

STATE OF NEW JERSEY
BOARD OF PUBLIC UTILITIES

IN THE MATTER OF THE PROVISION
OF BASIC GENERATION SERVICE FOR
THE PERIOD BEGINNING JUNE 1, 2012

Docket No. EO11040250

ROCKLAND ELECTRIC COMPANY

**PROPOSAL FOR
BASIC GENERATION SERVICE
REQUIREMENTS TO BE PROCURED EFFECTIVE
JUNE 1, 2012**

**COMPANY SPECIFIC ADDENDUM
COMPLIANCE FILING**

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July 1, 2011

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RECO's COMPANY SPECIFIC ADDENDUM

A. Introduction to RECO's Company Specific Filing

In its Decision and Order dated May 16, 2011 in Docket EO11040250, 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, 2011 on the procurement of basic generation service ("BGS") for the period beginning June 1, 2012. 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, 2012, filed by New Jersey's four EDCs on July 1, 2011 ("EDC Compliance Filing"). This document has been revised to reflect the Board's Order dated November 9, 2011 in Docket No. EO11040250

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 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 November 22, 2010 in Docket No. EO10050338, the Board lowered the threshold for the BGS-CIEP class, to include all commercial and industrial customers with a peak load share of 750 kW and greater.² RECO will 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 Auction.

As to the BGS-FP Auction, RECO currently has one 36-month tranche that terminates on May 31, 2012, one 36-month tranche that terminates on May 31, 2013, and two 36-month tranches that terminate May 31, 2014. Accordingly, since the load requirements of RECO's Eastern Division are comprised of a total of four

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.

tranches, in the BGS-FP Auction for the period commencing June 1, 2012, RECO will include one 36-month tranche (for the period June 1, 2012 through May 31, 2015).

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, 2012; 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-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.

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 2012 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, 2012.

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, 2013. 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, 2013.

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 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 to reconcile previous over- or under-collections. The BGS-FP and BGS-CIEP Reconciliation Charges will be published in separate BGS Reconciliation Charge tariff leaves on a monthly basis. 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 in month $x+2$. Two of these differences are as follows:

1. The difference between BGS Costs (as defined above; this amount is known as month $x+1$) and the month x BGS revenue (which is

also determined in month $x+1$). The 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 for 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 for each month in the quarter based on the criteria above.

F. Description of BGS Tariff Changes

Draft tariff leaves indicating "X.XXX" for the rates that will change as a result of the BGS-FP and BGS-CIEP Auctions are included in Attachment A. Final tariff leaves including the actual BGS rates and tariff provisions to become effective on

June 1, 2012 will be filed with the Board upon its issuance of an appropriate Board order approving the BGS Auction Process.

G. RECO RFP

In December 2009, RECO issued an RFP for four separate financial swaps. One pertained to the forecasted capacity requirement (i.e., approximately 56 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, 2010, June 1, 2011, and June 1, 2012, 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 26, 2010. 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. By Order dated March 1, 2010, the Board approved the results of the RECO RFP. Accordingly, RECO entered into energy swap agreements for the annual periods commencing June 1, 2010, June 1, 2011, and June 1, 2012, and a capacity swap agreement for the entire three-year period. As a result, there is no need for RECO to take any additional action regarding its Central and Western Divisions for the period from June 1, 2012 through May 31, 2013.

Since the auction administered by RECO involves commodity swap transactions, RECO must still purchase the physical electric supply needed to meet its

default 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.

H. BGS Rate Design Methodology

RECO BGS Pricing Spreadsheet

As described in the EDC Compliance Filing, the resulting charge for each BGS rate element (e.g., Service Classification No. 1 summer charge, winter charge) for BGS supply service will be based on a factor applied to the tranche weighted average of the winning BGS-FP bid prices adjusted for the seasonal payment factors. These factors have been developed based on the ratios of the estimated underlying market costs of each rate element (for each service classification) to the overall all-in BGS cost. The tables included in Attachment B present all of the input data, intermediate calculations, and the final results in the calculation of these factors.

Table #1 (% Usage during PJM On-Peak Period) contains the percentage of on-peak load, by month, for each service classification. The on-peak period as used in this table (referred to as PJM periods) is defined as the 16-hour period from 7 AM to 11 PM, Monday through Friday. All remaining weekday hours and all hours on weekends and holidays recognized by the National Electric Reliability Council (“NERC”) are considered the off-peak period. This is consistent with the time periods used in the forwards market for trading of bulk power. The values in this table for each

month are the average on-peak percentages from the year 2011 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 2011.

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, updated based on data available in early November 2011, 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 2012 to May 2013, 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 2008 to May 2011, which equals 0.4011%. Marginal losses are excluded from the loss factors based on historic de-rating factors for the period July 2008 to February 2011.

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 2011. The values in the top portion of Table #9 will be updated in January 2012 to reflect the aggregate amount by rate schedule that will be in effect on June 1, 2012. 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 2012 to 2015 for RECO) and NYISO zones as calculated in Table #19. Also shown is the level of blocking in current BGS charges for Service Classification Nos. 1 and 5, which will be utilized in the later calculations of the blocking of BGS charges for these service classifications.

An estimate of the cost of ancillary services is included in Table #10 (Ancillary Services). The Ancillary Services estimate is a weighted average of estimated Ancillary

Services costs in RECO's PJM zone (i.e., \$3 per MWh) and RECO's estimate of Ancillary Services costs in RECO's NYISO zone as calculated in Table #20.

Table #11 (Summary of Obligation Costs Expressed as \$/MWh @ customer for non-demand rates only) shows the result of the allocation of both the transmission and generation costs on a per MWh basis to those service classifications under which BGS service will be billed only on a per kWh basis.

Table #12 (Summary of BGS Unit Costs @ customer) is the result of the inclusion of the transmission, generation capacity, and Ancillary Services costs to the costs shown in Table #8. The bottom portion of this table shows the total estimated costs for BGS, based on the assumptions utilized in the above tables, and the average per unit cost, as measured at the customer meters and the bulk system meters.

Table #13 (Ratio of BGS Unit Costs @ customer to All-In Average Cost @ transmission nodes) indicates the ratio of the individual rate element costs from Table #12 to the overall all-in cost as measured at the bulk system plus constant, where applicable.

Table #14 (Summary of BGS Unit Costs Less Transmission @customer) provides the BGS unit costs as developed in Table 12, with the exception of transmission. The bottom portion of the table shows the total estimated costs for BGS less transmission costs and the average unit cost as measured at the customer meters and the bulk system.

Table #15 (Ratio of BGS Unit Costs Less Transmission @ customer to All-In Average Cost @ transmission nodes) indicates the ratio of the individual rate element costs from Table #14 to the overall all-in cost as measured at the bulk system. These ratios are used to establish the BGS prices to retail customers.

Table #16 (Summary of Total BGS Costs by Season) shows the summary of the total and percentage of costs by rate and by season. A calculation in the lower portion of this table shows the resulting average costs per MWh for the winter and summer costs and MWhs, while the ratio of these seasonal unit costs to the all-in cost (from Table #12) is shown in the lower right hand portion of this table.

Table #17 (Summary of Total BGS Costs by Season Less Transmission) shows the summary of the total and percentage of costs by rate and by season. This is similar to the values indicated in Table #16, however this table excludes the cost for transmission. A calculation in the lower portion of this table shows the resulting average costs per MWh for the winter and summer costs and MWhs, while the ratio of these seasonal unit costs to the all-in cost (from Table #14) is shown in the lower right hand portion of this table.

Tables #18 (Forward Energy Prices), #19 (Generation Capacity Prices) and #20 (Ancillary Services) show the calculation of weighted average prices for energy, generation capacity and Ancillary Services as more fully described under “Table #4”, “Table #9” and “Table #10”.

The second spreadsheet used in the calculation of the final BGS-FP rates is included as Attachment C. The tables in this spreadsheet calculate the weighted average winning bid price and convert it into the final BGS-FP rates that are charged to customers. An explanation of each of the six tables, labeled as Table A through F, is as follows:

Table A (Weighted Average Price Calculation) contains the results of the BGS (i.e., current and prior two) auctions adjusted to include the impacts of RECO’s

RFP for the Central and Western Divisions.⁵ 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.” As was the case in the 2010 and 2011 BGS-FP Auctions, the inputs to the BGS Pricing Spreadsheet may result in atypical values where the summer payment factor is less than one, while the winter factor is higher than one. To the extent the seasonal factors for the 12-month BGS period beginning June 1, 2012 (as calculated in Table #16) produces atypical results, the Company reserves its right to set the seasonal factors to 1.0 for both the Summer and Winter periods in any updates to the Company’s BGS Pricing Spreadsheet. Accordingly, the Company has set the seasonal factors to 1.0 for both the Summer and Winter periods.

Table B (Ratio of BGS Unit Costs Less Transmission @ Customer to All-In Average Cost @ transmission nodes) is a repeat of the values shown in Table #15 from Attachment B, the bid factors calculated based on current market conditions.

Table C (Determination of Preliminary Retail Rates to be Charged to BGS Customers) contains the preliminary customer BGS-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

⁵ The price shown for the tranche to be secured in the 2012 auction and RFP are for illustrative purposes only, and will be replaced with actual data in determining RECO's final June 2012 BGS-FP rates.

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 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; and
6. The Company's Rate Design Methodology and Tariff Sheets are approved by the Board.

DRAFT

Revised Leaf No. 50
Superseding Revised Leaf No. 50

GENERAL INFORMATION

No. 31 BASIC GENERATION SERVICE ("BGS")

- (1) Basic Generation Service – Fixed Pricing (BGS-FP)
Applicable to Service Classification Nos. 1, 2, 3, 4, 5 and 6

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

<u>Service Classification</u>	<u>Summer Months*</u>	<u>Other Months</u>
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. 31(2):

	<u>Summer Months*</u>	<u>Other Months</u>
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)

ISSUED:

EFFECTIVE:

ISSUED BY: William Longhi, President
Saddle River, New Jersey 07458

DRAFT

Revised Leaf No. 52
Superseding Revised Leaf No. 52

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 750 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: William Longhi, President
Saddle River, New Jersey 07458

Development of BGS Cost and Bid Factors for Rates Effective June 1, 2012

Based on 2010 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	47.16%	44.41%	43.15%	46.90%	28.85%	28.85%	51.18%
February	51.01%	48.16%	48.17%	51.01%	28.85%	28.85%	53.18%
March	52.75%	49.41%	49.38%	55.08%	30.48%	30.48%	56.06%
April	50.02%	48.00%	47.48%	57.34%	27.80%	27.80%	54.51%
May	48.93%	47.36%	48.85%	56.11%	22.27%	22.27%	52.63%
June	54.63%	52.46%	53.69%	59.13%	21.97%	21.97%	55.65%
July	48.45%	46.86%	47.82%	50.58%	18.46%	18.46%	49.53%
August	59.15%	56.55%	57.37%	60.86%	23.82%	23.82%	56.34%
September	54.30%	51.42%	53.16%	58.98%	28.03%	28.03%	54.35%
October	49.92%	47.52%	47.93%	56.86%	27.80%	27.80%	51.84%
November	50.96%	48.85%	48.52%	52.64%	29.75%	29.75%	53.97%
December	49.20%	47.85%	44.90%	45.12%	29.44%	29.44%	50.01%

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	----	----	33.80%	----	----	----	----
February	----	----	35.80%	----	----	----	----
March	----	----	34.39%	----	----	----	----
April	----	----	33.22%	----	----	----	----
May	----	----	34.04%	----	----	----	----
June	----	----	35.31%	----	----	----	----
July	----	----	36.60%	----	----	----	----
August	----	----	41.87%	----	----	----	----
September	----	----	39.80%	----	----	----	----
October	----	----	35.37%	----	----	----	----
November	----	----	34.93%	----	----	----	----
December	----	----	34.13%	----	----	----	----

Table #3 Class Usage @ customer

*Calendar month billed sales forecasted for 2011
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 FP</u>
January	62,596	1,937	31	4,505	730	525	46,976	117,300
February	54,559	1,804	28	4,615	608	468	45,878	107,960
March	51,298	1,491	22	4,167	648	419	45,379	103,424
April	44,819	1,043	18	3,576	497	442	44,876	95,271
May	45,041	949	17	2,634	453	443	45,523	95,060
June	64,403	1,144	20	2,641	418	406	53,302	122,334
July	84,373	1,438	26	3,027	442	421	54,856	144,583
August	86,766	1,579	25	3,069	490	423	56,878	149,230
September	72,519	1,349	20	2,774	549	468	52,815	130,494
October	58,846	1,215	19	2,781	636	542	51,433	115,472
November	49,004	1,125	20	2,394	639	619	45,495	99,296
December	<u>57,225</u>	<u>1,504</u>	<u>24</u>	<u>2,900</u>	<u>719</u>	<u>586</u>	<u>47,792</u>	<u>110,750</u>
Total	731,449	16,578	270	39,083	6,829	5,762	591,203	1,391,174

Table #4 Forwards Prices - Energy Only @ bulk system

in \$/MWh (See Table 18)

	<u>On-Peak</u>	<u>Off-Peak</u>
January	61.93	48.00
February	61.93	48.00
March	54.03	41.71
April	54.03	41.71
May	52.94	40.90
June	56.65	36.07
July	64.88	40.86
August	64.88	40.86
September	52.70	33.74
October	48.58	37.41
November	48.87	37.64
December	56.78	43.74

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 =	1.08422	1.08422	1.08422	1.08422	1.08422	1.08422	1.08422
Expansion Factor (net Marginal Losses)	1.06962	1.06962	1.06962	1.06962	1.06962	1.06962	1.06962

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	\$	54.37	\$ 53.76	\$ 54.16	\$ 54.89	\$ 46.39	\$ 46.40	\$ 53.98
	PJM on pk	\$ 65.34	\$ 65.27	\$ 65.44	\$ 64.96	\$ 63.92	\$ 64.00	\$ 64.87
	PJM off pk	\$ 41.42	\$ 41.33	\$ 41.49	\$ 41.37	\$ 41.04	\$ 41.08	\$ 41.22
Winter - all hrs	\$	52.94	\$ 53.33	\$ 53.14	\$ 53.95	\$ 50.01	\$ 49.64	\$ 53.07
	PJM on pk	\$ 59.70	\$ 60.47	\$ 60.30	\$ 60.24	\$ 59.80	\$ 59.39	\$ 59.41
	PJM off pk	\$ 46.20	\$ 46.86	\$ 46.79	\$ 47.02	\$ 46.12	\$ 45.80	\$ 45.95
Annual	\$	53.54	\$ 53.47	\$ 53.49	\$ 54.22	\$ 49.00	\$ 48.68	\$ 53.41
System Total	\$	53.46						

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	\$	16,749	\$ 296	\$ 5	\$ 632	\$ 88	\$ 80	\$ 11,761
	PJM on pk	\$ 10,896	\$ 187	\$ 3	\$ 428	\$ 28	\$ 26	\$ 7,628
	PJM off pk	\$ 5,852	\$ 109	\$ 2	\$ 203	\$ 60	\$ 54	\$ 4,133
Winter - all hrs	\$	22,414	\$ 590	\$ 10	\$ 1,487	\$ 247	\$ 201	\$ 19,813
	PJM on pk	\$ 12,618	\$ 318	\$ 5	\$ 870	\$ 84	\$ 68	\$ 11,728
	PJM off pk	\$ 9,796	\$ 272	\$ 4	\$ 617	\$ 163	\$ 133	\$ 8,085
Annual	\$	39,163	\$ 886	\$ 14	\$ 2,119	\$ 335	\$ 280	\$ 31,573
System Total	\$	74,372						

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	\$	54.37	\$ 53.76	\$ 54.16	\$ 54.89	\$ 46.39	\$ 46.40	\$ 53.98
				\$ 68.90				
				\$ 44.95				
RECO On pk				\$ 68.90				
RECO Off pk				\$ 44.95				
Winter - all hrs	\$	52.94	\$ 53.33	\$ 53.14	\$ 53.95	\$ 50.01	\$ 49.64	\$ 53.07
				\$ 61.99				
				\$ 48.48				
RECO On pk				\$ 61.99				
RECO Off pk				\$ 48.48				
Annual Average	\$	53.54	\$ 53.47	\$ 53.49	\$ 54.22	\$ 49.00	\$ 48.68	\$ 53.41
System Average	\$	53.46						

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

Obligations - annual average forecasted for 2011; 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	325.998	4.624	0.056	8.817	0.000	0.000	145.222	484.717
Trans Obl - MW	285.720	3.713	0.061	9.072	0.000	0.000	137.196	435.762

of Months and Days used in this analysis

# of summer days =	122	# of summer months =	4
# of winter days =	244	# of winter months =	8
		total # months =	12

Transmission Cost \$ 32,114 per MW-yr

Generation Capacity cost summer \$155.52 \$/MW/day Resulting avg gen cap cost = summer >> \$ 56.76 per kW/yr
 (see Table 19) winter \$155.49 \$/MW/day winter >> \$ 56.75 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)	10.696 ¢/kWh	20.26%	Block 1 (0-250 kWh/month)	9.713		31.04%
Block 2 (>250 kWh/m)	11.814 ¢/kWh	79.74%	Block 2 (251-700 kWh/month)	10.839	1.126	35.62%
Calculated inversion =	1.118 ¢/kWh		Block 3 (>700 kWh/month)	11.598	1.885	33.35%

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)

	<u>SC1</u>	<u>SC5</u>	<u>SC3</u>	<u>SC2 ND</u>	<u>SC4</u>	<u>SC6</u>
Transmission Obl - all months \$	12.54 \$	7.19 \$	7.26 \$	7.45 \$	- \$	-
Generation Obl -						
per annual MWh \$	25.37 \$	15.87 \$	11.80 \$	12.84 \$	- \$	-
per summer MWh \$	20.08 \$	15.92 \$	11.68 \$	14.53 \$	- \$	-
per winter MWh \$	29.21 \$	15.85 \$	11.87 \$	12.13 \$	- \$	-

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 \$	89.90 \$	79.78 \$	76.00 \$	79.79 \$	49.30 \$	49.31
RECO On pk			\$ 109.42			
RECO Off pk			\$ 55.12			
Block 1 \$	80.99 \$	69.48				
Block 2 \$	92.17 \$	80.74				
Block 3	\$	88.33				
Winter - all hrs \$	97.61 \$	79.28 \$	75.18 \$	76.44 \$	52.92 \$	52.55
RECO On pk			\$ 106.57			
RECO Off pk			\$ 58.65			
Annual -all hrs \$	94.36 \$	79.45 \$	75.46 \$	77.43 \$	51.91 \$	51.59

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 \$	56.89	<u>Gen Cost (per kW of Billed Demand/Month)</u>
		<u>SC2 Dem</u>
Winter - all hrs \$	55.98	summer \$ 4.776
		winter \$ 5.299
Annual - all hrs per MWh only \$	56.32	<u>Trans cost</u>
		all months \$ 2.68 per kW of T obl /month

Table #12 (Continued)

<u>Including T&G Obligation \$</u>	
Summer - all hrs	\$ 76.28
Winter - all hrs	\$ 78.60
Annual - including T&G Obl \$	\$ 77.75

ALL RATES

Grand Total Cost in \$1000 = \$ 120,001
 All-In Average cost @ customer = \$ 86.26 per MWh at customer (per customer metered MWh)
 All-In Average costs @ transmission nodes = \$ 80.64 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	1.115	0.989		0.989	0.611	0.612
RECO On pk			1.357			
RECO Off pk			0.683			
Constant Blk 1 \$	(8.91) \$	(10.30)				
Constant Blk 2 \$	2.27 \$	0.96				
Constant Blk 3	NA \$	8.55				
Winter - all hrs	1.210	0.983		0.948	0.656	0.652
RECO On pk			1.321			
RECO Off pk			0.727			
Annual - all hrs	1.170	0.985	0.936	0.960	0.644	0.640

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>	
Summer - all hrs	0.946	\$	(19.389)	PLUS: <u>Gen Cost (per kW of Billed Demand/Month)</u> <u>SC2 Dem</u> summer \$ 4.776 winter \$ 5.299 <u>Trans cost</u> all months \$ 2.676 per kW of T obl /month
Winter - all hrs	0.975	\$	(22.625)	
Annual - including T&G Obl \$	0.964			

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	\$	77.36	\$ 72.59	\$ 68.75	\$ 72.33	\$ 49.30	\$ 49.31
	RECO On pk			\$ 102.16			
	RECO Off pk			\$ 47.86			
	Block 1	\$ 68.44	\$ 62.29				
	Block 2	\$ 79.62	\$ 73.55				
	Block 3		\$ 81.14				
Winter - all hrs	\$	85.06	\$ 72.09	\$ 67.92	\$ 68.99	\$ 52.92	\$ 52.55
	RECO On pk			\$ 99.31			
	RECO Off pk			\$ 51.39			
Annual -all hrs	\$	81.82	\$ 72.26	\$ 68.20	\$ 69.97	\$ 51.91	\$ 51.59

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:	
Summer - all hrs	\$ 56.89		<u>Gen Cost (per kW of Billed Demand/Month)</u>
			<u>SC2 Dem</u>
Winter - all hrs	\$ 55.98	summer \$	4.776
		winter \$	5.299
Annual - all hrs per MWh only	\$ 56.32		
<u>Including Generation Obligation \$</u>			
Summer - all hrs	\$ 69.54		
Winter - all hrs	\$ 70.73		
Annual - including T&G Obl \$	\$ 70.30		

ALL RATES

Grand Total Cost in \$1000 = \$ 106,007
 All-In Average cost @ customer = \$ 76.20 per MWh at customer (per customer metered MWh)
 All-In Average costs @ transmission nodes = \$ 71.24 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	1.086	1.019		1.015	0.692	0.692
RECO On pk			1.434			
RECO Off pk			0.672			
Constant Blk 1 \$	(8.91) \$	(10.30)				
Constant Blk 2 \$	2.27 \$	0.96				
Constant Blk 3	NA \$	8.55				
Winter - all hrs	1.194	1.012		0.968	0.743	0.738
RECO On pk			1.394			
RECO Off pk			0.721			
Annual - all hrs	1.148	1.014	0.957	0.982	0.729	0.724

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	0.976	(12.648)	<u>Gen Cost (per kW of Billed Demand/Month)</u>
			<u>SC2 Dem</u>
Winter - all hrs	0.993	(14.758)	summer \$ 4.776
			winter \$ 5.299
Annual - including T&G Obl \$	0.987		

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	\$ 27,695	\$ 440	\$ 7	\$ 918	\$ 94	\$ 85	16,619	
Winter	\$ 41,326	\$ 878	\$ 13	\$ 2,108	\$ 261	\$ 213	29,346	
Total	\$ 69,021	\$ 1,317	\$ 20	\$ 3,026	\$ 355	\$ 297	45,965	
% of Annual Total \$ by Rate								
Summer	40%	33%	34%	30%	26%	29%	36%	
Winter	60%	67%	66%	70%	74%	71%	64%	
Total Costs - in \$1000								
Summer	\$ 45,857							
Winter	\$ 74,144							
Total	\$ 120,001							
% of Annual Total \$								
Summer	38%	If total \$ were split on a per MWh basis (on transmission node MWhs):					<u>Ratio to All-In Cost</u>	
Winter	62%	\$ 78.43	per MWh @ transmission nodes			Summer	0.9725	
		\$ 82.08	per MWh @ transmission nodes			Winter	1.0178	

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	\$ 23,831	\$ 400	\$ 6	\$ 833	\$ 94	\$ 85	15,150	
Winter	\$ 36,015	\$ 798	\$ 12	\$ 1,902	\$ 261	\$ 213	26,409	
Total	\$ 59,845	\$ 1,198	\$ 18	\$ 2,735	\$ 355	\$ 297	41,559	
% of Annual Total \$ by Rate								
Summer	40%	33%	34%	30%	26%	29%	36%	
Winter	60%	67%	66%	70%	74%	71%	64%	
Total Costs - in \$1000								
Summer	\$ 40,398							
Winter	\$ 65,609							
Total	\$ 106,007							
% of Annual Total \$								
Summer	38%	If total \$ were split on a per MWh basis (on transmission node MWhs):					<u>Ratio to All-In Cost</u>	
Winter	62%	\$ 69.09	per MWh @ transmission nodes			Summer	0.9698	
		\$ 72.63	per MWh @ transmission nodes			Winter	1.0195	

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	56.39	0.78	44.18	107%	106%	60.50	46.70
February	56.39	0.78	44.18	107%	106%	60.50	46.70
March	50.01	0.78	39.18	107%	106%	53.66	41.42
April	50.01	0.78	39.18	107%	106%	53.66	41.42
May	49.14	0.78	38.50	107%	106%	52.72	40.70
June	52.16	0.64	33.19	107%	106%	56.06	35.21
July	59.62	0.64	37.93	107%	106%	64.07	40.24
August	59.62	0.64	37.93	107%	106%	64.07	40.24
September	48.54	0.64	30.88	107%	106%	52.17	32.76
October	44.40	0.78	34.78	107%	106%	47.64	36.77
November	44.70	0.78	35.02	107%	106%	47.96	37.02
December	52.85	0.78	41.40	107%	106%	56.70	43.77

NYISO Forward Prices - Energy Only @ bulk system <i>in \$/MWh</i>			Weighted Average Forward Prices - Energy Only @ bulk system (90.4% PJM - 9.6% NYISO) <i>in \$/MWh</i>			
	<u>On-Peak</u>	<u>Off-Peak</u>		<u>On-Peak</u>	<u>Off-Peak</u>	
January	75.50	60.25	January	61.93	48.00	90.4%
February	75.50	60.25	February	61.93	48.00	9.6%
March	57.50	44.50	March	54.03	41.71	
April	57.50	44.50	April	54.03	41.71	
May	55.00	42.75	May	52.94	40.90	
June	62.25	44.25	June	56.65	36.07	
July	72.50	46.75	July	64.88	40.86	
August	72.50	46.75	August	64.88	40.86	
September	57.75	43.00	September	52.70	33.74	
October	57.50	43.50	October	48.58	37.41	
November	57.50	43.50	November	48.87	37.64	
December	57.50	43.50	December	56.78	43.74	

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

	<u>PJM</u> <u>90.4%</u>	<u>NYISO</u> <u>9.6%</u>	<u>Weighted</u> <u>Average</u>
Summer	\$170.28	15.98	\$155.52
Winter	\$170.28	15.58	\$155.49

Table #20 Ancillary Services

	<u>PJM</u> <u>90.4%</u>	<u>NYISO</u> <u>9.6%</u>	<u>Weighted</u> <u>Average</u>
	\$3.00	\$2.07	\$2.91

Assumptions:

- Gen Cost = \$155.52 per MW-day in summer
\$155.49 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 6/11 to 5/12 Forwards @ PJM West as of 6/7/10
Based on 6/11 to 5/12 Forwards @ NYISO Zone G as of 6/8/10
- Usage patterns = Forecasted 2011 energy use by class, PJM on/off % from 2010 class load profiles,
RECO billing on/off % from 6/10 to 5/11 actual data
- Obligations = Class totals for 2011
- 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 >>	2010 Auction 36 Month	2011 Auction 36 Month	2012 Auction 36 Month	Total	Notes:
1	Tranches	1	2	1	4	From then-current auction
2	Winning Bid Price (¢/kWh)*	10.332	10.684	10.684		Winning Bids. Note: 10.684¢ for 2012 auction is simply illustrative
3	Transmission (¢/kWh)	0.940	0.940	0.940		Average transmission cost included in bid
4	BGS (¢/kWh)	9.392	9.744	9.744		= (2) - (3)
5	Weighted Avg BGS	2.348	4.872	2.436	9.656	= (1) / Total Tranches * (4)
6	Weighted Avg Trans	0.235	0.470	0.235	0.940	= (1) / Total Tranches * (3)
7	Weighted Avg Total Price (¢/kWh)				10.596	
<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	528,781				From then-current Bid Factor Spreadsheet
11	Winter MWh	<u>816,940</u>				From then-current Bid Factor Spreadsheet
12		1,345,721				
<u>Total Cost</u>						
13	Summer	13,658,406	28,247,467	14,123,733	56,029,606	= (1) / Total Tranches * (2) / 100 * (8) * (10) * 1,000
14	Winter	<u>21,101,567</u>	<u>43,640,948</u>	<u>21,820,474</u>	<u>86,562,989</u>	= (1) / Total Tranches * (2) / 100 * (9) * (11) * 1,000
15	Total	34,759,973	71,888,415	35,944,207	142,592,595	= (13) + (14)
<u>Average Cost (NJ Statewide Auction)</u>						
16	Summer	10.596 ¢/kWh				= sum(line 13) / (10) / 1000 * 100 rounded to 3 decimal places
17	Winter	10.596 ¢/kWh				= sum(line 14) / (11) / 1000 * 100 rounded to 3 decimal places
18	Total	10.596 ¢/kWh				= sum(line 15) / (12) / 1000 * 100 rounded to 3 decimal places
<u>Average Cost (Including RECO RFP)</u>						
		BGS Auction	RECO RFP		Total	
19	Tranches	4	0.423		4.423	Includes RECO RFP equivalent tranches
20	Price ¢/kWh	10.596	8.595			BGS Auction from (18). Note: 8.595¢ for RFP is illustrative. (excludes transmission).
21	Transmission	0.940	0			
22	BGS	9.656	8.595			= (20) - (21)
23	Weighted Avg BGS	8.732	0.822		9.554	= (19) / Total Tranches * (22)
24	Weighted Avg Trans	0.851	0.000		0.851	= (19) / Total Tranches * (21)
25	Weighted Avg Total Price				10.405	= (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	1.086	1.019		1.015	0.692	0.692
RECO On pk			1.434			
RECO Off pk			0.672			
Constant Blk 1 \$	(8.91) \$	(10.30)				
Constant Blk 2 \$	2.27 \$	0.96				
Constant Blk 3	NA \$	8.55				
Winter - all hrs	1.194	1.012		0.968	0.743	0.738
RECO On pk			1.394			
RECO Off pk			0.721			
Annual - all hrs	1.148	1.014	0.957	0.982	0.729	0.724

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	0.976	(12.648)	<u>Gen Cost (per kW of Billed Demand/Month)</u>
Winter - all hrs	0.993	(14.758)	<u>SC2 Dem</u>
Annual - including T&G Obl \$	0.987		summer \$ 4.776
			winter \$ 5.299

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

All-In Average costs @ Trans node =	\$ 104.05 /MWh*
Less Transmission	\$ (8.50) /MWh**
BGS Cost	\$ 95.55 /MWh

* Price from Table A (which does not include transmission for the Central/Western Division).
** RECO average transmission rate of 9.40 minus Central/West transmission contribution to weighted average rate 0.423/4.423 *\$9.40 per MWh). \$0.90

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)	10.376	9.736		9.698	6.612	6.612	8.060
Peak kWh (¢/kWh)			13.701				
Off-Peak kWh (¢/kWh)			6.421				
Block1	9.485	8.706					
Block2	10.603	9.832					
Block3	NA	10.591					
Demand Charge (\$/kW)							4.776
<u>Winter</u>							
All kWh (¢/kWh)	11.408	9.669		9.249	7.099	7.051	8.012
Peak kWh (¢/kWh)			13.319				
Off-Peak kWh (¢/kWh)			6.889				
Demand Charge (\$/kW)							5.299

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	\$ 31,964	\$ 536	\$ 8	\$ 1,116	\$ 126	\$ 114	\$ 20,314
Winter	\$ 48,300	\$ 1,070	\$ 16	\$ 2,550	\$ 350	\$ 285	\$ 35,423
Total	\$ 80,264	\$ 1,606	\$ 24	\$ 3,666	\$ 476	\$ 399	\$ 55,737
Total							
Summer	\$ 54,178						
Winter	\$ 87,994						
Total	\$ 142,172						

Total Supplier Payments - in \$1000

Eastern Division	<u>Total</u>	<u>Transmission</u>	<u>Net BGS</u>
Summer	\$ 56,030	\$ 4,219	\$ 51,811
Winter	\$ 86,563	\$ 8,437	\$ 78,126
Total	\$ 142,593	\$ 12,656	\$ 129,937

Central/Western Division	<u>Total</u>	<u>Transmission</u>	<u>Net BGS</u>
Summer	\$ 4,872	\$ -	\$ 4,872
Winter	\$ 7,425	\$ -	\$ 7,425
Total	\$ 12,297	\$ -	\$ 12,297

Total RECO FP	<u>Total</u>	<u>Transmission</u>	<u>Net BGS</u>
Summer	\$ 60,902	\$ 4,219	\$ 56,683
Winter	\$ 93,988	\$ 8,437	\$ 85,551
Total	\$ 154,890	\$ 12,656	\$ 142,234

Differences	<u>BGS Revenue</u>	<u>BGS Costs</u>	<u>Difference</u>	Rate Adjustment Factors
Summer	\$ 54,178	\$ 56,683	\$ 2,505	1.04623
Winter	\$ 87,994	\$ 85,551	\$ (2,443)	0.97224
Total	\$ 142,172	\$ 142,234	\$ 62	

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)	10.856	10.186		10.146	6.918	6.918	8.433
Peak kWh (¢/kWh)			14.334				
Off-Peak kWh (¢/kWh)			6.718				
Block1	9.923	9.108					
Block2	11.093	10.287					
Block3	NA	11.081					
Demand Charge (\$/kW)							4.997
<u>Winter</u>							
All kWh (¢/kWh)	11.091	9.401		8.992	6.902	6.855	7.790
Peak kWh (¢/kWh)			12.949				
Off-Peak kWh (¢/kWh)			6.698				
Demand Charge (\$/kW)							5.152

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)				10.856	7.402	7.402	9.023
Peak kWh (¢/kWh)			15.337				
Off-Peak kWh (¢/kWh)			7.188				
Block1	10.618	9.746					
Block2	11.870	11.007					
Block3	NA	11.857					
Demand Charge (\$/kW)							5.350
<u>Winter</u>							
All kWh (¢/kWh)	11.867	10.059		9.621	7.385	7.335	8.335
Peak kWh (¢/kWh)			13.855				
Off-Peak kWh (¢/kWh)			7.167				
Demand Charge (\$/kW)							5.510

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	\$ 33,443	\$ 561	\$ 9	\$ 1,168	\$ 131	\$ 119	\$ 21,254
Winter	\$ 46,958	\$ 1,041	\$ 16	\$ 2,479	\$ 340	\$ 277	\$ 34,441
Total	\$ 80,401	\$ 1,602	\$ 25	\$ 3,647	\$ 471	\$ 396	\$ 55,695
Total							
Summer	\$ 56,685						
Winter	\$ 85,552						
Total	\$ 142,237						

Supplier Payments - in \$1000

Eastern Division

	<u>Total</u>	<u>Transmission</u>	<u>Net BGS</u>
Summer	\$ 56,030	\$ 4,219	\$ 51,811
Winter	\$ 86,563	\$ 8,437	\$ 78,126
Total	\$ 142,593	\$ 12,656	\$ 129,937

Central/Western Division

	<u>Total</u>	<u>Transmission</u>	<u>Net BGS</u>
Summer	\$ 4,872	\$ -	\$ 4,872
Winter	\$ 7,425	\$ -	\$ 7,425
Total	\$ 12,297	\$ -	\$ 12,297

Total RECO FP

	<u>Total</u>	<u>Transmission</u>	<u>Net BGS</u>
Summer	\$ 60,902	\$ 4,219	\$ 56,683
Winter	\$ 93,988	\$ 8,437	\$ 85,551
Total	\$ 154,890	\$ 12,656	\$ 142,234

Differences

	<u>BGS Revenue</u>	<u>BGS Costs</u>	<u>Difference</u>
Summer	\$ 56,685	\$ 56,683	\$ (2)
Winter	\$ 85,552	\$ 85,551	\$ (1)
Total	\$ 142,237	\$ 142,234	\$ (3)