STATE OF NEW JERSEY
BOARD OF PUBLIC UTILITIES

IN THE MATTER OF THE PROVISION OF BASIC GENERATION SERVICE FOR THE PERIOD BEGINNING JUNE 1, 2014	Docket No. ER13050378

ROCKLAND ELECTRIC COMPANY

PROPOSAL FOR BASIC GENERATION SERVICE REQUIREMENTS TO BE PROCURED EFFECTIVE JUNE 1, 2014

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 May 29, 2013 in Docket ER13050378, 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, 2013 on the procurement of basic generation service ("BGS") for the period beginning June 1, 2014. 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, 2014, filed by New Jersey's four EDCs on July 1, 2013 ("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's committed supply consists of RECO's share (which amounts to less than 1 MW) as a member of the Orange and Rockland System[1], of one NUG contract. RECO would net its share of the output from this NUG project, allocated to RECO pursuant to the terms of the

[1] The Orange and Rockland System is comprised of RECO, Orange and Rockland Utilities, Inc. ("Orange and Rockland"), and Pike County Light & Power Company.

FERC-approved Power Supply Agreement between RECO and Orange and Rockland, from the BGS Load of RECO's Central and Western Divisions.

None of RECO's Committed Supply will qualify as a Class I or Class II renewable resource that could be used to meet the New Jersey Renewable Portfolio Standards' requirements. Accordingly, RECO ***will not*** provide any renewable attributes, required to meet the Board's Renewable Portfolio Standards, to BGS Suppliers.

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.[2] RECO continues to comply with this directive and will include these customers as one tranche (at 65.5 MW of BGS-CIEP eligible load per tranche) in the BGS-CIEP Auction.

As to the BGS-FP Auction, RECO currently has two 36-month tranches that terminate on May 31, 2014, one 36-month tranche that terminates on May 31, 2015, and one 36-month tranche that terminates on May 31, 2016. Accordingly, since the load requirements of RECO's Eastern Division are comprised of a total of four tranches, in the BGS-FP Auction for the period commencing June 1, 2014, RECO will include two 36-month tranches (for the period June 1, 2014 through May 31, 2017).

[2] 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.

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, 2014; 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 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-FP 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

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

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 tranches successfully in the 2013 BGS Auction, RECO proposes to employ the following procedures:

- RECO will not submit any day-ahead energy bids, rather the BGS-CIEP load will be filled from the PJM real time market.
- RECO will prepare a BGS-CIEP load backcast for the previous day and submit this backcast to PJM.
- RECO will purchase capacity credits from eRPM in PJM or from bilateral purchases on a monthly and daily basis.
- RECO will purchase ancillary services on a daily basis from the real time PJM market.
- RECO will set its CIEP Standby Fee at the level determined by the Board.
- RECO will fulfill any Class I, Class II, and Solar requirements, for its unsubscribed BGS tranches, by securing the needed PJM Generation Attributes Tracking ("GATS") system generated renewable energy certificates ("RECs") through any available PJM market, or bilaterally. In the event RECs are not available on the market, RECO will make the necessary Alternative Compliance Payments.

[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.

- 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, 2014

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-FP tranches, RECO only will seek replacement supply until May 31, 2015. 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, 2015.

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-FP 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-FP and BGS-CIEP reconciliation charges from a monthly to a quarterly mechanism. RECO will track and defer separately for the BGS-FP 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-FP 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-FP and BGS-CIEP Reconciliation Charges, applicable to all BGS-FP 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-FP 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-FP and BGS-CIEP Reconciliation Charges will be subject to deferred accounting with interest and will be determined individually as set forth below:

The BGS-FP 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-FP 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-FP 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 the 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-FP and BGS-CIEP Auctions are included in Attachment A. In addition, the Company is including draft tariff leaves to add the CIEP Standby Fee to Service Classification No. 2. Although the tariff leaves outlining the terms of BGS-CIEP service state that the CIEP Standby Fee is applicable to BGS-CIEP customers, adding this to the list of Rates-Monthly in Service Classification No. 2 will conform the language in Service Classification No.2 to that of Service Classification No. 7.   Final tariff leaves including the actual BGS rates and tariff provisions to become effective on June 1, 2014 will be filed with the Board upon its issuance of an appropriate Board order approving the BGS Auction Process.

G. RECO RFP

RECO must purchase the physical electric supply needed to meet its full service obligations for its non-PJM areas (i.e., RECO'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, RECO intends to make such purchases from markets administered by the NYISO.

In December 2012, in order to hedge the electric supply for the non-PJM areas, RECO issued an RFP for four separate financial swaps pertaining to RECO's energy and capacity requirements for its Central and Western Divisions.   However, the auction for these swap arrangements failed to attract the necessary number of bidders to have a competitive solicitation. As a result, by Secretary's Letter dated December 19, 2013, in BPU Docket No. ER12060485, the Board directed RECO to amend its BGS Company Specific Addendum to remedy the failure of its energy and capacity auctions.

On January 4, 2013, RECO filed a proposal to conduct an auction where it would solicit competitive bids from qualified bidders for "fixed for floating" financially settled NYMEX futures transactions with respect to (i) an energy tranche ("Energy Transaction"), and (ii) an Unforced Capacity ("UCAP") tranche ("UCAP Transaction"). On March 20, 2013 in BPU Docket No. ER12060485, the Board issued an Order ("March 20, 2013 Order") approving the RECO proposal but modified the proposal to require that bids remain open until accepted by the Board. RECO conducted its auction on April 26, 2013, and on April 30, 2013 the Board issued an Order approving the auction results.

For the 2014-2015 BGS year, RECO proposes to conduct an auction similar to the auction conducted in April 2013 for its energy tranche.[5] However, because of recent developments in the NYISO capacity market, RECO will not be able to conduct such an auction for its capacity requirement. Specifically, on April 30, 2013, in FERC Docket Number ER13-1380, the NYISO filed a proposal at the Federal Energy Regulatory Commission ("FERC") to create a new capacity market zone ("NCZ") in the Lower Hudson Valley region consisting of NYISO Load Zones G, H, I, and J. This new capacity market zone would include RECO's Central and Western Divisions. There currently is no NYMEX product for this new capacity zone, and no NYMEX product is expected for this zone in time for the RECO auction. Therefore, for

[5] As it has for previous RFPs, RECO would purchase ancillary services through the NYISO.

Energy Year 2015, RECO proposes to purchase the capacity needs of BGS customers located in its Central and Western Divisions in the NYISO monthly capacity market and blend its forecast of those prices into the BGS-FP price. Because RECO's Central and Western Divisions constitute less than ten percent of RECO's BGS load, and because the impact of the forecasted prices would be further diluted by the three-year nature of the BGS product, RECO anticipates that the impact of these capacity purchases on total BGS prices should be minimal. RECO will make a monthly compliance filing with the Board reporting the actual prices paid from the NYISO market.

For its energy tranche, RECO proposes to conduct an auction similar to the auction approved by the Board in its March 20, 2013 Order. As it did for the April 26, 2013 auction, RECO will solicit competitive bids from qualified bidders for "fixed for floating" financially settled NYMEX futures transactions with respect to an energy tranche ("Energy Transaction"). The Energy Transaction is a NYMEX NYISO Zone G Day-Ahead (Peak and Off-Peak) product.[6]

The term of the Energy Transaction will be June 1, 2014 to May 31, 2015, which would correspond with Energy Year 2015. Bidders must bid a fixed price for the entire 12-month term of the auction period. The Floating Price for both peak and off-peak hours will be equal to the arithmetic hourly average of the NYISO Zone G Day-Ahead Locational Based Marginal Prices for such hours provided by the NYISO for the contract month. The Fixed Price for the term of the auction period will be the winning bid price. The winning bidder of the Energy Transaction will be the Futures Seller. RECO will be the Futures Buyer. The Energy Transaction will be for a fixed quantity

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[6] The NYMEX product codes used in the April 26, 2013 auction were T3 (NYISO Zone G Day-Ahead Peak Calendar – Month 5 MW Futures) and KH (NYISO Zone G Off-Peak LBMP Futures). RECO will use either these or similar product codes for the energy tranche.

(e.g., 40 MW) and presented in contract sizes consistent with the above product and pre-determined by RECO. As was the April, 2013 auction, the auction will be administered by an independent third-party (i.e., World Energy Services). The fees for conducting the auction will be paid for by the winning bidder(s).

The T3 (on-peak) product monthly contract amount is calculated as follows: the number of on-peak days in the month multiplied by the number of contracts needed per peak day (assuming one contract is equal to 80 MWh, or 5 MW times 16 peak hours in a day). The KH (off-peak) product monthly contract amount is calculated as follows: divide the number of off-peak MWh in a month by 2.5 (MW) times the number of off-peak hours in a month. The winning bidder will not be bearing any volumetric or credit risk.

At the end of the auction RECO will evaluate the proposals submitted by bidders to determine which proposals are in the best economic interests of its BGS customers, and recommend those bids to the NJBPU for approval, as it did for the April 26, 2013 auction. RECO reserves the right to reject any and all winning bids. RECO expects to circulate this information to potential bidders at least one month before the auction.

RECO proposes that the energy tranche auction occur in January 2014 immediately preceding a Board agenda meeting, as was done for the April 26, 2013 auction, to limit the amount of time between the NYMEX auction and acceptance of the bids by the Board. RECO requests that the result of the energy tranche auction be kept confidential until the BGS auction results are announced.

RECO will continue to average the winning auction price with the RECO BGS-FP price to determine the rates for those customers in RECO's service territory taking BGS-FP service.

In the event that the energy tranche auction fails to attract the necessary number of bidders to have a competitive solicitation, after notice to the Board, RECO will purchase the energy need of its BGS customers in the Central and Western Divisions in the NYISO Day-Ahead and Real Time Markets, and blend its forecast of those prices into the BGS-FP price. In the event RECO makes these purchases from the NYISO market, RECO will make a monthly compliance filing with the Board indicating the actual prices paid.

H. BGS Rate Design Methodology

RECO BGS Pricing Spreadsheet

As described in the EDC Compliance Filing, the resulting charge for each BGS rate element (e.g., 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-FP 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 2012 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-FP 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 2013.

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 2014 to May 2015, 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 2010 to December 2012, which equals 0.3822%. Marginal losses are excluded from the loss factors based on historic de-rating factors for the period May 2010 to April 2013.

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, 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, by service classification, that are currently being utilized in the year 2013. The values in the top portion of Table #9 will be updated in January 2014 to reflect the aggregate amount by rate schedule that will be in effect on June 1, 2014. 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 price for transmission service and seasonally differentiated costs of generation capacity. The cost of transmission service is equal to the current rate for RECO's network transmission service in the PJM Open Access Transmission Tariff. 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 2014 to 2017 for RECO) and NYISO zones as calculated in Table #19. Also shown is the level of blocking in current BGS charges for Service Classification Nos. 1

and 5, 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 is included in Table #10 (Ancillary Services). The Ancillary Services estimate is a weighted average of estimated Ancillary Services costs in RECO's PJM zone (i.e., $3 per MWH) and RECO's estimate of Ancillary Services costs in RECO's NYISO zone as calculated in Table #20.

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) 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-FP 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-FP 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 adjusted to include the impacts of RECO's RFP for the Central and Western Divisions.[7] 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."

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-FP 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-FP 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-FP energy related charges.

[7] The price shown for the tranches to be secured in the 2014 auction and RFP are for illustrative purposes only, and will be replaced with actual data in determining RECO's final June 2014 BGS-FP rates.

Table E (Final Retail BGS Rates) contains the final adjusted BGS-FP rates, which are equal to the preliminary BGS –FP 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.

Table F (Spreadsheet Error Checking) contains a comparison of the total anticipated rate revenue billed to customers based on the final BGS-FP 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-FP 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-FP and BGS-CIEP customers. RECO will review and verify the basis for any transmission cost adjustment, 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 to utilize an auction format only for the financial swaps for the forecasted energy requirements for these BGS-FP customers and the default proposal if this auction is approved by the Board; and

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

Development of BGS Cost and Bid Factors for Rates Effective June 1, 2014

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

Based on 2012 Load Profile Information
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	51.68%	48.58%	47.61%	49.21%	30.41%	30.41%	54.08%
February	50.45%	47.49%	46.17%	47.93%	30.61%	30.61%	54.58%
March	48.11%	44.87%	45.26%	49.70%	27.94%	27.94%	53.26%
April	52.60%	49.94%	50.71%	54.93%	29.48%	29.48%	56.82%
May	51.20%	49.48%	52.10%	57.05%	23.12%	23.12%	55.94%
June	50.61%	49.02%	50.06%	56.97%	19.64%	19.64%	53.83%
July	57.79%	56.04%	56.48%	61.25%	21.57%	21.57%	58.36%
August	53.59%	57.23%	53.30%	59.84%	21.37%	21.37%	55.42%
September	48.65%	50.29%	48.45%	59.34%	26.82%	26.82%	52.91%
October	55.66%	52.07%	52.16%	58.41%	30.52%	30.52%	57.27%
November	48.23%	44.61%	43.72%	48.68%	28.40%	28.40%	51.16%
December	48.69%	45.69%	43.34%	46.83%	29.03%	29.03%	51.80%

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	----	----	33.9%	----	----	----	----
February	----	----	34.2%	----	----	----	----
March	----	----	35.0%	----	----	----	----
April	----	----	34.0%	----	----	----	----
May	----	----	35.0%	----	----	----	----
June	----	----	34.1%	----	----	----	----
July	----	----	38.0%	----	----	----	----
August	----	----	40.8%	----	----	----	----
September	----	----	35.7%	----	----	----	----
October	----	----	36.6%	----	----	----	----
November	----	----	33.9%	----	----	----	----
December	----	----	34.0%	----	----	----	----

Table #3 **Class Usage @ customer**

Calendar month billed sales forecasted for 2013

in MWh	SC1	SC5	SC3	SC2 ND	SC4	SC6	SC2 Dem	Total
January	64,142	1,863	32	4,762	661	523	40,200	112,183
February	56,834	1,676	27	5,182	562	467	42,700	107,448
March	49,266	1,334	22	4,217	569	442	37,501	93,351
April	46,181	1,089	19	3,631	459	471	37,327	89,177
May	46,903	961	18	2,729	430	439	38,239	89,719
June	63,601	1,121	21	2,521	387	405	41,349	109,405
July	79,862	1,349	24	3,076	422	393	46,134	131,260
August	86,040	1,536	25	3,110	466	385	46,978	138,540
September	74,468	1,390	21	2,958	504	448	46,872	126,661
October	54,860	1,025	16	2,510	576	512	37,809	97,308
November	46,429	1,197	20	2,325	613	550	36,518	87,652
December	56,843	1,361	25	3,006	677	522	40,281	102,715
Total	725,429	15,902	270	40,027	6,326	5,557	491,908	1,285,419

Table #4 **Forwards Prices - Energy Only @ bulk system**

in $/MWh (See Table 18)

	On-Peak	Off-Peak
January	53.73	41.07
February	53.73	41.07
March	47.79	36.92
April	47.88	36.99
May	49.59	37.76
June	54.19	33.12
July	65.67	39.96
August	62.43	37.98
September	49.48	30.63
October	46.55	35.70
November	46.55	35.70
December	48.59	37.25

Table #5 **Losses**

	SC1	SC5	SC3	SC2 ND	SC4	SC6	SC2 Dem
Expansion Factor =	1.08401	1.08401	1.08401	1.08401	1.08024	1.08024	1.08401
Expansion Factor (net Marginal Losses)	1.07132	1.07132	1.07132	1.07132	1.06759	1.06759	1.07132

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		$ 51.79	$ 51.76	$ 51.64	$ 53.19	$ 43.56	$ 43.44	$ 52.00
	PJM on pk	$ 63.73	$ 63.49	$ 63.70	$ 63.23	$ 61.84	$ 61.73	$ 63.15
	PJM off pk	$ 38.39	$ 38.29	$ 38.43	$ 38.48	$ 38.23	$ 38.14	$ 38.28
Winter - all hrs		$ 47.52	$ 47.40	$ 47.34	$ 47.94	$ 44.48	$ 44.39	$ 47.86
	PJM on pk	$ 53.67	$ 54.01	$ 53.98	$ 54.02	$ 53.38	$ 53.27	$ 53.57
	PJM off pk	$ 41.16	$ 41.38	$ 41.39	$ 41.59	$ 40.87	$ 40.80	$ 41.07
Annual		$ 49.31	$ 48.88	$ 48.79	$ 49.47	$ 44.22	$ 44.11	$ 49.39
System Total		$ 49.29						

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		$ 15,741	$ 279	$ 5	$ 621	$ 77	$ 71	$ 9,429
	PJM on pk	$ 10,240	$ 183	$ 3	$ 439	$ 25	$ 23	$ 6,316
	PJM off pk	$ 5,502	$ 96	$ 2	$ 182	$ 53	$ 48	$ 3,113
Winter - all hrs		$ 20,029	$ 498	$ 8	$ 1,360	$ 202	$ 174	$ 14,866
	PJM on pk	$ 11,509	$ 271	$ 5	$ 782	$ 70	$ 60	$ 9,043
	PJM off pk	$ 8,521	$ 228	$ 4	$ 577	$ 132	$ 114	$ 5,822
Annual		$ 35,771	$ 777	$ 13	$ 1,980	$ 280	$ 245	$ 24,295
System Total		$ 63,361						

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		$ 51.79	$ 51.76	$ 51.64	$ 53.19	$ 43.56	$ 43.44	$ 52.00
	RECO On pk			$ 67.47				
	RECO Off pk			$ 42.20				
Winter - all hrs		$ 47.52	$ 47.40	$ 47.34	$ 47.94	$ 44.48	$ 44.39	$ 47.86
	RECO On pk			$ 55.59				
	RECO Off pk			$ 43.00				
Annual Average		$ 49.31	$ 48.88	$ 48.79	$ 49.47	$ 44.22	$ 44.11	$ 49.39
System Average		$ 49.29						

Table #9 **Generation & Transmission Obligations and Costs and Other Adjustments**
Obligations - annual average forecasted for 2013; costs are market estimates

in MW	SC1	SC5	SC3	SC2 ND	SC4	SC6	SC2 Dem	Total FP
Gen Obl - MW	298.982	4.534	0.077	12.088	0.0	0.0	155.865	471.546
Trans Obl - MW	261.951	4.029	0.069	10.293	0.0	0.0	133.238	409.580

# 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 $ 32,114 per MW-yr 87.98

Generation Capacity cost	summer	$141.58	$/MW/day	Resulting avg gen cap cost =	summer >> $	51.68 per kW/yr
(see Table 19)	winter	$136.15	$/MW/day		winter >> $	49.69 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 (0-250 kWh/month)	9.256	¢/kWh	20.26%	Block 1 (0-250 kWh/month)	8.501		31.04%
Block 2 (>250 kWh/m)	10.638	¢/kWh	79.74%	Block 2 (251-700 kWh/month)	9.895	1.394	35.62%
Calculated inversion =	1.382	¢/kWh		Block 3 (>700 kWh/month)	10.834	2.333	33.35%

Table #10 **Ancillary Services**
forecasted overall annual average $2.86 /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	$ 11.60	$ 8.14	$ 8.21	$ 8.26	$ -	$ -
Generation Obl -						
per annual MWh	$ 20.75	$ 14.36	$ 14.36	$ 15.21	$ -	$ -
per summer MWh	$ 16.99	$ 14.51	$ 14.62	$ 17.90	$ -	$ -
per winter MWh	$ 23.47	$ 14.28	$ 14.23	$ 14.10	$ -	$ -

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		$ 83.23	$ 77.27	$ 77.32	$ 82.21	$ 46.42	$ 46.30
	RECO On pk			$ 117.67			
	RECO Off pk			$ 53.27			
	Block 1	$ 72.21	$ 64.52				
	Block 2	$ 86.03	$ 78.46				
	Block 3		$ 87.85				
Winter - all hrs		$ 85.45	$ 72.68	$ 72.64	$ 73.16	$ 47.34	$ 47.25
	RECO On pk			$ 107.95			
	RECO Off pk			$ 54.07			
Annual -all hrs		$ 84.52	$ 74.23	$ 74.22	$ 75.80	$ 47.08	$ 46.97

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

	SC2 Dem
Summer - all hrs	$ 54.86
Winter - all hrs	$ 50.72
Annual - all hrs per MWh only	$ 52.25

PLUS:

Gen Cost (per kW of Billed Demand/Month)

	SC2 Dem
summer	$ 5.521
winter	$ 5.815

Trans cost

all months $ 2.68 per kW of T obl /month

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

Including T&G Obligation $		
Summer - all hrs	$	77.57
Winter - all hrs	$	76.51
Annual - including T&G Obl $	$	76.90

ALL RATES

Grand Total Cost in $1000 =	$	103,936	
All-In Average cost @ customer =	$	80.86	per MWh at customer (per customer metered MWh)
All-In Average costs @ transmission nodes =	$	75.48	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			**1.103**		**1.024**		**1.089**	**0.615**	**0.613**
	RECO On pk					**1.559**			
	RECO Off pk					**0.706**			
	Constant Blk 1	**$**	**(11.02)**	**$**	**(12.75)**				
	Constant Blk 2	**$**	**2.80**	**$**	**1.19**				
	Constant Blk 3		NA	**$**	**10.58**				
Winter - all hrs			**1.132**		**0.963**		**0.969**	**0.627**	**0.626**
	RECO On pk					**1.430**			
	RECO Off pk					**0.716**			
Annual - all hrs			1.120		0.984	0.983	1.004	0.624	0.622

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	**1.028**	**$**	**(22.711)**
Winter - all hrs	**1.014**	**$**	**(25.788)**
Annual - including T&G Obl $	1.019		

PLUS:

Gen Cost (per kW of Billed Demand/Month)

		SC2 Dem
summer	$	5.521
winter	$	5.815

Trans cost

all months	$	2.676	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		$	71.64	$	69.13	$	69.11	$	73.95	$	46.42	$	46.30
	RECO On pk					$	109.47						
	RECO Off pk					$	45.06						
	Block 1	$	60.62	$	56.38								
	Block 2	$	74.44	$	70.32								
	Block 3			$	79.71								
Winter - all hrs		$	73.85	$	64.54	$	64.43	$	64.90	$	47.34	$	47.25
	RECO On pk					$	99.74						
	RECO Off pk					$	45.86						
Annual -all hrs		$	72.92	$	66.10	$	66.01	$	67.54	$	47.08	$	46.97

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	$	54.86
Winter - all hrs	$	50.72
Annual - all hrs per MWh only	$	52.25
Including Generation Obligation $		
Summer - all hrs	$	69.70
Winter - all hrs	$	67.33
Annual - including T&G Obl $	$	68.20

PLUS:

Gen Cost (per kW of Billed Demand/Month)

		SC2 Dem
summer	$	5.521
winter	$	5.815

ALL RATES

Grand Total Cost in $1000 =	$	90,783	
All-In Average cost @ customer =	$	70.62	per MWh at customer (per customer metered MWh)
All-In Average costs @ tansmission nodes =	$	65.93	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			**1.087**		**1.049**		**1.122**	**0.704**	**0.702**
	RECO On pk					**1.660**			
	RECO Off pk					**0.683**			
	Constant Blk 1	**$**	**(11.02)**	**$**	**(12.75)**				
	Constant Blk 2	**$**	**2.80**	**$**	**1.19**				
	Constant Blk 3		NA	**$**	**10.58**				
Winter - all hrs			**1.120**		**0.979**		**0.984**	**0.718**	**0.717**
	RECO On pk					**1.513**			
	RECO Off pk					**0.696**			
Annual - all hrs			1.106		1.003	1.001	1.024	0.714	0.712

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	**1.057**	**(14.846)**
Winter - all hrs	**1.021**	**(16.603)**
Annual - including T&G Obl $	**1.035**	

PLUS:

Gen Cost (per kW of Billed Demand/Month)

		SC2 Dem
summer	$	5.521
winter	$	5.815

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	$ 25,300	$ 417	$ 7	$ 959	$ 83	$ 76	$ 14,066
Winter	$ 36,014	$ 764	$ 13	$ 2,075	$ 215	$ 185	$ 23,763
Total	$ 61,314	$ 1,181	$ 20	$ 3,034	$ 298	$ 261	$ 37,829
% of Annual Total $ by Rate							
Summer	41%	35%	35%	32%	28%	29%	37%
Winter	59%	65%	65%	68%	72%	71%	63%

Total Costs - in $1000	
Summer	$ 40,907
Winter	$ 63,029
Total	$ 103,936

% of Annual Total $		If total $ were split on a per MWh basis (on transmission node MWhs):	Ratio to All-In Cost	
Summer	39%	$ 75.48 per MWh @ transmission nodes	Summer	**1.0001**
Winter	61%	$ 75.47 per MWh @ transmission nodes	Winter	**0.9999**

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	$ 21,775	$ 373	$ 6	$ 863	$ 83	$ 76	$ 12,640
Winter	$ 31,126	$ 678	$ 12	$ 1,841	$ 215	$ 185	$ 20,910
Total	$ 52,902	$ 1,051	$ 18	$ 2,703	$ 298	$ 261	$ 33,550
% of Annual Total $ by Rate							
Summer	41%	35%	35%	32%	28%	29%	38%
Winter	59%	65%	65%	68%	72%	71%	62%

Total Costs - in $1000	
Summer	$ 35,815
Winter	$ 54,968
Total	$ 90,783

% of Annual Total $		If total $ were split on a per MWh basis (on transmission node MWhs):	Ratio to All-In Cost	
Summer	39%	$ 66.09 per MWh @ transmission nodes	Summer	**1.0025**
Winter	61%	$ 65.82 per MWh @ transmission nodes	Winter	**0.9984**

Table #18 **Forward Energy Prices**

PJM Forward Prices - Energy Only @ bulk system *in $/MWh*	**On-Peak**	**Off/On Peak LMP ratio**	**Off-Peak**	**Zone to Western Hub Basis Differential** *in $/MWh* **On-Peak**	**Off-Peak**	**PJM Forward Prices (incl basis differential)** *in $/MWh* **On-Peak**	**Off-Peak**
January	48.60	0.78	38.11	107%	105%	52.19	40.03
February	48.60	0.78	38.11	107%	105%	52.19	40.03
March	44.70	0.78	35.05	107%	105%	48.01	36.82
April	44.80	0.78	35.13	107%	105%	48.11	36.90
May	46.35	0.78	36.35	107%	105%	49.78	38.18
June	50.21	0.61	30.79	107%	106%	53.97	32.77
July	61.31	0.61	37.59	107%	106%	65.90	40.01
August	57.93	0.61	35.52	107%	106%	62.27	37.80
September	46.31	0.61	28.40	107%	106%	49.78	30.22
October	42.88	0.78	33.63	107%	105%	46.05	35.33
November	42.88	0.78	33.63	107%	105%	46.05	35.33
December	45.00	0.78	35.29	107%	105%	48.33	37.07

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

	On-Peak	**Off-Peak**
January	66.50	49.75
February	66.50	49.75
March	46.00	37.75
April	46.00	37.75
May	48.00	34.25
June	56.00	36.00
July	63.75	39.50
August	63.75	39.50
September	47.00	34.00
October	50.75	38.75
November	50.75	38.75
December	50.75	38.75

Weighted Average Forward Prices - Energy Only @ bulk system (89.3% PJM - 10.7% NYISO)
in $/MWh

	On-Peak	**Off-Peak**	
January	53.73	41.07	89.3%
February	53.73	41.07	10.7%
March	47.79	36.92	
April	47.88	36.99	
May	49.59	37.76	
June	54.19	33.12	
July	65.67	39.96	
August	62.43	37.98	
September	49.48	30.63	
October	46.55	35.70	
November	46.55	35.70	
December	48.59	37.25	

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

	PJM 89.3%	NYISO 10.7%	Weighted Average
Summer	$140.76	$148.37	$141.58
Winter	$140.76	97.79	$136.15

Table #20 **Ancillary Services**

PJM 89.3%	NYISO 10.7%	Weighted Average
$3.00	$1.68	$2.86

Assumptions:

Gen Cost =		$141.58	per MW-day in summer
		$136.15	per MW-day in winter
Trans cost =	$	32,114	per MW-yr
Analysis time period =		4	summer months
		8	winter months
Ancillary Services =	$	2.86	/MWh
Energy Costs =	Based on 6/13 to 5/14 Forwards @ PJM West as of 06/17/13		
	Based on 6/13 to 5/17 Forwards @ NYISO Zone G as of 06/17/13		
Usage patterns =	Forecasted 2013 energy use by class, PJM on/off % from 2012 class load profiles, RECO billing on/off % from 6/12 to 5/13 actual data		
Obligations =	Class totals for 2013		
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 >>	2012 Auction 36 Month	2013 Auction 36 Month	2014 Auction 36 Month	Total	Notes:
1	Tranches	1	1	2	4	From then-current auction
2	Winning Bid Price (¢/kWh)*	9.251	9.258	9.258		Winning Bids (Note: 2014 Auction Price Shown for Illustrative Purposes Only)
3	Transmission (¢/kWh)	0.955	0.955	0.955		Average transmission cost included in bid
4	BGS (¢/kWh)	8.296	8.303	8.303		=(2) - (3)
5	Weighted Avg BGS	2.074	2.076	4.151	8.301	= (1) / Total Tranches * (4)
6	Weighted Avg Trans	0.239	0.239	0.478	0.955	= (1) / Total Tranches * (3)
7	Weighted Avg Total Price (¢/kWh)				**9.256**	
	Seasonal Payment Factors					
8	Summer	1.0000	1.0000	1.0001 **		From then-current Bid Factor Spreadsheet
9	Winter	1.0000	1.0000	0.9999 **		From then-current Bid Factor Spreadsheet
	Applicable Customer Usage @ tansmission nodes			(Eastern Division)		
10	Summer MWh	483,761				From then-current Bid Factor Spreadsheet
11	Winter MWh	745,479				From then-current Bid Factor Spreadsheet
12		1,229,239				
	Total Cost					
13	Summer	11,188,173	11,196,639	22,395,518	44,780,330	= (1) / Total Tranches * (2) / 100 * (8) * (10) * 1,000
14	Winter	17,241,058	17,254,104	34,504,756	68,999,918	= (1) / Total Tranches * (2) / 100* (9) * (11) * 1,000
15	Total	28,429,231	28,450,743	56,900,274	113,780,248	= (13) + (14)
	Average Cost (NJ Statewide Auction)					
16	Summer	9.257 ¢/kWh				= sum(line 13) / (10) / 1000 * 100 rounded to 3 decimal places
17	Winter	9.256 ¢/kWh				= sum(line 14) / (11) / 1000 * 100 rounded to 3 decimal places
18	Total	**9.256** ¢/kWh				= sum(line 15) / (12) / 1000 * 100 rounded to 3 decimal places
	Average Cost (Including RECO RFP)					
		BGS Auction	RECO RFP		Total	
19	Tranches	4	0.481		4.481	Includes RECO RFP equivalent tranches
20	Price ¢/kWh	9.256	6.562			BGS Auction from (18). Note: 6.562¢ for RFP is illustrative. (excludes transmission).
21	Transmission	0.955	0.000			
22	BGS	8.301	6.562			= (20) - (21)
23	Weighted Avg BGS	7.410	0.704		8.114	= (19) / Total Tranches * (22)
24	Weighted Avg Trans	0.853	0.000		0.853	= (19) / Total Tranches * (21)
25	**Weighted Avg Total Price**				$\boxed{\textbf{8.967}}$	= (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		**1.087**	**1.049**		**1.122**	**0.704**	**0.702**
	RECO On pk			**1.660**			
	RECO Off pk			**0.683**			
	Constant Blk 1	**$ (11.02)**	**$ (12.75)**				
	Constant Blk 2	**$ 2.80**	**$ 1.19**				
	Constant Blk 3	NA	**$ 10.58**				
Winter - all hrs		**1.120**	**0.979**		**0.984**	**0.718**	**0.717**
	RECO On pk			**1.513**			
	RECO Off pk			**0.696**			
Annual - all hrs		1.106	1.003	1.001	1.024	0.714	0.712

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	**1.057**	**(14.846)**
Winter - all hrs	**1.021**	**(16.603)**
Annual - including T&G Obl $	**1.035**	

PLUS:

Gen Cost (per kW of Billed Demand/Month)

	SC2 Dem
summer	$ 5.521
winter	$ 5.815

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

All-In Average costs @ Trans node =	$ 89.67	/MWh*	* Price from Table A (which does not include transmission for the Central/Western Division).
Less Transmission	$ (8.52)	/MWh**	** RECO average transmission rate of 9.55 minus Central/West transmission contribution to weighted average rate 0.481/4.481 *$9.55 per MWh). $1.03
BGS Cost	$ 81.15	/MWh	

Retail BGS Rates (excl SUT) (¢/kWh)

	SC1	SC5	SC3	SC2 ND	SC4	SC6	SC2 Dem
Summer							
All kWh (¢/kWh)	8.821	8.512		9.105	5.713	5.697	7.093
Peak kWh (¢/kWh)			13.471				
Off-Peak kWh (¢/kWh)			5.542				
Block1	7.719	7.238					
Block2	9.101	8.632					
Block3	NA	9.571					
Demand Charge ($/kW)							5.521
Winter							
All kWh (¢/kWh)	9.089	7.944		7.985	5.826	5.818	6.625
Peak kWh (¢/kWh)			12.278				
Off-Peak kWh (¢/kWh)			5.648				
Demand Charge ($/kW)							5.815

Table D Calculation of Rate Adjustment Factors

Total BGS Revenue (Excl SUT) - in $1000	SC1	SC5	SC3	SC2 ND	SC4	SC6	SC2 Dem
Summer	$ 26,813	$ 459	$ 8	$ 1,062	$ 102	$ 93	$ 15,554
Winter	$ 38,306	$ 835	$ 14	$ 2,265	$ 265	$ 228	$ 25,732
Total	$ 65,119	$ 1,294	$ 22	$ 3,327	$ 367	$ 321	$ 41,286

Total	
Summer	$ 44,091
Winter	$ 67,645
Total	$ 111,736

Total Supplier Payments - in $1000

Eastern Division	Total	Transmission	Net BGS
Summer	$ 44,780	$ 3,914	$ 40,866
Winter	$ 69,000	$ 7,828	$ 61,172
Total	$ 113,780	$ 11,742	$ 102,038

Central/Western Division	Total	Transmission	Net BGS
Summer	$ 3,862	$ -	$ 3,862
Winter	$ 5,882	$ -	$ 5,882
Total	$ 9,744	$ -	$ 9,744

Total RECO FP	Total	Transmission	Net BGS
Summer	$ 48,642	$ 3,914	$ 44,728
Winter	$ 74,882	$ 7,828	$ 67,054
Total	$ 123,524	$ 11,742	$ 111,782

Differences	BGS Revenue	BGS Costs	Difference	Rate Adjustment Factors
Summer	$ 44,091	$ 44,728	$ 637	**1.01445**
Winter	$ 67,645	$ 67,054	$ (591)	**0.99126**
Total	$ 111,736	$ 111,782	$ 46	

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

Rates Excluding SUT:

	SC1	SC5	SC3	SC2 ND	SC4	SC6	SC2 Dem
Summer							
All kWh (¢/kWh)	8.948	8.635		9.237	5.796	5.779	7.195
Peak kWh (¢/kWh)			13.666				
Off-Peak kWh (¢/kWh)			5.622				
Block1	7.831	7.343					
Block2	9.233	8.757					
Block3	NA	9.709					
Demand Charge ($/kW)							5.601
Winter							
All kWh (¢/kWh)	9.01	7.875		7.915	5.775	5.767	6.567
Peak kWh (¢/kWh)			12.171				
Off-Peak kWh (¢/kWh)			5.599				
Demand Charge ($/kW)							5.764

Rates Including SUT: SUT @ 7.0%

	SC1	SC5	SC3	SC2 ND	SC4	SC6	SC2 Dem
Summer							
All kWh (¢/kWh)				9.884	6.202	6.184	7.699
Peak kWh (¢/kWh)			14.623				
Off-Peak kWh (¢/kWh)			6.016				
Block1	8.379	7.857					
Block2	9.879	9.370					
Block3	NA	10.389					
Demand Charge ($/kW)							5.99
Winter							
All kWh (¢/kWh)	9.641	8.426		8.469	6.179	6.171	7.027
Peak kWh (¢/kWh)			13.023				
Off-Peak kWh (¢/kWh)			5.991				
Demand Charge ($/kW)							6.17

Table F Spreadsheet Error Checking

Total BGS Revenue (Excl SUT) - in $1000

	SC1	SC5	SC3	SC2 ND	SC4	SC6	SC2 Dem
Summer	$ 27,199	$ 466	$ 8	$ 1,077	$ 103	$ 94	$ 15,778
Winter	$ 37,973	$ 827	$ 14	$ 2,245	$ 263	$ 226	$ 25,507
Total	$ 65,172	$ 1,293	$ 22	$ 3,322	$ 366	$ 320	$ 41,285

Total	
Summer	$ 44,725
Winter	$ 67,055
Total	$ 111,780

Supplier Payments - in $1000

Eastern Division

	Total	Transmission	Net BGS
Summer	$ 44,780	$ 3,914	$ 40,866
Winter	$ 69,000	$ 7,828	$ 61,172
Total	$ 113,780	$ 11,742	$ 102,038

Central/Western Division

	Total	Transmission	Net BGS
Summer	$ 3,862	$ -	$ 3,862
Winter	$ 5,882	$ -	$ 5,882
Total	$ 9,744	$ -	$ 9,744

Total RECO FP

	Total	Transmission	Net BGS
Summer	$ 48,642	$ 3,914	$ 44,728
Winter	$ 74,882	$ 7,828	$ 67,054
Total	$ 123,524	$ 11,742	$ 111,782

Differences

	BGS Revenue	BGS Costs	Difference
Summer	$ 44,725	$ 44,728	$ 3
Winter	$ 67,055	$ 67,054	$ (1)
Total	$ 111,780	$ 111,782	$ 2

GENERAL INFORMATION

No. 31 BASIC GENERATION SERVICE ("BGS")

(1) Basic Generation Service – Fixed Pricing (BGS-FP)
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 250 kWh	X.XX ¢	X.XX ¢
1 – Over 250 kWh	X.XX ¢	X.XX ¢
2 (Non-Demand Billed) – All kWh	X.XX ¢	X.XX ¢
3 – Peak	X.XX ¢	X.XX ¢
3 – Off-Peak	X.XX ¢	X.XX ¢
4 – All kWh	X.XX ¢	X.XX ¢
5 – First 250 kWh	X.XX ¢	X.XX ¢
5 – Next 450 kWh	X.XX ¢	X.XX ¢
5 – Over 700 kWh	X.XX ¢	X.XX ¢
6 – All kWh	X.XX ¢	X.XX ¢

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 ($/kW)	No Charge	No Charge
Over 5 kW ($/kW)	X.XX	X.XX
Usage Charges		
All kWh (¢/kWh)	X.XX ¢	X.XX ¢

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)

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 Locational Marginal Prices for the Rockland Electric Transmission Zone, plus Ancillary Services (including PJM Administrative Charges) at the rate of $0.00642 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.XXX
Charge applicable in other months.. $ X.XXX

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)

SERVICE CLASSIFICATION NO. 2
GENERAL SERVICE (Continued)

RATE – MONTHLY (Continued)

(8) CIEP Standby Fee

In accordance with General Information Section 32, a CIEP Standby Fee shall be assessed on all kWh of customers eligible for BGS-CIEP service.

(~~8~~9) Basic Generation Service

Customers taking Basic Generation Service from the Company will be billed for such service in accordance with General Information Section No. 31.

In accordance with Riders CBT, SUT and TEFA, the charges in this Rate Schedule include provision for the New Jersey Corporation Business Tax, the New Jersey Sales and Use Tax, and until it expires, a temporary Transitional Energy Facility Assessment. When billed to customers exempt from one or more of these taxes, as set forth in Riders CBT, SUT and TEFA, such charges will be reduced by the relevant amount of such taxes included therein.

MINIMUM MONTHLY CHARGE

Unmetered Service	$ 8.68
Non-Demand Metered Service	$10.07
Secondary Service (Demand Metered)	$14.00 Plus the demand charge.
Primary Service	$75.00 Plus the demand charge.

DETERMINATION OF DEMAND

For demands in excess of 5 kW the monthly billing demand in kW shall be either the greatest connected load or the greatest 15-minute integrated demand, determined as follows:

(1) Billing demand may be on a connected load basis when

(a) demand meter would not reduce the billing demand, or

(b) the installation is temporary, or

(c) the device has a large instantaneous or highly fluctuating demand.

(2) Billing shall be on a demand meter basis in all other cases and shall be billed at not less than 90% of the kVA demand. The billing demand for the billing months of October through May inclusive shall not be less than 70% of the highest metered demand for the preceding billing months of June through September inclusive.

(Continued)

SERVICE CLASSIFICATION NO. 2
GENERAL SERVICE (Continued)

SPECIAL PROVISIONS

(A) Short Term Secondary Service

When short term service is requested, the Company reserves the right to require a deposit of the estimated bill for the period service is desired. The minimum charge for such short term service shall be an amount equal to six times the minimum monthly charge, payable in advance. When construction is necessary, the cost of installation and removal of all equipment, less salvage value, shall be borne by the customer, and a sufficient amount to cover these charges shall be paid in advance. A part of a month shall be considered a full month for computing all charges hereunder.

(B) Space Heating

Customers who take service under this classification for 10 kW or more of permanently installed space heating equipment may elect to have the electricity for this service billed separately. All monthly use shall be billed at a Distribution Charge of 2.520 ¢/kWh during the billing months of October through May and 4.036 ¢/kWh during the summer billing months. When this option is requested it shall apply for at least 12 months and shall be subject to a minimum charge of $26.96 per year per kW of space heating capacity. This provision applies for both heating and cooling where the two services are combined by the manufacturer in a single self-contained unit.

All usage under this Special Provision shall also be subject to Parts (3), (4), (5), (6), (7) and (~~8~~9) of RATE – MONTHLY.

(C) Auxiliary Or Standby Service

Auxiliary or standby service will not be supplied under this service classification.

Any customer who operates or receives electric service from a qualifying facility and who requires auxiliary or standby service shall be eligible to take such service under Service Classification No. 7 of this Schedule. The term "qualifying facility" shall mean a generating facility that meets the qualifying facility requirements established by the Federal Energy Regulatory Commission's rules (18 CFR Part 292) implementing the Public Utility Regulatory Policies Act of 1978.

(Continued)