

STATE OF NEW JERSEY
BOARD OF PUBLIC UTILITIES

IN THE MATTER OF THE PROVISION
OF BASIC GENERATION SERVICE FOR
THE PERIOD BEGINNING JUNE 1, 2027

Docket No. ER26040105

ROCKLAND ELECTRIC COMPANY

**PROPOSAL FOR
BASIC GENERATION SERVICE
REQUIREMENTS TO BE PROCURED EFFECTIVE
JUNE 1, 2027**

**COMPANY SPECIFIC ADDENDUM
COMPLIANCE FILING**

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RECO's COMPANY SPECIFIC ADDENDUM

A. Introduction to RECO's Company Specific Filing

In its Decision and Order dated April 22, 2026 in Docket No. ER26040105, the New Jersey Board of Public Utilities ("Board" or "NJBPU") directed New Jersey's four investor owned electric distribution companies ("EDCs") to file proposals with the Board by no later than July 1, 2026 on the procurement of basic generation service ("BGS") for the period beginning June 1, 2027. This document constitutes Rockland Electric Company's ("RECO" or the "Company") company-specific portion of the compliance filing as mandated by the Board. RECO is also a party to and incorporates by reference the Proposal for BGS Requirements to be Procured Effective June 1, 2027, filed by New Jersey's four EDCs on July 1, 2026 ("EDC Compliance Filing").

B. Use of Committed Supply

"Committed Supply" means any and all power supplies to which the EDCs have an existing physical or financial entitlement that may extend into or through the BGS bid period. This will include Non-Utility Generation ("NUG") contracts, including any restructured replacement power contracts; any wholesale purchases previously contracted for by the EDCs, and any generation assets, or options for/calls upon assets, still owned or under contract to the EDCs. RECO has no Committed Supply.

C. RECO Tranche Configuration

In its Decision and Order issued June 18, 2012 in Docket No. ER12020150, the Board lowered the threshold for the BGS-CIEP class to include all commercial and industrial customers with a peak load share of 500 kW and greater.¹ RECO continues to comply with this directive and will include these customers as one tranche in the BGS-CIEP Auction.

As to the BGS-RSCP Auction, RECO currently has one 36-month tranche that terminates on May 31, 2027, two 36-month tranches that terminate on May 31, 2028, and one 36-month tranche that terminates on May 31, 2029. Accordingly, because the load requirements of RECO's Eastern Division are comprised of a total of four tranches, in the BGS-RSCP Auction for the period commencing June 1, 2027, RECO will include one 36-month tranche (for the period June 1, 2027 through May 31, 2030).

D. Contingency Plans

While not every contingency can be anticipated, the following three contingencies are of particular concern:

- (a) The Auction Process fails to provide 100 percent of RECO's BGS Load (*i.e.*, an insufficient number of bids to provide for a fully subscribed auction volume);
- (b) A default by one of the winning bidders prior to June 1, 2027; and
- (c) A default during the supply period.

The three contingencies are discussed further below.

¹ In accordance with the Board's December 8, 2005 Decision and Order (see footnote 13, at page 16), RECO will determine all eligibility criteria by measuring when a customer's billing demand exceeds the eligibility level during any two months of a calendar year.

(a) Insufficient Number of Bids

A viable Auction Process requires a sufficient degree of competition. To encourage a sufficient degree of competition, the volume of BGS power purchased at the Auction will be finally decided after the receipt of first round bids. Provided that there are sufficient bids at the starting price, the Auction will be held for 100 percent of the BGS Load² (*i.e.*, both BGS-RSCP and BGS-CIEP).

It is possible, however, that the number of initial bids will not result in a competitive auction for 100 percent of the BGS Load. Any determination to reduce the percentage of BGS Load included in the Auction Process will be made by the Auction Manager, in consultation with the EDCs and the NJBPU advisor. It is also possible that none of RECO's BGS Load tranches will be bid upon even at the starting price.

In the event that the Auction Volume is reduced to less than 100 percent of BGS Load, or there are unsubscribed tranches at the end of the Auction, each EDC will implement a contingency plan for the remaining tranches. Under RECO's contingency plan, RECO currently intends to purchase that percentage of BGS Load, not met through the Auction Process, in PJM administered markets.³ This purchase is a strong feature of the Auction proposal because it provides bidders a strong incentive to participate in the Auction Process.

During the 2006 BGS Auction, RECO did not receive any bids on its BGS-CIEP tranche. As a result, RECO was forced to purchase its BGS-CIEP supply from the PJM markets.

² Excluding the three 36-month tranches that were auctioned off successfully in the previous two BGS-RSCP Auctions.

³ While RECO's current intention is to purchase from PJM administered markets, RECO reserves the right to consider other alternatives. Although unlikely, in the event that purchases from New York Independent System Operator ("NYISO") administered markets provide a more cost-effective alternative to PJM, RECO reserves the right to make purchases from NYISO administered markets.

In the event that RECO is not able to auction its BGS-CIEP tranche successfully in the 2026

BGS Auction, RECO proposes to employ the following procedures:

- RECO will not submit any day-ahead energy bids, rather the BGS-CIEP load will be filled from the PJM real time market.
- RECO will prepare a BGS-CIEP load backcast for the previous day and submit this backcast to PJM.
- RECO will purchase capacity credits from eRPM in PJM or from bilateral purchases on a monthly and daily basis.
- RECO will purchase ancillary services on a daily basis from the real time PJM market.
- RECO will set its CIEP Standby Fee at the level determined by the Board.
- RECO will fulfill any Class I, Class II, and Solar requirements, for its unsubscribed BGS tranches, by securing the needed PJM Generation Attributes Tracking (“GATS”) system generated renewable energy certificates (“RECs”) through any available PJM market, or bilaterally. In the event RECs are not available on the market, RECO will make the necessary Alternative Compliance Payments.
- All costs and revenue (with the exception of retail margin revenue) will flow through the reconciliation account for BGS-CIEP. Costs will include the procurement of all necessary services, including energy, capacity, ancillary services, Class I, II and Solar RECs, and any other expenses related to the implementation of RECO’s contingency plan.

(b) Defaults prior to June 1, 2027

If a winning bidder defaults prior to the commencement of the BGS service, then the open tranches may be offered to the other winning bidder(s) or these tranches will be bid out as quickly as possible. Additional costs will be assessed against the defaulting company's BGS credit security.

(c) Defaults during the Supply Period

If a default occurs during the supply period, then Tranches supplied by the defaulting party may be offered to other suppliers, bid out, or procured in PJM administered markets. If a default involves RECO's 36-month BGS-RSCP tranche, RECO only will seek replacement supply until May 31, 2028. For the remainder of the 36-month period, RECO will seek replacement supply through whatever process is implemented by the Board for the period commencing June 1, 2028.

Additional costs will be assessed against the defaulting company's BGS credit security.

E. Accounting and Cost Recovery

The accounting and cost recovery that RECO proposes with respect to BGS is summarized in this section.

(a) System Control Charge ("SCC")

If applicable to RECO, the SCC will be calculated initially, and then annually on a cents per kWh basis and the charge will be applied to all of the Company's electric distribution customers. This charge would be published in a separate SCC tariff leaf. This tariff leaf would be filed with the Board upon the Board's issuance of the appropriate order(s). If applicable to RECO, the SCC would be

applied to all distribution customers' bills to provide recovery for appliance cycling load management costs. The charge would be set initially to recover estimated annual expenditures as approved by the Board. The SCC would be subject to deferred accounting with interest at the rate applicable to SBC deferrals.

(b) BGS-RSCP and BGS-CIEP Reconciliation Charges

In its August 15, 2012 Order⁴, the Board approved the Company's proposal to change the BGS-RSCP and BGS-CIEP reconciliation charges from a monthly to a quarterly mechanism. RECO will track and defer separately for the BGS-RSCP and BGS-CIEP classes of customers, on a monthly basis, any differences between BGS revenue and BGS costs.

BGS costs are comprised of the following:

1. Payments made for provisions of BGS-RSCP and BGS-CIEP service;
2. RECO's pro-rata share of any procurement of capacity, energy, and ancillary services, pursuant to its FERC-approved Power Supply Agreement, and other costs incurred, including hedging and costs associated with the RECO Request for Proposal ("RFP");
3. The cost of any procurement of capacity, energy, ancillary services, transmission, RPS compliance, and other costs incurred under the Contingency Plan less any payments recovered from defaulting suppliers;
4. Costs incurred by RECO to participate in the BGS Auction as well as any costs incurred to conduct the RECO RFP, including outside attorney and consultant expenses and other costs incurred by or allocated to RECO related to the conduct of the Auction; and
5. Any administrative costs associated with the provision of BGS-RSCP and BGS-CIEP service.

⁴ *In the Matter of the Petition of Rockland Electric Company to Revise the Methodology for its Basic Generation Service Reconciliation Charge*, BPU Docket No. ER12079643, Decision and Order (dated August 15, 2012).

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

- a. 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 NJBPU, as performed by the Board's consultant;
 - outside counsel legal costs associated with the prosecution and/or defense of BGS patent claims; and
 - costs associated with viewing the annual auction in real time, which may include, but are not limited to, costs for physical space and equipment/media connections.
- b. Directly-incurred costs include, but are not limited to, labor costs consistent with the Order of Implementation related to the BGS Administrative Expense Audit⁵.

Estimates of commonly-incurred costs for each BGS Auction cycle are paid for by the winning bidders of the auction at the start of each Energy Year ("EY")⁶ 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 by BGS customers through the BGS Reconciliation Charges.

Reconciliation charges are necessary to reconcile the differences between monthly BGS supply costs and BGS revenues from customers for BGS service.

⁵ *In the Matter of the Request for Proposal for a Financial Audit of the New Jersey Electric Distribution Companies' Basic Generation Administrative Expense and Other Related Expense*, BPU Docket No. EA17010004, Order of Implementation (dated July 15, 2020).

⁶ The Energy Year is defined as the 12-month period commencing June 1.

Separate BGS-RSCP and BGS-CIEP Reconciliation Charges, applicable to all BGS-RSCP and BGS-CIEP customers, respectively, will be calculated and assessed quarterly on a cents per kWh basis to reconcile previous over- or under-collections. The BGS-RSCP and BGS-CIEP Reconciliation Charges will be published in separate BGS Reconciliation Charge tariff leaves on a quarterly basis. These tariff leaves will be filed with the Board fifteen days prior to the first day of the effective quarter.

The BGS-RSCP and BGS-CIEP Reconciliation Charges will be subject to deferred accounting with interest and will be determined individually as set forth below:

The BGS-RSCP and BGS-CIEP Reconciliation Charges will be used to true up the differences between BGS costs and BGS revenues from customers. Differences in costs and cost recovery will be computed for each month in the quarter and assessed through the BGS-RSCP and BGS-CIEP Reconciliation Charges applied to customers' bills in the following quarter. Two of these differences are as follows:

1. The difference between BGS Costs and BGS revenues for each month in the quarter.
2. The difference between the total reconciliation charge revenue intended to be recovered in each quarter and the actual reconciliation charge revenues recovered in the quarter. This difference will be driven by differences between actual kWh in the quarter in which the reconciliation charge was assessed and the kWh used to calculate the charge.

The reconciliation charges to be applied in the following quarter are calculated individually for BGS-RSCP and BGS-CIEP service as the net of the two

differences described above on a monthly basis for the current quarter (plus or minus any cumulative under or over recovery from the prior quarter) divided by the forecasted BGS kWh for the following quarter.

For any given quarter, the reconciliation charges shall not exceed a charge or credit of 2.0 cents per kWh, including sales and use tax. In the event the 2.0 cents per kWh limit is imposed, any remaining over- or under-collection balance shall be included in the subsequent quarter's reconciliation charges to the extent possible within the 2.0 cents per kWh limitation.

The following table summarizes RECO's current process.

Reconciliation for the Months of:	Quarter Rate is In Effect:
February – April	June 1 - August 31
May – July	September 1 - November 30
August – October	December 1 - February 28
November – January	March 1 - May 31

Interest will be applied based on two-year constant maturity treasuries as published in the Federal Reserve Statistical Release on the first day of each month or the closest day thereafter on which rates are published, plus 60-basis points. However, the interest rate shall not exceed the Company's overall rate of return as authorized by the Board. The interest rate will be determined for each month in the quarter based on the criteria above.

F. Description of BGS Tariff Changes

Draft tariff leaves indicating "X.XXX" for the rates that will change as a result of the BGS-RSCP and BGS-CIEP Auctions are included in Attachment A.

Final tariff leaves including the actual BGS rates and tariff provisions to become effective on June 1, 2027 will be filed with the Board upon its issuance of an appropriate Board order approving the BGS Auction Process.

G. RECO RFP

RECO's Central and Western divisions are physically connected to the New York Control Area administered by the New York Independent System Operator ("NYISO"). Therefore, RECO must purchase the energy and capacity needs of its Central and Western BGS customers from markets administered by the NYISO.

With regard to the purchase of energy, in the Board's November 17, 2023 Order in Docket No. ER23030124 (the "2023 Order"), the Board approved a Request for Proposal ("RFP") process for RECO to solicit competitive bids from qualified bidders for fixed energy supply prices for BGS customers in RECO's Central and Western Divisions, commencing June 1, 2024. On January 30, 2024, RECO conducted its RFP for the period June 1, 2024 through May 31, 2027. As a result of rewarding a three-year financial contract, RECO's purchases were hedged through May 31, 2027, and another procurement proposal must be made for the BGS year commencing June 1, 2027.

(a) Proposal

For the BGS year commencing June 1, 2027, RECO proposes the same procurement process that the Board approved in the 2023 Order. Rockland proposes to enter into a bi-lateral agreement or agreements to hedge the cost of energy purchases

from the NYISO. The bi-lateral agreement or agreements will be a financial hedge, where no energy commodity is provided by the counterparty.

The Company proposes to conduct the bidding approximately two weeks before the BGS auction. The bids would be submitted by bidders the day before a Board agenda meeting, and the bid agreement would specify that the bidder will hold the bid open until the earlier of approval of the bid by the Board or midnight the day of the Board agenda meeting. Any bidder that has an ISDA⁷ in place with the Company prior to bidding will be eligible to bid. Bidders will enter into binding bid agreements, but the Company will not require bid collateral, in order to encourage bidder participation. The Company reserves the right to reject any and all winning bids.

Rockland will seek bids on financial transactions for NYISO Zone G energy for the periods specified below. Each transaction will be a fixed-price transaction for approximately 15 MW “around-the-clock” of NYISO Zone G energy. Rockland is seeking to procure transactions to cover the period of June 1, 2027 to May 31, 2030 and will seek pricing for the following four periods:

1. Year 1: June 1, 2027 through May 31, 2028;
2. Year 2: June 1, 2028 through May 31, 2029;
3. Year 3: June 1, 2029 through May 31, 2030; and
4. Blended Price: June 1, 2027 through May 31, 2030.

⁷ The ISDA Master Agreement, published by the International Swaps and Derivatives Association (ISDA), is a document that outlines the terms applied to a derivatives transaction between two parties.

Rockland will enter into a NYISO Zone G fixed-for-floating swap with a counterparty, whereby Rockland effectively pays the fixed price monthly for the term of the transaction.

Rockland will review the bids with Board Staff and its BGS auction consultant and select a winning bid that is the most competitive and that is consistent with market conditions. Rockland will submit this winning bid to the Board for approval. In the event that the bids that the Company receives do not reflect market conditions, the Board does not approve the winning bidder, or the bidder defaults on the bid agreement, the Company will report a failed procurement and will proceed to the default procurement process set out below.⁸

With regards to the procurement of capacity, on August 16, 2013, the FERC approved the creation of a new capacity market zone in the Lower Hudson Valley region encompassing NYISO Load Zones G, H, I, and J in FERC Docket No. ER13-1380. Lower Hudson Valley capacity is not actively traded, and the Company does not expect the above to change before the BGS Auction.⁹ As a result of the capacity market changes at the NYISO noted above, RECO will purchase the capacity needs of its BGS customers in its Central and Western Divisions in the NYISO capacity market and blend its forecast of those prices into the BGS-RSCP price. This is the same proposal approved by the Board in its November 17, 2023 Order in Docket No. ER23030124. The impact of these capacity purchases is expected to be minimal because the

⁸ If the Company uses an in-house auction facility, a technical failure of the auction facility will require that the Company proceed to the default procurement process.

⁹ Such cleared products are necessary benchmarks that enable bidders to develop their bids for financial hedging contracts.

Company's Central and Western Divisions constitute only about ten percent of the Company's BGS load.

(b) Default Procurement

In the event of a default procurement, RECO will purchase the energy needs of its BGS customers in the Central and Western Divisions in the NYISO Day-Ahead and Real Time Markets without a financial hedge. Currently, to determine rates for BGS service classifications, the Company calculates a load-weighted price to calculate BGS service classification rates. The load-weighted price combines, for the Central/Western division, the hedging contract fixed price and the Company's forecast of the NYISO capacity price, and for the Eastern division, three-year, tranche-weighted BGS auction prices. For this default proposal, the Company will use the BGS auction price as the input for the Central/Western portion of the load-weighted price.

H. BGS Rate Design Methodology

RECO BGS Pricing Spreadsheet

As described in the EDC Compliance Filing, the resulting charge for each BGS rate element (*e.g.*, SC No. 1 summer charge, winter charge) for BGS supply service will be based on a factor applied to the tranche weighted average of the winning BGS-RSCP bid prices adjusted for the seasonal payment factors. These factors have been developed based on the ratios of the estimated underlying market costs of each rate element (for each service classification) to the overall all-in BGS cost. The tables included in Attachment B present all of the input data, intermediate calculations, and the final results in the calculation of these factors.

Table #1 (% Usage during PJM On-Peak Period) contains the percentage of on-peak load, by month, for each service classification. The on-peak period as used in this table (referred to as PJM periods) is defined as the 16-hour period from 7:00 AM to 11:00 PM, Monday through Friday. All remaining weekday hours and all hours on weekends and holidays recognized by the National Electric Reliability Council (“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 the average on-peak percentages from the year 2025 based on load profile information.

Table #2 (% Usage During RECO On-Peak Billing Period) contains percentages of on-peak load, by month, for RECO BGS-RSCP service classifications that are billed on a time of use basis (SC No. 1 Voluntary Time of Day (“SC No. 1 VTOD”) and SC No. 3). These percentages are based on RECO’s time periods used for customer billing.

Table #3 (Class Usage @ customer) contains monthly sales forecasted for the calendar year 2027 with a migration adjustment for retail access. The values in Table #3 will be updated in January 2027 to better reflect the amount by Service Classification that could be in effect starting on June 1, 2027.

Table #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 a weighted average forecast of PJM and NYISO energy prices as calculated in Table #18. The PJM values are the published energy on-peak forwards for the PJM West trading hub for the period of June 2027 to May 2028, and an estimate based on off/on peak LMP ratios for the off-peak periods of each month. The NYISO

values are based on a combination of forward and historical prices. An adjustment to the PJM forward prices used to calculate the prices contained in Table #4 must be made to correct for the effects of the basis differential in the PJM system between the PJM West trading hub and the RECO zone where the BGS supply will be utilized. Table #18 contains an estimate of this basis differential, 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 RECO's PJM zone.

Table #5 (Losses) contains the factors utilized for average system losses, including PJM losses and unaccounted for supply (net of marginal losses) that are input by service classification and voltage level. Loss factors are those in RECO's current, Board approved, Third Party Supplier Agreement. PJM losses are the average percentage PJM EHV losses plus Inadvertent Energy for the period of January 2023 to December 2025, which equals 0.6323%. Marginal losses are excluded from the loss factors based on historic de-rating factors for the period May 2023 to April 2026.

Table #6 (Summary of Average BGS Energy Only Unit Costs @ customer – PJM Time Periods) is the calculation of the energy only costs by service classification, time period and season. These values are the seasonal and time period average costs per MWh as measured at the customer billing meter (from Table #3), based on the forward prices (from Table #4) adjusted for losses (from Table #5), and monthly time period weights (from Table #1). These average costs do not include the costs associated with Ancillary Services, Renewable Portfolio Standard compliance, Generation Capacity or Transmission costs, which will be considered in subsequent calculations.

Table #7 (Summary of Average BGS Energy Only Costs @ customer – PJM Time Periods) indicates the total value, in thousands of dollars, of the average BGS energy-only costs. These are the results of the multiplication of the unit costs from Table #6, the monthly time period weights from Table #1 and the total sales to customers from Table #3.

Since the end result of these calculations is to be utilized in the development of retail BGS rates, the rates utilizing time of use pricing must be developed based upon the time periods as defined for billing.

Table #8 (Summary of Average BGS Energy Only Units Costs @ customer – RECO Time Periods) shows the result of this adjustment for SC No. 1 – VTOD and SC No. 3 rates billed on a time of use basis. These values are calculated by starting with the values in Table #6. Because RECO bills fewer peak hours than the peak hours defined by PJM, the prices in Table #6 would result in a revenue shortfall when applied to RECO's SC No. 1 – VTOD and SC No. 3 peak and off-peak kWh consumption. To correct for this difference, the shortfall for each is divided by the total kWh for the SC and the resulting per unit shortfall is added to both the on-peak and off-peak charges in Table #6 to arrive at the prices in Table #8. The next steps set up the values necessary for the inclusion of the costs of the Generation Capacity and Transmission.

The top portion of Table #9 (Generation & Transmission Obligations and Costs and Other Adjustments) shows the total obligations with a migration adjustment, by rate schedule, that are currently being utilized in the year 2026. The values in the top portion of Table #9 will be updated in January 2027 to better reflect the aggregate amount by rate schedule that could be in effect on June 1, 2027. 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 annual cost for transmission service and the average price of generation capacity for the three relevant RPM auctions. Typically, the generation capacity costs used in the development of the BGS-RSCP rates are the relevant current wholesale market prices for capacity based on the average 2027/2028, 2028/2029, and 2029/2030 Base Residual Auction (“BRA”) results under the Reliability Pricing Model (“RPM”) applicable to load served in the RECO zone. This process has been impacted in recent years by delays in conducting the BRAs- resulting in the need for contract supplements with Capacity Proxy Prices for delivery years with delayed BRAs.

Due to delays of the BRAs, contracts from the 2025 and 2026 BGS auctions contained supplements with Capacity Proxy Prices. With the delays of the BRAs for the 2027/2028 Delivery Year and the 2028/2029 Delivery Year, a Capacity Proxy Price of \$270.35/MW-day was used in place of the 2027/2028 BRA value in the 2025 contracts, while a Capacity Proxy Price of \$333.69/MW-day was used in place of the 2027/2028 BRA value and the 2028/2029 BRA value in the 2026 contracts.

At this time, the BRAs for the 2028/2029 and 2029/2030 Delivery Year are not yet available but the BRAs are scheduled to be held in July 2026, and December 2026, respectively. Given the continued delay in the schedule of these BRAs, a Capacity Proxy price of \$333.69 per MW-Day has been used in place of the prices paid for capacity for 2028/2029 and 2029/2030 Delivery Years, respectfully.

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 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 Reliability Pricing Model or its successor or otherwise, and the Capacity Proxy Price for the 2028/2029 Delivery Year.

For EY 2030, as 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 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 Reliability Pricing Model or its successor or otherwise, and the Capacity Proxy Price for the 2029/2030 Delivery Year.

RECO will file new tariff sheets for EY 2029 and EY 2030, reflecting the impact of this price adjustment. The rate design spreadsheets include the formulas that will be used to reflect the impact of payments made pursuant to the Supplements.

The SMA Supplement signed by BGS-RSCP Suppliers in February 2025 is still in effect for a portion of the load for EY 2028 (i.e., the year beginning June 1, 2027). Payments to BGS-RSCP suppliers that executed the Supplement to the SMAs approved by the Board on November 21, 2024 and November 21, 2025 will be adjusted for the price difference paid by the 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 Auction, or the RPM’s successor or otherwise, the price paid by the BGS-RSCP Suppliers for Capacity in the Company’s PJM Zone will be known. At that time, RECO 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 Supplement executed by BGS Suppliers in February 2025. The value of \$333.69 per MW-day is used as an approximation for the for the price paid by BGS-RSCP Suppliers for Capacity in the Company's PJM Zone for the 2027/2028 Delivery Year.

The cost of transmission service is equal to the rate in the PJM Open Access Transmission Tariff for network transmission service in the RECO zone. The generation capacity costs are based on an estimate of the relevant current wholesale market prices in the PJM (*i.e.*, three-year average for the period 2027 to 2030 for RECO using a proxy price for 2030), and NYISO zones as calculated in Table #19. Also shown is the level of blocking in the BGS charges for SC No. 1, which will be utilized in the later calculations of the blocking of BGS charges for this service classification group.

An estimate of the cost of ancillary services and Renewable Portfolio Standard is included in Table #10 (Ancillary Services and Renewable Portfolio Standard). The Ancillary Services estimate is a weighted average of estimated Ancillary Services costs in RECO's PJM zone (*i.e.*, \$2 per MWh) and RECO's estimate of Ancillary Services costs in RECO's NYISO zone as calculated in Table #20. Additionally, Renewable Portfolio Standard costs estimated to be \$16.14 per MWh are included in the calculation of the BGS-RSCP rates to reflect compliance costs.

Table #11 (Summary of Obligation Costs Expressed as \$/MWh @ customer for non-demand rates only) shows the result of the allocation of both the transmission and generation costs on a per MWh basis to those service classifications under which BGS service will be billed only on a per kWh basis.

Table #12 (Summary of BGS Unit Costs @ customer) is the result of the inclusion of the transmission, generation capacity, and Ancillary Services costs to the costs shown in Table #8. The bottom portion of 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 and the bulk system meters.

Table #13 (Ratio of BGS Unit Costs @ customer to All-In Average Cost @ transmission nodes) indicates the ratio of the individual rate element costs from Table #12 to the overall all-in cost as measured at the bulk system plus constant, where applicable.

Table #14 (Summary of BGS Unit Costs Less Transmission @customer) provides the BGS unit costs as developed in Table 12, with the exception of transmission. The bottom portion of the table shows the total estimated costs for BGS less transmission costs and the average unit cost as measured at the customer meters and the bulk system.

Table #15 (Ratio of BGS Unit Costs Less Transmission @ customer to All-In Average Cost @ transmission nodes) indicates the ratio of the individual rate element costs from Table #14 to the overall all-in cost as measured at the bulk system. These ratios are used to establish the BGS prices to retail customers.

Table #16 (Summary of Total BGS Costs by Season) shows the summary of the total and percentage of costs by rate and by season. A calculation in the lower portion of this table shows the resulting average costs per MWh for the winter and summer costs and MWhs, while the ratio of these seasonal unit costs to the all-in cost (from Table #12) is shown in the lower right-hand portion of this table.

Table #17 (Summary of Total BGS Costs by Season Less Transmission) shows the summary of the total and percentage of costs by rate and by season. This is similar to the values indicated in Table #16, however this table excludes the cost for transmission. A calculation in the lower portion of this table shows the resulting average costs per MWh for the winter and summer costs and MWhs, while the ratio of these seasonal unit costs to the all-in cost (from Table #14) is shown in the lower right-hand portion of this table.

Tables #18 (Forward Energy Prices), #19 (Generation Capacity Prices), and #20 (Ancillary Services and Renewable Portfolio Standard Prices) show the calculation of weighted average prices for energy, generation capacity and Ancillary Services as more fully described under “Table #4”, “Table #9” and “Table #10”. An estimate of the effects of the cost of the Renewable Portfolio Standard is included in the development of the final BGS rates. The values of \$2.28¹⁰ per MWh and \$16.14 per MWh are used, respectively for ancillary services and Renewable Portfolio Standard Prices. Since the actual costs are a complex combination of many factors, this Board-approved estimate of the overall annual average value, expressed on a dollar per MWh basis, is used as a reasonable and practical alternative.

The second spreadsheet used in the calculation of the final BGS-RSCP rates is included as Attachment C. 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 Table A through F, is as follows:

¹⁰ The weighted average of both PJM and NYISO ancillary service cost estimates.

Table A (Weighted Average Price Calculation) contains the results of the BGS (*i.e.*, current and prior two) auctions. The Capacity Proxy Price True-up cost in cents per kWh will be used to reflect the impact of payments made pursuant to the supplements executed by BGS Suppliers in February 2025 and February 2026. Upon conclusion of the Third Incremental RPM Auction through the Reliability Pricing Model 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 \$270.35 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. The table also includes the impacts of RECO's RFP for the Central and Western Divisions, where the RFP winning bid price is applied to the results of the prior two BGS auctions.¹¹ From these values, the weighted average total price (shown on line #48) is calculated. All the formulas used in this table are shown in the right-hand column of this table, under the head of "Notes." To the extent the seasonal factors for the 12-month BGS period beginning June 1, 2027 (as calculated in Table #16) produce a summer payment factor less than one and a winter payment factor greater than one, the Company reserves its right to set the seasonal factors to 1.0 for both the Summer and Winter periods in any updates to the Company's BGS Pricing Spreadsheet. Accordingly, the Company has set the seasonal factors to 1.0 for both the Summer and Winter periods.

¹¹ The prices shown for the tranche to be secured in the 2027 BGS Auction are for illustrative purposes only and will be replaced with actual data in determining RECO's final June 2027 BGS-RSCP rates.

Table B (Ratio of BGS Unit Costs Less Transmission @ Customer to All-In Average Cost @ transmission nodes) is a repeat of the values shown in Table #15 from Attachment B, the bid factors calculated based on current market conditions.

Table C (Determination of Preliminary Retail Rates to be Charged to BGS Customers) contains the preliminary customer BGS-RSCP rates as the product of the weighted average total price (from Table A) and the Bid Factors from Table B.

Table D (Calculation of Rate Adjustment Factors) 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 Rate Adjustment Factors is also performed in this table. These factors are equal to the seasonal dollar differences between the anticipated billed revenue and supplier payments, divided by the total anticipated seasonal billed BGS-RSCP portfolio related charges.

Table E (Final Retail 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 Rate Adjustment Factors that were developed in Table D. The resulting rates are then adjusted to include the New Jersey Sales and Use Tax at the rate of 6.625%.

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.

I. Capacity Charges

Capacity charges are the separate charges designed to recover the costs associated with generation capacity for BGS-RSCP customers. These charges are expressed on a per-kW of generation capacity obligation basis.

Typically, the generation capacity costs designed to be used in the development of the BGS-RSCP rates are the relevant current wholesale market prices for capacity based on the average, 2027/2028, 2028/2029, and 2029/2030 BRA for RPM results applicable to load served in the RECO zone. This process has been impacted in recent years by delays in conducting the BRAs resulting in the need for contract supplements with Capacity Proxy Prices for delivery years with delayed BRAs. Due to the postponement of the BRAs, contracts from the 2025 and 2026 BGS Auctions contained supplements with Capacity Proxy Prices.

Due to delays of the BRAs, contracts from the 2025 and 2026 BGS auctions contained supplements with Capacity Proxy Prices. With the delays of the BRAs for the 2027/2028 Delivery Year and the 2028/2029 Delivery Year, a Capacity Proxy Price of \$270.35/MW-day was used in place of the 2027/2027 BRA value in the 2025 contracts, while a Capacity Proxy Price of \$333.69/MW-day was used in place of the 2027/2028 BRA value and the 2029/2030 BRA value in the 2026 contracts.

At this time, the BRAs for the 2028/2029 and 2029/2030 Delivery Year are not yet available, but the BRAs are scheduled to be held in July 2026, and December 2026, respectively. Given the continued delay in the schedule of these BRAs, a Capacity Proxy Price of \$333.69 per MW-day has been used in place of the prices paid for capacity for 2028/2029 and 2029/2030 Delivery Years, respectfully.

For EY 2029, if Supplement A to the BGS-RSCP SMA is approved by the BPU and, if BRA for the 2028/2029 Delivery has not occurred at least five 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” charged to BGS-RSCP Suppliers for Capacity in the Company’s RECO Zone, as may be determined under the Reliability Pricing Model or its successor or otherwise, and the Capacity Proxy Price for the 2028/2029 Delivery Year.

For EY 2030, if Supplement B is approved by the BPU and if the BRA for the 2029/2030 Delivery has not occurred at least five 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” charged to BGS-RSCP Suppliers for Capacity in the Company’s RECO Zone, as may be determined under the Reliability Pricing Model or its successor or otherwise, and the Capacity Proxy Price for the 2029/2030 Delivery Year.

RECO will file new tariff sheets for EY 2029 and EY 2030 reflecting the impact of this price adjustment. 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 this true-up as the actual value is not known at this time. Attachment D provides an illustrative example of the calculation.

The SMA Supplement signed by BGS-RSCP Suppliers in February 2025 is still in effect for a portion of the load for EY 2028 (the year beginning June 1, 2027). Payments to BGS-RSCP suppliers that executed the Supplements to the SMAs approved

by the Board on November 27, 2023 and November 21, 2024 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 RECO 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 Supplement executed by BGS-RSCP Suppliers in February 2025. Due to the delays in the BRA schedule a Capacity Proxy Price of \$333.69 per MW-day is used as an approximation for the Final PJM RPM Net Zonal Price for the 2027/2028 Delivery Year.

J. Transmission Charges

The transmission charges applicable to RECO's BGS-RSCP and BGS-CIEP customers are based on the currently effective transmission rates applicable to the RECO zone, as stated in PJM's Open Access Transmission Tariff ("PJM Transmission Rates"). The PJM Transmission Rates will change from time to time as FERC approves changes in the PJM Open Access Transmission Tariff. Such changes in the PJM Transmission Rates, including but not limited to changes associated with the Seams Elimination Charge/Cost Adjustments/Assignments ("SECA"), Transmission Enhancement Charges ("TECs") and Reliability Must Run ("RMR") charges, will result in changes to RECO's transmission rates applicable to its BGS-RSCP and BGS-CIEP customers. RECO will review and verify the basis for any transmission cost

adjustment, and file supporting documentation from the PJM Transmission Rates as well as any rate translation spreadsheets used.

K. Conclusion

In connection with this filing, the Company requests that the Board issue an order making the following findings and determinations:

1. The Company's proposed treatment of its Committed Supply is approved by the Board;
2. The Company's proposed accounting for BGS is approved by the Board for purposes of accounting and BGS cost recovery;
3. 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;
4. RECO's Contingency Plan is approved by the Board, and the costs incurred as a result of this Contingency Plan are presumptively prudent, subject to deferral, and approved for full and timely recovery;
5. The RECO-specific statewide Auction results are approved by the Board and produce BGS supply costs that are reasonable and prudent, subject to deferral, and approved for full and timely recovery;
6. The Company's proposal for its Central and Western Divisions is approved by the Board; and

7. The Company's Rate Design Methodology and Tariff Sheets are approved by the Board.

GENERAL INFORMATION

No. 31 BASIC GENERATION SERVICE (“BGS”)

- (1) Basic Generation Service – Residential Small Commercial Pricing (BGS-RSCP)
Applicable to Service Classification Nos. 1, 2, 3, 4, and 6

Applicable to Service Classification Nos. 1, 2 (Non-Demand Billed), 3, 4, and 6
Charges per kilowatthour:

<u>Service Classification</u>	<u>Summer Months*</u>	<u>Other Months</u>
1 (Non-TOD) – First 600 kWh	X.XXX¢	XX.XXX¢
1 (Non-TOD) – Over 600 kWh	XX.XXX¢	XX.XXX¢
1 (TOD) – Peak	XX.XXX¢	XX.XXX¢
1 (TOD) – Off-Peak	X.XXX¢	XX.XXX¢
2 - (Non-Demand Billed) – All kWh	X.XXX¢	X.XXX¢
3 – Peak	XX.XXX¢	XX.XXX¢
3 – Off-Peak	X.XXX¢	X.XXX¢
4 – All kWh	X.XXX¢	X.XXX¢
6 – All kWh	X.XXX¢	X.XXX¢

Applicable to Service Classification No. 2 Demand Billed customers who do not take BGS-CIEP service in accordance with General Information Section No. 31(2):

	<u>Summer Months*</u>	<u>Other Months</u>
Demand Charges		
All kW (\$/kW)	X.XX	X.XX
Usage Charges		
All kWh (¢/kWh)	X.XXX¢	X.XXX¢

The above Basic Generation Service Charges reflect costs for Energy, Generation Capacity, and Ancillary Services (including ISO Administrative Charges).

*Definition of Summer Billing Months - June through September

(Continued)

ISSUED:

EFFECTIVE:

ISSUED BY: Michele O’Connell, President
Mahwah, New Jersey 07430

GENERAL INFORMATION

No. 31 BASIC GENERATION SERVICE (“BGS”) (Continued)

(2) Basic Generation Service – Commercial and Industrial Energy Pricing (BGS-CIEP)

This service is applicable to all Service Classification No. 7 customers, and Service Classification No. 2 customers who maintain a billing demand of 500 kW or greater during any two months of a calendar year, taking BGS from the Company. Service Classification No. 2 metered customers who do not meet the above criteria may elect to take BGS-CIEP service on a voluntary basis. See General Information Section No. 31(1).

BGS Energy Charges:

Charges per kilowatthour:

BGS Energy Charges are hourly and are provided at the real time PJM Load Weighted Average Residual Metered Load Aggregate Locational Marginal Prices for the Rockland Electric Transmission Zone, plus Ancillary Services (including PJM Administrative Charges) at the rate of \$0.00640 per kilowatthour, adjusted for losses and applicable taxes.

BGS Capacity Charges:

Charges per kilowatt of Capacity Obligation as determined in accordance with General Information Section No. 31(C):

Charge applicable in Summer* months.....\$ X.XXXX
Charge applicable in other months.....\$ X.XXXX

The above charges shall recover each customer’s share of the overall summer peak load assigned to the Rockland Electric Transmission Zone by PJM as adjusted by PJM assigned capacity related factors.

In accordance with Rider SUT, the above charges include provision for the New Jersey Sales and Use Tax. When billed to customers exempt from this tax, as set forth in Rider SUT, such charges will be reduced by the relevant amount of such tax included therein.

* June through September

(Continued)

ISSUED:

EFFECTIVE:

ISSUED BY: Michele O’Connell, President
Mahwah, New Jersey 07430

Development of BGS Cost and Bid Factors for Rates Effective June 1, 2027

Based on 2026 Load Profile Information
On-Peak periods defined as the 16 hr PJM Trading period, adj for NERC holidays

Table #1	% Usage During PJM On-Peak Period	Profile Meter					Profile Meter
		Profile Meter Data	Profile Meter Data	Data	--- Other Analysis ---		Data
		<u>SC1</u>	<u>SC3</u>	<u>SC2 ND</u>	<u>SC4</u>	<u>SC6</u>	<u>SC2 Dem</u>
	January	80.67%	51.72%	46.14%	48.34%	48.34%	56.18%
	February	81.83%	53.44%	46.32%	50.01%	50.01%	57.85%
	March	79.81%	53.41%	48.65%	50.92%	50.92%	57.50%
	April	86.03%	56.29%	45.80%	52.41%	52.41%	60.43%
	May	80.59%	50.01%	45.77%	47.37%	47.37%	54.93%
	June	94.48%	58.74%	51.68%	60.64%	60.64%	63.26%
	July	94.58%	59.48%	46.15%	60.92%	60.92%	63.42%
	August	86.65%	54.14%	52.71%	54.07%	54.07%	58.55%
	September	85.44%	54.95%	47.59%	53.12%	53.12%	59.39%
	October	86.75%	54.59%	47.34%	53.19%	53.19%	59.55%
	November	76.91%	51.18%	46.50%	50.18%	50.18%	55.08%
	December	83.07%	53.40%	45.27%	52.74%	52.74%	57.93%

On-Peak periods as defined in specified rate schedule

Table #2	% Usage During RECO On-Peak Billing Period	N/A		N/A	N/A	N/A	N/A	
		<u>SC1</u>	<u>SC3</u>	<u>SC2 ND</u>	<u>SC4</u>	<u>SC6</u>	<u>SC2 Dem</u>	<u>SC1 TOD</u>
	(data rounded to nearest %)							
	January	----	38.1%	----	----	----	----	23.2%
	February	----	38.1%	----	----	----	----	24.4%
	March	----	34.0%	----	----	----	----	23.4%
	April	----	35.3%	----	----	----	----	22.7%
	May	----	38.3%	----	----	----	----	26.5%
	June	----	39.8%	----	----	----	----	30.5%
	July	----	42.6%	----	----	----	----	31.4%
	August	----	45.6%	----	----	----	----	31.8%
	September	----	37.1%	----	----	----	----	29.4%
	October	----	38.7%	----	----	----	----	24.1%
	November	----	37.1%	----	----	----	----	26.0%
	December	----	35.1%	----	----	----	----	24.6%

Table #3 Class Usage @ customer

Calendar month billed sales forecasted for 2027

in MWh

	<u>SC1</u>	<u>SC3</u>	<u>SC2 ND</u>	<u>SC4</u>	<u>SC6</u>	<u>SC2 Dem</u>	<u>Total</u>
January	62,434	29	1,461	616	477	29,715	94,731
February	55,849	26	1,504	644	392	30,985	89,401
March	49,737	24	1,112	544	380	27,467	79,263
April	45,076	24	875	373	308	24,317	70,972
May	47,795	22	750	476	409	27,610	77,061
June	66,132	26	739	416	379	28,260	95,951
July	91,475	30	931	419	334	34,268	127,457
August	91,359	34	955	403	355	36,838	129,943
September	80,661	29	862	460	388	33,853	116,253
October	55,225	24	810	533	490	31,336	88,416
November	45,707	21	789	577	509	25,254	72,857
December	<u>56,464</u>	<u>26</u>	<u>1,225</u>	<u>601</u>	<u>480</u>	<u>27,717</u>	<u>86,512</u>
Total	747,912	315	12,013	6,059	4,899	357,620	1,128,818

Table #4 Forwards Prices - Energy Only @ bulk system

in \$/MWh (See Table 18)

	<u>On-Peak</u>	<u>Off-Peak</u>
January	97.05	81.91
February	86.88	71.97
March	56.42	45.96
April	54.55	45.21
May	53.43	44.06
June	55.58	34.35
July	80.45	48.98
August	67.80	39.98
September	56.87	35.33
October	58.51	47.84
November	60.49	49.46
December	74.23	62.03

Table #5 Losses

	<u>SC1</u>	<u>SC3</u>	<u>SC2 ND</u>	<u>SC4</u>	<u>SC6</u>	<u>SC2 Dem</u>
Expansion Factor =	1.08674	1.08674	1.08674	1.08296	1.08296	1.08674
Expansion Factor (net Marginal Losses)	1.07678	1.07678	1.07678	1.07303	1.06623	1.07678

Table #6 Summary of Average BGS Energy Only Unit Costs @ customer - PJM Time Periods
based on Forwards prices corrected for basis differential & losses
in \$/MWh

		<u>SC1</u>	<u>SC3</u>	<u>SC2 ND</u>	<u>SC4</u>	<u>SC6</u>	<u>SC2 Dem</u>
Summer - all hrs	\$	69.20	\$ 59.29	\$ 57.37	\$ 58.60	\$ 58.26	\$ 60.48
	PJM on pk	\$ 72.14	\$ 71.55	\$ 71.34	\$ 70.60	\$ 70.18	\$ 71.50
	PJM off pk	\$ 42.43	\$ 43.23	\$ 43.70	\$ 42.62	\$ 42.41	\$ 43.25
Winter - all hrs	\$	72.80	\$ 68.90	\$ 70.55	\$ 68.79	\$ 67.75	\$ 68.88
	PJM on pk	\$ 75.03	\$ 74.82	\$ 77.50	\$ 74.98	\$ 73.86	\$ 74.24
	PJM off pk	\$ 62.65	\$ 62.21	\$ 64.52	\$ 62.45	\$ 61.49	\$ 61.64
Annual	\$	71.22	\$ 65.27	\$ 66.73	\$ 65.94	\$ 64.94	\$ 65.75
System Total	\$	69.38					

Table #7 Summary of Average BGS Energy Only Costs @ customer - PJM Time Periods
based on Forwards prices corrected for basis differential & losses
in \$1000

		<u>SC1</u>	<u>SC3</u>	<u>SC2 ND</u>	<u>SC4</u>	<u>SC6</u>	<u>SC2 Dem</u>
Summer - all hrs	\$	22,811	\$ 7	\$ 200	\$ 99	\$ 85	\$ 8,058
	PJM on pk	\$ 21,430	\$ 5	\$ 123	\$ 68	\$ 58	\$ 5,812
	PJM off pk	\$ 1,381	\$ 2	\$ 77	\$ 31	\$ 26	\$ 2,246
Winter - all hrs	\$	30,452	\$ 14	\$ 602	\$ 300	\$ 233	\$ 15,456
	PJM on pk	\$ 25,737	\$ 8	\$ 307	\$ 165	\$ 129	\$ 9,570
	PJM off pk	\$ 4,715	\$ 6	\$ 295	\$ 135	\$ 105	\$ 5,887
Annual	\$	53,263	\$ 21	\$ 802	\$ 399	\$ 318	\$ 23,514
System Total	\$	78,317					

Table #8 Summary of Average BGS Energy Only Unit Costs @ customer - RECO Time Periods
based on Forwards prices corrected for basis differential & losses - RECO billing time periods in \$/MWh

		<u>SC1</u>	<u>SC3</u>	<u>SC2 ND</u>	<u>SC4</u>	<u>SC6</u>	<u>SC2 Dem</u>	<u>SC1 TOD</u>
Summer - all hrs	\$	69.20	\$ 59.29	\$ 57.37	\$ 58.60	\$ 58.26	\$ 60.48	\$ 69.20
			\$ 75.86				\$	\$ 89.66
			\$ 47.54				\$	\$ 59.95
Winter - all hrs	\$	72.80	\$ 68.90	\$ 70.55	\$ 68.79	\$ 67.75	\$ 68.88	\$ 72.80
			\$ 76.86				\$	\$ 82.17
			\$ 64.25				\$	\$ 69.79
Annual Average	\$	71.22	\$ 65.27	\$ 66.73	\$ 65.94	\$ 64.94	\$ 65.75	\$ 71.22
System Average	\$	69.38						

Table #9 Generation & Transmission Obligations and Costs and Other Adjustments
Obligations - annual average forecasted for 2026; costs are market estimates in MW

	<u>SC1</u>	<u>SC3</u>	<u>SC2 ND</u>	<u>SC4</u>	<u>SC6</u>	<u>SC2 Dem</u>	<u>Total FP</u>
Gen Obl - MW	277.965	0.065	2.209	0.0	0.0	81.422	361.661
Trans Obl - MW	305.281	0.137	3.111	0.0	0.0	89.141	397.670

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

Transmission Cost* \$ 53,766 per MW-yr 146.90

Generation Capacity cost summer \$323.07 \$/MW/day Resulting avg gen cap cost = summer >> \$ 117.92 per kW/yr
 (see Table 19) winter \$311.84 \$/MW/day winter >> \$ 113.82 per kW/yr

Current residential summer BGS charges
 Current Tariff and % of total summer usage

	----- SC1 -----	
	Charges	% usage
Block 1 (0-600 kWh/month)	8.465 ¢/kWh	43.01%
Block 2 (>600 kWh/month)	17.944 ¢/kWh	56.99%
Calculated inversion =	9.479 ¢/kWh	

Table #10 Ancillary Services
forecasted overall annual average

\$18.42 /MWh

Table #11 Summary of Obligation Costs Expressed as \$/MWh @ customer (for non-demand rates only)

	<u>SC1</u>	<u>SC3</u>	<u>SC2 ND</u>	<u>SC4</u>	<u>SC6</u>	<u>SC1 TOD</u>
Transmission Obl - all months \$	21.95 \$	23.37 \$	13.92 \$	- \$	- \$	21.95
Generation Obl -						
per annual MWh \$	42.93 \$	23.82 \$	21.24 \$	- \$	- \$	42.93
per summer MWh \$	33.24 \$	21.52 \$	24.97 \$	- \$	- \$	33.24
per winter MWh \$	50.56 \$	25.22 \$	19.71 \$	- \$	- \$	50.56

Table #12 Summary of BGS Unit Costs @ customer

NON-DEMAND RATES (includes energy, G&T obligations, and Ancillary Services - adjusted to billing time periods in \$/MWh)

	<u>SC1</u>	<u>SC3</u>	<u>SC2 ND</u>	<u>SC4</u>	<u>SC6</u>	<u>SC1 TOD</u>
Summer - all hrs \$	142.81 \$	122.59 \$	114.69 \$	77.02 \$	76.68 \$	142.81
RECO On pk \$		169.52				237.80
RECO Off pk \$		89.33				100.31
Block 1 \$	88.79					
Block 2 \$	183.58					
Winter - all hrs \$	163.73 \$	135.90 \$	122.61 \$	87.21 \$	86.17 \$	163.73
RECO On pk \$		187.09				330.46
RECO Off pk \$		106.04				110.16
Annual -all hrs \$	154.51 \$	130.88 \$	120.31 \$	84.36 \$	83.36 \$	154.51

DEMAND RATES (includes energy and Ancillary Services, G&T obligations charged separately - adjusted to billing time periods in \$/MWh)

	<u>SC2 Dem</u>	PLUS:	
Summer - all hrs \$	78.90		<u>Gen Cost (per kW of Billed Demand/Month)</u>
			<u>SC2 Dem</u>
Winter - all hrs \$	87.30	summer	\$ 7.05
		winter	\$ 8.16
		<u>Trans cost</u>	
Annual - all hrs per MWh only \$	84.17	all months \$	4.48 per kW of T obl /month

Table #12 (Continued)

<u>Including T&G Obligation \$</u>		<u>Gen Cost (per kW of Billed Demand/Month)</u>	
Summer - all hrs	\$ 115.00		
			<u>SC2 Dem</u>
Winter - all hrs	\$ 129.15	summer	\$ 7.05
		winter	\$ 8.16
Annual - including T&G Obl \$	\$ 123.88		

ALL RATES

Grand Total Cost in \$1000 = \$ 162,266
 All-In Average cost @ customer = \$ 143.75 per MWh at customer (per customer metered MWh)
 All-In Average costs @ transmission nodes = \$ 133.51 per MWh at transmission nodes (per metered MWh at transmission node)

Table #13 Ratio of BGS Unit Costs @ customer to All-In Average Cost @ transmission nodes

NON-DEMAND RATES

Includes energy, G&T obligations, and Ancillary Services - adjusted to billing time periods

	<u>SC1</u>	<u>SC3</u>	<u>SC2 ND</u>	<u>SC4</u>	<u>SC6</u>	<u>SC1 TOD</u>
Summer - all hrs	1.070		0.859	0.577	0.574	
RECO On pk		1.270				1.781
RECO Off pk		0.669				0.751
Constant Blk 1 \$	(54.02)					
Constant Blk 2 \$	40.77					
Winter - all hrs	1.226		0.918	0.653	0.645	
RECO On pk		1.401				2.4750
RECO Off pk		0.794				0.8250
Annual - all hrs	1.157	0.980	0.901	0.632	0.624	1.1570

Table #13 (Continued)

DEMAND RATES

Includes energy and Ancillary Services, G&T obligations charged separately - adjusted to billing time periods

	<u>SC2 Dem Multiplier</u>	\$	<u>SC2 Dem Constant</u>	(36.095)	PLUS:	
Summer - all hrs	0.861				<u>Gen Cost (per kW of Billed Demand/Month)</u>	
					SC2 Dem	
Winter - all hrs	0.967		(41.848)		summer	\$ 7.05
					winter	\$ 8.16
Annual - including T&G Obl \$	0.928				<u>Trans cost</u>	
					all months	\$ 4.48 per kW of T obl /month

Table #14 Summary of BGS Unit Costs Less Transmission @ customer

NON-DEMAND RATES

Includes energy, generation capacity obligation, and Ancillary Services - adjusted to billing time periods. Transmission billed at retail tariff level. in \$/MWh

		<u>SC1</u>		<u>SC3</u>		<u>SC2 ND</u>		<u>SC4</u>		<u>SC6</u>		<u>SC1 TOD</u>
Summer - all hrs	\$	120.86	\$	99.22	\$	100.76	\$	77.02	\$	76.68	\$	120.86
RECO On pk			\$	146.15							\$	215.85
RECO Off pk			\$	65.96							\$	78.37
Block 1	\$	66.84										
Block 2	\$	161.63										
Winter - all hrs	\$	141.79	\$	112.53	\$	108.68	\$	87.21	\$	86.17	\$	141.79
RECO On pk			\$	163.72							\$	308.51
RECO Off pk			\$	82.67							\$	88.21
Annual -all hrs	\$	132.56	\$	107.51	\$	106.38	\$	84.36	\$	83.36	\$	132.56

Table #14 (Continued)

DEMAND RATES

*Includes energy and Ancillary Services, generation obligation charged separately - adjusted to billing time periods.
Transmission billed at retail tariff level. In \$/MWh.*

		<u>SC2 Dem</u>		<u>PLUS:</u>				<u>SC2 Dem</u>
Summer - all hrs	\$	78.90			<u>Gen Cost (per kW of Billed Demand/Month)</u>			
Winter - all hrs	\$	87.30			summer	\$	7.050	
					winter	\$	8.160	
Annual - all hrs per MWh only	\$	84.17						
<u>Including Generation Obligation \$</u>								
Summer - all hrs	\$	103.01						
Winter - all hrs	\$	114.91						
Annual - including T&G Obl \$	\$	110.48						

ALL RATES

Grand Total Cost in \$1000 =	\$	140,886						
All-In Average cost @ customer =	\$		124.81	per MWh at customer (per customer metered MWh)				
All-In Average costs @ transmission nodes =	\$		115.92	per MWh at transmission node system (per metered MWh at transmission node)				

Table #15 Ratio of BGS Unit Costs Less Transmission @ customer to All-In Average Cost @ transmission nodes

NON-DEMAND RATES

Includes energy, G&T obligations, and Ancillary Services - adjusted to billing time periods

	<u>SC1</u>	<u>SC3</u>	<u>SC2 ND</u>	<u>SC4</u>	<u>SC6</u>	<u>SC1 TOD</u>
Summer - all hrs	1.043		0.869	0.664	0.662	
RECO On pk		1.261				1.862
RECO Off pk		0.569				0.676
Constant Blk 1 \$	(54.02)					
Constant Blk 2 \$	40.77					
Winter - all hrs	1.223		0.938	0.752	0.743	
RECO On pk		1.412				2.661
RECO Off pk		0.713				0.761
Annual - all hrs	1.144	0.927	0.918	0.728	0.719	1.144

DEMAND RATES

includes energy and Ancillary Services, G&T obligations charged separately - adjusted to billing time periods

	<u>SC2 Dem Multiplier</u>	<u>SC2 Dem Constant</u>	PLUS:	
Summer - all hrs	0.889	(24.104)	<u>Gen Cost (per kW of Billed Demand/Month)</u>	
Winter - all hrs	0.991	(27.611)		SC2 Dem
Annual - including T&G Obl \$	0.953		summer	\$ 7.050
			winter	\$ 8.160

Table #16 Summary of Total BGS Costs by Season

	<u>SC1</u>	<u>SC3</u>	<u>SC2 ND</u>	<u>SC4</u>	<u>SC6</u>	<u>SC2 Dem</u>	<u>SC1 TOD</u>	
Total Costs by Rate - in \$1000								
Summer	\$ 47,073	\$ 15	\$ 400	\$ 131	\$ 112	\$ 15,320	47,073	
Winter	\$ 68,487	\$ 27	\$ 1,045	\$ 380	\$ 297	\$ 28,981	68,487	
Total	\$ 115,559	\$ 41	\$ 1,445	\$ 511	\$ 408	\$ 44,301	115,559	
% of Annual Total \$ by Rate								
Summer	41%	35%	28%	26%	27%	35%	41%	
Winter	59%	65%	72%	74%	73%	65%	59%	
Total Costs - in \$1000								
Summer	\$ 63,050							
Winter	\$ 99,217							
Total	\$ 162,266							
% of Annual Total \$								
Summer	39%	If total \$ were split on a per MWh basis (on transmission node MWhs):					<u>Ratio to All-In Cost</u>	
Winter	61%	\$ 124.69	per MWh @ transmission nodes				Summer	0.9340
		\$ 139.79	per MWh @ transmission nodes				Winter	1.0470

Table #17 Summary of Total BGS Costs by Season - Less Transmission

	<u>SC1</u>	<u>SC3</u>	<u>SC2 ND</u>	<u>SC4</u>	<u>SC6</u>	<u>SC2 Dem</u>	<u>SC1 TOD</u>	
Total Costs by Rate - in \$1000								
Summer	\$ 39,839	\$ 12	\$ 351	\$ 131	\$ 112	\$ 13,723	39,839	
Winter	\$ 59,307	\$ 22	\$ 927	\$ 380	\$ 297	\$ 19,590	59,307	
Total	\$ 99,146	\$ 34	\$ 1,278	\$ 511	\$ 408	\$ 33,313	99,146	
% of Annual Total \$ by Rate								
Summer	40%	35%	27%	26%	27%	41%	40%	
Winter	60%	65%	73%	74%	73%	59%	60%	
Total Costs - in \$1000								
Summer	\$ 54,167							
Winter	\$ 80,523							
Total	\$ 134,690							
% of Annual Total \$								
Summer	40%	If total \$ were split on a per MWh basis (on transmission node MWhs):					<u>Ratio to All-In Cost</u>	
Winter	60%	\$ 107.13	per MWh @ transmission nodes				Summer	0.9242
		\$ 113.45	per MWh @ transmission nodes				Winter	0.9787

Table #18 Forward Energy Prices

PJM Forward Prices - Energy Only @ bulk system <i>in \$/MWh</i>	<u>On-Peak</u>	<u>Off/On Peak</u> <u>LMP ratio</u>	Zone to Western Hub Basis Differential <i>in \$/MWh</i>			PJM Forward Prices (incl basis differential) <i>in \$/MWh</i>	
			<u>Off-Peak</u>	<u>On-Peak</u>	<u>Off-Peak</u>	<u>On-Peak</u>	<u>Off-Peak</u>
January	101.55	0.8003	81.27	88%	90%	89.80	73.27
February	90.60	0.8003	72.51	88%	90%	80.11	65.37
March	61.65	0.8003	49.34	88%	90%	54.51	44.48
April	61.95	0.8003	49.58	88%	90%	54.78	44.70
May	61.15	0.8003	48.94	88%	90%	54.07	44.12
June	67.30	0.5490	36.95	83%	91%	56.04	33.44
July	97.00	0.5490	53.25	83%	91%	80.77	48.20
August	80.50	0.5490	44.19	83%	91%	67.03	40.00
September	68.95	0.5490	37.85	83%	91%	57.23	34.26
October	67.15	0.8003	53.74	88%	90%	59.38	48.45
November	67.30	0.8003	53.86	88%	90%	59.51	48.56
December	76.80	0.8003	61.46	88%	90%	67.91	55.41

NYISO Forward Prices - Energy Only @ bulk system
in \$/MWh

	<u>On-Peak</u>	<u>Off-Peak</u>
January	149.00	143.85
February	135.40	119.30
March	70.15	56.55
April	52.90	48.90
May	48.85	43.60
June	52.25	40.84
July	78.19	54.57
August	73.35	39.80
September	54.25	43.00
October	52.30	43.45
November	67.50	55.95
December	119.55	109.50

Weighted Average Forward Prices - Energy Only @ bulk system (87.8% PJM - 12.2% NYISO)
in \$/MWh

	<u>On-Peak</u>	<u>Off-Peak</u>
January	97.05	81.91
February	86.88	71.97
March	56.42	45.96
April	54.55	45.21
May	53.43	44.06
June	55.58	34.35
July	80.45	48.98
August	67.80	39.98
September	56.87	35.33
October	58.51	47.84
November	60.49	49.46
December	74.23	62.03

Table #19 Generation Capacity Prices (\$/MW/Day)

	<u>PJM Base Capacity</u>	<u>PJM 87.8%</u>	<u>NYISO 12.2%</u>	<u>Weighted Average</u>
Summer	\$333.69	\$333.69	\$246.96	\$323.07
Winter	\$333.69	\$333.69	155.21	\$311.84

Table #20 Ancillary Services

	<u>PJM Ancillary Services</u>	<u>NYISO Ancillary Services</u>	<u>Renewable Power Cost</u>	<u>PJM 87.8%</u>	<u>NYISO 12.2%</u>	<u>Weighted Average</u>
	\$2.00	\$4.25	\$16.14	\$18.14	\$20.39	\$18.42

Assumptions:

- Gen Cost = \$323.07 per MW-day in summer
\$311.84 per MW-day in winter
- Trans cost = \$ 53,766 per MW-yr
- Analysis time period = 4 summer months
8 winter months
- Ancillary Services = \$ 18.42 /MWh
- Energy Costs = Based on Jun 2027 to May 2028 Forwards @ PJM West as of June 01, 2026
Based on Jun 2027 to May 2028 Forwards @ NYISO Zone G and Lower Hudson Valley (LHV) as of June 22, 2026
- Usage patterns = Forecasted 2026 energy use by class, PJM on/off % from 2025 class load profiles,
RECO billing on/off % from 6/25 to 5/26 actual data
- Obligations = Class totals for 2026
- Losses = Per RECO's Third Party Supplier Agreement adjusted for PJM 500kV losses and inadvertent energy.
- 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
- RECO Billing time periods = as per specific rate schedule

Table A Weighted Average Price Calculation

Line #	Specific BGS-FP Auction >>	2025 Auction 36 Month	2026 Auction 36 Month	2027 Auction 36 Month	Total	Notes:
1	Tranches	1	2	1	4	From then-current auction
2(a)	Winning Bid Price (¢/kWh)*	11.615	12.057	12.057		Winning Auction Prices
2(b)	Capacity Proxy Price True-up - in (¢/kWh)*	0.786				Entered After 2027 BGS Auction
3	BGS (¢/kWh)	12.401	12.057	12.057		= 2(a) + 2(b)
4	Weighted Avg BGS	3.100	6.029	3.014	12.143	= (1) / Total Tranches * (3)
5	Weighted Avg Total Price (¢/kWh)				12.143	
<u>Seasonal Payment Factors</u>						
6	Summer	1.0000	1.0000	1.0000 **		From then-current Bid Factor Spreadsheet
7	Winter	1.0000	1.0000	1.0000 **		From then-current Bid Factor Spreadsheet
<u>Applicable Customer Usage @ transmission nodes</u> (Eastern Division)						
8	Summer MWh	443,737				From then-current Bid Factor Spreadsheet
9	Winter MWh	<u>622,884</u>				From then-current Bid Factor Spreadsheet
10		1,066,621				
<u>Total Cost</u>						
11	Summer	13,756,952	26,750,677	13,375,339	53,882,968	= (1) / Total Tranches * (3) / 100 * (6) * (8) * 1,000
12	Winter	<u>19,310,964</u>	<u>37,550,567</u>	<u>18,775,283</u>	<u>75,636,814</u>	= (1) / Total Tranches * (3) / 100 * (7) * (9) * 1,000
13	Total	33,067,916	64,301,244	32,150,622	129,519,782	= (11) + (12)
<u>Average Cost (NJ Statewide Auction)</u>						
14	Summer	12.143 ¢/kWh				= sum(line 11) / (8) / 1000 * 100 rounded to 3 decimal places
15	Winter	12.143 ¢/kWh				= sum(line 12) / (9) / 1000 * 100 rounded to 3 decimal places
16	Total	12.143 ¢/kWh				= sum(line 13) / (10) / 1000 * 100 rounded to 3 decimal places
<u>Average Cost (Including RECO RFP)</u>						
		BGS Auction	RECO RFP		Total	
17	Tranches	4	0.558		4.558	Includes RECO RFP equivalent tranches
18	Price ¢/kWh	12.143	10.106			BGS Auction from (16)
19	Weighted Avg BGS	10.656	1.237		11.894	= (17) / Total Tranches * (18)
20	Weighted Avg Total Price				11.894	= (19)

* Includes Impact of PJM Marginal Losses

** Auction results set to 1.0 to avoid using an atypical result from the current 12-month forward prices.

Table B Ratio of BGS Unit Costs Less Transmission @ customer to All-In Average Cost @ transmission nodes
 (from Table 15 of Bid Factor Spreadsheet)

NON-DEMAND RATES

includes energy, G&T obligations, and Ancillary Services - adjusted to billing time periods

	<u>SC1</u>	<u>SC3</u>	<u>SC2 ND</u>	<u>SC4</u>	<u>SC6</u>	<u>SC1 TOD</u>
Summer - all hrs	1.043		0.869	0.664	0.662	
RECO On pk		1.261				1.862
RECO Off pk		0.569				0.676
Constant Blk 1 \$	(54.02)					
Constant Blk 2 \$	40.77					
Winter - all hrs	1.223		0.938	0.752	0.743	
RECO On pk		1.412				2.661
RECO Off pk		0.713				0.761
Annual - all hrs	1.144	0.927	0.918	0.728	0.719	1.144

DEMAND RATES

includes energy and Ancillary Services, G&T obligations charged separately - adjusted to billing time periods

	<u>SC2 Dem Multiplier</u>	<u>SC2 Dem Constant</u>	PLUS:	
Summer - all hrs	0.889	(24.104)	<u>Gen Cost (per kW of Billed Demand/Month)</u>	
				<u>SC2 Dem</u>
Winter - all hrs	0.991	(27.611)	summer \$	7.05
			winter \$	8.16
Annual - including T&G Obl \$	0.953			

Table C Determination of Preliminary Retail Rates to be Charged to BGS Customers

All-In Average costs @ Trans node =	\$	118.94 /MWh*	* Price from Table A (which does not include transmission for the Central/Western Division).
Less Transmission	\$	- /MWh**	
BGS Cost	\$	118.94 /MWh	

Retail BGS Rates (excl SUT) (¢/kWh)

	<u>SC1</u>	<u>SC3</u>	<u>SC2 ND</u>	<u>SC4</u>	<u>SC6</u>	<u>SC2 Dem</u>	<u>SC1 TOD</u>
<u>Summer</u>							
All kWh (¢/kWh)	12.405		10.336	7.898	7.874	8.163	
Peak kWh (¢/kWh)		14.998					22.147
Off-Peak kWh (¢/kWh)		6.768					8.040
Block1	7.003						
Block2	16.482						
Demand Charge (\$/kW) All kW						7.05	
<u>Winter</u>							
All kWh (¢/kWh)	14.546		11.157	8.944	8.837	9.026	
Peak kWh (¢/kWh)		16.794					31.650
Off-Peak kWh (¢/kWh)		8.480					9.051
Demand Charge (\$/kW) All kW						8.16	

Table D Calculation of Rate Adjustment Factors

	<u>SC1</u>	<u>SC3</u>	<u>SC2 ND</u>	<u>SC4</u>	<u>SC6</u>	<u>SC2 Dem</u>	<u>SC1 TOD</u>
<u>Total BGS Revenue (Excl SUT) - in \$1000</u>							
Summer	\$ 40,890	\$ 12	\$ 360	\$ 134	\$ 115	\$ 14,086	\$ 40,842
Winter	\$ 60,844	\$ 23	\$ 951	\$ 390	\$ 304	\$ 26,450	\$ 60,847
Total	\$ 101,734	\$ 35	\$ 1,311	\$ 524	\$ 419	\$ 40,536	\$ 101,689
Total							
Summer	\$ 55,597						
Winter	\$ 88,962						
Total	\$ 144,559						
<u>Total Supplier Payments - in \$1000</u>							
Eastern Division	<u>Total</u>	<u>Transmission</u>	<u>Net BGS</u>				
Summer	\$ 53,883		\$ 53,883				
Winter	\$ 75,637		\$ 75,637				
Total	\$ 129,520	\$ -	\$ 129,520				
Central/Western Division	<u>Total</u>	<u>Transmission</u>	<u>Net BGS</u>				
Summer	\$ 6,256	\$ -	\$ 6,256				
Winter	\$ 8,781	\$ -	\$ 8,781				
Total	\$ 15,037	\$ -	\$ 15,037				
Total RECO FP	<u>Total</u>	<u>Transmission</u>	<u>Net BGS</u>				
Summer	\$ 60,139	\$ -	\$ 60,139				
Winter	\$ 84,418	\$ -	\$ 84,418				
Total	\$ 144,557	\$ -	\$ 144,557				
Differences	<u>BGS Revenue</u>	<u>BGS Costs</u>	<u>Difference</u>				
Summer	\$ 55,597	\$ 60,139	\$ 4,542				
Winter	\$ 88,962	\$ 84,418	\$ (4,544)				
Total	\$ 144,559	\$ 144,557	\$ (2)				
							Rate Adjustment Factors
							1.08169
							0.94892

Table E Final Retail BGS Rates (¢/kWh)

Rates Excluding SUT:

	<u>SC1</u>	<u>SC3</u>	<u>SC2 ND</u>	<u>SC4</u>	<u>SC6</u>	<u>SC2 Dem</u>	<u>SC1 TOD</u>
<u>Summer</u>							
All kWh (¢/kWh)	13.418		11.180	8.543	8.517	8.830	
Peak kWh (¢/kWh)		16.223					23.956
Off-Peak kWh (¢/kWh)		7.321					8.697
Block1	7.575						
Block2	17.828						
Demand Charge (\$/kW) All kW						7.63	
<u>Winter</u>							
All kWh (¢/kWh)	13.803		10.587	8.487	8.386	8.565	
Peak kWh (¢/kWh)		15.936					30.033
Off-Peak kWh (¢/kWh)		8.047					8.589
Demand Charge (\$/kW) All kW						7.74	

Rates Including SUT:

	SUT @						
	<u>SC1</u>	<u>SC3</u>	<u>SC2 ND</u>	<u>SC4</u>	<u>SC6</u>	<u>SC2 Dem</u>	<u>SC1 TOD</u>
<u>Summer</u>							
All kWh (¢/kWh)			11.921	9.109	9.081	9.415	
Peak kWh (¢/kWh)		17.298					25.543
Off-Peak kWh (¢/kWh)		7.806					9.273
Block1	8.077						
Block2	19.009						
Demand Charge (\$/kW) All kW						8.14	
<u>Winter</u>							
All kWh (¢/kWh)	14.717		11.288	9.049	8.942	9.132	
Peak kWh (¢/kWh)		16.992					32.023
Off-Peak kWh (¢/kWh)		8.580					9.158
Demand Charge (\$/kW) All kW						8.25	

Table F Spreadsheet Error Checking

Total BGS Revenue (Excl SUT) - in \$1000

		<u>SC1</u>		<u>SC3</u>		<u>SC2 ND</u>		<u>SC4</u>		<u>SC6</u>		<u>SC2 Dem</u>
Summer	\$	44,229	\$	13	\$	390	\$	145	\$	124	\$	15,239
Winter	\$	57,736	\$	21	\$	903	\$	370	\$	289	\$	25,097
Total	\$	101,965	\$	34	\$	1,293	\$	515	\$	413	\$	40,336
Total												
Summer	\$	60,140										
Winter	\$	84,416										
Total	\$	144,556										

Supplier Payments - in \$1000

Eastern Division

		<u>Total</u>	<u>Transmission</u>	<u>Net BGS</u>
Summer	\$	53,883	\$ -	\$ 53,883
Winter	\$	75,637	\$ -	\$ 75,637
Total	\$	129,520	\$ -	\$ 129,520

Central/Western Division

		<u>Total</u>	<u>Transmission</u>	<u>Net BGS</u>
Summer	\$	6,256	\$ -	\$ 6,256
Winter	\$	8,781	\$ -	\$ 8,781
Total	\$	15,037	\$ -	\$ 15,037

Total RECO FP

		<u>Total</u>	<u>Transmission</u>	<u>Net BGS</u>
Summer	\$	60,139	\$ -	\$ 60,139
Winter	\$	84,418	\$ -	\$ 84,418
Total	\$	144,557	\$ -	\$ 144,557

Differences

		<u>BGS Revenue</u>	<u>BGS Costs</u>	<u>Difference</u>
Summer	\$	60,140	\$ 60,139	\$ (1)
Winter	\$	84,416	\$ 84,418	\$ 2
Total	\$	144,556	\$ 144,557	\$ 1

**Development of Capacity Proxy Price True-Up - \$/MWh
Using 2027/2028 Illustrative Data for RECO**

Using 2027/2028 Illustrative Data for RECO

Capacity Proxy
Price True-Up
Development for
Winning
Suppliers from
2025 BGS-
RSCP Auction
2027/28

1 Zonal Capacity Price (\$/MW-day)	
2 Capacity Proxy Price (\$/MW-day)	
3 Capacity Proxy Price True-Up - \$/MW-day	\$333.69 as may be determined by the RPM or its successor or otherwise
4 BGS-RSCP Gen Obl - MW	\$270.35 per Board Orders dated 11/21/2024
5 Days in Year	
6 Capacity Proxy Price True-Up Annual Cost	<u>\$63.34 = line 1 - line 2</u> 361.7
7 Eligible Tranches	366
8 Total Tranches	<u>\$8,384,184 = line 3 * line 4 * line 5</u>
9 % of tranches eligible for payment	1 from Table A 4 from Table A
10 Capacity Proxy Price True-Up Cost	<u>25.00% = line 7 / line 8</u>
11 Total Applicable Customer Usage @ transmission nodes - in MWh	\$2,096,046 = line 6 * line 9
12 Eligible Customer Usage @ transmission nodes - in MWh	1,066,621
13 Capacity Proxy Price True-Up - \$/MWh	<u>266,655 = line 9 * line 11</u> <u>\$7.86 = line 10/ line 12 - rounded to 2 decimal places</u>

Development of Capacity Proxy Price True-Up - \$/MWh
Using 2028/2029 Illustrative Data for RECO

Using 2028/2029 Illustrative Data for RECO

	Capacity Proxy Price True-Up Development for Winning Suppliers from 2026 BGS- RSCP Auction 2028/29 Delivery Year	Capacity Proxy Price True-Up Development for Winning Suppliers from 2027 BGS- RSCP Auction (If needed) 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 Orders 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	361.7	361.7	
5 Days in Year	365	365	
6 Capacity Proxy Price True-Up Annual Cost	\$172,928	\$172,928	= line 3 * line 4 * line 5
7 Eligible Tranches	2	1	from Table A
8 Total Tranches	4	4	from Table A
9 % of tranches eligible for payment	50.00%	25.00%	= line 7 / line 8
10 Capacity Proxy Price True-Up Cost	\$86,464	\$43,232	= line 6 * line 9
11 Total Applicable Customer Usage @ transmission nodes - in MWh	1,066,621	1,066,621	
12 Eligible Customer Usage @ transmission nodes - in MWh	533,310	266,655	= line 9 * line 11
13 Capacity Proxy Price True-Up - \$/MWh	\$0.16	\$0.16	= line 10/ line 12 - rounded to 2 decimal places

**Development of Capacity Proxy Price True-Up - \$/MWh
Using 2029/2030 Illustrative Data for RECO**

Using 2029/2030 Illustrative Data for RECO

Capacity Proxy
Price True-Up
Development for
Winning
Suppliers from
2027 BGS-
RSCP Auction
(If needed)
2029/30

1 Zonal Capacity Price (\$/MW-day)	
2 Capacity Proxy Price (\$/MW-day)	
3 Capacity Proxy Price True-Up - \$/MW-day	\$335.00 as may be determined by the RPM or its successor or otherwise
4 BGS-RSCP Gen Obl - MW	\$333.69 per Board Order dated XX/XX/2026
5 Days in Year	
6 Capacity Proxy Price True-Up Annual Cost	\$1.31 = line 1 - line 2
7 Eligible Tranches	361.7
8 Total Tranches	365
9 % of tranches eligible for payment	\$172,928 = line 3 * line 4 * line 5
10 Capacity Proxy Price True-Up Cost	
11 Total Applicable Customer Usage @ transmission nodes - in MWh	1 from Table A
12 Eligible Customer Usage @ transmission nodes - in MWh	4 from Table A
13 Capacity Proxy Price True-Up - \$/MWh	25.00% = line 7 / line 8
	\$43,232 = line 6 * line 9
	1,066,621
	266,655 = line 9 * line 11
	\$0.16 = line 10/ line 12 - rounded to 2 decimal places

ROCKLAND ELECTRIC COMPANY

2028 BGS Auction

Illustrative Purposes Only

Table A Weighted Average Price Calculation

Line #	Specific BGS-FP Auction >>	2026 Auction 36 Month	2027 Auction 36 Month	2028 Auction 36 Month	Total	Notes:
1	Tranches	2	1	1	4	From then-current auction
2(a)	Winning Bid Price (¢/kWh)*	12.057	12.057	12.073		
2(b)	Capacity Proxy Price True-up - in (¢/kWh)*	0.016	0.016			Entered After 2028 BGS Auction
3	BGS (¢/kWh)	12.073	12.073	12.073		= 2(a) + 2(b)
4	Weighted Avg BGS	6.037	3.018	3.018	12.073	= (1) / Total Tranches * (3)
5	Weighted Avg Total Price (¢/kWh)				12.073	
<u>Seasonal Payment Factors</u>						
6	Summer	1.0000	1.0000	1.0000 **		From then-current Bid Factor Spreadsheet
7	Winter	1.0000	1.0000	1.0000 **		From then-current Bid Factor Spreadsheet
<u>Applicable Customer Usage @ transmission nodes</u> (Eastern Division)						
8	Summer MWh	443,737				From then-current Bid Factor Spreadsheet
9	Winter MWh	622,884				From then-current Bid Factor Spreadsheet
10		1,066,621				
<u>Total Cost</u>						
11	Summer	26,786,176	13,393,088	13,393,088	53,572,352	= (1) / Total Tranches * (3) / 100 * (6) * (8) * 1,000
12	Winter	37,600,398	18,800,199	18,800,199	75,200,796	= (1) / Total Tranches * (3) / 100 * (7) * (9) * 1,000
13	Total	64,386,574	32,193,287	32,193,287	128,773,148	= (11) + (12)
<u>Average Cost (NJ Statewide Auction)</u>						
14	Summer	12.073 ¢/kWh				= sum(line 11) / (8) / 1000 * 100 rounded to 3 decimal places
15	Winter	12.073 ¢/kWh				= sum(line 12) / (9) / 1000 * 100 rounded to 3 decimal places
16	Total	12.073 ¢/kWh				= sum(line 13) / (10) / 1000 * 100 rounded to 3 decimal places
<u>Average Cost (Including RECO RFP)</u>						
		BGS Auction	RECO RFP		Total	
17	Tranches	4	0.558		4.558	Includes RECO RFP equivalent tranches
18	Price ¢/kWh	12.073	10.106			BGS Auction from (16) Note 10.106¢ for RFP is illustrative
19	Weighted Avg BGS	10.595	1.237		11.832	= (17) / Total Tranches * (18)
20	Weighted Avg Total Price				11.832	= (19)

* Includes Impact of PJM Marginal Losses

** Auction results set to 1.0 to avoid using an atypical result from the current 12-month forward prices.

ROCKLAND ELECTRIC COMPANY

2029 BGS Auction

Illustrative Purposes Only

Table A Weighted Average Price Calculation

Line #	Specific BGS-FP Auction >>	2027 Auction 36 Month	2028 Auction 36 Month	2029 Auction 36 Month	Total	Notes:
1	Tranches	1	1	2	4	From then-current auction
2(a)	Winning Bid Price (¢/kWh)*	12.057	12.073	12.073		
2(b)	Capacity Proxy Price True-up - in (¢/kWh)*	0.016				Entered After 2029 BGS Auction
3	BGS (¢/kWh)	12.073	12.073	12.073		= 2(a) + 2(b)
4	Weighted Avg BGS	3.018	3.018	6.037	12.073	= (1) / Total Tranches * (3)
5	Weighted Avg Total Price (¢/kWh)				12.073	
<u>Seasonal Payment Factors</u>						
6	Summer	1.0000	1.0000	1.0000 **		From then-current Bid Factor Spreadsheet
7	Winter	1.0000	1.0000	1.0000 **		From then-current Bid Factor Spreadsheet
<u>Applicable Customer Usage @ transmission nodes</u> (Eastern Division)						
8	Summer MWh	443,737				From then-current Bid Factor Spreadsheet
9	Winter MWh	622,884				From then-current Bid Factor Spreadsheet
10		1,066,621				
<u>Total Cost</u>						
11	Summer	13,393,088	13,393,088	26,786,176	53,572,352	= (1) / Total Tranches * (3) / 100 * (6) * (8) * 1,000
12	Winter	18,800,199	18,800,199	37,600,398	75,200,796	= (1) / Total Tranches * (3) / 100 * (7) * (9) * 1,000
13	Total	32,193,287	32,193,287	64,386,574	128,773,148	= (11) + (12)
<u>Average Cost (NJ Statewide Auction)</u>						
14	Summer	12.073 ¢/kWh				= sum(line 11) / (8) / 1000 * 100 rounded to 3 decimal places
15	Winter	12.073 ¢/kWh				= sum(line 12) / (9) / 1000 * 100 rounded to 3 decimal places
16	Total	12.073 ¢/kWh				= sum(line 13) / (10) / 1000 * 100 rounded to 3 decimal places
<u>Average Cost (Including RECO RFP)</u>						
		BGS Auction	RECO RFP		Total	
17	Tranches	4	0.558		4.558	Includes RECO RFP equivalent tranches
18	Price ¢/kWh	12.073	10.106			BGS Auction from (16) Note 10.106¢ for RFP is illustrative
19	Weighted Avg BGS	10.595	1.237		11.832	= (17) / Total Tranches * (18)
20	Weighted Avg Total Price				11.832	= (19)

* Includes Impact of PJM Marginal Losses

** Auction results set to 1.0 to avoid using an atypical result from the current 12-month forward prices.