

STATE OF NEW JERSEY
BOARD OF PUBLIC UTILITIES

IN THE MATTER OF THE PROVISION
OF BASIC GENERATION SERVICE FOR
THE PERIOD BEGINNING JUNE 1, 2015

Docket No. ER14040370

ROCKLAND ELECTRIC COMPANY

**PROPOSAL FOR
BASIC GENERATION SERVICE
REQUIREMENTS TO BE PROCURED EFFECTIVE
JUNE 1, 2015**

**COMPANY SPECIFIC ADDENDUM
COMPLIANCE FILING**

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RECO's COMPANY SPECIFIC ADDENDUM

A. Introduction to RECO's Company Specific Filing

In its Decision and Order dated May 21, 2014 in Docket ER14040370, the New Jersey Board of Public Utilities ("Board" or "NJBP") directed New Jersey's four investor owned electric distribution companies ("EDCs") to file proposals with the Board by no later than July 1, 2014 on the procurement of basic generation service ("BGS") for the period beginning June 1, 2015. 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, 2015, filed by New Jersey's four EDCs on July 1, 2014 ("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 System¹, 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 64.4 MW of BGS-CIEP eligible load per tranche) in the BGS-CIEP Auction.

As to the BGS-RSCP Auction, In this document, "Basic Generation Service Fixed-Price or BGS-FP" has the same meaning and is entirely interchangeable with "Basic Generation Service Residential Small Commercial Pricing or BGS-RSCP"., RECO currently has one 36-month tranche that terminates on May 31, 2015, one 36-month tranche that terminates on May 31, 2016, and two 36-month tranches that terminate on May 31, 2017. 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, 2015, RECO will include one 36-month tranche (for the period June 1, 2015 through May 31, 2018).

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, 2015; 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 Load³ (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.

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

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 tranches successfully in the 2015 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

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.

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, 2015

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, 2016. 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, 2016.

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 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-RSCP and BGS-CIEP Auctions are included in Attachment A. For the Service Classification ("SC") No. 1 BGS-RSCP rate structure, the Company is proposing to change the residential first block threshold from 250 kWh to 600 kWh. This change to the first block threshold has been proposed for SC No. 1 distribution charges in the Company's on-going base rate proceeding in BPU Docket No. ER13111135. Since separate block structures for distribution and BGS rates could be quite confusing for SC No. 1 customers, the Company is also proposing the change to the BGS-RSCP SC No. 1 first block threshold in this filing. Should the Board reject the Company's proposal in the base rate proceeding, the Company would revert the BGS-RSCP SC No. 1 first block threshold to 250 kWh in future updates to the Company's BGS Proposal.

The Company is also proposing to introduce a charge for the first 5 kW of demand for SC No. 2 demand billed customers who take BGS-RSCP service to be consistent with changes proposed to SC No. 2 distribution demand charges in the base rate proceeding. In the base rate proceeding, the Company proposed to eliminate 33% of the distribution demand block rate differential in the SC No. 2 Secondary Demand

Billed class. For the BGS rates applicable to BGS-RSCP eligible SC No. 2 demand billed customers, the Company is also proposing a 33% elimination of the demand differential in this filing. Should the Board reject the Company's proposal in the base rate filing to introduce a charge for the first 5 kW and eliminate 33% of the distribution demand block rate differential for SC No. 2 demand billed customers, the Company would revert to a zero charge for first 5 kW of demand for BGS-RSCP SC No. 2 demand billed customers and eliminate the phase-out of the distribution demand block rate differential in future updates to the Company's BGS Proposal.

Final tariff leaves including the actual BGS rates and tariff provisions to become effective on June 1, 2015 will be filed with the Board upon its issuance of an appropriate Board order approving the BGS Auction Process.

G. RECO RFP

(a) RFP Proposal

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. As explained below, regulatory actions by the Federal Energy Commission ("FERC") and the Commodity Futures Trading Commission ("CFTC") impact RECO's procurement proposal for the 2015/2016 BGS year.

On August 16, 2013, FERC approved the creation of a new capacity market zone in the Lower Hudson Valley region consisting of NYISO Load Zones G, H, I, and J in FERC docket number ER13-1380. However, certain parties are appealing

the FERC approval. No cleared product currently exists for the new capacity zone, and RECO does not expect a cleared product to exist before the BGS auction.

As a result of the capacity market changes at the NYISO noted above, RECO proposes to purchase the capacity needs of its BGS customers in its Central and Western Divisions in the NYISO monthly capacity market and blend its forecast of those prices into the BGS-RSCP price. This is the same proposal approved by the Board in its November 22, 2013 Order in BPU Docket number ER13050378, and is necessary because, as in 2013, there currently is no cleared product for the new capacity zone nor is a cleared product expected before the BGS auction. 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 reporting the prices paid for capacity in the NYISO market.

The regulatory action of the CFTC impacts RECO's energy procurement proposal. CFTC trade rules provide that pricing for block trades must be "fair and reasonable" at the time of "execution."⁵ Execution occurs when the Board approves the auction results. The Company's concern is that price spreads during the intervening period between the auction and Board approval could result in the auction price no longer being considered "fair and reasonable" in the opinion of the CFTC. If that

⁵ The CFTC rules state as follows:

Block trades must be transacted at prices that are "fair and reasonable" in light of (i) the size of the transaction, (ii) the prices and sizes of other transactions in the same contract at the relevant time, (iii) the prices and sizes of transactions in other relevant markets, including, without limitation, the underlying cash market or related futures markets, at the relevant time, and (iv) the circumstances of the markets or the parties to the block trade. *Market Regulation Advisory Notice* at p. 3 (May 5, 2014).

occurred, both the Company and the winning bidder could be exposed to CFTC sanctions of up to \$1 million per offense.⁶ The possibility of market movement and CFTC sanctions require a change in the Company's energy procurement process for the Central and Western Divisions. In addition, because both the Company and the bidder would be subject to sanctions, maintaining the same procedure, i.e., a delay between the auction and Board approval, could discourage potential bidders from participating in the auction.

To address the CFTC issues, RECO proposes to purchase the energy needs 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-RSCP price. RECO will make a monthly compliance filing indicating the actual prices paid. As noted above for RECO's capacity procurement, 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 energy purchases on total BGS prices should be minimal.

(b) Alternative Proposal for Energy Procurement

In the event the Board wants to continue with an RFP process for energy procurement, the Company proposes to adjust the NYMEX auction procedures used in January 2014 to account for the CFTC trade rules explained above. To address potential CFTC regulatory violations, RECO proposes that prior to the commencement of the auction, Board Staff and the Company agree on a range of acceptable prices for

⁶ 17 CFR 143.8.

the bids in the NYMEX auction. So long as the winning bids are within the predefined range, they will be deemed acceptable by the Board, and the bid can be timely executed by RECO without a delay in execution that would result if RECO was required to wait for Board approval at a Board Agenda meeting. This will remove the risk that the pricing of the trades will not be considered “fair and reasonable” at the time of execution and removes the concomitant risk of violating CFTC rules. RECO will evaluate the proposals submitted by bidders to determine which proposals are in the best economic interests of its BGS customers.

RECO also proposes that it conduct two NYMEX auctions in 2015 and procure two energy tranches: one tranche for the 2015/2016 BGS year and one tranche for the 2016/2017 BGS year. This will allow RECO to take advantage of currently low energy prices two years forward and protect customers in the event of upward movement in forward energy prices in a 2016 NYMEX auction.

With the exception of these two adjustments, RECO’s NYMEX auctions for the two energy tranches would proceed in the same manner as the January 28, 2014 NYMEX auction. RECO will solicit competitive bids from qualified bidders for “fixed for floating” financially settled NYMEX futures transactions with respect to the energy tranches (“Energy Transactions”). The Energy Transactions are NYMEX NYISO Zone G Day-Ahead (Peak and Off-Peak) products.

The terms of the Energy Transactions would be June 1, 2015 to May 31, 2016 and June 1, 2016 to May 31, 2017. Bidders must bid a fixed price for each 12-month term. 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 each Energy Transaction will be the Futures Seller. RECO will be the Futures Buyer. Each Energy Transaction will be for a fixed quantity (e.g., 40 MW) and presented in contract sizes consistent with the above product and pre-determined by RECO. As in the January 2014 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. 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 two energy tranche auctions occur in January 2015 prior to a Board agenda meeting, and the auction outcome will be reported to the Board at the agenda meeting following the NYMEX auction. RECO requests that the result of the energy tranche auction be kept confidential until the BGS auction results are announced.

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

(c) Default Proposal

If the Board accepts the proposal for an amended energy RFP as set forth in (b) above, and the energy tranche NYMEX auctions fail to attract the necessary number of bidders to have a competitive solicitation, after notice to the Board, RECO will purchase the energy needs of its BGS customers in the Central and Western Divisions in the NYISO Day-Ahead and Real Time Markets, and blend its forecast of those prices into the BGS-RSCP price, as set forth in section “a” above. In the event RECO makes these purchases from the NYISO market, RECO will make a monthly compliance filing indicating the actual prices paid, also as set for the in section “a” above.

H. Capacity Charges

Should PJM make changes to the Reliability Pricing Model (“RPM”) that results in significant increases in the capacity charges assessed to BGS Suppliers, the payments to BGS Suppliers will increase by the difference between the PJ RPM Zonal Net Load Price established in the RPM IA (or Base Residual Auction) already held by PJM as of the date of this filing and the actual or revised PJM RPA Net Load Price charged to BGS Suppliers times the BGS Supplier’s actual capacity obligation.

I. 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-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 2013 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 2014 with a migration adjustment for retail access. The values in Table #3 will be updated in January 2015 to better reflect the amount by Service Classification that could be in effect starting on June 1, 2015.

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 2015 to May 2016, 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 2011 to December 2013, which equals 0.4658%. Marginal losses are excluded from the loss factors based on historic de-rating factors for the period May 2011 to April 2014.

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 including a migration adjustment, by service classification, that are currently being utilized in the year 2014. The values in the top portion of Table #9 will be updated in January 2015 to better reflect the aggregate amount by rate schedule that could be in effect on June 1, 2015.

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 2015 to 2018 for RECO), plus the incremental RPM Capacity cost, if necessary, 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-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 adjusted to include the incremental RPM Capacity cost, if necessary, and 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.” To the extent the seasonal factors for the 12-month BGS period beginning June 1, 2015 (as calculated in Table #16) produce a summer payment factor less than one and a winter payment factor greater than one, the Company reserves its right to set the seasonal factors to 1.0 for both the Summer and Winter periods in any updates to the Company’s BGS Pricing Spreadsheet.

⁷ The price shown for the tranche to be secured in the 2015 auction and RFP are for illustrative purposes only, and will be replaced with actual data in determining RECO's final June2015 BGS-FP rates.

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 –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-RSCP rates

developed in Table E and the anticipated total season payments to BGS suppliers, based on the data in Table A.

Table G (Development of 2015/16 Incremental RPM Cost - \$/MWh) contains an illustrative example of the development of the incremental costs associated with possible changes to the PJM capacity market.

J. Transmission Charges

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

K. Conclusion

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

1. The Company's proposed treatment of its Committed Supply is approved by the Board;

2. The Company's proposed accounting for BGS is approved by the Board for purposes of accounting and BGS cost recovery;
3. There will exist a presumption of prudence with respect to the BGS Auction Plan method and the costs incurred for BGS service under the Auction Plan;
4. RECO's Contingency Plan is approved by the Board, and the costs incurred as a result of this Contingency Plan are presumptively prudent, subject to deferral, and approved for full and timely recovery;
5. The RECO-specific statewide Auction results are approved by the Board and produce BGS supply costs that are reasonable and prudent, subject to deferral, and approved for full and timely recovery;
6. The Company's proposal for its Central and Western Divisions is approved by the Board; and
7. The Company's Rate Design Methodology and Tariff Sheets are approved by the Board.

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(Continued)

ISSUED:

EFFECTIVE:

ISSUED BY: Timothy Cawley, President
Mahwah, New Jersey 07430

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:

<u>Service Classification</u>	<u>Summer Months*</u>	<u>Other Months</u>
1 – First 600 kWh	X.XX ¢	X.XX ¢
1 – Over 600 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):

	<u>Summer Months*</u>	<u>Other Months</u>
Demand Charges		
First 5 kW (\$/kW)	X.XX	X.XX
Over 5 kW (\$/kW)	X.XX	X.XX
Usage Charges		
All kWh (¢/kWh)	X.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)

ISSUED:

EFFECTIVE:

ISSUED BY: Timothy Cawley, President
 Mahwah, New Jersey 07430

GENERAL INFORMATION

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

- (1) Basic Generation Service – Residential Small Commercial Pricing (BGS-RSCP) (Continued)
Applicable to Service Classification Nos. 1, 2, 3, 4, 5 and 6

Service Classification No. 2 metered customers who are not required to take BGS-CIEP service in accordance with General Information Section No. 31(2) and are located in the Company’s Eastern Division may elect to take BGS-CIEP service on a voluntary basis. Such customers must notify the Company no later than the second business day in the month of January of each year to elect BGS-CIEP service for the annual period commencing June 1 of that year. Customers voluntarily taking BGS-CIEP service who, during the applicable annual period, elect to purchase Competitive Energy Supply from a Third-Party Supplier and then return to the Company’s BGS, shall be required to take BGS-CIEP service for the remainder of the annual period. Customers voluntarily taking BGS-CIEP service who wish to transfer to BGS-FP service as their default supply service must notify the Company no later than the second business day of the month of January in order to effectuate such transfer for service commencing on the following June 1. Customers who do not provide such notification to the Company shall remain on BGS-CIEP service for the twelve-month period commencing the following June 1.

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.

(Continued)

ISSUED:

EFFECTIVE:

ISSUED BY: Timothy Cawley, President
Mahwah, New Jersey 07430

GENERAL INFORMATION

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

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

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

BGS Energy Charges:

Charges per kilowatthour:

BGS Energy Charges are hourly and are provided at the real time PJM Load Weighted Average 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)

ISSUED:

EFFECTIVE:

ISSUED BY: Timothy Cawley, President
Mahwah, New Jersey 07430

GENERAL INFORMATION

No. 31 BASIC GENERATION SERVICE ("BGS") (Continued)

(4) BGS Reconciliation Charges

Separate BGS-FP and BGS-CIEP reconciliation charges shall be computed quarterly and assessed on all BGS-FP and BGS-CIEP customers. The billing quarters shall be defined as the three-month periods beginning March, June, September, and December. The reconciliation charges shall recover the differences, including interest, between amounts paid to BGS suppliers and BGS revenue for the preceding quarter for the applicable BGS supply. For any given quarter, the reconciliation charges shall not exceed a charge or a credit of 2.0 cents per kWh, including SUT. 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. Interest will be calculated as determined by the Board in its Order dated February 6, 2009 in Docket Number ER08050310.

These charges include all applicable taxes and are charged on a monthly basis for all usage billed in the month indicated.

BGS-RSCP Reconciliation Charge..... X.XXX ¢/kWh
BGS-CIEP Reconciliation Charge X.XXX ¢/kWh

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.

The BGS Reconciliation Charges shall be filed with the Board not less than fifteen days prior to the date on which they are proposed to become effective.

ISSUED:

EFFECTIVE:

ISSUED BY: Timothy Cawley, President
Mahwah, New Jersey 07430

Development of BGS Cost and Bid Factors for Rates Effective June 1, 2015

Based on 2013 Load Profile Information

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

Table #1 % Usage During PJM On-Peak Period

	Profile Meter Data <u>SC1</u>	Profile Meter Data <u>SC5</u>	Profile Meter Data <u>SC3</u>	Profile Meter Data <u>SC2 ND</u>	--- Other Analysis ---		Profile Meter Data <u>SC2 Dem</u>
					<u>SC4</u>	<u>SC6</u>	
January	51.80%	49.45%	49.02%	50.67%	30.41%	30.41%	53.85%
February	50.49%	45.63%	46.94%	49.48%	30.61%	30.61%	53.97%
March	48.12%	45.58%	46.18%	48.94%	27.94%	27.94%	52.20%
April	51.94%	47.86%	49.84%	57.16%	29.48%	29.48%	57.03%
May	52.10%	52.51%	49.04%	58.24%	22.07%	22.07%	55.18%
June	51.21%	50.53%	50.91%	59.71%	20.62%	20.62%	54.91%
July	52.85%	52.78%	52.90%	57.28%	20.63%	20.63%	55.38%
August	50.97%	54.35%	50.73%	57.60%	20.40%	20.40%	53.19%
September	51.19%	53.10%	51.08%	61.61%	28.16%	28.16%	55.13%
October	52.50%	53.09%	52.60%	61.55%	30.52%	30.52%	56.84%
November	46.10%	44.02%	43.95%	47.71%	26.98%	26.98%	49.59%
December	51.28%	47.52%	47.82%	50.78%	30.41%	30.41%	53.92%

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

On-Peak periods as defined in specified rate schedule

(data rounded to nearest %)	N/A <u>SC1</u>	N/A <u>SC5</u>	<u>SC3</u>	N/A <u>SC2 ND</u>	N/A <u>SC4</u>	N/A <u>SC6</u>	N/A <u>SC2 Dem</u>
January	----	----	33.5%	----	----	----	----
February	----	----	35.6%	----	----	----	----
March	----	----	35.4%	----	----	----	----
April	----	----	33.9%	----	----	----	----
May	----	----	34.3%	----	----	----	----
June	----	----	32.2%	----	----	----	----
July	----	----	37.3%	----	----	----	----
August	----	----	37.4%	----	----	----	----
September	----	----	35.8%	----	----	----	----
October	----	----	34.5%	----	----	----	----
November	----	----	35.1%	----	----	----	----
December	----	----	33.9%	----	----	----	----

Table #3 Class Usage @ customer

*Calendar month billed sales forecasted for 2015
in MWh*

	<u>SC1</u>	<u>SC5</u>	<u>SC3</u>	<u>SC2 ND</u>	<u>SC4</u>	<u>SC6</u>	<u>SC2 Dem</u>	<u>Total</u>
January	58,903	1,750	34	3,892	513	498	31,136	96,725
February	48,785	1,610	27	3,998	425	449	28,832	84,125
March	44,406	1,399	21	3,559	428	410	27,943	78,165
April	41,964	1,112	19	2,438	320	427	28,292	74,570
May	41,481	862	16	1,739	281	428	28,246	73,051
June	57,802	1,058	18	1,875	326	354	32,670	94,102
July	78,062	1,288	24	2,410	320	360	36,104	118,567
August	82,031	1,315	23	2,726	353	356	36,184	122,988
September	69,614	1,416	18	2,330	385	426	33,708	107,895
October	48,708	997	17	2,213	455	496	30,357	83,243
November	41,775	1,074	18	2,252	513	476	28,051	74,158
December	<u>49,760</u>	<u>1,344</u>	<u>26</u>	<u>2,891</u>	<u>526</u>	<u>499</u>	<u>30,261</u>	<u>85,306</u>
Total	663,289	15,222	260	32,323	4,843	5,175	371,784	1,092,895

Table #4 Forwards Prices - Energy Only @ bulk system

in \$/MWh (See Table 18)

	<u>On-Peak</u>	<u>Off-Peak</u>
January	82.39	58.88
February	76.02	54.30
March	57.95	41.83
April	49.48	35.20
May	49.63	35.37
June	52.13	32.17
July	68.61	41.95
August	59.21	36.14
September	44.88	27.99
October	46.08	32.84
November	47.33	33.71
December	54.92	39.76

Table #5 Losses

	<u>SC1</u>	<u>SC5</u>	<u>SC3</u>	<u>SC2 ND</u>	<u>SC4</u>	<u>SC6</u>	<u>SC2 Dem</u>
Expansion Factor =	1.08492	1.08492	1.08492	1.08492	1.08115	1.08115	1.08492
Expansion Factor (net Marginal Losses)	1.07335	1.07335	1.07335	1.07335	1.06961	1.06961	1.07335

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

		<u>SC1</u>	<u>SC5</u>	<u>SC3</u>	<u>SC2 ND</u>	<u>SC4</u>	<u>SC6</u>	<u>SC2 Dem</u>
Summer - all hrs	\$	50.20	\$ 49.84	\$ 50.54	\$ 51.66	\$ 42.22	\$ 42.22	\$ 50.59
	PJM on pk	\$ 61.81	\$ 60.93	\$ 62.28	\$ 61.18	\$ 59.16	\$ 59.13	\$ 61.30
	PJM off pk	\$ 37.84	\$ 37.42	\$ 38.10	\$ 37.99	\$ 37.25	\$ 37.25	\$ 37.69
Winter - all hrs	\$	55.17	\$ 56.10	\$ 56.48	\$ 57.25	\$ 50.71	\$ 50.13	\$ 54.89
	PJM on pk	\$ 64.25	\$ 65.75	\$ 66.22	\$ 65.74	\$ 64.00	\$ 63.38	\$ 63.07
	PJM off pk	\$ 45.86	\$ 47.22	\$ 47.46	\$ 47.97	\$ 45.32	\$ 44.81	\$ 45.25
Annual	\$	53.02	\$ 54.01	\$ 54.58	\$ 55.63	\$ 48.29	\$ 47.85	\$ 53.28
System Total	\$	53.15						

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

		<u>SC1</u>	<u>SC5</u>	<u>SC3</u>	<u>SC2 ND</u>	<u>SC4</u>	<u>SC6</u>	<u>SC2 Dem</u>
Summer - all hrs	\$	14,434	\$ 253	\$ 4	\$ 483	\$ 58	\$ 63	\$ 7,015
	PJM on pk	\$ 9,166	\$ 163	\$ 3	\$ 337	\$ 19	\$ 20	\$ 4,644
	PJM off pk	\$ 5,268	\$ 90	\$ 2	\$ 146	\$ 40	\$ 43	\$ 2,371
Winter - all hrs	\$	20,732	\$ 569	\$ 10	\$ 1,316	\$ 175	\$ 184	\$ 12,795
	PJM on pk	\$ 12,223	\$ 320	\$ 6	\$ 789	\$ 64	\$ 67	\$ 7,954
	PJM off pk	\$ 8,508	\$ 250	\$ 4	\$ 527	\$ 112	\$ 118	\$ 4,842
Annual	\$	35,166	\$ 822	\$ 14	\$ 1,798	\$ 234	\$ 248	\$ 19,810
System Total	\$	58,092						

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

		<u>SC1</u>	<u>SC5</u>	<u>SC3</u>	<u>SC2 ND</u>	<u>SC4</u>	<u>SC6</u>	<u>SC2 Dem</u>
Summer - all hrs	\$	50.20	\$ 49.84	\$ 50.54	\$ 51.66	\$ 42.22	\$ 42.22	\$ 50.59
				\$ 66.05				
				\$ 41.87				
RECO On pk								
RECO Off pk								
Winter - all hrs	\$	55.17	\$ 56.10	\$ 56.48	\$ 57.25	\$ 50.71	\$ 50.13	\$ 54.89
				\$ 68.78				
				\$ 50.02				
RECO On pk								
RECO Off pk								
Annual Average	\$	53.02	\$ 54.01	\$ 54.58	\$ 55.63	\$ 48.29	\$ 47.85	\$ 53.28
System Average	\$	53.15						

Table #9 Generation & Transmission Obligations and Costs and Other Adjustments

Obligations - annual average forecasted for 2014; costs are market estimates in MW

	<u>SC1</u>	<u>SC5</u>	<u>SC3</u>	<u>SC2 ND</u>	<u>SC4</u>	<u>SC6</u>	<u>SC2 Dem</u>	<u>Total FP</u>
Gen Obl - MW	309.025	4.338	0.071	9.493	0.0	0.0	109.355	432.282
Trans Obl - MW	259.835	3.662	0.061	7.992	0.0	0.0	92.159	363.709
# 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 (see Table 19)	summer	\$223.70 \$/MW/day		Resulting avg gen cap cost =	summer >> \$	81.65 per kW/yr		
	winter	\$209.58 \$/MW/day			winter >> \$	76.50 per kW/yr		

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

	<u>SC1</u>			<u>SC5</u>		
	Charges	% usage		Chgs (¢/kWh)	Differences	% usage
Block 1 (0-250 kWh/month)	9.001 ¢/kWh	42.93%		8.188		30.91%
Block 2 (>250 kWh/m)	10.528 ¢/kWh	57.07%		9.728	1.540	35.63%
Calculated inversion =	1.527 ¢/kWh			10.767	2.579	33.46%

Table #10 Ancillary Services
forecasted overall annual average

\$2.85 /MWh

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

	<u>SC1</u>	<u>SC5</u>	<u>SC3</u>	<u>SC2 ND</u>	<u>SC4</u>	<u>SC6</u>
Transmission Obl - all months \$	12.58 \$	7.73 \$	7.55 \$	7.94 \$	- \$	-
Generation Obl -						
per annual MWh \$	36.44 \$	22.29 \$	21.40 \$	22.97 \$	- \$	-
per summer MWh \$	29.33 \$	23.32 \$	23.35 \$	27.74 \$	- \$	-
per winter MWh \$	41.88 \$	21.77 \$	20.49 \$	21.04 \$	- \$	-

Table #12 Summary of BGS Unit Costs @ customer

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

	<u>SC1</u>	<u>SC5</u>	<u>SC3</u>	<u>SC2 ND</u>	<u>SC4</u>	<u>SC6</u>
Summer - all hrs \$	94.97 \$	83.73 \$	84.29 \$	90.18 \$	45.07 \$	45.07
RECO On pk			\$ 141.48			
RECO Off pk			\$ 52.27			
Block 1 \$	86.25 \$	69.62				
Block 2 \$	101.52 \$	85.02				
Block 3	\$	95.41				
Winter - all hrs \$	112.48 \$	88.45 \$	87.37 \$	89.07 \$	53.56 \$	52.98
RECO On pk			\$ 138.63			
RECO Off pk			\$ 60.42			
Annual -all hrs \$	104.89 \$	86.88 \$	86.38 \$	89.39 \$	51.14 \$	50.70

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

	<u>SC2 Dem</u>	PLUS:		
Summer - all hrs \$	53.44	<u>Gen Cost (per kW of Billed Demand/Month)</u>		
			≤ 5 kW	> 5 kW
Winter - all hrs \$	57.74	summer	\$ 2.061	\$ 7.168
		winter	\$ 2.220	\$ 7.919
Annual - all hrs per MWh only \$	56.13	<u>Trans cost</u>		
		all months \$	2.68 per kW of T obl /month	

Table #12 (Continued)

<u>Including T&G Obligation \$</u>		<u>Gen Cost (per kW of Billed Demand/Month)</u>			
				<u>≤ 5 kW</u>	<u>> 5 kW</u>
Summer - all hrs	\$ 86.61	summer	\$ 2.061	\$ 7.168	
Winter - all hrs	\$ 94.68	winter	\$ 2.220	\$ 7.919	
Annual - including T&G Obl \$	87.10				

ALL RATES

Grand Total Cost in \$1000 = \$ 106,700
 All-In Average cost @ customer = \$ 97.63 per MWh at customer (per customer metered MWh)
 All-In Average costs @ transmission nodes = \$ 90.96 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

	<u>SC1</u>	<u>SC5</u>	<u>SC3</u>	<u>SC2 ND</u>	<u>SC4</u>	<u>SC6</u>
Summer - all hrs	1.044	0.921		0.991	0.495	0.496
RECO On pk			1.555			
RECO Off pk			0.575			
Constant Blk 1 \$	(8.71) \$	(14.12)				
Constant Blk 2 \$	6.56 \$	1.28				
Constant Blk 3	NA \$	11.67				
Winter - all hrs	1.237	0.972		0.979	0.589	0.582
RECO On pk			1.524			
RECO Off pk			0.664			
Annual - all hrs	1.153	0.955	0.950	0.983	0.562	0.557

Table #13 (Continued)

DEMAND RATES

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

	<u>SC2 Dem Multiplier</u>	\$	<u>SC2 Dem Constant</u>		PLUS:			
Summer - all hrs	0.952	\$	(33.173)		<u>Gen Cost (per kW of Billed Demand/Month)</u>			
							<u>≤ 5 kW</u>	<u>> 5 kW</u>
Winter - all hrs	1.041	\$	(36.940)		summer	\$	2.06	\$ 7.17
					winter	\$	2.22	\$ 7.92
Annual - including T&G Obl \$	0.958				<u>Trans cost</u>			
					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

		<u>SC1</u>	<u>SC5</u>	<u>SC3</u>	<u>SC2 ND</u>	<u>SC4</u>	<u>SC6</u>
Summer - all hrs	\$	82.39	\$ 76.01	\$ 76.74	\$ 82.24	\$ 45.07	\$ 45.07
	RECO On pk			\$ 133.93			
	RECO Off pk			\$ 44.72			
	Block 1	\$ 73.67	\$ 61.89				
	Block 2	\$ 88.94	\$ 77.29				
	Block 3		\$ 87.68				
Winter - all hrs	\$	99.90	\$ 80.73	\$ 79.82	\$ 81.13	\$ 53.56	\$ 52.98
	RECO On pk			\$ 131.09			
	RECO Off pk			\$ 52.87			
Annual -all hrs	\$	92.31	\$ 79.15	\$ 78.83	\$ 81.45	\$ 51.14	\$ 50.70

Table #14 (Continued)

DEMAND RATES

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

	<u>SC2 Dem</u>	PLUS:			
		<u>Gen Cost (per kW of Billed Demand/Month)</u>			
				<u>< 5 kW</u>	<u>> 5 kW</u>
Summer - all hrs	\$ 53.44				
Winter - all hrs	\$ 57.74	summer	\$	2.061	\$ 7.168
		winter	\$	2.220	\$ 7.919
Annual - all hrs per MWh only	\$ 56.13				
<u>Including Generation Obligation \$</u>					
Summer - all hrs	\$ 79.50				
Winter - all hrs	\$ 86.21				
Annual - including T&G Obl \$	\$ 83.71				

ALL RATES

Grand Total Cost in \$1000 = \$ 96,718
 All-In Average cost @ customer = \$ 88.50 per MWh at customer (per customer metered MWh)
 All-In Average costs @ transmission nodes = \$ 82.45 per MWh at transmission node system (per metered MWh at transmission node)

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

NON-DEMAND RATES

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

	<u>SC1</u>	<u>SC5</u>	<u>SC3</u>	<u>SC2 ND</u>	<u>SC4</u>	<u>SC6</u>
Summer - all hrs	0.999	0.922		0.997	0.547	0.547
RECO On pk			1.624			
RECO Off pk			0.542			
Constant Blk 1 \$	(8.71) \$	(14.12)				
Constant Blk 2 \$	6.56 \$	1.28				
Constant Blk 3	NA \$	11.67				
Winter - all hrs	1.212	0.979		0.984	0.650	0.643
RECO On pk			1.590			
RECO Off pk			0.641			
Annual - all hrs	1.120	0.960	0.956	0.988	0.620	0.615

DEMAND RATES

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

	<u>SC2 Dem Multiplier</u>	<u>SC2 Dem Constant</u>	PLUS:			
			<u>Gen Cost (per kW of Billed Demand/Month)</u>			
				<u>< 5 kW</u>		<u>> 5 kW</u>
Summer - all hrs	0.964	(26.059)				
Winter - all hrs	1.046	(28.477)	summer	\$ 2.061	\$	7.168
			winter	\$ 2.220	\$	7.919
Annual - including T&G Obl \$	1.015					

Table #16 Summary of Total BGS Costs by Season

	<u>SC1</u>	<u>SC5</u>	<u>SC3</u>	<u>SC2 ND</u>	<u>SC4</u>	<u>SC6</u>	<u>SC2 Dem</u>	
Total Costs by Rate - in \$1000								
Summer	\$ 27,304	\$ 425	\$ 7	\$ 842	\$ 62	\$ 67	11,381	
Winter	\$ 42,268	\$ 897	\$ 15	\$ 2,047	\$ 185	\$ 195	21,002	
Total	\$ 69,573	\$ 1,322	\$ 22	\$ 2,889	\$ 248	\$ 262	32,383	
% of Annual Total \$ by Rate								
Summer	39%	32%	31%	29%	25%	26%	35%	
Winter	61%	68%	69%	71%	75%	74%	65%	
Total Costs - in \$1000								
Summer	\$ 40,089							
Winter	\$ 66,610							
Total	\$ 106,700							
% of Annual Total \$			If total \$ were split on a per MWh basis (on transmission node MWhs):				<u>Ratio to All-In Cost</u>	
Summer	38%	\$ 84.21	per MWh @ transmission nodes				Summer	0.9258
Winter	62%	\$ 95.57	per MWh @ transmission nodes				Winter	1.0507

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

	<u>SC1</u>	<u>SC5</u>	<u>SC3</u>	<u>SC2 ND</u>	<u>SC4</u>	<u>SC6</u>	<u>SC2 Dem</u>	
Total Costs by Rate - in \$1000								
Summer	\$ 23,687	\$ 386	\$ 6	\$ 768	\$ 62	\$ 67	10,394	
Winter	\$ 37,541	\$ 819	\$ 14	\$ 1,865	\$ 185	\$ 195	19,029	
Total	\$ 61,228	\$ 1,205	\$ 20	\$ 2,633	\$ 248	\$ 262	29,423	
% of Annual Total \$ by Rate								
Summer	39%	32%	31%	29%	25%	26%	35%	
Winter	61%	68%	69%	71%	75%	74%	65%	
Total Costs - in \$1000								
Summer	\$ 35,372							
Winter	\$ 59,648							
Total	\$ 95,019							
% of Annual Total \$			If total \$ were split on a per MWh basis (on transmission node MWhs):				<u>Ratio to All-In Cost</u>	
Summer	37%	\$ 74.30	per MWh @ transmission nodes				Summer	0.9011
Winter	63%	\$ 85.58	per MWh @ transmission nodes				Winter	1.0380

Table #18 Forward Energy Prices

PJM Forward Prices - Energy Only @ bulk system <i>in \$/MWh</i>	Off/On Peak		Zone to Western Hub Basis Differential <i>in \$/MWh</i>			PJM Forward Prices (incl basis differential) <i>in \$/MWh</i>	
	<u>On-Peak</u>	<u>LMP ratio</u>	<u>Off-Peak</u>	<u>On-Peak</u>	<u>Off-Peak</u>	<u>On-Peak</u>	<u>Off-Peak</u>
January	68.76	0.73	49.88	112%	110%	76.70	55.08
February	62.36	0.73	45.23	112%	110%	69.56	49.95
March	50.14	0.73	36.37	112%	110%	55.93	40.16
April	44.28	0.73	32.12	112%	110%	49.39	35.47
May	44.59	0.73	32.34	112%	110%	49.74	35.71
June	49.77	0.62	30.98	103%	102%	51.45	31.74
July	66.56	0.62	41.44	103%	102%	68.80	42.45
August	56.37	0.62	35.09	103%	102%	58.27	35.95
September	43.37	0.62	27.00	103%	102%	44.83	27.66
October	41.08	0.73	29.80	112%	110%	45.82	32.91
November	41.93	0.73	30.42	112%	110%	46.77	33.59
December	47.88	0.73	34.73	112%	110%	53.41	38.35

NYISO Forward Prices - Energy Only @ bulk system <i>in \$/MWh</i>	Off/On Peak		Weighted Average Forward Prices - Energy Only @ bulk system (89.3% PJM - 10.7% NYISO) <i>in \$/MWh</i>		
	<u>On-Peak</u>	<u>Off-Peak</u>	<u>On-Peak</u>	<u>Off-Peak</u>	
January	129.75	90.50	82.39	58.88	89.3%
February	129.75	90.50	76.02	54.30	10.7%
March	74.75	55.75	57.95	41.83	
April	50.25	33.00	49.48	35.20	
May	48.75	32.50	49.63	35.37	
June	57.75	35.75	52.13	32.17	
July	67.00	37.75	68.61	41.95	
August	67.00	37.75	59.21	36.14	
September	45.25	30.75	44.88	27.99	
October	48.25	32.25	46.08	32.84	
November	52.00	34.75	47.33	33.71	
December	67.50	51.50	54.92	39.76	

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

	<u>PJM Base Capacity</u>	<u>Incremental RPM Capacity</u>	<u>PJM 89.3%</u>	<u>NYISO 10.7%</u>	<u>Weighted Average</u>
Summer	\$135.07	\$75.30	\$210.37	\$334.51	\$223.70
Winter	\$135.07	\$75.30	\$210.37	203.01	\$209.58

Table #20 Ancillary Services

	<u>PJM 89.3%</u>	<u>NYISO 10.7%</u>	<u>Weighted Average</u>
	\$3.00	\$1.60	\$2.85

Assumptions:

- Gen Cost = \$223.70 per MW-day in summer
\$209.58 per MW-day in winter
- Trans cost = \$ 32,114 per MW-yr
- Analysis time period = 4 summer months
8 winter months
- Ancillary Services = \$ 2.85 /MWh
- Energy Costs = Based on 6/14 to 5/15 Forwards @ PJM West as of 06/02/14
Based on 6/14 to 5/15 Forwards @ NYISO Zone G as of 06/17/14
- Usage patterns = Forecasted 2014 energy use by class, PJM on/off % from 2013 class load profiles,
RECO billing on/off % from 6/13 to 5/14 actual data
- Obligations = Class totals for 2014
- 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

<u>Line #</u>	<u>Specific BGS-FP Auction >></u>	2013 Auction <u>36 Month</u>	2014 Auction <u>36 Month</u>	2015 Auction <u>36 Month</u>	<u>Total</u>	<u>Notes:</u>
1	Tranches	1	2	1	4	From then-current auction
2(a)	Winning Bid Price (¢/kWh)*	9.258	9.561	9.561		
2(b)	Incremental RPM Cost - in (¢/kWh)	0.753	0.753	0.753		
2(c)	Winning Bid Price (¢/kWh)*	10.011	10.314	10.314		Winning Bids (Note: 2014 Auction Price Shown for Illustrative Purposes Only)
3	Transmission (¢/kWh)	0.851	0.851	0.851		Average transmission cost included in bid
4	BGS (¢/kWh)	9.160	9.463	9.463		= (2c) - (3)
5	Weighted Avg BGS	2.290	4.732	2.366	9.387	= (1) / Total Tranches * (4)
6	Weighted Avg Trans	0.213	0.425	0.213	0.851	= (1) / Total Tranches * (3)
7	Weighted Avg Total Price (¢/kWh)				10.238	
<u>Seasonal Payment Factors</u>						
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
<u>Applicable Customer Usage @ transmission nodes</u> (Eastern Division)						
10	Summer MWh	424,972				From then-current Bid Factor Spreadsheet
11	Winter MWh	<u>622,134</u>				From then-current Bid Factor Spreadsheet
12		1,047,107				
<u>Total Cost</u>						
13	Summer	10,635,994	21,915,821	10,957,910	43,509,725	= (1) / Total Tranches * (2c) / 100 * (8) * (10) * 1,000
14	Winter	<u>15,570,470</u>	<u>32,083,475</u>	<u>16,041,737</u>	<u>63,695,682</u>	= (1) / Total Tranches * (2c) / 100 * (9) * (11) * 1,000
15	Total	26,206,464	53,999,296	26,999,647	107,205,407	= (13) + (14)
<u>Average Cost (NJ Statewide Auction)</u>						
16	Summer	10.238 ¢/kWh				= sum(line 13) / (10) / 1000 * 100 rounded to 3 decimal places
17	Winter	10.238 ¢/kWh				= sum(line 14) / (11) / 1000 * 100 rounded to 3 decimal places
18	Total	10.238 ¢/kWh				= sum(line 15) / (12) / 1000 * 100 rounded to 3 decimal places
<u>Average Cost (Including RECO RFP)</u>						
		BGS <u>Auction</u>	RECO <u>RFP</u>		<u>Total</u>	
19	Tranches	4	0.481		4.481	Includes RECO RFP equivalent tranches
20	Price ¢/kWh	10.238	6.562			BGS Auction from (18). Note: 6.562¢ for RFP is illustrative. (excludes transmission).
21	Transmission	0.851	0.000			
22	BGS	9.387	6.562			= (20) - (21)
23	Weighted Avg BGS	8.379	0.704		9.084	= (19) / Total Tranches * (22)
24	Weighted Avg Trans	0.760	0.000		0.760	= (19) / Total Tranches * (21)
25	Weighted Avg Total Price				9.843	= (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

	<u>SC1</u>	<u>SC5</u>	<u>SC3</u>	<u>SC2 ND</u>	<u>SC4</u>	<u>SC6</u>
Summer - all hrs	0.999	0.922		0.997	0.547	0.547
RECO On pk			1.624			
RECO Off pk			0.542			
Constant Blk 1 \$	(8.71) \$	(14.12)				
Constant Blk 2 \$	6.56 \$	1.28				
Constant Blk 3	NA \$	11.67				
Winter - all hrs	1.212	0.979		0.984	0.650	0.643
RECO On pk			1.590			
RECO Off pk			0.641			
Annual - all hrs	1.120	0.960	0.956	0.988	0.620	0.615

DEMAND RATES

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

	<u>SC2 Dem</u> <u>Multiplier</u>	<u>SC2 Dem</u> <u>Constant</u>	PLUS:			
Summer - all hrs	0.964	(26.059)	<u>Gen Cost (per kW of Billed Demand/Month)</u>			
			<u>0</u>	<u>< 5 kW</u>	<u>> 5 kW</u>	
Winter - all hrs	1.046	(28.477)	summer \$	- \$	2.061 \$	7.168
			winter \$	- \$	2.220 \$	7.919
Annual - including T&G Obl \$	1.015					

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

All-In Average costs @ Trans node =	\$ 98.43 /MWh*
Less Transmission	\$ (7.60) /MWh**
BGS Cost	\$ 90.83 /MWh

* Price from Table A (which does not include transmission for the Central/Western Division).
 ** RECO average transmission rate of 8.51 minus Central/West transmission contribution to weighted average rate 0.481/4.481 *\$8.51 per MWh). \$0.91

Retail BGS Rates (excl SUT) (¢/kWh)

	<u>SC1</u>	<u>SC5</u>	<u>SC3</u>	<u>SC2 ND</u>	<u>SC4</u>	<u>SC6</u>	<u>SC2 Dem</u>
<u>Summer</u>							
All kWh (¢/kWh)	9.074	8.375		9.056	4.968	4.968	6.150
Peak kWh (¢/kWh)			14.751				
Off-Peak kWh (¢/kWh)			4.923				
Block1	8.203	6.963					
Block2	9.730	8.503					
Block3	NA	9.542					
Demand Charge (\$/kW) 1st 5kW							2.061
Demand Charge (\$/kW) > 5 kW							7.168
<u>Winter</u>							
All kWh (¢/kWh)	11.009	8.892		8.938	5.904	5.840	6.653
Peak kWh (¢/kWh)			14.442				
Off-Peak kWh (¢/kWh)			5.822				
Demand Charge (\$/kW) 1st 5kW							2.220
Demand Charge (\$/kW) > 5 kW							7.919

Table D Calculation of Rate Adjustment Factors

	<u>SC1</u>	<u>SC5</u>	<u>SC3</u>	<u>SC2 ND</u>	<u>SC4</u>	<u>SC6</u>	<u>SC2 Dem</u>
Total BGS Revenue (Excl SUT) - in \$1000							
Summer	\$ 26,088	\$ 425	\$ 7	\$ 846	\$ 69	\$ 74	\$ 12,141
Winter	\$ 41,370	\$ 902	\$ 16	\$ 2,054	\$ 204	\$ 215	\$ 22,148
Total	\$ 67,458	\$ 1,327	\$ 23	\$ 2,900	\$ 273	\$ 289	\$ 34,289
Total							
Summer	\$ 39,650						
Winter	\$ 66,909						
Total	\$ 106,559						

Total Supplier Payments - in \$1000

Eastern Division	<u>Total</u>	<u>Transmission</u>	<u>Net BGS</u>
Summer	\$ 43,510	\$ 3,475	\$ 40,035
Winter	\$ 63,696	\$ 6,951	\$ 56,745
Total	\$ 107,205	\$ 10,426	\$ 96,779
Central/Western Division	<u>Total</u>	<u>Transmission</u>	<u>Net BGS</u>
Summer	\$ 3,390	\$ -	\$ 3,390
Winter	\$ 4,909	\$ -	\$ 4,909
Total	\$ 8,299	\$ -	\$ 8,299
Total RECO FP	<u>Total</u>	<u>Transmission</u>	<u>Net BGS</u>
Summer	\$ 46,900	\$ 3,475	\$ 43,425
Winter	\$ 68,605	\$ 6,951	\$ 61,654
Total	\$ 115,504	\$ 10,426	\$ 105,078
Differences	<u>BGS Revenue</u>	<u>BGS Costs</u>	<u>Difference</u>
Summer	\$ 39,650	\$ 43,425	\$ 3,775
Winter	\$ 66,909	\$ 61,654	\$ (5,255)
Total	\$ 106,559	\$ 105,078	\$ (1,481)

Rate
 Adjustment
 Factors
1.0952
0.92146

Table E Final Retail BGS Rates (¢/kWh)

Rates Excluding SUT:

	<u>SC1</u>	<u>SC5</u>	<u>SC3</u>	<u>SC2 ND</u>	<u>SC4</u>	<u>SC6</u>	<u>SC2 Dem</u>
<u>Summer</u>							
All kWh (¢/kWh)	9.938	9.172		9.918	5.441	5.441	6.735
Peak kWh (¢/kWh)			16.155				
Off-Peak kWh (¢/kWh)			5.392				
Block1	8.984	7.626					
Block2	10.656	9.312					
Block3	NA	10.450					
Demand Charge (\$/kW) 1st 5kW							2.257
Demand Charge (\$/kW) > 5 kW							7.850
<u>Winter</u>							
All kWh (¢/kWh)	10.144	8.194		8.236	5.440	5.381	6.130
Peak kWh (¢/kWh)			13.308				
Off-Peak kWh (¢/kWh)			5.365				
Demand Charge (\$/kW) 1st 5kW							2.046
Demand Charge (\$/kW) > 5 kW							7.297

Rates Including SUT:

	SUT @						
			7.0%				
	<u>SC1</u>	<u>SC5</u>	<u>SC3</u>	<u>SC2 ND</u>	<u>SC4</u>	<u>SC6</u>	<u>SC2 Dem</u>
<u>Summer</u>							
All kWh (¢/kWh)				10.612	5.822	5.822	7.206
Peak kWh (¢/kWh)			17.286				
Off-Peak kWh (¢/kWh)			5.769				
Block1	9.613	8.160					
Block2	11.402	9.964					
Block3	NA	11.182					
Demand Charge (\$/kW) 1st 5kW							2.4100
Demand Charge (\$/kW) > 5 kW							8.4000
<u>Winter</u>							
All kWh (¢/kWh)	10.854	8.768		8.813	5.821	5.758	6.559
Peak kWh (¢/kWh)			14.240				
Off-Peak kWh (¢/kWh)			5.741				
Demand Charge (\$/kW) 1st 5kW							2.1900
Demand Charge (\$/kW) > 5 kW							7.8100

Table F Spreadsheet Error Checking

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

	<u>SC1</u>	<u>SC5</u>	<u>SC3</u>	<u>SC2 ND</u>	<u>SC4</u>	<u>SC6</u>	<u>SC2 Dem</u>
Summer	\$ 28,573	\$ 466	\$ 8	\$ 926	\$ 75	\$ 81	\$ 13,296
Winter	\$ 38,119	\$ 831	\$ 14	\$ 1,893	\$ 188	\$ 198	\$ 20,407
Total	\$ 66,692	\$ 1,297	\$ 22	\$ 2,819	\$ 263	\$ 279	\$ 33,703
Total Summer	\$ 43,425						
Total Winter	\$ 61,650						
Total	\$ 105,075						

Supplier Payments - in \$1000

Eastern Division

	<u>Total</u>	<u>Transmission</u>	<u>Net BGS</u>
Summer	\$ 43,510	\$ 3,475	\$ 40,035
Winter	\$ 63,696	\$ 6,951	\$ 56,745
Total	\$ 107,205	\$ 10,426	\$ 96,779

Central/Western Division

	<u>Total</u>	<u>Transmission</u>	<u>Net BGS</u>
Summer	\$ 3,390	\$ -	\$ 3,390
Winter	\$ 4,909	\$ -	\$ 4,909
Total	\$ 8,299	\$ -	\$ 8,299

Total RECO FP

	<u>Total</u>	<u>Transmission</u>	<u>Net BGS</u>
Summer	\$ 46,900	\$ 3,475	\$ 43,425
Winter	\$ 68,605	\$ 6,951	\$ 61,654
Total	\$ 115,504	\$ 10,426	\$ 105,078

Differences

	<u>BGS Revenue</u>	<u>BGS Costs</u>	<u>Difference</u>
Summer	\$ 43,425	\$ 43,425	\$ (0)
Winter	\$ 61,650	\$ 61,654	\$ 4
Total	\$ 105,075	\$ 105,078	\$ 3

ROCKLAND ELECTRIC COMPANY
2015 BGS Auction

TABLE-G Development of 2015/16 Incremental RPM Cost - \$/MWh

	2015/16 Delivery Year	Notes:
1 Incremental RPM Cost - \$/MW-day	\$50.00	illustrative assumption
2 BGS-RSCP Gen Obl - MW	432.3	from Table #9 of the current Bid Factor Spreadsheet
3 Days in Year	<u>365</u>	
4 Incremental Annual RPM Cost	\$7,889,147	= line 1 * line 2 * line 3
5 Applicable Customer Usage @ transmission nodes - <i>in MWh</i>	1,047,107	from Table #A of the Weighted Average Price Calculation
6 Incremental Annual RPM Cost - \$/MWh	\$7.53	= line 4 / line 5 - rounded to 2 decimal places