

STATE OF NEW JERSEY
BOARD OF PUBLIC UTILITIES

IN THE MATTER OF THE PROVISION
OF BASIC GENERATION SERVICE FOR
THE PERIOD BEGINNING JUNE 1, 2023

Docket No. ER22030127

ROCKLAND ELECTRIC COMPANY

**PROPOSAL FOR
BASIC GENERATION SERVICE
REQUIREMENTS TO BE PROCURED EFFECTIVE
JUNE 1, 2023**

**COMPANY SPECIFIC ADDENDUM
COMPLIANCE FILING**

Margaret Comes, Esq.
4 Irving Place
New York, NY 10003
(212) 460-3013
Attorney for Rockland Electric Company

November 30, 2022

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RECO's COMPANY SPECIFIC ADDENDUM

A. Introduction to RECO's Company Specific Filing

In its Decision and Order dated April 6, 2022 in Docket No. ER22030127, 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, 2022 on the procurement of basic generation service ("BGS") for the period beginning June 1, 2023. This document constitutes the company-specific portion of the compliance filing for Rockland Electric Company ("RECO" or the "Company") mandated by the Board. RECO's filing also includes and incorporates by reference the Proposal for BGS Requirements to be Procured Effective June 1, 2023, filed by New Jersey's four EDCs on July 1, 2022 ("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 (at 51.2 MW of BGS-CIEP eligible load per tranche) in the BGS-CIEP Auction.

As to the BGS-RSCP Auction, RECO currently has two 36-month tranches that terminate on May 31, 2023, one 36-month tranche that terminates on May 31, 2024, and one 36-month tranche that terminates on May 31, 2025. Accordingly, since 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, 2023, RECO will include two 36-month tranches (for the period June 1, 2023 through May 31, 2026).

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, 2023; and
- (c) A default during the supply period.

The three contingencies are discussed further below:

- (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

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.

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 amount 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. In the event that RECO is not able to auction its BGS-CIEP tranche successfully in the 2023 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.

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.

- 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, 2023

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 tranches, RECO only will seek replacement supply until May 31, 2024. 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, 2024.

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 Decision and Order in Docket No. ER12070643, 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;

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.
 - rent and maintenance of office space in New Jersey for the Auction Manager;
 - 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.
- b. Directly-incurred costs include, but are not limited to, the following:
- Labor costs

As noted, one element of commonly-incurred costs have been the costs associated with the rent and maintenance of office space in New Jersey for the Auction Manager to conduct the annual BGS Auction. Due to restrictions and safeguards related to the COVID-19 pandemic, the February 2022 BGS Auction was conducted remotely, as was the prior BGS Auction (*i.e.*, the aforementioned office space was not utilized), without issue. Given the success of conducting the recent auction in this manner, RECO believes that it would be prudent (and will reduce costs for the benefit of BGS customers) to conduct future BGS Auctions in this same remote manner. As such, in the 2021 BGS Proposal filed on July 1, 2021, the EDCs proposed to begin the process of subletting or otherwise closing the physical BGS office located in Newark, N.J., in an effort to eliminate or otherwise reduce the costs related to the same. On November 17, 2021, the Board approved the EDCs’ request to close or sublet the physical BGS office space, and effective May 16, 2022 the BGS office was sublet to a new (sub)tenant.

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”)⁴

⁴ The Energy Year is defined as the 12-month period commencing June 1.

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.

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

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.⁵

For the BGS rates applicable to BGS-RSCP eligible SC No. 2 demand billed customers, the Company has applied a reduction of 50% in the differential for the first 5 kW and above 5 kW of demand.

Final tariff leaves including the actual BGS rates and tariff provisions to become effective on June 1, 2023 will be filed with the Board upon its issuance of an appropriate Board order approving the BGS Auction Process.

G. RECO RFP

Rockland’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. As explained below, RECO does not need to conduct an RFP for the 2023 BGS Auction.

With regard to the purchase of energy, in the Board’s November 18, 2020 Order in Docket No. ER20030190, the Board approved a Request for Proposal (“RFP”) process for Rockland to solicit competitive bids from qualified bidders for fixed energy supply prices for BGS customers in Rockland's Central and Western Divisions,

⁵ RECO will be making a filing to address supply rates for residential EV charging pursuant to the Board’s Order of November 9, 2022.

commencing June 1, 2021. On January 26, 2021, Rockland conducted its RFP for the period June 1, 2021 through May 31, 2024. As a result of the RFP, RECO entered into a three year Fixed for Floating Energy Swap contract with Exelon Generation Company, LLC. The Board approved this RFP result in its January 27, 2021 Order in Docket No. ER20030190. The RFP price will be rolled into Rockland's BGS auction price to develop a weighted average BGS-RSCP price for the period June 1, 2023 through May 31, 2024. Therefore, RECO does not need to conduct an RFP for the 2023 BGS Auction.

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.⁶ 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 18, 2020 Order in Docket No. ER20030190. The impact of these capacity purchases is expected to be minimal because the Company's Central and Western Divisions constitute only about ten percent of the Company's BGS load.

H. BGS Rate Design Methodology

⁶ Such cleared products are necessary benchmarks that enable bidders to develop their bids for financial hedging contracts.

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 AM to 11 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 2022 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. 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 2023 with a migration adjustment for retail access. The values in

Table #3 will be updated in January 2023 to better reflect the amount by Service Classification that could be in effect starting on June 1, 2023.

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 2023 to May 2024, 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 2019 to December 2021, which equals 0.6009%. Marginal losses are excluded from the loss factors based on historic de-rating factors for the period January 2019 to December 2021.

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 Service Classification 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. 3 peak and off-peak kWh consumption. To correct for this difference, the shortfall is divided by the total kWh for Service Classification No. 3

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 2022. The values in the top portion of Table #9 will be updated in January 2023 to better reflect the aggregate amount by rate schedule that could be in effect on June 1, 2023. 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 2023/2024, 2024/2025, and 2025/2026 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.

However, PJM has issued a schedule of upcoming BRAs and the recently conducted BRA produced a preliminary price paid for capacity of \$49.59 per MW-day for the 2023/2024 Delivery Year for the RECO Zone. Due to the postponements of the BRAs, contracts from the 2021 and 2022 BGS auctions contained supplements with Capacity Proxy Prices. With the prior postponements of the BRAs for the 2023/2024 Delivery Year and the 2024/2025 Delivery Year, the Capacity Proxy Prices of \$146.51/MW-day was used in place of the 2023/2024 BRA value in the 2021 contracts,

while a Capacity Proxy Price of \$118.12/MW-day was used in place of the 2023/2024 BRA value and a Capacity Proxy Price of \$87.98/MW-day was used in place of the 2024/2025 BRA value in the 2022 contracts.

Given the continued delay in the schedule of BRAs for the 2024/2025 Delivery Year and 2025/2026 Delivery Year, a Capacity Proxy Price of \$66.38 per MW-Day has been used in place of the 2024/2025 BRA value and a Capacity Proxy Price of \$44.63 per MW-Day have been used in place of the prices paid for 2024/2025 and 2025/2026 Delivery Years, respectfully.

For EY 2025, with Supplement A to the BGS-RSCP Supplier Master Agreement approved by the Board on November 9, 2022 and if the BRA for the 2024/2025 Delivery has not occurred at least 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 Reliability Pricing Model or its successor or otherwise, and the Capacity Proxy Price for the 2024/2025 Delivery Year.

For EY 2026, with Supplement B to the BGS-RSCP Supplier Master Agreement approved by the Board on November 9, 2022 and if the BRA for the 2025/2026 Delivery has not occurred at least 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 Reliability Pricing Model or its successor or otherwise, and the Capacity Proxy Price for the 2025/2026 Delivery Year.

RECO will file new tariff sheets for EY 2025 and EY 2026, 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 Supplements signed by BGS Suppliers in February 2021 and February 2022 are still in effect for a portion of the load for EY 2024 (the year beginning June 1, 2023). Payments to BGS-RSCP suppliers that executed the Supplement to the SMA approved by the Board on November 18, 2020 and November 17, 2021 will be adjusted for the price difference between the price paid by the BGS-RSCP Suppliers for Capacity in the Company's PJM Zone and the Capacity Proxy Price for the 2023/2024 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 Supplements executed by BGS Suppliers in February 2021 and February 2022. The value of the recently concluded BRA in June 2022 is used as an approximation for the Final PJM RPM Net Zonal Price for the 2023/2024 Delivery Year (\$49.59 per MW-Day).

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 2023 to 2026 for RECO using a proxy price for 2026), 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 \$16.92 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 \$2.00 per MWh and \$16.92 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:

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 \$ per MWh will be used to reflect the impact of payments made pursuant to the supplements executed by BGS Suppliers in February 2021 and February 2022. 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 2023/2024 Delivery Year. The value of the recently concluded BRA in June of 2022 is used as an approximation of the price paid by BGS-RSCP Suppliers for Capacity in the Company's PJM Zone for 2023/2024. The table also includes the

impacts of RECO's RFP for the Central and Western Divisions.⁷ However, upon the conclusion of the RECO RFP, the RFP winning bid price will be applied to the results of the prior two BGS auctions. From these values, the weighted average total price (shown on line #20) is calculated. All of 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, 2023 (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.

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

⁷ The prices shown for the tranches to be secured in the 2023 BGS Auction and RFP are for illustrative purposes only and will be replaced with actual data in determining RECO's final June 2023 BGS-RSCP rates.

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, 2023/2024, 2024/2025, and 2025/2026 BRA for RPM results applicable to load served in the RECO zone. PJM has now issued a calendar of upcoming BRAs and the recently concluded June 2022 BRA produced a preliminary price paid for capacity of \$49.59 per MW-day for the 2023/2024 Delivery Year for the RECO zone. Due to the postponement of the BRAs prior year BGS Auction contracts contained supplements with Capacity Proxy Prices.

With the prior postponement of the BRAs for the 2023/2024 and 2024/2025 Delivery Years, a Capacity Proxy Prices of \$146.51 and \$118.12 per MW-Day have been used in place of the 2023/2024 and 2024/2025 BRA values.

Given the continued delay in the schedule of BRAs for the 2024/2025 Delivery Year and 2025/2026 Delivery Year, a Capacity Proxy Price of \$87.98 per MW-Day and a Capacity Proxy Price of \$66.38 per MW-Day have has been used in place of the prices paid for capacity for 2024/2025 and 2025/2026 Delivery Year, respectfully.

For EY 2025, with Supplement A to the BGS-RSCP SMA approved by the Board on November 9, 2022 and if the BRA for the 2024/2025 Delivery has not occurred at least 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 RECO Zone, as may be determined under the RPM or its successor or otherwise, and the Capacity Proxy Price for the 2024/2025 Delivery Year.

For EY 2026, with Supplement B to the BGS-RSCP SMA approved by the Board on November 9, 2022 and if the BRA for the 2025/2026 Delivery has not occurred at least 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 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 2025/2026 Delivery Year.

RECO will file new tariff sheets for EY 2025 and EY 2026, 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 Supplements to the SMAs signed by BGS-RSCP Suppliers in February 2021 and February 2022 are still in effect for a portion of the load for EY 2024 (the year beginning June 1, 2023). Payments to BGS-RSCP suppliers that executed the Supplements to the SMAs approved by the Board on November 18, 2020 and November 17, 2021 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 2023/2024 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 Supplements executed by BGS-RSCP Suppliers in February 2021 and February 2022. The value of the recently concluded BRA in June of 2022 is used as an approximation for the price paid by BGS-RSCP Suppliers for Capacity in the Company's PJM Zone for the 2023/2024 Delivery Year (\$49.59 per MW-Day)

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.

Attachment A

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 – First 600 kWh	X.XX¢	X.XXX¢
1 – Over 600 kWh	X.XXX¢	X.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		
First 5 kW (\$/kW)	X.XX	X.XX
Over 5 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: Robert Sanchez, 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.....\$ XX.XXXX

Charge applicable in other months.....\$ XX.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: Robert Sanchez, President
Mahwah, New Jersey 07430

Attachment B & C

Development of BGS Cost and Bid Factors for Rates Effective June 1, 2023

Table #1 % Usage During PJM On-Peak Period

Based on 2022 Load Profile Information
On-Peak periods defined as the 16 hr PJM Trading period, adj for NERC holidays

	<i>Profile Meter Data</i>	<i>Profile Meter Data</i>	<i>Profile Meter Data</i>	<i>--- Other Analysis ---</i>	<i>Profile Meter Data</i>	
	<u>SC1</u>	<u>SC3</u>	<u>SC2 ND</u>	<u>SC4</u>	<u>SC6</u>	<u>SC2 Dem</u>
January	48.84%	44.39%	31.84%	50.34%	50.34%	51.00%
February	51.74%	46.03%	33.60%	53.20%	53.20%	53.06%
March	53.28%	48.02%	33.82%	55.58%	55.58%	55.93%
April	51.09%	44.76%	31.51%	52.53%	52.53%	54.01%
May	51.33%	43.24%	26.75%	53.05%	53.05%	53.55%
June	55.53%	47.70%	27.37%	56.32%	56.32%	57.39%
July	52.01%	41.21%	24.43%	49.75%	49.75%	52.15%
August	59.02%	47.22%	28.37%	56.90%	56.90%	58.67%
September	52.80%	43.63%	32.55%	52.10%	52.10%	54.60%
October	49.82%	43.07%	32.00%	50.72%	50.72%	53.36%
November	49.80%	45.26%	33.05%	52.17%	52.17%	53.49%
December	49.68%	44.35%	31.91%	51.31%	51.31%	50.98%

Table #2 % Usage During RECO On-Peak Billing Period *On-Peak periods as defined in specified rate schedule*

	<i>N/A</i>		<i>N/A</i>	<i>N/A</i>	<i>N/A</i>	<i>N/A</i>
<i>(data rounded to nearest %)</i>	<u>SC1</u>	<u>SC3</u>	<u>SC2 ND</u>	<u>SC4</u>	<u>SC6</u>	<u>SC2 Dem</u>
January	----	32.6%	----	----	----	----
February	----	35.9%	----	----	----	----
March	----	33.6%	----	----	----	----
April	----	34.8%	----	----	----	----
May	----	36.0%	----	----	----	----
June	----	39.5%	----	----	----	----
July	----	41.7%	----	----	----	----
August	----	42.9%	----	----	----	----
September	----	41.8%	----	----	----	----
October	----	40.0%	----	----	----	----
November	----	37.6%	----	----	----	----
December	----	35.8%	----	----	----	----

Table #3 Class Usage @ customer

*Calendar month billed sales forecasted for 2023
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	53,239	34	1,624	666	481	30,833	86,875
February	47,896	33	1,786	545	414	25,152	75,826
March	44,102	29	2,145	582	378	26,175	73,410
April	39,241	20	1,241	474	369	28,132	69,476
May	38,907	23	978	460	340	24,922	65,630
June	54,169	27	947	411	321	27,144	83,019
July	81,121	32	1,106	440	312	30,812	113,822
August	82,132	29	1,097	484	326	32,396	116,463
September	70,852	31	1,006	517	400	30,886	103,691
October	48,960	22	1,016	584	473	28,689	79,742
November	41,052	23	975	637	524	25,481	68,691
December	<u>49,172</u>	<u>27</u>	<u>1,490</u>	<u>674</u>	<u>529</u>	<u>27,119</u>	<u>79,011</u>
Total	650,839	330	15,411	6,471	4,863	337,742	1,015,656

Table #4 Forwards Prices - Energy Only @ bulk system

in \$/MWh (See Table 18)

	<u>On-Peak</u>	<u>Off-Peak</u>
January	95.56	78.30
February	90.44	74.14
March	57.13	46.89
April	48.65	40.52
May	47.93	39.76
June	55.87	38.40
July	69.82	47.56
August	64.35	43.90
September	53.30	36.43
October	50.57	41.52
November	53.93	43.98
December	64.69	52.12

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 =	1.08640	1.08640	1.08640	1.08261	1.08261	1.08640
Expansion Factor (net Marginal Losses)	1.07635	1.07635	1.07338	1.07261	1.06614	1.07635

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	\$	57.33	\$ 54.67	\$ 51.29	\$ 56.05	\$ 55.74	\$ 56.97
	PJM on pk \$	66.90	\$ 66.11	\$ 65.88	\$ 65.60	\$ 65.23	\$ 66.20
	PJM off pk \$	45.69	\$ 45.39	\$ 45.59	\$ 44.97	\$ 44.72	\$ 45.38
Winter - all hrs	\$	64.35	\$ 65.24	\$ 63.28	\$ 63.92	\$ 63.60	\$ 63.64
	PJM on pk \$	70.53	\$ 72.52	\$ 72.45	\$ 69.82	\$ 69.50	\$ 69.22
	PJM off pk \$	58.02	\$ 59.28	\$ 58.94	\$ 57.46	\$ 57.15	\$ 57.30
Annual	\$	61.24	\$ 61.43	\$ 60.05	\$ 61.67	\$ 61.41	\$ 61.24
System Total	\$	61.23					

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	\$	16,526	\$ 7	\$ 213	\$ 104	\$ 76	\$ 6,907
	PJM on pk \$	10,581	\$ 4	\$ 77	\$ 65	\$ 48	\$ 4,470
	PJM off pk \$	5,945	\$ 3	\$ 136	\$ 39	\$ 28	\$ 2,438
Winter - all hrs	\$	23,332	\$ 14	\$ 712	\$ 295	\$ 223	\$ 13,777
	PJM on pk \$	12,947	\$ 7	\$ 262	\$ 169	\$ 127	\$ 7,962
	PJM off pk \$	10,385	\$ 7	\$ 450	\$ 127	\$ 96	\$ 5,816
Annual	\$	39,858	\$ 20	\$ 925	\$ 399	\$ 299	\$ 20,685
System Total	\$	62,186					

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>
Summer - all hrs	\$	57.33	\$ 54.67	\$ 51.29	\$ 56.05	\$ 55.74	\$ 56.97
			\$ 66.79				
			\$ 46.07				
RECO On pk							
RECO Off pk							
Winter - all hrs	\$	64.35	\$ 65.24	\$ 63.28	\$ 63.92	\$ 63.60	\$ 63.64
			\$ 73.77				
			\$ 60.53				
RECO On pk							
RECO Off pk							
Annual Average	\$	61.24	\$ 61.43	\$ 60.05	\$ 61.67	\$ 61.41	\$ 61.24
System Average	\$	61.23					

Table #9 Generation & Transmission Obligations and Costs and Other Adjustments
Obligations - annual average forecasted for 2022; 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		303.960	0.117	2.805	0.0	0.0	82.917	389.799	TRUE
Trans Obl - MW		308.009	0.115	2.921	0.0	0.0	85.701	396.746	TRUE
# 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*	\$	42,548	per MW-yr	116.25					
Generation Capacity cost	summer		\$67.15	\$/MW/day	Resulting avg gen cap cost =	summer >>	\$	24.51	per kW/yr
(see Table 19)	winter		\$53.21	\$/MW/day		winter >>	\$	19.42	per kW/yr
Current residential summer BGS charges									
<i>Current Tariff and % of total summer usage</i>									
		----- SC1 -----							
		Charges		% usage					
Block 1 (0-600 kWh/month)		4.599	¢/kWh	42.97%					
Block 2 (>600 kWh/m)		9.956	¢/kWh	57.03%					
Calculated inversion =		5.357	¢/kWh						

Table #10 Ancillary Services
forecasted overall annual average

\$18.89 /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>
Transmission Obl - all months \$	20.14 \$	14.83 \$	8.06 \$	- \$	-
Generation Obl -					
per annual MWh \$	9.89 \$	7.51 \$	3.85 \$	- \$	-
per summer MWh \$	8.64 \$	8.05 \$	5.53 \$	- \$	-
per winter MWh \$	10.88 \$	7.20 \$	3.24 \$	- \$	-

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>
Summer - all hrs \$	104.99 \$	96.44 \$	83.77 \$	74.94 \$	74.63
RECO On pk \$		119.90			
RECO Off pk \$		79.79			
Block 1 \$	74.44				
Block 2 \$	128.01				
Winter - all hrs \$	114.26 \$	106.15 \$	93.47 \$	82.81 \$	82.49
RECO On pk \$		127.74			
RECO Off pk \$		94.25			
Annual -all hrs \$	110.16 \$	102.65 \$	90.86 \$	80.56 \$	80.30

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 \$	75.86		<u>Gen Cost (per kW of Billed Demand/Month)</u>	
			≤ 5 kW	> 5 kW
Winter - all hrs \$	82.53	summer	\$ 0.575	\$ 1.820
		winter	\$ 0.720	\$ 1.550
		<u>Trans cost</u>		
Annual - all hrs per MWh only \$	80.13	all months \$	3.55	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	\$ 92.80				
			≤ 5 kW	> 5 kW	
Winter - all hrs	\$ 100.25	summer	\$ 0.575	\$	1.820
		winter	\$ 0.720	\$	1.550
Annual - including T&G Obl \$	\$ 96.13				

ALL RATES

Grand Total Cost in \$1000 = \$ 106,507
 All-In Average cost @ customer = \$ 104.87 per MWh at customer (per customer metered MWh)
 All-In Average costs @ transmission nodes = \$ 97.44 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>
Summer - all hrs	1.078		0.860	0.769	0.766
RECO On pk		1.231			
RECO Off pk		0.819			
Constant Blk 1 \$	(30.55)				
Constant Blk 2 \$	23.02				
Winter - all hrs	1.173		0.959	0.850	0.847
RECO On pk		1.311			
RECO Off pk		0.967			
Annual - all hrs	1.131	1.054	0.932	0.827	0.824

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>	(16.931)	PLUS:			
Summer - all hrs	0.952				<u>Gen Cost (per kW of Billed Demand/Month)</u>			
							≤ 5 kW	> 5 kW
Winter - all hrs	1.029	\$		(17.722)	summer	\$	0.58	\$ 1.82
					winter	\$	0.72	\$ 1.55
Annual - including T&G Obl \$	0.987				<u>Trans cost</u>			
					all months	\$	3.546	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>
Summer - all hrs	\$	84.86	\$	81.61	\$	75.71	\$	74.94	\$	74.63
			\$	105.08						
			\$	64.96						
	Block 1	\$	54.31							
	Block 2	\$	107.88							
Winter - all hrs	\$	94.13	\$	91.33	\$	85.41	\$	82.81	\$	82.49
			\$	112.91						
			\$	79.42						
Annual -all hrs	\$	90.02	\$	87.82	\$	82.79	\$	80.56	\$	80.30

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>	PLUS:			
		<u>Gen Cost (per kW of Billed Demand/Month)</u>			
			<u>< 5 kW</u>	<u>> 5 kW</u>	
Summer - all hrs	\$ 75.86				
Winter - all hrs	\$ 82.53	summer	\$ 0.575	\$	1.820
		winter	\$ 0.720	\$	1.550
Annual - all hrs per MWh only	\$ 80.13				
<u>Including Generation Obligation \$</u>					
Summer - all hrs	\$ 82.77				
Winter - all hrs	\$ 89.02				
Annual - including T&G Obl \$	\$ 86.78				

ALL RATES

Grand Total Cost in \$1000 =	\$ 90,114		
All-In Average cost @ customer =	\$	88.72	per MWh at customer (per customer metered MWh)
All-In Average costs @ transmission nodes =	\$	82.44	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>
Summer - all hrs	1.029		0.918	0.909	0.905
RECO On pk		1.275			
RECO Off pk		0.788			
Constant Blk 1 \$	(30.55)				
Constant Blk 2 \$	23.02				
Winter - all hrs	1.142		1.036	1.005	1.001
RECO On pk		1.370			
RECO Off pk		0.963			
Annual - all hrs	1.092	1.065	1.004	0.977	0.974

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	1.004	(6.906)	<u>Gen Cost (per kW of Billed Demand/Month)</u>			
				<u>< 5 kW</u>		<u>> 5 kW</u>
Winter - all hrs	1.080	(6.494)	summer	\$ 0.575	\$	1.820
			winter	\$ 0.720	\$	1.550
Annual - including T&G Obl \$	1.053					

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>
Total Costs by Rate - in \$1000												
Summer	\$	30,266	\$	11	\$	348	\$	139	\$	101	\$	11,092
Winter	\$	41,428	\$	22	\$	1,052	\$	383	\$	289	\$	21,375
Total	\$	71,694	\$	34	\$	1,400	\$	521	\$	390	\$	32,467
% of Annual Total \$ by Rate												
Summer		42%		34%		25%		27%		26%		34%
Winter		58%		66%		75%		73%		74%		66%
Total Costs - in \$1000												
Summer	\$	41,958										
Winter	\$	64,549										
Total	\$	106,507										
% of Annual Total \$												
Summer		39%										
Winter		61%										

If total \$ were split on a per MWh basis (on transmission node MWhs):

Summer	\$	93.49	per MWh @ transmission nodes
Winter	\$	100.19	per MWh @ transmission nodes

Ratio to All-In Cost

Summer	0.9595
Winter	1.0282

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>
Total Costs by Rate - in \$1000												
Summer	\$	24,462	\$	10	\$	315	\$	139	\$	101	\$	9,877
Winter	\$	34,127	\$	19	\$	961	\$	383	\$	289	\$	18,944
Total	\$	58,589	\$	29	\$	1,276	\$	521	\$	390	\$	28,821
% of Annual Total \$ by Rate												
Summer		42%		34%		25%		27%		26%		34%
Winter		58%		66%		75%		73%		74%		66%
Total Costs - in \$1000												
Summer	\$	34,903										
Winter	\$	54,723										
Total	\$	89,626										
% of Annual Total \$												
Summer		39%										
Winter		61%										

If total \$ were split on a per MWh basis (on transmission node MWhs):

Summer	\$	77.77	per MWh @ transmission nodes
Winter	\$	84.94	per MWh @ transmission nodes

Ratio to All-In Cost

Summer	0.9433
Winter	1.0303

Table #18 Forward Energy Prices

PJM Forward Prices - Energy Only @ bulk system <i>in \$/MWh</i>	<u>On-Peak</u>	<u>Off/On Peak 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	106.10	0.7862	83.42	91%	95%	96.55	79.25
February	100.15	0.7862	78.74	91%	95%	91.14	74.80
March	62.35	0.7862	49.02	91%	95%	56.74	46.57
April	54.75	0.7862	43.04	91%	95%	49.82	40.89
May	54.50	0.7862	42.85	91%	95%	49.60	40.71
June	66.65	0.6456	43.03	88%	91%	58.65	39.16
July	82.80	0.6456	53.46	88%	91%	72.86	48.65
August	76.20	0.6456	49.19	88%	91%	67.06	44.76
September	63.25	0.6456	40.83	88%	91%	55.66	37.16
October	57.95	0.7862	45.56	91%	95%	52.73	43.28
November	60.70	0.7862	47.72	91%	95%	55.24	45.33
December	70.75	0.7862	55.62	91%	95%	64.38	52.84

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

	<u>On-Peak</u>	<u>Off-Peak</u>
January	88.25	71.25
February	85.25	69.25
March	60.00	49.25
April	40.00	37.75
May	35.50	32.75
June	35.25	32.75
July	47.25	39.50
August	44.25	37.50
September	35.75	31.00
October	34.50	28.50
November	44.25	34.00
December	67.00	46.75

**Weighted Average Forward Prices - Energy Only @ bulk system (88.1% PJM - 11.9% NYISO)
*in \$/MWh***

	<u>On-Peak</u>	<u>Off-Peak</u>
January	95.56	78.30
February	90.44	74.14
March	57.13	46.89
April	48.65	40.52
May	47.93	39.76
June	55.87	38.40
July	69.82	47.56
August	64.35	43.90
September	53.30	36.43
October	50.57	41.52
November	53.93	43.98
December	64.69	52.12

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

	<u>PJM Base Capacity</u>	<u>PJM 88.1%</u>	<u>NYISO 11.9%</u>	<u>Weighted Average</u>
Summer	\$53.53	\$53.53	\$168.22	\$67.15
Winter	\$53.53	\$53.53	50.87	\$53.21

Table #20 Ancillary Services

	<u>PJM Ancillary Services</u>	<u>NYISO Ancillary Services</u>	<u>Renewable Power Cost</u>	<u>PJM 88.1%</u>	<u>NYISO 11.9%</u>	<u>Weighted Average</u>
	\$2.00	\$1.77	\$16.92	\$18.92	\$18.69	\$18.89

Assumptions:

- Gen Cost = \$67.15 per MW-day in summer
\$53.21 per MW-day in winter
- Trans cost = \$ 42,548 per MW-yr
- Analysis time period = 4 summer months
8 winter months
- Ancillary Services = \$ 18.89 /MWh
- Energy Costs = Based on Jun 2023 to May 2024 Forwards @ PJM West as of November 01, 2022
Based on Jun 2023 to May 2024 Forwards @ NYISO Zone G and Lower Hudson Valley (LHV) as of June 14, 2022
- Usage patterns = Forecasted 2022 energy use by class, PJM on/off % from 2021 class load profiles,
RECO billing on/off % from 6/21 to 5/22 actual data
- Obligations = Class totals for 2022
- 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 >>	2021 Auction 36 Month	2022 Auction 36 Month	2023 Auction 36 Month	Total	Notes:
1	Tranches	1	1	2	4	From then-current auction
2(a)	Winning Bid Price (¢/kWh)*	6.692	8.206	8.206		(Note: 2023 Auction Price Shown for Illustrative Purposes Only)
2(b)	Capacity Proxy Price True-up - in (¢/kWh)*	-1.435	-1.031	0.000		Entered After 2023 BGS Auction
3	BGS (¢/kWh)	5.257	7.175	8.206		= 2(a) + 2(b)
4	Weighted Avg BGS	1.314	1.794	4.103	7.211	= (1) / Total Tranches * (3)
5	Weighted Avg Total Price (¢/kWh)				7.211	
<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	395,506				From then-current Bid Factor Spreadsheet
9	Winter MWh	<u>567,777</u>				From then-current Bid Factor Spreadsheet
10		963,283				
<u>Total Cost</u>						
11	Summer	5,197,939	7,094,390	16,227,614	28,519,943	= (1) / Total Tranches * (3) / 100 * (6) * (8) * 1,000
12	Winter	<u>7,462,007</u>	<u>10,184,496</u>	<u>23,295,882</u>	<u>40,942,385</u>	= (1) / Total Tranches * (3) / 100 * (7) * (9) * 1,000
13	Total	12,659,946	17,278,886	39,523,496	69,462,328	= (11) + (12)
<u>Average Cost (NJ Statewide Auction)</u>						
14	Summer	7.211 ¢/kWh				= sum(line 11) / (8) / 1000 * 100 rounded to 3 decimal places
15	Winter	7.211 ¢/kWh				= sum(line 12) / (9) / 1000 * 100 rounded to 3 decimal places
16	Total	7.211 ¢/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	0.539		4.539	Includes RECO RFP equivalent tranches
18	Price ¢/kWh	7.211	7.784			BGS Auction from (16) Note 7.784¢ for RFP is illustrative
19	Weighted Avg BGS	6.355	0.924		7.279	= (17) / Total Tranches * (18)
20	Weighted Avg Total Price				7.279	= (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>
Summer - all hrs	1.029		0.918	0.909	0.905
RECO On pk		1.275			
RECO Off pk		0.788			
Constant Blk 1 \$	(30.55)				
Constant Blk 2 \$	23.02				
Winter - all hrs	1.142		1.036	1.005	1.001
RECO On pk		1.370			
RECO Off pk		0.963			
Annual - all hrs	1.092	1.065	1.004	0.977	0.974

DEMAND RATES

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

	<u>SC2 Dem</u> <u>Multiplier</u>	<u>SC2 Dem</u> <u>Constant</u>	PLUS:		
			<u>Gen Cost (per kW of Billed Demand/Month)</u>		
			<u>0</u>	<u>< 5 kW</u>	<u>> 5 kW</u>
Summer - all hrs	1.004	(6.906)			
Winter - all hrs	1.080	(6.494)	summer \$	- \$ 0.575	\$ 1.820
			winter \$	- \$ 0.720	\$ 1.550
Annual - including T&G Obl \$	1.053				

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

All-In Average costs @ Trans node =	\$	72.79	/MWh*				* Price from Table A (which does not include
Less Transmission	\$	-	/MWh**				transmission for the Central/Western Division).
BGS Cost	\$	72.79	/MWh				
							\$1.78
<u>Retail BGS Rates (excl SUT) (¢/kWh)</u>							
		<u>SC1</u>	<u>SC3</u>	<u>SC2 ND</u>	<u>SC4</u>	<u>SC6</u>	<u>SC2 Dem</u>
<u>Summer</u>							
All kWh (¢/kWh)	7.490		6.682	6.617	6.587	6.618	
Peak kWh (¢/kWh)		9.281					
Off-Peak kWh (¢/kWh)		5.736					
Block1	4.435						
Block2	9.792						
Demand Charge (\$/kW) 1st 5kW						0.575	
Demand Charge (\$/kW) > 5 kW						1.820	
<u>Winter</u>							
All kWh (¢/kWh)	8.313		7.541	7.315	7.286	7.212	
Peak kWh (¢/kWh)		9.972					
Off-Peak kWh (¢/kWh)		7.010					
Demand Charge (\$/kW) 1st 5kW						0.720	
Demand Charge (\$/kW) > 5 kW						1.550	

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>
Total BGS Revenue (Excl SUT) - in \$1000						
Summer	\$ 21,592	\$ 9	\$ 278	\$ 123	\$ 89	\$ 8,861
Winter	\$ 30,140	\$ 17	\$ 849	\$ 338	\$ 255	\$ 17,020
Total	\$ 51,732	\$ 26	\$ 1,127	\$ 461	\$ 344	\$ 25,881
Total						
Summer	\$ 30,952					
Winter	\$ 48,619					
Total	\$ 79,571					
<u>Total Supplier Payments - in \$1000</u>						
Eastern Division	<u>Total</u>	<u>Transmission</u>	<u>Net BGS</u>			
Summer	\$ 28,520		\$ 28,520		4,959.00	
Winter	\$ 40,942		\$ 40,942		9,917.00	
Total	\$ 69,462	\$ -	\$ 69,462			
Central/Western Division	<u>Total</u>	<u>Transmission</u>	<u>Net BGS</u>			
Summer	\$ 4,187	\$ -	\$ 4,187			
Winter	\$ 5,955	\$ -	\$ 5,955			
Total	\$ 10,142	\$ -	\$ 10,142			
Total RECO FP	<u>Total</u>	<u>Transmission</u>	<u>Net BGS</u>			
Summer	\$ 32,707	\$ -	\$ 32,707			
Winter	\$ 46,897	\$ -	\$ 46,897			
Total	\$ 79,604	\$ -	\$ 79,604			
Differences	<u>BGS Revenue</u>	<u>BGS Costs</u>	<u>Difference</u>		<u>Rate Adjustment Factors</u>	
Summer	\$ 30,952	\$ 32,707	\$ 1,755		1.0567	
Winter	\$ 48,619	\$ 46,897	\$ (1,722)		0.96459	
Total	\$ 79,571	\$ 79,604	\$ 33			

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>Summer</u>						
All kWh (¢/kWh)	7.915		7.061	6.992	6.960	6.993
Peak kWh (¢/kWh)		9.807				
Off-Peak kWh (¢/kWh)		6.061				
Block1	4.686					
Block2	10.347					
Demand Charge (\$/kW) 1st 5kW						0.608
Demand Charge (\$/kW) > 5 kW						1.923
<u>Winter</u>						
All kWh (¢/kWh)	8.019		7.274	7.056	7.028	6.957
Peak kWh (¢/kWh)		9.619				
Off-Peak kWh (¢/kWh)		6.762				
Demand Charge (\$/kW) 1st 5kW						0.695
Demand Charge (\$/kW) > 5 kW						1.495

Rates Including SUT:

	SUT @		6.625%			
	<u>SC1</u>	<u>SC3</u>	<u>SC2 ND</u>	<u>SC4</u>	<u>SC6</u>	<u>SC2 Dem</u>
<u>Summer</u>						
All kWh (¢/kWh)			7.529	7.455	7.421	7.456
Peak kWh (¢/kWh)		10.457				
Off-Peak kWh (¢/kWh)		6.463				
Block1	4.996					
Block2	11.032					
Demand Charge (\$/kW) 1st 5kW						0.65
Demand Charge (\$/kW) > 5 kW						2.05
<u>Winter</u>						
All kWh (¢/kWh)	8.550		7.756	7.523	7.494	7.418
Peak kWh (¢/kWh)		10.256				
Off-Peak kWh (¢/kWh)		7.210				
Demand Charge (\$/kW) 1st 5kW						0.74
Demand Charge (\$/kW) > 5 kW						1.59

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	\$ 22,817	\$ 9	\$ 293	\$ 129	\$ 94	\$ 9,363
Winter	\$ 29,074	\$ 16	\$ 819	\$ 326	\$ 246	\$ 16,419
Total	\$ 51,891	\$ 25	\$ 1,112	\$ 455	\$ 340	\$ 25,782
Total Summer	\$ 32,705					
Winter	\$ 46,900					
Total	\$ 79,605					

Supplier Payments - in \$1000

Eastern Division

	<u>Total</u>	<u>Transmission</u>	<u>Net BGS</u>	
Summer	\$ 28,520	\$ -	\$ 28,520	4959
Winter	\$ 40,942	\$ -	\$ 40,942	9917
Total	\$ 69,462	\$ -	\$ 69,462	

Central/Western Division

	<u>Total</u>	<u>Transmission</u>	<u>Net BGS</u>
Summer	\$ 4,187	\$ -	\$ 4,187
Winter	\$ 5,955	\$ -	\$ 5,955
Total	\$ 10,142	\$ -	\$ 10,142

Total RECO FP

	<u>Total</u>	<u>Transmission</u>	<u>Net BGS</u>
Summer	\$ 32,707	\$ -	\$ 32,707
Winter	\$ 46,897	\$ -	\$ 46,897
Total	\$ 79,604	\$ -	\$ 79,604

Differences

	<u>BGS Revenue</u>	<u>BGS Costs</u>	<u>Difference</u>
Summer	\$ 32,705	\$ 32,707	\$ 2
Winter	\$ 46,900	\$ 46,897	\$ (3)
Total	\$ 79,605	\$ 79,604	\$ (1)

Attachment D

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

Using 2023/2024 Illustrative Data for RECO

- 1 Zonal Capacity Price (\$/MW-day)
- 2 Capacity Proxy Price (\$/MW-day)

- 3 Capacity Proxy Price True-Up - \$/MW-day
- 4 BGS-RSCP Gen Obl - MW
- 5 Days in Year
- 6 Capacity Proxy Price True-Up Annual Cost

- 7 Eligible Tranches
- 8 Total Tranches
- 9 % of tranches eligible for payment

- 10 Capacity Proxy Price True-Up Cost

- 11 Total Applicable Customer Usage @ transmission nodes - in MWh
- 12 Eligible Customer Usage @ transmission nodes - in MWh

- 13 Capacity Proxy Price True-Up - \$/MWh

Capacity Proxy Price True-Up Development for Winning Suppliers from 2021 BGS-RSCP Auction	Capacity Proxy Price True-Up Development for Winning Suppliers from 2022 BGS-RSCP Auction	
2023/24 Delivery Year	2023/24 Delivery Year	Notes:
\$49.59	\$49.59	as may be determined by the RPM or its successor or otherwise
\$146.51	118.12	per Board Orders dated 11/18/2020 and 11/17/2021
-\$96.92	-\$68.53	= line 1 - line 2
389.8	389.8	
366	366	
-\$13,827,231	-\$9,776,931	= line 3 * line 4 * line 5
1	1	from Table A
4	4	from Table A
25.00%	25.00%	= line 7 / line 8
-\$3,456,808	-\$2,444,233	= line 6 * line 9
963,283	948,217	
240,821	237,054	= line 9 * line 11
-\$14.35	-\$10.31	= line 10/ line 12 - rounded to 2 decimal places

Development of Capacity Proxy Price True-Up - \$/MWh
Using 2024/2025 Illustrative Data for RECO

Using 2024/2025 Illustrative Data for RECO

	Capacity Proxy Price True-Up Development for Winning Suppliers from 2022 BGS-RSCP Auction	Capacity Proxy Price True-Up Development for Winning Suppliers from 2023 BGS-RSCP Auction	
	2024/25 Delivery Year	2024/25 Delivery Year	Notes:
1 Zonal Capacity Price (\$/MW-day)	\$50.00	\$50.00	as may be determined by the RPM or its successor or otherw
2 Capacity Proxy Price (\$/MW-day)	\$87.98	66.38	per Board Orders dated 11/17/2021 and 11/09/2022
3 Capacity Proxy Price True-Up - \$/MW-day	-\$37.98	-\$16.38	= line 1 - line 2
4 BGS-RSCP Gen Obl - MW	389.8	389.8	
5 Days in Year	365	365	
6 Capacity Proxy Price True-Up Annual Cost	-\$5,403,667	-\$2,330,491	= line 3 * line 4 * line 5
7 Eligible Tranches	2	2	from Table A
8 Total Tranches	4	4	from Table A
9 % of tranches eligible for payment	50.00%	50.00%	= line 7 / line 8
10 Capacity Proxy Price True-Up Cost	-\$2,701,833	-\$1,165,246	= line 6 * line 9
11 Total Applicable Customer Usage @ transmission nodes - in MWh	963,283	948,217	
12 Eligible Customer Usage @ transmission nodes - in MWh	481,641	474,109	= line 9 * line 11
13 Capacity Proxy Price True-Up - \$/MWh	<u><u>-\$5.61</u></u>	<u><u>-\$2.46</u></u>	= line 10/ line 12 - rounded to 2 decimal places

Development of Capacity Proxy Price True-Up - \$/MWh
Using 2025/2026 Illustrative Data for RECO

Using 2025/2026 Illustrative Data for RECO

Capacity Proxy
Price True-Up
Development for
Winning
Suppliers from
2023 BGS-
RSCP Auction
2025/26

	Delivery Year	Notes:
1 Zonal Capacity Price (\$/MW-day)	\$50.00	as may be determined by the RPM or its successor or otherw
2 Capacity Proxy Price (\$/MW-day)	\$44.63	per Board Order dated 11/09/2022
3 Capacity Proxy Price True-Up - \$/MW-day	\$5.37	= line 1 - line 2
4 BGS-RSCP Gen Obl - MW	389.8	
5 Days in Year	365	
6 Capacity Proxy Price True-Up Annual Cost	\$764,026	= line 3 * line 4 * line 5
7 Eligible Tranches	2	from Table A
8 Total Tranches	4	from Table A
9 % of tranches eligible for payment	50.00%	= line 7 / line 8
10 Capacity Proxy Price True-Up Cost	\$382,013	= line 6 * line 9
11 Total Applicable Customer Usage @ transmission nodes - in MWh	963,283	
12 Eligible Customer Usage @ transmission nodes - in MWh	481,641	= line 9 * line 11
13 Capacity Proxy Price True-Up - \$/MWh	<u>\$0.79</u>	= line 10/ line 12 - rounded to 2 decimal places

Table A Weighted Average Price Calculation

Line #	Specific BGS-FP Auction >>	2022 Auction 36 Month	2023 Auction 36 Month	2024 Auction 36 Month	Total	Notes:
1	Tranches	1	2	1	4	From then-current auction
2(a)	Winning Bid Price (¢/kWh)*	8.206	8.206	6.960		(Note: 2023 Auction Price Shown for Illustrative Purposes Only)
2(b)	Capacity Proxy Price True-up - in (¢/kWh)*	-5.610	-2.460			Entered After 2023 BGS Auction
3	BGS (¢/kWh)	2.596	5.746	6.960		= 2(a) + 2(b)
4	Weighted Avg BGS	0.649	2.873	1.740	5.262	= (1) / Total Tranches * (3)
5	Weighted Avg Total Price (¢/kWh)				5.262	
<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	386,727				From then-current Bid Factor Spreadsheet
9	Winter MWh	<u>561,490</u>				From then-current Bid Factor Spreadsheet
10		948,217				
<u>Total Cost</u>						
11	Summer	7,933,713	15,867,427	6,729,057	30,530,197	= (1) / Total Tranches * (3) / 100 * (6) * (8) * 1,000
12	Winter	<u>11,518,967</u>	<u>23,037,935</u>	<u>9,769,926</u>	<u>44,326,828</u>	= (1) / Total Tranches * (3) / 100 * (7) * (9) * 1,000
13	Total	19,452,680	38,905,362	16,498,983	74,857,025	= (11) + (12)
<u>Average Cost (NJ Statewide Auction)</u>						
14	Summer	7.894 ¢/kWh				= sum(line 11) / (8) / 1000 * 100 rounded to 3 decimal places
15	Winter	7.894 ¢/kWh				= sum(line 12) / (9) / 1000 * 100 rounded to 3 decimal places
16	Total	7.894 ¢/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	0.601		4.601	Includes RECO RFP equivalent tranches
18	Price ¢/kWh	7.894	6.590			BGS Auction from (16) Note 6.59¢ for RFP is illustrative
19	Weighted Avg BGS	6.863	0.861		7.724	= (17) / Total Tranches * (18)
20	Weighted Avg Total Price				7.724	= (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 A Weighted Average Price Calculation

Line #	Specific BGS-FP Auction >>	2023 Auction 36 Month	2024 Auction 36 Month	2025 Auction 36 Month	Total	Notes:
1	Tranches	2	1	1	4	From then-current auction
2(a)	Winning Bid Price (¢/kWh)*	8.206	6.960	6.960		(Note: 2025 Auction Price Shown for Illustrative Purposes Only)
2(b)	Capacity Proxy Price True-up - in (¢/kWh)*	0.790				Entered After 2024 BGS Auction
3	BGS (¢/kWh)	8.996	6.960	6.960		= 2(a) + 2(b)
4	Weighted Avg BGS	4.498	1.740	1.740	7.978	= (1) / Total Tranches * (3)
5	Weighted Avg Total Price (¢/kWh)				7.978	
<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	386,727				From then-current Bid Factor Spreadsheet
9	Winter MWh	<u>561,490</u>				From then-current Bid Factor Spreadsheet
10		948,217				
<u>Total Cost</u>						
11	Summer	15,867,427	6,729,057	6,729,057	29,325,541	= (1) / Total Tranches * (3) / 100 * (6) * (8) * 1,000
12	Winter	<u>23,037,935</u>	<u>9,769,926</u>	<u>9,769,926</u>	<u>42,577,787</u>	= (1) / Total Tranches * (3) / 100 * (7) * (9) * 1,000
13	Total	38,905,362	16,498,983	16,498,983	71,903,328	= (11) + (12)
<u>Average Cost (NJ Statewide Auction)</u>						
14	Summer	7.583 ¢/kWh				= sum(line 11) / (8) / 1000 * 100 rounded to 3 decimal places
15	Winter	7.583 ¢/kWh				= sum(line 12) / (9) / 1000 * 100 rounded to 3 decimal places
16	Total	7.583 ¢/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	0.601		4.601	Includes RECO RFP equivalent tranches
18	Price ¢/kWh	7.583	6.590			BGS Auction from (16) Note 6.59¢ for RFP is illustrative
19	Weighted Avg BGS	6.592	0.861		7.453	= (17) / Total Tranches * (18)
20	Weighted Avg Total Price				7.453	= (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.