STATE OF NEW JERSEY
BOARD OF PUBLIC UTILITIES

IN THE MATTER OF THE PROVISION OF BASIC GENERATION SERVICE FOR THE PERIOD BEGINNING JUNE 1, 2018	Docket No. ER17040335

ROCKLAND ELECTRIC COMPANY

PROPOSAL FOR BASIC GENERATION SERVICE REQUIREMENTS TO BE PROCURED EFFECTIVE JUNE 1, 2018

COMPANY SPECIFIC ADDENDUM COMPLIANCE FILING

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TABLE OF CONTENTS

RECO's COMPANY SPECIFIC ADDENDUM

A. Introduction to RECO's Company Specific Filing

In its Decision and Order dated April 21, 2017 in Docket ER17040335, 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, 2017 on the procurement of basic generation service ("BGS") for the period beginning June 1, 2018. 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, 2018, filed by New Jersey's four EDCs on June 30, 2017 ("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 56.3 MW of BGS-CIEP eligible load per tranche) in the BGS-CIEP Auction.

As to the BGS-RSCP[2] Auction, RECO currently has one 36-month tranche that terminates on May 31, 2018, one 36-month tranche that terminates on May 31, 2019, and two 36-month tranches that terminate on May 31, 2020. 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, 2018, RECO will include one 36-month tranche (for the period June 1, 2018 through May 31, 2021).

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, 2018; 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.

[2] The name Basic Generation Service Fixed Pricing ("BGS-FP") had previously been replaced with the new name Basic Generation Service Residential & Small Commercial Pricing ("BGS-RSCP").

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 Load[3] (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.[4] 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 2018 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.

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

[4] 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, transmission (including SECA, transmission enhancement and RMR), and any other expenses related to the implementation of RECO's contingency plan.

(b) Defaults prior to June 1, 2018

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, 2019. 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, 2019.

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 to BGS-RSCP and BGS-CIEP suppliers;

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, 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 incremental administrative costs, including any costs related to compliance with Renewable Portfolio Standards, associated with the provision of BGS service.

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. For the BGS rates applicable to BGS-RSCP eligible SC No. 2 demand billed customers, the Company is maintaining the 33% demand differential for the first 5 kW and above 5 kW demand that was previously approved in its filing in Docket No. ER14040370.

Final tariff leaves including the actual BGS rates and tariff provisions to become effective on June 1, 2018 will be filed with the Board upon its issuance of an appropriate Board order approving the BGS Auction Process.

G. RECO RFP

Rockland must purchase the physical electric supply and capacity needed to meet its full service obligations for its non-PJM areas (i.e., the Company's Central and Western Divisions), which are included in the New York Control Area that is administered by the New York Independent System Operator ("NYISO"). As in the past, the Company will make such purchases from markets administered by the NYISO.

A. Proposal

With regard to the procurement of capacity, on August 16, 2013, 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 number ER13-1380. Lower Hudson Valley capacity is not actively traded, and the Company does not expect the above to change before the BGS Auction.

As a result of the capacity market changes at the NYISO noted above, Rockland 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 October 31, 2016 Order in BPU Docket number ER16040337. The impact of these capacity purchases are expected to be minimal because the Company's Central and Western Divisions constitute only about ten percent of the Company's BGS load.

With regard to the procurement of electric supply, on April 15, 2015 in Docket Number ER140403370 the Board approved Rockland's proposal to secure a hedging contract for its electric procurement through bi-lateral contracts. On May 18, 2015 the Company conducted its procurement process and selected a winning bidder for a financial hedging contract commencing June 1, 2015 and extending through May 31, 2018. The Board approved the selection in its Order dated May 19, 2015. As a result of this new, three-year financial contract, Rockland's energy purchases will be hedged through May 31, 2018, and another procurement proposal must be made for the BGS year commencing June 1, 2018.

For the 2018 BGS year, Rockland proposes to enter into a bi-lateral agreement or agreements to hedge the cost of energy purchases from the NYISO.[5] The bi-lateral agreement or agreements may be either a financial hedge, where no energy commodity is provided by the counterparty, or a physical hedge in which the counterparty will provide the energy commodity.[6]

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 ISDA[7] 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.

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[5] The Company may use an in-house auction facility to obtain competitive bids from eligible bidders. There would be no fee charged to ratepayers or bidders for such an in-house auction.

[6] A transaction for physical delivery will require negotiation of an EEI Master Power Purchase and Sale agreement ("Power Purchase Agreement") so that a Power Purchase Agreement is in place with the Company prior to bidding.

[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 seek bids on physical and financial transactions for NYISO Zone G energy for the periods specified below. Each transaction will be a fixed-price transaction for approximately 10 MW "around-the-clock" of NYISO Zone G energy. Rockland is seeking to procure transactions to cover the period of June 1, 2018 to May 31, 2021 and will seek pricing for the following four periods:

1. Year 1: June 1, 2018 through May 31, 2019;
2. Year 2: June 1, 2019 through May 31, 2020;
3. Year 3: June 1, 2020 through May 31, 2021; and
4. Blended Price: June 1, 2018 through May 31, 2021.

If the transaction is financial, 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. If the transaction is physical, Rockland will enter into a NYISO Zone G energy purchase with a supplier, whereby Rockland effectively pays a 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]

B. Default Procurement

[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.

Rockland 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

<u>RECO BGS Pricing Spreadsheet</u>

As described in the EDC Compliance Filing, the resulting charge for each BGS rate element (e.g., Service Classification 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 2016 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 (Service Classification 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 2018 with a migration adjustment for retail access. The values in Table #3 will be updated in January 2018 to better reflect the amount by Service Classification that could be in effect starting on June 1, 2018.

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 2018 to May 2019, 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 June 2014 to May 2017, which equals 0.4264%. Marginal losses are excluded from the loss factors based on historic de-rating factors for the period June 2014 to May 2017.

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 Service Classification 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 2017. The values in the top portion of Table #9 will be updated in January 2018 to better reflect the aggregate amount by rate schedule that could be in effect on June 1, 2018. 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. 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 used are the relevant current wholesale market prices for capacity. 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 2018 to 2021 for RECO), and NYISO zones as calculated in Table #19. Also shown is the level of blocking in the BGS charges for Service Classification (“SC”) Nos. 1 and 5[9], which will be utilized in the later calculations of the blocking of BGS charges for these service classifications.

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 $6.96 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

[9] The Company has included in Table#9 the differential that will be in effect on January 1, 2018 for SC Nos. 1 and 5. These rates reflect the reduction in the New Jersey Sales and Use Tax from 6.875% to 6.625%.

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) 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".

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, and the impacts of RECO's RFP for the Central and Western Divisions.[10] However, upon the conclusion of the RECO RFP cost will be applied to the results of the prior two BGS auctions. From these values, the weighted average total price (shown on line #25) 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, 2018 (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

[10] The prices shown for the tranches to be secured in the 2018 auction and RFP are for illustrative purposes only, and will be replaced with actual data in determining RECO's final June 2018 BGS-RSCP rates.

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), excluding the weighted average transmission rate included therein, 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 energy 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%, which becomes effective January 1, 2018 (as revised from the current rate of 6.875%).

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. 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.

J. 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, 5 and 6

Applicable to Service Classification Nos. 1, 2 (Non-Demand Billed), 3, 4, 5, and 6
Charges per kilowatthour:

Service Classification	Summer Months*	Other Months
1 – First 600 kWh	X.XXX¢	XX.XXX¢
1 – Over 600 kWh	XX.XXX¢	XX.XXX¢
2 (Non-Demand Billed) – All kWh	X.XXX¢	X.XXX¢
3 – Peak	XX.XXX¢	XX.XXX¢
3 – Off-Peak	XX.XXX¢	X.XXX¢
4 – All kWh	X.XXX¢	X.XXX¢
5 – First 600 kWh	X.XXX¢	X.XXX¢
5 – Over 600 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):

	Summer Months*	Other Months
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, Renewable Portfolio Standard costs, and Ancillary Services (including ISO Administrative Charges).

*Definition of Summer Billing Months - June through September

(Continued)

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 $0.00641 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)

Development of BGS Cost and Bid Factors for Rates Effective June 1, 2018

Based on 2016 Load Profile Information

Table #1 **% Usage During PJM On-Peak Period**

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

	Profile Meter Data	*Profile Meter Data*	*Profile Meter Data*	*Profile Meter Data*	*--- Other Analysis ---*		*Profile Meter Data*
	SC1	**SC5**	**SC3**	**SC2 ND**	**SC4**	**SC6**	**SC2 Dem**
January	47.91%	50.29%	48.22%	45.95%	52.64%	52.64%	52.51%
February	49.93%	49.31%	46.79%	45.48%	53.47%	53.47%	53.98%
March	51.05%	49.01%	48.86%	50.13%	55.95%	55.95%	56.44%
April	45.65%	42.03%	45.35%	47.72%	51.74%	51.74%	52.09%
May	48.98%	47.90%	50.30%	52.80%	54.79%	54.79%	55.75%
June	53.68%	54.09%	53.95%	55.07%	56.19%	56.19%	57.62%
July	51.43%	49.49%	50.20%	44.91%	50.60%	50.60%	52.62%
August	54.76%	55.45%	54.64%	50.92%	56.05%	56.05%	57.82%
September	48.72%	46.33%	49.29%	50.28%	51.28%	51.28%	53.09%
October	49.01%	48.14%	48.14%	52.29%	54.15%	54.15%	56.22%
November	49.26%	48.15%	48.80%	50.91%	52.21%	52.21%	54.38%
December	46.09%	50.90%	45.81%	46.68%	49.52%	49.52%	50.15%

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

On-Peak periods as defined in specified rate schedule

	N/A	*N/A*		*N/A*	*N/A*	*N/A*	*N/A*
(data rounded to nearest %)	**SC1**	**SC5**	**SC3**	**SC2 ND**	**SC4**	**SC6**	**SC2 Dem**
January	----	----	34.1%	----	----	----	----
February	----	----	37.3%	----	----	----	----
March	----	----	34.5%	----	----	----	----
April	----	----	34.1%	----	----	----	----
May	----	----	35.3%	----	----	----	----
June	----	----	34.8%	----	----	----	----
July	----	----	37.7%	----	----	----	----
August	----	----	41.2%	----	----	----	----
September	----	----	39.1%	----	----	----	----
October	----	----	40.4%	----	----	----	----
November	----	----	37.5%	----	----	----	----
December	----	----	36.5%	----	----	----	----

Table #3 **Class Usage @ customer**
Calendar month billed sales forecasted for 2018

in MWh	SC1	SC5	SC3	SC2 ND	SC4	SC6	SC2 Dem	Total
January	57,886	1,520	24	2,358	535	464	30,722	93,507
February	50,189	1,578	36	2,588	443	416	29,840	85,089
March	44,012	1,260	23	2,344	419	420	29,278	77,756
April	39,523	1,136	19	1,775	345	388	27,107	70,291
May	42,176	811	17	1,658	318	389	28,628	73,995
June	57,347	963	21	1,607	306	384	30,106	90,733
July	76,955	1,242	23	2,019	323	385	35,258	116,204
August	80,992	1,506	21	1,968	357	355	34,938	120,135
September	63,771	1,098	21	1,754	391	428	32,380	99,840
October	45,399	872	15	1,106	471	452	28,560	76,873
November	42,908	990	16	2,357	469	553	29,327	76,619
December	47,869	1,134	23	2,247	516	533	29,440	81,761
Total	649,023	14,107	254	23,781	4,890	5,164	365,585	1,062,803

Table #4 **Forwards Prices - Energy Only @ bulk system**
in $/MWh (See Table 18)

	On-Peak	Off-Peak
January	50.12	36.62
February	47.88	35.04
March	37.04	27.16
April	30.96	22.85
May	30.45	22.12
June	31.82	19.47
July	37.17	22.48
August	34.64	20.97
September	31.32	19.19
October	31.48	22.89
November	31.64	23.19
December	35.81	25.98

Table #5

Losses	SC1	SC5	SC3	SC2 ND	SC4	SC6	SC2 Dem
Expansion Factor =	1.08449	1.08449	1.08449	1.08449	1.08072	1.08072	1.08449
Expansion Factor (net Marginal Losses)	1.07426	1.07426	1.07426	1.07426	1.07052	1.07052	1.07426

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

		SC1	SC5	SC3	SC2 ND	SC4	SC6	SC2 Dem
Summer - all hrs		$ 29.98	$ 29.85	$ 29.78	$ 29.55	$ 29.75	$ 29.73	$ 30.28
	PJM on pk	$ 36.90	$ 36.87	$ 36.67	$ 36.64	$ 36.35	$ 36.34	$ 36.69
	PJM off pk	$ 22.40	$ 22.39	$ 22.32	$ 22.46	$ 22.16	$ 22.16	$ 22.36
Winter - all hrs		$ 35.21	$ 35.95	$ 36.07	$ 35.45	$ 35.44	$ 34.82	$ 35.25
	PJM on pk	$ 40.92	$ 41.94	$ 41.95	$ 40.85	$ 40.59	$ 39.88	$ 40.18
	PJM off pk	$ 29.83	$ 30.33	$ 30.71	$ 30.35	$ 29.65	$ 29.14	$ 29.48
Annual		$ 32.96	$ 33.87	$ 33.98	$ 33.63	$ 33.84	$ 33.29	$ 33.45
System Total		$ 33.16						

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

		SC1	SC5	SC3	SC2 ND	SC4	SC6	SC2 Dem
Summer - all hrs		$ 8,365	$ 144	$ 3	$ 217	$ 41	$ 46	$ 4,017
	PJM on pk	$ 5,379	$ 91	$ 2	$ 135	$ 27	$ 30	$ 2,689
	PJM off pk	$ 2,986	$ 52	$ 1	$ 82	$ 14	$ 16	$ 1,328
Winter - all hrs		$ 13,026	$ 334	$ 6	$ 583	$ 125	$ 126	$ 8,210
	PJM on pk	$ 7,341	$ 189	$ 3	$ 326	$ 76	$ 76	$ 5,047
	PJM off pk	$ 5,685	$ 146	$ 3	$ 256	$ 49	$ 50	$ 3,163
Annual		$ 21,391	$ 478	$ 9	$ 800	$ 165	$ 172	$ 12,227
System Total		$ 35,241						

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

		SC1	SC5	SC3	SC2 ND	SC4	SC6	SC2 Dem
Summer - all hrs		$ 29.98	$ 29.85	$ 29.78	$ 29.55	$ 29.75	$ 29.73	$ 30.28
	RECO On pk			$ 38.65				
	RECO Off pk			$ 24.30				
Winter - all hrs		$ 35.21	$ 35.95	$ 36.07	$ 35.45	$ 35.44	$ 34.82	$ 35.25
	RECO On pk			$ 43.24				
	RECO Off pk			$ 32.00				
Annual Average		$ 32.96	$ 33.87	$ 33.98	$ 33.63	$ 33.84	$ 33.29	$ 33.45
System Average		$ 33.16						

Table #9 **Generation & Transmission Obligations and Costs and Other Adjustments**
Obligations - annual average forecasted for 2017; costs are market estimates

in MW	SC1	SC5	SC3	SC2 ND	SC4	SC6	SC2 Dem	Total FP
Gen Obl - MW	332.069	4.497	0.081	5.208	0.0	0.0	99.454	441.309
Trans Obl - MW	251.976	3.597	0.059	5.688	0.0	0.0	85.793	347.113

\# of Months and Days used in this analysis

# of summer days =	122	# of summer months =	4
# of winter days =	243	# of winter months =	8
		total # months =	12

Transmission Cost* $ 44,799 per MW-yr 122.74 *Reflects PJM OATT Rate (subject to change in future filings)

Generation Capacity cost	summer	$188.73 $/MW/day	Resulting avg gen cap cost =	summer >>	$ 68.89 per kW/yr
(see Table 19)	winter	$162.79 $/MW/day		winter >>	$ 59.42 per kW/yr

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

---------- SC1 ----------	Charges	% usage	---------- SC5 ----------	Chgs (¢/kWh)	Differences	% usage
Block 1 (0-600 kWh/month)	7.692 ¢/kWh	42.10%	Block 1 (0-600 kWh/month)	7.963		61.66%
Block 2 (>600 kWh/m)	10.117 ¢/kWh	57.90%	Block 2 (>600 kWh/m)	9.666	1.703	38.35%
Calculated inversion =	2.425 ¢/kWh					

Table #10 **Ancillary Services**
forecasted overall annual average $8.90 /MWh

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

	SC1	SC5	SC3	SC2 ND	SC4	SC6
Transmission Obl - all months	$ 17.39	$ 11.42	$ 10.43	$ 10.72	$ -	$ -
Generation Obl -						
per annual MWh	$ 32.02	$ 19.95	$ 20.00	$ 13.71	$ -	$ -
per summer MWh	$ 27.40	$ 21.54	$ 22.20	$ 16.32	$ -	$ -
per winter MWh	$ 35.51	$ 19.13	$ 18.90	$ 12.54	$ -	$ -

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)*

		SC1	SC5	SC3	SC2 ND	SC4	SC6
Summer - all hrs		$ 83.67	$ 71.71	$ 71.31	$ 65.49	$ 38.65	$ 38.63
	RECO On pk			$ 116.12			
	RECO Off pk			$ 43.63			
	Block 1	$ 69.63	$ 65.18				
	Block 2	$ 93.88	$ 82.21				
Winter - all hrs		$ 97.01	$ 75.40	$ 74.30	$ 67.61	$ 44.34	$ 43.72
	RECO On pk			$ 114.94			
	RECO Off pk			$ 51.33			
Annual -all hrs		$ 91.27	$ 74.14	$ 73.31	$ 66.95	$ 42.74	$ 42.19

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

	SC2 Dem
Summer - all hrs	$ 39.18
Winter - all hrs	$ 44.15
Annual - all hrs per MWh only	$ 42.35

PLUS:

Gen Cost (per kW of Billed Demand/Month)

	≤ 5 kW	> 5 kW
summer	$ 1.716	$ 5.933
winter	$ 1.563	$ 5.505

Trans cost
all months $ 3.73 per kW of T obl /month

Table #12 ***(Continued)***

Including T&G Obligation $		
Summer - all hrs	$	69.81
Winter - all hrs	$	75.44
Annual - including T&G Obl $	$	69.88

Gen Cost (per kW of Billed Demand/Month)		≤ 5 kW		> 5 kW
summer	$	1.716	$	5.933
winter	$	1.563	$	5.505

ALL RATES

Grand Total Cost in $1000 = $ 87,869

All-In Average cost @ customer = $ 82.68 per MWh at customer (per customer metered MWh)

All-In Average costs @ transmission nodes = $ 76.96 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

			SC1		SC5	SC3	SC2 ND	SC4	SC6
Summer - all hrs			**1.087**		**0.932**		**0.851**	**0.502**	**0.502**
	RECO On pk					**1.509**			
	RECO Off pk					**0.567**			
	Constant Blk 1	**$**	**(14.04)**	**$**	**(6.53)**				
	Constant Blk 2	**$**	**10.21**	**$**	**10.50**				
Winter - all hrs			**1.260**		**0.980**		**0.878**	**0.576**	**0.568**
	RECO On pk					**1.493**			
	RECO Off pk					**0.667**			
Annual - all hrs			1.186		0.963	0.952	0.870	0.555	0.548

Table #13 ***(Continued)***

DEMAND RATES

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

	SC2 Dem Multiplier		SC2 Dem Constant
Summer - all hrs	**0.907**	**$**	**(30.631)**
Winter - all hrs	**0.980**	**$**	**(31.293)**
Annual - including T&G Obl $	0.908		

PLUS:

Gen Cost (per kW of Billed Demand/Month)

		≤ 5 kW		> 5 kW
summer	$	1.72	$	5.93
winter	$	1.56	$	5.51

Trans cost

all months $ 3.733 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

			SC1		SC5		SC3		SC2 ND		SC4		SC6
Summer - all hrs		$	66.27	$	60.29	$	60.88	$	54.77	$	38.65	$	38.63
	RECO On pk					$	105.69						
	RECO Off pk					$	33.20						
	Block 1	$	52.23	$	53.76								
	Block 2	$	76.48	$	70.79								
Winter - all hrs		$	79.61	$	63.98	$	63.87	$	56.89	$	44.34	$	43.72
	RECO On pk					$	104.52						
	RECO Off pk					$	40.90						
Annual -all hrs		$	73.88	$	62.72	$	62.88	$	56.24	$	42.74	$	42.19

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.

		SC2 Dem
Summer - all hrs	$	39.18
Winter - all hrs	$	44.15
Annual - all hrs per MWh only	$	42.35
Including Generation Obligation $		
Summer - all hrs	$	60.15
Winter - all hrs	$	64.44
Annual - including T&G Obl $	$	62.89

PLUS:

Gen Cost (per kW of Billed Demand/Month)

		< 5 kW		> 5 kW
summer	$	1.716	$	5.933
winter	$	1.563	$	5.505

ALL RATES

Grand Total Cost in $1000 = $ 73,604

All-In Average cost @ customer = $ 69.25 per MWh at customer (per customer metered MWh)

All-In Average costs @ tansmission nodes = $ 64.47 per MWh at tranmission 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

		SC1	SC5	SC3	SC2 ND	SC4	SC6
Summer - all hrs		**1.028**	**0.935**		**0.850**	**0.599**	**0.599**
	RECO On pk			**1.639**			
	RECO Off pk			**0.515**			
	Constant Blk 1	**$ (14.04)**	**$ (6.53)**				
	Constant Blk 2	**$ 10.21**	**$ 10.50**				
Winter - all hrs		**1.235**	**0.992**		**0.882**	**0.688**	**0.678**
	RECO On pk			**1.621**			
	RECO Off pk			**0.634**			
Annual - all hrs		1.146	0.973	0.975	0.872	0.663	0.654

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

	SC2 Dem Multiplier	SC2 Dem Constant
Summer - all hrs	**0.933**	**(20.975)**
Winter - all hrs	**1.000**	**(20.292)**
Annual - including T&G Obl $	**0.975**	

PLUS:

Gen Cost (per kW of Billed Demand/Month)

	< 5 kW	> 5 kW
summer	$ 1.716	$ 5.933
winter	$ 1.563	$ 5.505

Table #16 **Summary of Total BGS Costs by Season**

		SC1		SC5		SC3		SC2 ND		SC4		SC6		SC2 Dem
Total Costs by Rate - in $1000														
Summer	$	23,348	$	345	$	6	$	481	$	53	$	60	$	8,769
Winter	$	35,889	$	701	$	13	$	1,111	$	156	$	158	$	16,779
Total	$	59,237	$	1,046	$	19	$	1,592	$	209	$	218	$	25,549
% of Annual Total $ by Rate														
Summer		39%		33%		32%		30%		25%		28%		34%
Winter		61%		67%		68%		70%		75%		72%		66%

Total Costs - in $1000		
Summer	$	33,063
Winter	$	54,807
Total	$	87,869

% of Annual Total $		If total $ were split on a per MWh basis (on transmission node MWhs):			Ratio to All-In Cost	
Summer	38%	$	72.09	per MWh @ transmission nodes	Summer	**0.9367**
Winter	62%	$	80.23	per MWh @ transmission nodes	Winter	**1.0425**

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

		SC1		SC5		SC3		SC2 ND		SC4		SC6		SC2 Dem
Total Costs by Rate - in $1000														
Summer	$	18,495	$	290	$	5	$	402	$	53	$	60	$	7,488
Winter	$	29,454	$	595	$	11	$	935	$	156	$	158	$	14,217
Total	$	47,949	$	885	$	16	$	1,337	$	209	$	218	$	21,705
% of Annual Total $ by Rate														
Summer		39%		33%		32%		30%		25%		28%		34%
Winter		61%		67%		68%		70%		75%		72%		66%

Total Costs - in $1000		
Summer	$	26,793
Winter	$	45,526
Total	$	72,319

% of Annual Total $		If total $ were split on a per MWh basis (on transmission node MWhs):			Ratio to All-In Cost	
Summer	37%	$	58.42	per MWh @ transmission nodes	Summer	**0.9062**
Winter	63%	$	66.65	per MWh @ transmission nodes	Winter	**1.0338**

Table #18 **Forward Energy Prices**

	PJM Forward Prices - Energy Only @ bulk system *in $/MWh*			Zone to Western Hub Basis Differential *in $/MWh*		PJM Forward Prices (incl basis differential) *in $/MWh*	
	On-Peak	**Off/On Peak LMP ratio**	**Off-Peak**	**On-Peak**	**Off-Peak**	**On-Peak**	**Off-Peak**
January	47.85	0.75	35.86	99%	96%	47.32	34.45
February	45.55	0.75	34.14	99%	96%	45.04	32.80
March	36.31	0.75	27.21	99%	96%	35.90	26.14
April	31.37	0.75	23.51	99%	96%	31.02	22.58
May	30.92	0.75	23.17	99%	96%	30.57	22.26
June	33.92	0.65	21.97	93%	87%	31.64	19.21
July	39.03	0.65	25.28	93%	87%	36.40	22.10
August	36.24	0.65	23.47	93%	87%	33.80	20.52
September	33.48	0.65	21.68	93%	87%	31.23	18.96
October	32.00	0.75	23.98	99%	96%	31.64	23.04
November	31.75	0.75	23.80	99%	96%	31.40	22.86
December	34.50	0.75	25.86	99%	96%	34.11	24.84

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

	On-Peak	**Off-Peak**
January	72.25	53.75
February	70.25	52.75
March	46.00	35.25
April	30.50	25.00
May	29.50	21.00
June	33.25	21.50
July	43.25	25.50
August	41.25	24.50
September	32.00	21.00
October	30.25	21.75
November	33.50	25.75
December	49.25	35.00

Weighted Average Forward Prices - Energy Only @ bulk system (88.8% PJM - 11.2% NYISO)
in $/MWh

	On-Peak	**Off-Peak**	
January	50.12	36.62	88.8%
February	47.88	35.04	11.2%
March	37.04	27.16	
April	30.96	22.85	
May	30.45	22.12	
June	31.82	19.47	
July	37.17	22.48	
August	34.64	20.97	
September	31.32	19.19	
October	31.48	22.89	
November	31.64	23.19	
December	35.81	25.98	

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

	PJM Base Capacity	RPM Cost*	PJM 88.8%	NYISO 11.2%	Weighted Average
Summer	$169.65	$0.00	$169.65	$339.21	$188.73
Winter	$169.65	$0.00	$169.65	108.64	$162.79

The Incremental RPM Cost is not applicable for tranches from the 2016, 2017, or 2018 BGS-RSCP Auctions.

Table #20 **Ancillary Services**

PJM Ancillary Services	NYISO Ancillary Services	Renewable Power Cost	PJM 88.8%	NYISO 11.2%	Weighted Average
$2.00	$1.54	$6.96	$8.96	$8.50	$8.90

Assumptions:

Gen Cost =	$188.73	per MW-day in summer
	$162.79	per MW-day in winter
Trans cost =	$ 44,799	per MW-yr
Analysis time period =	4	summer months
	8	winter months
Ancillary Services =	$ 8.90	/MWh
Energy Costs =	Based on Jun 2018 to May 2019 Forwards @ PJM West as of December 01, 2017	
	Based on Jul 2017 to Jun 2018 Forwards @ NYISO Zone G and Lower Hudson Valley (LHV) as of June 13, 2017	
Usage patterns =	Forecasted 2017 energy use by class, PJM on/off % from 2016 class load profiles,	
	RECO billing on/off % from 6/16 to 5/17 actual data	
Obligations =	Class totals for 2017	
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 >>		2016 Auction 36 Month	2017 Auction 36 Month	2018 Auction 36 Month	Total	Notes:
1	Tranches		1	2	1	4	From then-current auction
2(a)	Winning Bid Price (¢/kWh)*		8.502	8.050	8.050		(Note: 2018 Auction Price Shown for Illustrative Purpose Only)
2(b)	Incremental RPM Cost - in (¢/kWh)		0	0	0		The Incremental RPM Cost is not applicable for tranches from the 2016, 2017, or 2018 BGS
2(c)	Winning Bid Price (¢/kWh)*		8.502	8.050	8.050		Winning Bids
3	Transmission (¢/kWh)		1.250	1.250	1.250		Average transmission cost included in bid
4	BGS (¢/kWh)		7.252	6.800	6.800		=(2c) - (3)
5	Weighted Avg BGS		1.813	3.400	1.700	6.913	= (1) / Total Tranches * (4)
6	Weighted Avg Trans		0.312	0.625	0.312	1.250	= (1) / Total Tranches * (3)
7	Weighted Avg Total Price (¢/kWh)					**8.163**	
	Seasonal Payment Factors						
8		Summer	1.0000	1.0000	1.0000 **		From then-current Bid Factor Spreadsheet
9		Winter	1.0000	1.0000	1.0000 **		From then-current Bid Factor Spreadsheet
	Applicable Customer Usage @ transmission nodes				(Eastern Division)		
10		Summer MWh	407,013				From then-current Bid Factor Spreadsheet
11		Winter MWh	606,242				From then-current Bid Factor Spreadsheet
12			1,013,255				
	Total Cost						
13		Summer	8,651,064	16,382,279	8,191,140	33,224,483	= (1) / Total Tranches * (2c) / 100 * (8) * (10) * 1,000
14		Winter	12,885,664	24,401,222	12,200,611	49,487,497	= (1) / Total Tranches * (2c) / 100* (9) * (11) * 1,000
15		Total	21,536,728	40,783,501	20,391,751	82,711,980	= (13) + (14)
	Average Cost (NJ Statewide Auction)						
16		Summer	8.163 ¢/kWh				= sum(line 13) / (10) / 1000 * 100 rounded to 3 decimal places
17		Winter	8.163 ¢/kWh				= sum(line 14) / (11) / 1000 * 100 rounded to 3 decimal places
18		Total	**8.163** ¢/kWh				= sum(line 15) / (12) / 1000 * 100 rounded to 3 decimal places

Average Cost (Including RECO RFP)

Line #		BGS Auction	RECO RFP	Total	Notes
19	Tranches	4	0.507	4.507	Includes RECO RFP equivalent tranches
20	Price ¢/kWh	8.163	8.809		BGS Auction from (18) Note 8.809¢ for RFP is illustrative (excludes transmission).
21	Transmission	1.250	0.000		
22	BGS	6.913	8.809		= (20) - (21)
23	Weighted Avg BGS	6.136	0.991	7.127	= (19) / Total Tranches * (22)
24	Weighted Avg Trans	1.109	0.000	1.109	= (19) / Total Tranches * (21)
25	**Weighted Avg Total Price**			$\boxed{\mathbf{8.236}}$	= (23) + (24)

* 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

		SC1	SC5	SC3	SC2 ND	SC4	SC6
Summer - all hrs		**1.028**	**0.935**		**0.850**	**0.599**	**0.599**
	RECO On pk			**1.639**			
	RECO Off pk			**0.515**			
	Constant Blk 1	**$ (14.04)**	**$ (6.53)**				
	Constant Blk 2	**$ 10.21**	**$ 10.50**				
Winter - all hrs		**1.235**	**0.992**		**0.882**	**0.688**	**0.678**
	RECO On pk			**1.621**			
	RECO Off pk			**0.634**			
Annual - all hrs		1.146	0.973	0.975	0.872	0.663	0.654

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

	SC2 Dem Multiplier	SC2 Dem Constant
Summer - all hrs	**0.933**	**(20.975)**
Winter - all hrs	**1.000**	**(20.292)**
Annual - including T&G Obl $	**0.975**	

PLUS:

Gen Cost (per kW of Billed Demand/Month)

	0	< 5 kW	> 5 kW
summer	$ -	$ 1.716	$ 5.933
winter	$ -	$ 1.563	$ 5.505

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

All-In Average costs @ Trans node =	$	82.36	/MWh*
Less Transmission	$	(11.09)	/MWh**
BGS Cost	$	71.27	/MWh

* Price from Table A (which does not include transmission for the Central/Western Division).
** RECO average transmission rate of 12.50 minus Central/West transmission contribution to weighted average rate 0.507/4.507 *$12.50 per MWh). $1.41

Retail BGS Rates (excl SUT) (¢/kWh)

	SC1	SC5	SC3	SC2 ND	SC4	SC6	SC2 Dem
Summer							
All kWh (¢/kWh)	7.327	6.664		6.058	4.269	4.269	4.552
Peak kWh (¢/kWh)			11.682				
Off-Peak kWh (¢/kWh)			3.671				
Block1	5.923	6.011					
Block2	8.348	7.714					
Demand Charge ($/kW) 1st 5kW							1.716
Demand Charge ($/kW)> 5 kW							5.933
Winter							
All kWh (¢/kWh)	8.802	7.070		6.286	4.904	4.832	5.098
Peak kWh (¢/kWh)			11.554				
Off-Peak kWh (¢/kWh)			4.519				
Demand Charge ($/kW) 1st 5kW							1.563
Demand Charge ($/kW) > 5 kW							5.505

Table D **Calculation of Rate Adjustment Factors**

	SC1	SC5	SC3	SC2 ND	SC4	SC6	SC2 Dem
Total BGS Revenue (Excl SUT) - in $1000							
Summer	$ 20,447	$ 320	$ 6	$ 445	$ 59	$ 66	$ 8,823
Winter	$ 32,564	$ 657	$ 12	$ 1,033	$ 172	$ 175	$ 16,599
Total	$ 53,011	$ 977	$ 18	$ 1,478	$ 231	$ 241	$ 25,422

Total	
Summer	$ 30,166
Winter	$ 51,212
Total	$ 81,378

Total Supplier Payments - in $1000

Eastern Division	Total	Transmission	Net BGS
Summer	$ 33,224	$ 4,600	$ 28,624
Winter	$ 49,487	$ 9,201	$ 40,286
Total	$ 82,712	$ 13,801	$ 68,911

Central/Western Division	Total	Transmission	Net BGS
Summer	$ 4,588	$ -	$ 4,588
Winter	$ 6,769	$ -	$ 6,769
Total	$ 11,357	$ -	$ 11,357

Total RECO FP	Total	Transmission	Net BGS
Summer	$ 37,812	$ 4,600	$ 33,212
Winter	$ 56,256	$ 9,201	$ 47,055
Total	$ 94,069	$ 13,801	$ 80,268

Differences	BGS Revenue	BGS Costs	Difference	Rate Adjustment Factors
Summer	$ 30,166	$ 33,212	$ 3,046	**1.10099**
Winter	$ 51,212	$ 47,055	$ (4,157)	**0.91884**
Total	$ 81,378	$ 80,268	$ (1,110)	

Table E **Final Retail BGS Rates (¢/kWh)**

Rates Excluding SUT:

	SC1	SC5	SC3	SC2 ND	SC4	SC6	SC2 Dem
Summer							
All kWh (¢/kWh)	8.067	7.337		6.670	4.700	4.700	5.012
Peak kWh (¢/kWh)			12.862				
Off-Peak kWh (¢/kWh)			4.042				
Block1	6.521	6.618					
Block2	9.191	8.493					
Demand Charge ($/kW) 1st 5kW							1.889
Demand Charge ($/kW) > 5 kW							6.532
Winter							
All kWh (¢/kWh)	8.088	6.496		5.776	4.506	4.440	4.684
Peak kWh (¢/kWh)			10.616				
Off-Peak kWh (¢/kWh)			4.152				
Demand Charge ($/kW) 1st 5kW							1.436
Demand Charge ($/kW) > 5 kW							5.058

Rates Including SUT: SUT @ 6.625%

	SC1	SC5	SC3	SC2 ND	SC4	SC6	SC2 Dem
Summer							
All kWh (¢/kWh)				7.112	5.011	5.011	5.344
Peak kWh (¢/kWh)			13.714				
Off-Peak kWh (¢/kWh)			4.310				
Block1	6.953	7.056					
Block2	9.800	9.056					
Demand Charge ($/kW) 1st 5kW							2.0100
Demand Charge ($/kW)> 5 kW							6.9600
Winter							
All kWh (¢/kWh)	8.624	6.926		6.159	4.805	4.734	4.994
Peak kWh (¢/kWh)			11.319				
Off-Peak kWh (¢/kWh)			4.427				
Demand Charge ($/kW) 1st 5kW							1.5300
Demand Charge ($/kW) > 5 kW							5.3900

Table F **Spreadsheet Error Checking**

Total BGS Revenue (Excl SUT) - in $1000

	SC1	SC5	SC3	SC2 ND	SC4	SC6	SC2 Dem
Summer	$ 22,512	$ 353	$ 6	$ 490	$ 65	$ 73	$ 9,714
Winter	$ 29,922	$ 604	$ 11	$ 949	$ 158	$ 160	$ 15,251
Total	$ 52,434	$ 957	$ 17	$ 1,439	$ 223	$ 233	$ 24,965

Total	
Summer	$ 33,213
Winter	$ 47,055
Total	$ 80,268

Supplier Payments - in $1000

Eastern Division

	Total	Transmission	Net BGS
Summer	$ 33,224	$ 4,600	$ 28,624
Winter	$ 49,487	$ 9,201	$ 40,286
Total	$ 82,712	$ 13,801	$ 68,911

Central/Western Division

	Total	Transmission	Net BGS
Summer	$ 4,588	$ -	$ 4,588
Winter	$ 6,769	$ -	$ 6,769
Total	$ 11,357	$ -	$ 11,357

Total RECO FP

	Total	Transmission	Net BGS
Summer	$ 37,812	$ 4,600	$ 33,212
Winter	$ 56,256	$ 9,201	$ 47,055
Total	$ 94,069	$ 13,801	$ 80,268

Differences

	BGS Revenue	BGS Costs	Difference
Summer	$ 33,213	$ 33,212	$ (1)
Winter	$ 47,055	$ 47,055	$ 0
Total	$ 80,268	$ 80,268	$ (0)