STATE OF NEW JERSEY
BOARD OF PUBLIC UTILITIES

IN THE MATTER OF THE PROVISION OF BASIC GENERATION SERVICE FOR THE PERIOD BEGINNING JUNE 1, 2010	Docket No. EO09050351

ROCKLAND ELECTRIC COMPANY

PROPOSAL FOR BASIC GENERATION SERVICE REQUIREMENTS TO BE PROCURED EFFECTIVE JUNE 1, 2010

COMPANY SPECIFIC ADDENDUM COMPLIANCE FILING

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July 1, 2009

Revised: November 24, 2009

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RECO's COMPANY SPECIFIC ADDENDUM

A. Introduction to RECO's Company Specific Filing

In it Decision and Order dated May 20, 2009 in Docket EO09050351, 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, 2009 on the procurement of basic generation service ("BGS") for the period beginning June 1, 2010. 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, 2010, filed by New Jersey's four EDCs on July 1, 2009 ("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 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 January 20, 2009 in Docket No. ER08050310 (“January 20, 2009 Order”), the Board maintained the current level for the BGS-CIEP class, beginning June 1, 2009, to include all commercial and industrial customers with a peak load share of 1,000 kW and greater.[2] The January 20, 2009 Order also directed Staff, in conjunction with input from the Energy Master Plan, to review this issue to determine if further mandatory expansion of the CIEP class for future procurement periods is warranted. RECO will comply with future determinations on this issue and continue to comply with this directive and include these customers as one tranche (at 75 MW of BGS-CIEP eligible load per tranche) in the BGS-CIEP

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

[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.

Auction. RECO will continue to assess a Retail Margin of 5 mills/kWh for all BGS-CIEP customers, as well as BGS-FP customers with a load of 750 kW or greater.

As to the BGS-FP Auction, RECO currently has one 36-month tranche that terminates on May 31, 2010, two 36-month tranches that terminate on May 31, 2011, and one 36-month tranche that terminates on May 31, 2012. 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, 2010, RECO will include one 36-month tranche (for the period June 1, 2010 through May 31, 2013).

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, 2010; 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 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 2010 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.

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

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

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

(b) Defaults prior to June 1, 2010.

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, 2011. 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, 2011.

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

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[5] 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 each month on a cents per kWh basis. The BGS-FP and BGS-CIEP Reconciliation Charges will be published in separate BGS Reconciliation Charge tariff leaves on a monthly basis.

[5] Retail Margin revenues and Board-approved expenses will be tracked using established accounting procedures and will be subject to deferred accounting. These revenues will be recorded separately as Retail Margin revenue and shall not be included in the calculations of reconciliation charges.

These tariff leaves will be filed with the Board approximately two days prior to the first day of the effective month.

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 for a month “x” will be computed in month x+1 and assessed through the BGS-FP and BGS-CIEP Reconciliation Charges applied to customers’ bills for month x+2. Two of these differences are shown below:

1. The difference between BGS Costs (as defined above; this amount is known in month x+1) and the month “x” BGS revenue (which is also determined in month x+1). This difference will be calculated in month x+1 for recovery in month x+2.
2. The difference between the total reconciliation charge revenue intended to be recovered in month “x” and the actual reconciliation charge revenue recovered in month “x”. This difference will be driven by differences between actual kWh in the month in which the reconciliation charge was assessed and the kWh used to calculate the charge. This amount will be known in month x+1.

The reconciliation charges to be applied in month x+2 are calculated individually for BGS-FP and BGS-CIEP service as the net of the two differences described above for month “x” (plus or minus any cumulative under or over recovery from prior months) divided by the forecasted BGS kWh in month “x+2”.

Interest will apply 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 monthly 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. Final tariff leaves including the actual BGS rates and tariff provisions to become effective on June 1, 2010 will be filed with the Board upon its issuance of an appropriate Board order approving the BGS Auction Process.

G. RECO RFP

On January 3, 2007, RECO issued an RFP for four separate financial swaps. One pertained to the forecasted capacity requirement (i.e., 52 MW) for RECO's BGS customers located in its non-PJM areas (i.e., RECO's Central and Western Divisions). The other three financial swaps pertained to the energy requirements of RECO's BGS customers located in RECO's Central and Western Divisions for the annual periods commencing June 1, 2007, June 1, 2008, and June 1, 2009, respectively. RECO sought proposals for each of these swaps. The purpose of these swap arrangements was to secure a favorable fixed price for RECO's capacity needs over a three year term, and energy needs over separate annual terms.

RECO received responses to the RECO RFP via a web-based reverse blind auction held on January 23, 2007. After reviewing these responses, both RECO and

Staff recommended that the Board approve energy swaps for each of the three annual terms, and a capacity swap for the entire three-year term. At its open session on January 25, 2007, the Board approved the results of the RECO RFP. Accordingly, RECO entered into energy swap agreements for the annual periods commencing June 1, 2007, June 1, 2008, and June 1, 2009, and a capacity swap agreement for the entire three-year period.

RECO proposes a similar competitive bid process to secure the full service requirements of its Central and Western Divisions commencing June 1, 2010. Specifically, RECO proposes to utilize an auction format to seek separate proposals for (1) energy swap agreements for annual periods commencing June 1, 2010, 2011, and 2012, and (2) a capacity swap agreement for the entire three-year period (i.e., June 1, 2010 through May 31, 2013). RECO anticipates that it will issue an RFP in December 2009 setting forth the details of the auction process and providing potential bidders with the documentation that will be used. As before, one financial swap will pertain to the forecasted capacity requirement and the other financial swaps will pertain to the forecasted energy requirements of RECO's BGS customers located in RECO's Central and Western Divisions.[6] Each of these financial swaps would be for 100% of the energy and capacity requirements of RECO's Central and Western Divisions.

RECO would propose to hold this auction approximately two weeks before the commencement of the BGS Auction. Specifically, RECO would utilize a

[6] Since there is no active, liquid market for ancillary services, RECO would be unable economically to utilize commodity swap transactions to lock in their price. Rather, RECO would purchase ancillary services, as required, through the NYISO.

web-based reverse blind auction with pre-approved bidders.[7] This auction would be administered by an independent third-party. RECO is in the process of finalizing the documentation for the auction and expects to circulate it to the parties to this proceeding in the near future.[8]

For each swap, on the day of the auction, RECO would establish a predetermined opening bid, based upon then current market prices, plus an adder (e.g., 10%). The auction would last for a predetermined period (e.g., 15 minutes), during which bidders could submit bids. The auction would employ a "hard stop", which means that at the conclusion of the predetermined period, the auction would end and the lowest bidder at that point would be declared the winner. During the auction, each bidder only would be allowed to see its own bid as well as the current lowest bid. Bidders would be "blind" to all other bids, as well as the identity of the bidder submitting the then current lowest bid. Representatives of RECO, the Board, and the New Jersey Department of the Public Advocate, Division of Rate Counsel, would be allowed to view the bids submitted by all bidders, although they would not be informed as to the identities of the bidders.

At the end of the auction, RECO would evaluate the proposals submitted by bidders to determine which proposals, over what annual time periods, are in the best

[7] In the event that any of RECO's affiliates participate in this auction, RECO will implement protocols so that such affiliate does not receive an advantage in either the solicitation and evaluation of competitive bids, or any other aspect of the competitive process. The format employed in a web-based reverse blind auction, when administered by an independent third-party, is particularly well suited to safeguarding the competitiveness of the procurement process.

[8] The auction documentation will include a Request for Proposal, Transaction Confirmation, Binding Bid Agreement, Pre-Bid Letter of Credit, Payment Guaranty, and Irrevocable Transferable Standby Letter of Credit Format.

economic interests of its BGS customers.[9] RECO then would present its recommendation(s) to the Board's representatives. The Board (or its representatives) would then determine whether the winning bid(s) should be accepted or rejected. RECO reserves the right to reject any and all winning bids. A major benefit of obtaining bids through a web-based auction is that this auction format significantly reduces the award time (to as little as a few hours). This expedited decision making process reduces the time (and corresponding risk) that a bid remains open, thereby allowing bidders to reduce the risk premium included in their bids. This results in savings to customers. Both RECO and Orange and Rockland have successfully utilized this auction format. RECO proposes that the Board issue its decision on the auction results within two business days of the conclusion of the auction.

Since the RFP administered by RECO would involve commodity swap transactions, RECO must still purchase the physical electric supply needed to meet its full service obligations. RECO intends to make such purchases from markets administered by the NYISO.

As approved by the Board, RECO will continue to average the RECO RFP price with the RECO BGS-FP prices to determine the rates for those customers taking BGS-FP service.

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[9] By seeking separate bids for (i) annual periods for energy commencing June 1, 2010, 2011, 2012, respectively, and (ii) capacity for the entire three-year period, RECO (after Board review and approval) retains the flexibility to lock in energy prices for one, two or three years, depending on the relative attractiveness of the bids submitted in light of market price forecasts.

H. BGS Rate Design Methodology

<u>RECO BGS Pricing Spreadsheet</u>

As described in the EDC Compliance Filing, the resulting charge for each BGS rate element (e.g., Service Classification No. 1 summer charge, winter charge) for BGS supply service will be based on a factor applied to the tranche weighted average of the winning BGS-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 2008 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 2009.

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 2010 to May 2011, and an estimate based on off/on peak LMP ratios for the off-peak periods of each month. The NYISO values are based on a combination of forward and historical prices. An adjustment to the PJM forward prices used to calculate the prices contained in Table #4 must be made to correct for the effects of the basis differential in the PJM system between the PJM West trading hub and the RECO zone where the BGS supply will be utilized. Table #18 contains an estimate of this basis differential, by month and time period, which when multiplied by the prices at the PJM West trading hub will result in costs for power delivered into RECO's PJM zone.

Table #5 (Losses) contains the factors utilized for average system losses, including PJM losses and unaccounted for supply (net of marginal losses) that are input by service classification and voltage level. Loss factors are those in RECO's current, Board approved, Third Party Supplier Agreement. PJM losses are the average percentage PJM EHV losses plus Inadvertent Energy for the period of June 2006 to May 2009, which equals 0.4908%. Marginal losses are excluded from the loss factors based on historic de-rating factors for the period July 2007 to February 2009.

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 2009. 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 2010 to 2013 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. These seasonal factors are calculated for illustrative purposes (please refer to the description under Table A).

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.[10] From these values, the weighted average

[10] The prices shown for the tranches to be secured in the 2010 auction and RFP are for illustrative purposes only, and will be replaced with actual data in determining RECO's final June 2010 BGS-FP rates.

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.” Since the seasonal factors for the 12-month BGS period beginning June 1, 2010 (as calculated in Table #16) produces atypical results, 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-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.

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 for the 90% portion of the load 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 to utilize an auction format to seek separate proposals for financial swaps for the forecasted capacity and energy requirements for the BGS customers located in RECO’s 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.

Draft

GENERAL INFORMATION

No. 28 BASIC GENERATION SERVICE ("BGS"): (Continued)

(A) 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.XXX ¢	X.XXX ¢
1 – Over 250 kWh	X.XXX ¢	X.XXX ¢
2 (Non-Demand Billed) – All kWh	X.XXX ¢	X.XXX ¢
3 – Peak	X.XXX ¢	X.XXX ¢
3 – Off-Peak	X.XXX ¢	X.XXX ¢
4 – All kWh	X.XXX ¢	X.XXX ¢
5 – First 250 kWh	X.XXX ¢	X.XXX ¢
5 – Next 450 kWh	X.XXX ¢	X.XXX ¢
5 – Over 700 kWh	X.XXX ¢	X.XXX ¢
6 – All kWh	X.XXX ¢	X.XXX ¢

Applicable to Service Classification No. 2 Demand Billed customers who do not take BGS-CIEP service in accordance with General Information Section No. 28(B):

	Summer Months*	Other Months
Demand Charges		
First 5 kW ($/kW)	No Charge	No Charge
Over 5 kW ($/kW)	X.XXX	X.XXX
Usage Charges		
All kWh (¢/kWh)	X.XXX ¢	X.XXX ¢

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

* Definition of Summer Billing Months
June through September

(Continued)

Draft

GENERAL INFORMATION

No. 28 BASIC GENERATION SERVICE ("BGS"): (Continued)

(B) 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 1,000 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. 28(A).

<u>BGS Energy Charges:</u>
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, plus a retail margin at the rate of $0.00535 per kilowatthour and applicable taxes.

<u>BGS Capacity Charges:</u>
Charges per kilowatt of Capacity Obligation as determined in accordance with General Information Section No. 28(C):

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

The above charges shall recover each customer's share of the overall summer peak load assigned to the Rockland Electric Transmission Zone by the PJM Interconnection, L.L.C. ("PJM") as adjusted by PJM assigned capacity related factors.

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

* June through September

(Continued)

Development of BGS Cost and Bid Factors for Rates Effective June 1, 2010

Based on 2008 Load Profile Information

Table #1 **% Usage During PJM On-Peak Period** *On-Peak periods defined as the 16 hr PJM Trading period, adj for NERC holidays*

	Profile Meter Data	*Profile Meter Data*	*Profile Meter Data*	*Profile Meter Data*	*--- Other Analysis ---*		*Profile Meter Data*
	SC1	**SC5**	**SC3**	**SC2 ND**	**SC4**	**SC6**	**SC2 Dem**
January	49.38%	48.68%	42.86%	45.86%	30.99%	30.99%	52.73%
February	52.17%	49.37%	46.41%	47.54%	32.68%	32.68%	54.28%
March	50.93%	49.63%	44.92%	46.19%	32.52%	32.52%	55.06%
April	52.92%	52.16%	50.75%	52.07%	33.32%	33.32%	57.47%
May	47.47%	46.52%	44.81%	47.97%	29.50%	29.50%	52.80%
June	54.62%	51.41%	52.70%	55.10%	33.52%	33.52%	59.32%
July	58.14%	53.99%	56.70%	56.43%	33.91%	33.91%	58.48%
August	52.78%	49.30%	51.84%	54.86%	30.92%	30.92%	53.47%
September	54.37%	51.25%	53.41%	57.30%	33.60%	33.60%	58.17%
October	52.66%	40.63%	52.43%	51.56%	27.46%	27.46%	55.94%
November	51.93%	42.82%	51.66%	45.24%	31.53%	31.53%	54.70%
December	55.12%	45.59%	55.26%	50.14%	34.86%	34.86%	56.62%

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	----	----	35.18%	----	----	----	----
February	----	----	35.79%	----	----	----	----
March	----	----	34.42%	----	----	----	----
April	----	----	33.57%	----	----	----	----
May	----	----	35.00%	----	----	----	----
June	----	----	39.97%	----	----	----	----
July	----	----	36.47%	----	----	----	----
August	----	----	35.82%	----	----	----	----
September	----	----	35.74%	----	----	----	----
October	----	----	35.98%	----	----	----	----
November	----	----	34.29%	----	----	----	----
December	----	----	32.72%	----	----	----	----

Table #3 **Class Usage @ customer**
Calendar month billed sales forecasted for 2009
in MWh

	SC1	SC5	SC3	SC2 ND	SC4	SC6	SC2 Dem	Total FP
January	64,393	2,067	32	5,019	719	494	55,021	127,745
February	56,458	2,072	25	4,756	591	439	51,926	116,267
March	50,022	1,542	24	4,291	592	428	48,549	105,448
April	45,383	1,309	22	3,750	498	424	48,994	100,380
May	46,905	1,147	16	2,986	470	420	51,708	103,652
June	66,842	1,317	24	3,324	416	398	55,198	127,519
July	88,881	1,859	28	3,656	436	389	61,981	157,230
August	89,374	1,859	29	3,626	496	372	62,060	157,816
September	74,767	1,637	24	3,410	545	438	58,704	139,525
October	56,450	1,247	17	2,977	631	504	53,411	115,237
November	50,721	1,373	19	3,117	670	557	49,803	106,260
December	61,832	1,937	27	3,907	729	524	55,653	124,609
Total	752,028	19,366	287	44,819	6,793	5,387	653,008	1,481,688

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

	On-Peak	Off-Peak
January	82.71	57.16
February	82.71	57.16
March	71.78	49.22
April	71.78	49.17
May	66.72	45.49
June	66.16	41.78
July	80.77	51.02
August	80.77	51.02
September	63.60	40.16
October	66.30	45.29
November	66.30	45.29
December	66.30	45.29

Table #5 **Losses**

	SC1	SC5	SC3	SC2 ND	SC4	SC6	SC2 Dem
Expansion Factor =	1.08520	1.08520	1.08520	1.08520	1.08142	1.08142	1.08520
Expansion Factor (net Marginal Losses)	1.06911	1.06911	1.06911	1.06911	1.06539	1.06539	1.06911

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		$ 66.75	$ 65.67	$ 66.18	$ 66.46	$ 59.11	$ 58.98	$ 66.84
	PJM on pk	$ 80.06	$ 79.98	$ 79.86	$ 79.30	$ 78.36	$ 78.17	$ 79.18
	PJM off pk	$ 50.46	$ 50.48	$ 50.32	$ 50.17	$ 49.65	$ 49.51	$ 50.30
Winter - all hrs		$ 66.39	$ 66.07	$ 66.21	$ 66.30	$ 61.11	$ 60.81	$ 66.94
	PJM on pk	$ 78.20	$ 79.46	$ 78.59	$ 79.05	$ 77.86	$ 77.53	$ 77.90
	PJM off pk	$ 53.78	$ 54.11	$ 54.60	$ 54.46	$ 53.35	$ 53.08	$ 53.57
Annual		$ 66.54	$ 65.93	$ 66.20	$ 66.35	$ 60.56	$ 60.27	$ 66.90
System Total		$ 66.64						

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		$ 21,350	$ 438	$ 7	$ 931	$ 112	$ 94	$ 15,905
	PJM on pk	$ 14,092	$ 275	$ 5	$ 622	$ 49	$ 41	$ 10,793
	PJM off pk	$ 7,258	$ 163	$ 2	$ 310	$ 63	$ 53	$ 5,112
Winter - all hrs		$ 28,691	$ 839	$ 12	$ 2,042	$ 299	$ 230	$ 27,783
	PJM on pk	$ 17,452	$ 476	$ 7	$ 1,173	$ 121	$ 93	$ 17,763
	PJM off pk	$ 11,240	$ 363	$ 5	$ 870	$ 179	$ 138	$ 10,020
Annual		$ 50,041	$ 1,277	$ 19	$ 2,974	$ 411	$ 325	$ 43,688
System Total		$ 98,735						

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		$ 66.75	$ 65.67	$ 66.18	$ 66.46	$ 59.11	$ 58.98	$ 66.84
	RECO On pk			$ 84.81				
	RECO Off pk			$ 55.27				
Winter - all hrs		$ 66.39	$ 66.07	$ 66.21	$ 66.30	$ 61.11	$ 60.81	$ 66.94
	RECO On pk			$ 81.91				
	RECO Off pk			$ 57.92				
Annual Average		$ 66.54	$ 65.93	$ 66.20	$ 66.35	$ 60.56	$ 60.27	$ 66.90
System Average		$ 66.64						

Table #9 **Generation & Transmission Obligations and Costs and Other Adjustments**
Obligations - annual average forecasted for 2009; costs are market estimates

in MW	SC1	SC5	SC3	SC2 ND	SC4	SC6	SC2 Dem	Total FP
Gen Obl - MW	310.237	4.758	0.052	9.064	0.000	0.000	150.610	474.721
Trans Obl - MW	347.808	3.576	0.047	6.167	0.000	0.000	109.862	467.460

# 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

Generation Capacity cost	summer	$141.97 $/MW/day	Resulting avg gen cap cost =	summer >> $	51.82 per kW/yr
(see Table 19)	winter	$134.18 $/MW/day		winter >> $	48.98 per kW/yr

---------- SC1 ----------	Charges		% usage	---------- SC5 ----------	Chgs (¢/kWh)	Differences	% usage
Block 1 (0-250 kWh/month)	12.477	¢/kWh	18.86%	Block 1 (0-250 kWh/month)	11.776		29.94%
Block 2 (>250 kWh/m)	13.362	¢/kWh	81.14%	Block 2 (251-700 kWh/month)	12.666	0.890	35.59%
Calculated inversion =	0.885	¢/kWh		Block 3 (>700 kWh/month)	13.267	1.491	34.48%

Table #10 **Ancillary Services**
forecasted overall annual average $2.91 /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	$ 14.85	$ 5.93	$ 5.21	$ 4.42	$ -	$ -
Generation Obl -						
per annual MWh	$ 20.60	$ 12.27	$ 9.01	$ 10.10	$ -	$ -
per summer MWh	$ 16.80	$ 12.35	$ 8.54	$ 11.20	$ -	$ -
per winter MWh	$ 23.41	$ 12.22	$ 9.28	$ 9.59	$ -	$ -

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		$ 101.31	$ 86.86	$ 82.85	$ 84.99	$ 62.02	$ 61.89
	RECO On pk			$ 116.07			
	RECO Off pk			$ 63.39			
	Block 1	$ 94.13	$ 78.55				
	Block 2	$ 102.98	$ 87.45				
	Block 3		$ 93.46				
Winter - all hrs		$ 107.56	$ 87.13	$ 83.61	$ 83.23	$ 64.02	$ 63.72
	RECO On pk			$ 116.88			
	RECO Off pk			$ 66.04			
Annual -all hrs		$ 104.90	$ 87.04	$ 83.33	$ 83.78	$ 63.47	$ 63.18

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

	SC2 Dem
Summer - all hrs	$ 69.75
Winter - all hrs	$ 69.85
Annual - all hrs per MWh only	$ 69.81

PLUS:

Gen Cost (per kW of Billed Demand/Month)

	SC2 Dem
summer	$ 4.123
winter	$ 4.406

Trans cost

all months	$ 2.68	per kW of T obl /month

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

Including T&G Obligation $		
Summer - all hrs	$	85.66
Winter - all hrs	$	87.34
Annual - including T&G Obl $	$	86.73

ALL RATES

Grand Total Cost in $1000 =	$	141,760	
All-In Average cost @ customer =	$	95.67	per MWh at customer (per customer metered MWh)
All-In Average costs @ transmission nodes =	$	89.49	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		**1.132**	**0.971**		**0.950**	**0.693**	**0.692**
	RECO On pk			**1.297**			
	RECO Off pk			**0.708**			
	Constant Blk 1	**$ (7.18)**	**$ (8.31)**				
	Constant Blk 2	**$ 1.67**	**$ 0.59**				
	Constant Blk 3	NA	**$ 6.60**				
Winter - all hrs		**1.202**	**0.974**		**0.930**	**0.715**	**0.712**
	RECO On pk			**1.306**			
	RECO Off pk			**0.738**			
Annual - all hrs		1.172	0.973	0.931	0.936	0.709	0.706

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

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

	SC2 Dem Multiplier		SC2 Dem Constant
Summer - all hrs	**0.957**	**$**	**(15.907)**
Winter - all hrs	**0.976**	**$**	**(17.497)**
Annual - including T&G Obl $	0.969		

PLUS:

Gen Cost (per kW of Billed Demand/Month)

		SC2 Dem	
summer	$	4.123	
winter	$	4.406	
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		$ 86.46	$ 80.93	$ 77.63	$ 80.57	$ 62.02	$ 61.89
	RECO On pk			$ 110.86			
	RECO Off pk			$ 58.18			
	Block 1	$ 79.27	$ 72.62				
	Block 2	$ 88.12	$ 81.52				
	Block 3		$ 87.53				
Winter - all hrs		$ 92.71	$ 81.20	$ 78.40	$ 78.81	$ 64.02	$ 63.72
	RECO On pk			$ 111.66			
	RECO Off pk			$ 60.83			
Annual -all hrs		$ 90.05	$ 81.11	$ 78.12	$ 79.36	$ 63.47	$ 63.18

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	$	69.75
Winter - all hrs	$	69.85
Annual - all hrs per MWh only	$	69.81
Including Generation Obligation $		
Summer - all hrs	$	80.72
Winter - all hrs	$	81.68
Annual - including T&G Obl $	$	81.33

PLUS:

Gen Cost (per kW of Billed Demand/Month)

		SC2 Dem
summer	$	4.123
winter	$	4.406

ALL RATES

Grand Total Cost in $1000 = $ 126,748
All-In Average cost @ customer = $ 85.54 per MWh at customer (per customer metered MWh)
All-In Average costs @ tansmission nodes = $ 80.02 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		**1.080**	**1.011**		**1.007**	**0.775**	**0.773**
	RECO On pk			**1.385**			
	RECO Off pk			**0.727**			
	Constant Blk 1	**$ (7.18)**	**$ (8.31)**				
	Constant Blk 2	**$ 1.67**	**$ 0.59**				
	Constant Blk 3	NA	**$ 6.60**				
Winter - all hrs		**1.159**	**1.015**		**0.985**	**0.800**	**0.796**
	RECO On pk			**1.395**			
	RECO Off pk			**0.760**			
Annual - all hrs		1.125	1.014	0.976	0.992	0.793	0.790

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	**1.009**	**(10.964)**
Winter - all hrs	**1.021**	**(11.830)**
Annual - including T&G Obl $	**1.016**	

PLUS:

Gen Cost (per kW of Billed Demand/Month)

	SC2 Dem
summer	$ 4.123
winter	$ 4.406

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	$ 32,405	$ 580	$ 9	$ 1,191	$ 117	$ 99	$ 20,383
Winter	$ 46,483	$ 1,106	$ 15	$ 2,564	$ 314	$ 241	$ 36,253
Total	$ 78,888	$ 1,686	$ 24	$ 3,755	$ 431	$ 340	$ 56,636
% of Annual Total $ by Rate							
Summer	41%	34%	36%	32%	27%	29%	36%
Winter	59%	66%	64%	68%	73%	71%	64%

Total Costs - in $1000	
Summer	$ 54,783
Winter	$ 86,977
Total	$ 141,760

% of Annual Total $		If total $ were split on a per MWh basis (on transmission node MWhs):	Ratio to All-In Cost	
Summer	39%	$ 88.03 per MWh @ transmission nodes	Summer	**0.9837**
Winter	61%	$ 90.44 per MWh @ transmission nodes	Winter	**1.0106**

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	$ 27,654	$ 540	$ 8	$ 1,129	$ 117	$ 99	$ 19,207
Winter	$ 40,064	$ 1,031	$ 14	$ 2,428	$ 314	$ 241	$ 33,901
Total	$ 67,718	$ 1,571	$ 22	$ 3,557	$ 431	$ 340	$ 53,108
% of Annual Total $ by Rate							
Summer	41%	34%	36%	32%	27%	29%	36%
Winter	59%	66%	64%	68%	73%	71%	64%

Total Costs - in $1000	
Summer	$ 48,754
Winter	$ 77,993
Total	$ 126,748

% of Annual Total $		If total $ were split on a per MWh basis (on transmission node MWhs):	Ratio to All-In Cost	
Summer	38%	$ 78.34 per MWh @ transmission nodes	Summer	**0.9791**
Winter	62%	$ 81.10 per MWh @ transmission nodes	Winter	**1.0135**

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	71.00	0.72	50.94	115%	109%	81.87	55.42
February	71.00	0.72	50.94	115%	109%	81.87	55.42
March	61.75	0.72	44.30	115%	109%	71.20	48.20
April	61.75	0.72	44.30	115%	109%	71.20	48.20
May	57.25	0.72	41.07	115%	109%	66.01	44.68
June	61.38	0.63	38.57	106%	106%	65.25	41.01
July	75.44	0.63	47.41	106%	106%	80.19	50.41
August	75.44	0.63	47.41	106%	106%	80.19	50.41
September	58.85	0.63	36.98	106%	106%	62.56	39.32
October	56.88	0.72	40.81	115%	109%	65.59	44.40
November	56.88	0.72	40.81	115%	109%	65.59	44.40
December	56.88	0.72	40.81	115%	109%	65.59	44.40

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

	On-Peak	Off-Peak
January	89.50	71.25
February	89.50	71.25
March	76.50	57.50
April	76.50	57.00
May	72.50	52.00
June	73.50	48.00
July	85.50	56.00
August	85.50	56.00
September	72.00	47.00
October	72.00	52.50
November	72.00	52.50
December	72.00	52.50

Weighted Average Forward Prices - Energy Only @ bulk system (89.7% PJM - 10.3% NYISO)
in $/MWh

	On-Peak	Off-Peak
January	82.71	57.16
February	82.71	57.16
March	71.78	49.22
April	71.78	49.17
May	66.72	45.49
June	66.16	41.78
July	80.77	51.02
August	80.77	51.02
September	63.60	40.16
October	66.30	45.29
November	66.30	45.29
December	66.30	45.29

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

	PJM 89.7%	NYISO 10.3%	Weighted Average
Summer	$141.38	147.07	$141.97
Winter	$141.38	71.27	$134.18

Table #20 **Ancillary Services**

PJM 89.7%	NYISO 10.3%	Weighted Average
$3.00	$2.14	$2.91

Assumptions:

Gen Cost =	$141.97	per MW-day in summer
	$134.18	per MW-day in winter
Trans cost =	$ 32,114	per MW-yr
Analysis time period =	4	summer months
	8	winter months
Ancillary Services =	$ 2.91	/MWh
Energy Costs =	Based on 6/10 to 5/11 Forwards @ PJM West as of 6/9/09	
	Based on 6/10 to 5/11 Forwards @ NYISO Zone G as of 6/10/09	
Usage patterns =	Forecasted 2009 energy use by class, PJM on/off % from 2008 class load profiles, RECO billing on/off % from 6/08 to 5/09 actual data	
Obligations =	Class totals for 2009	
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 >>	2008 Auction 36 Month	2009 Auction 36 Month	2010 Auction 36 Month	Total	Notes:
1	Tranches	2	1	1	4	From then-current auction
2	Winning Bid Price (¢/kWh)*	12.049	11.270	**11.270**		Winning Bids. Note: 11.270¢ for 2010 auction is simply illustrative
3	Transmission (¢/kWh)	0.948	0.948	0.948		Average transmission cost included in bid
4	BGS (¢/kWh)	11.101	10.322	10.322		=(2) - (3)
5	Weighted Avg BGS	5.551	2.581	2.581	10.712	= (1) / Total Tranches * (4)
6	Weighted Avg Trans	0.474	0.237	0.237	0.948	= (1) / Total Tranches * (3)
7	Weighted Avg Total Price (¢/kWh)				**11.660**	
	Seasonal Payment Factors					
8	Summer	1.0395	1.0271	1.0000 **		From then-current Bid Factor Spreadsheet
9	Winter	0.9743	0.9822	1.0000 **		From then-current Bid Factor Spreadsheet
	Applicable Customer Usage @ tansmission nodes			(Eastern Division)		
10	Summer MWh	558,373				From then-current Bid Factor Spreadsheet
11	Winter MWh	862,932				From then-current Bid Factor Spreadsheet
12		1,421,304				
	Total Cost					
13	Summer	34,967,905	16,158,489	15,732,148	66,858,542	= (1) / Total Tranches * (2) / 100 * (8) * (10) * 1,000
14	Winter	50,651,251	23,880,330	24,313,103	98,844,684	= (1) / Total Tranches * (2) / 100* (9) * (11) * 1,000
15	Total	85,619,156	40,038,819	40,045,251	165,703,226	= (13) + (14)
	Average Cost (NJ Statewide Auction)					
16	Summer	11.974 ¢/kWh				= sum(line 13) / (10) / 1000 * 100 rounded to 3 decimal places
17	Winter	11.455 ¢/kWh				= sum(line 14) / (11) / 1000 * 100 rounded to 3 decimal places
18	Total	**11.659** ¢/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	0.458		4.458	Includes RECO RFP equivalent tranches
20	Price ¢/kWh	11.659	9.582			BGS Auction from (18). Note: 9.582¢ for RFP is illustrative. (excludes transmission).
21	Transmission	0.948	0			
22	BGS	10.711	9.582			= (20) - (21)
23	Weighted Avg BGS	9.611	0.984		10.595	= (19) / Total Tranches * (22)
24	Weighted Avg Trans	0.850	0.000		0.850	= (19) / Total Tranches * (21)
25	**Weighted Avg Total Price**				$\boxed{11.446}$	= (23) + (24)

* Includes Impact of PJM Marginal Losses

** 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		**1.080**	**1.011**		**1.007**	**0.775**	**0.773**
	RECO On pk			**1.385**			
	RECO Off pk			**0.727**			
	Constant Blk 1	**$ (7.18)**	**$ (8.31)**				
	Constant Blk 2	**$ 1.67**	**$ 0.59**				
	Constant Blk 3	NA	**$ 6.60**				
Winter - all hrs		**1.159**	**1.015**		**0.985**	**0.800**	**0.796**
	RECO On pk			**1.395**			
	RECO Off pk			**0.760**			
Annual - all hrs		1.125	1.014	0.976	0.992	0.793	0.790

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	**1.009**	**(10.964)**
Winter - all hrs	**1.021**	**(11.830)**
Annual - including T&G Obl $	**1.016**	

PLUS:

Gen Cost (per kW of Billed Demand/Month)

	SC2 Dem
summer	$ 4.123
winter	$ 4.406

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

All-In Average costs @ Trans node =	$	114.46	/MWh*
Less Transmission	$	(8.51)	/MWh**
BGS Cost	$	105.95	/MWh

* Price from Table A (which does not include transmission for the Central/Western Division).
** RECO average transmission rate of 9.48 minus Central/West transmission contribution to weighted average rate 0.458/4.458 *$9.48 per MWh). $0.97

Retail BGS Rates (excl SUT) (¢/kWh)

	SC1	SC5	SC3	SC2 ND	SC4	SC6	SC2 Dem
Summer							
All kWh (¢/kWh)	11.443	10.712		10.669	8.211	8.190	9.594
Peak kWh (¢/kWh)			14.674				
Off-Peak kWh (¢/kWh)			7.703				
Block1	10.725	9.881					
Block2	11.610	10.771					
Block3	NA	11.372					
Demand Charge ($/kW)							4.123
Winter							
All kWh (¢/kWh)	12.280	10.754		10.436	8.476	8.434	9.635
Peak kWh (¢/kWh)			14.780				
Off-Peak kWh (¢/kWh)			8.052				
Demand Charge ($/kW)							4.406

Table D **Calculation of Rate Adjustment Factors**

Total BGS Revenue (Excl SUT) - in $1000	SC1	SC5	SC3	SC2 ND	SC4	SC6	SC2 Dem
Summer	$ 36,602	$ 715	$ 11	$ 1,495	$ 155	$ 131	$ 25,437
Winter	$ 53,070	$ 1,365	$ 19	$ 3,215	$ 415	$ 320	$ 44,902
Total	$ 89,672	$ 2,080	$ 30	$ 4,710	$ 570	$ 451	$ 70,339

Total	
Summer	$ 64,546
Winter	$ 103,306
Total	$ 167,852

Total Supplier Payments - in $1000

Eastern Division	Total	Transmission	Net BGS
Summer	$ 66,859	$ 4,490	$ 62,369
Winter	$ 98,845	$ 8,980	$ 89,865
Total	$ 165,703	$ 13,470	$ 152,233

Central/Western Division	Total	Transmission	Net BGS
Summer	$ 6,218	$ -	$ 6,218
Winter	$ 9,467	$ -	$ 9,467
Total	$ 15,685	$ -	$ 15,685

Total RECO FP	Total	Transmission	Net BGS
Summer	$ 73,077	$ 4,490	$ 68,587
Winter	$ 108,312	$ 8,980	$ 99,332
Total	$ 181,388	$ 13,470	$ 167,918

Differences	BGS Revenue	BGS Costs	Difference	Rate Adjustment Factors
Summer	$ 64,546	$ 68,587	$ 4,041	**1.0626**
Winter	$ 103,306	$ 99,332	$ (3,974)	**0.96153**
Total	$ 167,852	$ 167,918	$ 66	

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

Rates Excluding SUT:

	SC1	SC5	SC3	SC2 ND	SC4	SC6	SC2 Dem
Summer							
All kWh (¢/kWh)	12.159	11.383		11.337	8.725	8.703	10.195
Peak kWh (¢/kWh)			15.593				
Off-Peak kWh (¢/kWh)			8.185				
Block1	11.396	10.500					
Block2	12.337	11.445					
Block3	NA	12.084					
Demand Charge ($/kW)							4.381
Winter							
All kWh (¢/kWh)	11.808	10.34		10.035	8.150	8.110	9.264
Peak kWh (¢/kWh)			14.211				
Off-Peak kWh (¢/kWh)			7.742				
Demand Charge ($/kW)							4.237

Rates Including SUT: SUT @ 7.0%

	SC1	SC5	SC3	SC2 ND	SC4	SC6	SC2 Dem
Summer							
All kWh (¢/kWh)				12.131	9.336	9.312	10.909
Peak kWh (¢/kWh)			16.685				
Off-Peak kWh (¢/kWh)			8.758				
Block1	12.194	11.235					
Block2	13.201	12.246					
Block3	NA	12.930					
Demand Charge ($/kW)							4.690
Winter							
All kWh (¢/kWh)	12.635	11.064		10.737	8.721	8.678	9.912
Peak kWh (¢/kWh)			15.206				
Off-Peak kWh (¢/kWh)			8.284				
Demand Charge ($/kW)							4.530

Table F **Spreadsheet Error Checking**

Total BGS Revenue (Excl SUT) - in $1000

	SC1	SC5	SC3	SC2 ND	SC4	SC6	SC2 Dem
Summer	$ 38,892	$ 759	$ 11	$ 1,589	$ 165	$ 139	$ 27,030
Winter	$ 51,030	$ 1,313	$ 18	$ 3,091	$ 399	$ 307	$ 43,174
Total	$ 89,922	$ 2,072	$ 29	$ 4,680	$ 564	$ 446	$ 70,204

Total	
Summer	$ 68,585
Winter	$ 99,332
Total	$ 167,917

Supplier Payments - in $1000

Eastern Division

	Total	Transmission	Net BGS
Summer	$ 66,859	$ 4,490	$ 62,369
Winter	$ 98,845	$ 8,980	$ 89,865
Total	$ 165,703	$ 13,470	$ 152,233

Central/Western Division

	Total	Transmission	Net BGS
Summer	$ 6,218	$ -	$ 6,218
Winter	$ 9,467	$ -	$ 9,467
Total	$ 15,685	$ -	$ 15,685

Total RECO FP

	Total	Transmission	Net BGS
Summer	$ 73,077	$ 4,490	$ 68,587
Winter	$ 108,312	$ 8,980	$ 99,332
Total	$ 181,388	$ 13,470	$ 167,918

Differences

	BGS Revenue	BGS Costs	Difference
Summer	$ 68,585	$ 68,587	$ 2
Winter	$ 99,332	$ 99,332	$ (0)
Total	$ 167,917	$ 167,918	$ 1