculation of June 2027 to May 2028 BGS-RSCP Rates
based on results of February 2027 BGS RSCP Auction

Table B **Ratio of BGS Unit Costs @ customer to Average Cost @ transmission nodes**

from Table #14 of the bid factor spreadsheet --- round to 3 decimal places

includes energy, G obligations, Ancillary Services, and Renewable Power Cost - adjusted to billing time periods

		RS / EV-ERR	RS TOU - BGS	MGS - SEC / SEVC	MGS - PRI	AGS - SEC	AGS - PRI	SPL/CSL	DDC
Summer - all hrs			**1.687**	**0.935**	**0.785**	**0.872**	**0.852**	**0.622**	**0.800**
	On-Peak		**2.006**						
	Off-Peak		**0.610**						
All usage Multiplier		**1.012**							
Constant		**(2.984)**		for Block 1 (0-750 kWh/m) usage					
Constant		**5.668**		for Block 2 (>750 kWh/m) usage					
Winter - all hrs		**1.231**	**2.646**	**1.031**	**0.859**	**0.956**	**0.941**	**0.736**	**0.876**
	On-Peak		**2.783**						
	Off-Peak		**0.727**						
Annual - all hrs		**1.135**	**1.035**	**0.994**	**0.829**	**0.924**	**0.907**	**0.702**	**0.848**

Table C **Preliminary Resulting BGS Rates (in cents per kWh) -** *equal to bid factors times weighted average bid price rounded to 4 decimal places*

includes energy, G obligations, Ancillary Services, and Renewable Power Cost - adjusted to billing time periods

		RS / EV-ERR	RS TOU - BGS	MGS - SEC / SEVC	MGS - PRI	AGS - SEC	AGS - PRI	SPL/CSL	DDC
Summer - all hrs			***19.2298***	***10.6579***	***8.9481***	***9.9398***	***9.7118***	***7.0901***	***9.1190***
	On-Peak		***22.8660***						
	Off-Peak		***6.9533***						
for Block 1 (0-750 kWh/m) usage		***11.2372***							
for Block 2 (>750 kWh/m) usage		***12.1024***							
Winter - all hrs		***14.0319***	***30.1612***	***11.7522***	***9.7916***	***10.8973***	***10.7263***	***8.3895***	***9.9853***
	On-Peak		***31.7229***						
	Off-Peak		***8.2869***						

Atlantic City Electric Company
Calculation of June 2027 to May 2028 BGS-RSCP Rates
based on results of February 2027 BGS RSCP Auction

Table D **Revenue Recovery Calculations -** *Reconciliation of seasonal Customer Revenue and Supplier Payments, based on actual anticipated revenues and payments*

	RS / EV-ERR	RS TOU - BGS	MGS - SEC / SEVC	MGS - PRI	AGS - SEC	AGS - PRI	SPL/CSL	DDC
Total Rate Revenue - in $1000								
Summer	$ 190,039	$ 114	$ 42,411	$ 2,679	$ 38,801	$ 12,100	$ 1,143	$ 369
Winter	$ 298,692	$ 189	$ 75,284	$ 4,273	$ 68,553	$ 21,451	$ 3,186	$ 681
Total	$ 488,730	$ 303	$ 117,696	$ 6,952	$ 107,354	$ 33,551	$ 4,330	$ 1,049

Total Summer	$ 287,656
Total Winter	$ 472,308
Grand Total	$ 759,964

Total Supplier Payment - in $1000	
Summer	$ 314,973
Winter	$ 444,776
Total	$ 759,749
Differences - in $1000	
Summer	$ 27,317
Winter	$ (27,533)
Total	$ (215)

kWh Rate Adjustment Factors	*rounded to 5 decimal places*
1.09497	
0.94171	

% difference
8.6730%
-6.1902%
-0.0283%

Note: These differences are due to rounding and seasonal differences in Bidder Payments (which are based on prior wining bids and Seasonal Payment Factors) and current Rates (based on current seasonal market differentials)

Atlantic City Electric Company
Calculation of June 2027 to May 2028 BGS-RSCP Rates
based on results of February 2027 BGS RSCP Auction

Table E **Final Resulting BGS Rates (in cents per kWh) -** *with preliminary kWh rates adjusted by the kWh Rate Adjustment Factor rounded to 4 decimal places*

includes energy, G obligations, Ancillary Services, and Renewable Power Cost - adjusted to billing time periods

		RS / EV-ERR	RS TOU - BGS	MGS - SEC / SEVC	MGS - PRI	AGS - SEC	AGS - PRI	SPL/CSL	DDC
Summer - all hrs			***21.0561***	***11.6701***	***9.7979***	***10.8838***	***10.6341***	***7.7634***	***9.9850***
	On-Peak		***25.0376***						
	Off-Peak		***7.6137***						
for Block 1 (0-750 kWh/m) usage		***12.3044***							
for Block 2 (>750 kWh/m) usage		***13.2518***							
Winter - all hrs		***13.2140***	***28.4031***	***11.0672***	***9.2208***	***10.2621***	***10.1011***	***7.9005***	***9.4033***
	On-Peak		***29.8738***						
	Off-Peak		***7.8039***						

Table F **Spreadsheet Error Checking** - *Checking of seasonal Customer Revenue and Supplier Payments, based on final actual anticipated revenues and payments*

	RS / EV-ERR	RS TOU - BGS	MGS - SEC / SEVC	MGS - PRI	AGS - SEC	AGS - PRI	SPL/CSL	DDC
Total Rate Revenue - in $1000								
Summer	$ 208,087	$ 125	$ 46,439	$ 2,933	$ 42,486	$ 13,249	$ 1,252	$ 404
Winter	$ 281,281	$ 178	$ 70,896	$ 4,024	$ 64,557	$ 20,201	$ 3,001	$ 641
Total	$ 489,368	$ 303	$ 117,336	$ 6,957	$ 107,043	$ 33,450	$ 4,253	$ 1,045

Total Summer	$ 314,975
Total Winter	$ 444,778
Grand Total	$ 759,753

Total Supplier Payment - in $1000	
Summer	$ 314,973
Winter	$ 444,776
Total	$ 759,749
Differences - in $1000	
Summer	$ 2
Winter	$ 2
Total	$ 4

Attachment 4

Development of Capacity Proxy Price True-Up - $/MWh

2027/2028 Delivery Year - Illustrative Data

Capacity Proxy Price True-Up Development for Winning Suppliers from 2025 BGS-RSCP Auction

		2027/28 Delivery Year	*Notes:*
1	**Zonal Capacity Price ($/MW-day)**	$333.69	as may be determined by the RPM, or its successor, or otherwise
2	**Capacity Proxy Price ($/MW-day)**	$270.35	per Board Orders dated 11/21/2024
3	**Capacity Proxy Price True-Up - $/MW-day**	$63.34	= line 1 - line 2
4	**BGS-RSCP Gen Obl - MW**	1,763.9	
5	**Days in Year**	366	
6	**Capacity Proxy Price True-Up Annual Cost**	$40,892,643	= line 3 * line 4 * line 5
7	**Eligible Tranches**	7	from Table A
8	**Total Tranches**	22	from Table A
9	**% of tranches eligible for payment**	31.82%	= line 7 / line 8
10	**Capacity Proxy Price True-Up Cost**	$13,011,295	= line 6 * line 9
11	**Total Applicable Customer Usage @ bulk system - in MWh**	6,665,183	
12	**Eligible Customer Usage @ bulk system - *in MWh***	2,120,740	= line 9 * line 11
13	**Capacity Proxy Price True-Up - $/MWh**	**$6.14**	**= line 10/ line 12 - rounded to 2 decimal places**

Development of Capacity Proxy Price True-Up - $/MWh

2028/2029 Delivery Year - Illustrative Data

		Capacity Proxy Price True-Up Development for Winning Suppliers from 2026 BGS-RSCP Auction	Capacity Proxy Price True-Up Development for Winning Suppliers from 2027 BGS-RSCP Auction (if needed)	
		2028/29 Delivery Year	2028/29 Delivery Year	*Notes:*
1	**Zonal Capacity Price ($/MW-day)**	$335.00	$335.00	as may be determined by the RPM, or its successor, or otherwise
2	**Capacity Proxy Price ($/MW-day)**	$333.69	$333.69	per Board Order dated 11/21/2025 and XX/XX/2026
3	**Capacity Proxy Price True-Up - $/MW-day**	$1.31	$1.31	= line 1 - line 2
4	**BGS-RSCP Gen Obl - MW**	1,763.9	1,763.9	
5	**Days in Year**	365	365	
6	**Capacity Proxy Price True-Up Annual Cost**	$843,432	$843,432	= line 3 * line 4 * line 5
7	**Eligible Tranches**	8	7	from Table A
8	**Total Tranches**	22	22	from Table A
9	**% of tranches eligible for payment**	36.36%	31.82%	= line 7 / line 8
10	**Capacity Proxy Price True-Up Cost**	$306,703	$268,365	= line 6 * line 9
11	**Total Applicable Customer Usage @ bulk system - in MWh**	6,665,183	6,665,183	
12	**Eligible Customer Usage @ bulk system - *in MWh***	2,423,703	2,120,740	= line 9 * line 11
13	**Capacity Proxy Price True-Up - $/MWh**	**$0.13**	**$0.13**	**= line 10/ line 12 - rounded to 2 decimal places**

Development of Capacity Proxy Price True-Up - $/MWh

2029/2030 Delivery Year - Illustrative Data

Capacity Proxy Price True-Up Development for Winning Suppliers from 2027 BGS-RSCP Auction (if needed)

		2029/30 Delivery Year	*Notes:*
1	**Zonal Capacity Price ($/MW-day)**	$335.00	as may be determined by the RPM, or its successor, or otherwise
2	**Capacity Proxy Price ($/MW-day)**	$333.69	per Board Order dated XX/XX/2026
3	**Capacity Proxy Price True-Up - $/MW-day**	$1.31	= line 1 - line 2
4	**BGS-RSCP Gen Obl - MW**	1,763.9	
5	**Days in Year**	365	
6	**Capacity Proxy Price True-Up Annual Cost**	$843,432	= line 3 * line 4 * line 5
7	**Eligible Tranches**	7	from Table A
8	**Total Tranches**	22	from Table A
9	**% of tranches eligible for payment**	31.82%	= line 7 / line 8
10	**Capacity Proxy Price True-Up Cost**	$268,365	= line 6 * line 9
11	**Total Applicable Customer Usage @ bulk system - in MWh**	6,665,183	
12	**Eligible Customer Usage @ bulk system - *in MWh***	2,120,740	= line 9 * line 11
13	**Capacity Proxy Price True-Up - $/MWh**	**$0.13**	**= line 10/ line 12 - rounded to 2 decimal places**

Table A With Additional Line Item

Calculation of June 2028 to May 2029 BGS-RSCP Rates

Illustrative Purposes Only for ACE

Table A **Auction Results**

line #	Specific BGS-RSCP Auction >>	*remaining portion of 36 month bid - 2026 auction*	*remaining portion of 36 month bid - 2027 auction*	*36 month bid - 2028 auction*	*Notes:*
1	**Winning Bid - in $/MWh**	$ 112.75	$ 112.75	$ 112.88	winning Bids
1A	**28/29 Capacity Proxy Price True-up - in $/MWh**	$ 0.13	$ 0.13		entered after 2028 BGS Auction
1B	**Total - in $/MWh**	$ 112.88	$ 112.88	$ 112.88	= line 1 + line 1A
2	**# of Tranches for Bid**	8	7	7	from then current Bid
3	**Total # of Tranches**	22	22	22	from then current Bid
	Payment Factors				
4	Summer	1.0000	1.0000	1.0000	from then current Bid Factor Spreadsheet
5	Winter	1.0000	1.0000	1.0000	from then current Bid Factor Spreadsheet
	Applicable Customer Usage @ bulk system - in MWh				
6	Summer MWh	2,763,222			from current Bid Factor Spreadsheet
7	Winter MWh	3,901,961			
	Total Payment to Suppliers - *in $1000*				
8	Summer	$ 113,423	$ 99,245	$ 99,245	= (1 + 1A) * (2)/(3) * (4) * (6) / 1000
9	Winter	$ 160,165	$ 140,144	$ 140,144	= (1 + 1A) * (2)/(3) * (5) * (7) / 1000
10	Total	$ 273,588	$ 239,389	$ 239,389	
	Average Payment to Suppliers - *in $/MWh*				
11	Summer	$ 112.88			= sum(line 8) / (6) - rounded to 2 decimal places
12	Winter	$ 112.88			= sum(line 9) / (7) - rounded to 2 decimal places
13	Total weighted average	**$ 112.88**	<<< used in calculation of Customer Rates		= sum(line 10) / [(6) + (7)] rounded to 2 decimal places

Table A With Additional Line Item

Calculation of June 2029 to May 2030 BGS-RSCP Rates

Illustrative Purposes Only for ACE

Table A **Auction Results**

line #	Specific BGS-RSCP Auction >>	*remaining portion of 36 month bid - 2027 auction*	*remaining portion of 36 month bid - 2028 auction*	*36 month bid - 2029 auction*	*Notes:*
1	**Winning Bid - in $/MWh**	$ 112.75	$ 112.88	$ 112.88	winning Bids
1A	**29/30 Capacity Proxy Price True-up - in $/MWh**	$ 0.13			entered after 2029 BGS Auction
1B	**Total - in $/MWh**	$ 112.88	$ 112.88	$ 112.88	= line 1 + line 1A
2	**# of Tranches for Bid**	7	7	8	from then current Bid
3	**Total # of Tranches**	22	22	22	from then current Bid
	Payment Factors				
4	Summer	1.0000	1.0000	1.0000	from then current Bid Factor Spreadsheet
5	Winter	1.0000	1.0000	1.0000	from then current Bid Factor Spreadsheet
	Applicable Customer Usage @ bulk system - in MWh				
6	Summer MWh	2,763,222			from current Bid Factor Spreadsheet
7	Winter MWh	3,901,961			
	Total Payment to Suppliers - *in $1000*				
8	Summer	$ 99,245	$ 99,245	$ 113,423	= (1 + 1A) * (2)/(3) * (4) * (6) / 1000
9	Winter	$ 140,144	$ 140,144	$ 160,165	= (1 + 1A) * (2)/(3) * (5) * (7) / 1000
10	Total	$ 239,389	$ 239,389	$ 273,588	
	Average Payment to Suppliers - *in $/MWh*				
11	Summer	$ 112.88			= sum(line 8) / (6) - rounded to 2 decimal places
12	Winter	$ 112.88			= sum(line 9) / (7) - rounded to 2 decimal places
13	Total weighted average	**$ 112.88**	<<< used in calculation of Customer Rates		= sum(line 10) / [(6) + (7)] rounded to 2 decimal places