

STATE OF NEW JERSEY
BOARD OF PUBLIC UTILITIES

I/M/O THE PROVISION OF BASIC
GENERATION SERVICE PURSUANT TO
THE ELECTRIC DISCOUNT AND ENERGY
COMPETITION ACT, N.J.S.A. 48:3-49 et
seq.

Docket Nos. EX01110754 and EO02070384.

ROCKLAND ELECTRIC COMPANY

**PROPOSAL FOR AUCTION OF
BASIC GENERATION SERVICE
RIGHTS AND RESPONSIBILITIES
FOR THE POST-TRANSITION PERIOD**

**COMPANY SPECIFIC ADDENDUM
COMPLIANCE FILING**

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RECO's COMPANY SPECIFIC ADDENDUM

A. Introduction to RECO's Company Specific Filing

The Electric Discount and Energy Connection Act (“EDECA”) implements retail choice for electric supply in New Jersey and establishes a four year period following the start date for retail choice (i.e., August 1, 1999 to July 31, 2003) (“Transition Period”) during which New Jersey’s four electric distribution companies (“EDCs”) are required to sustain statutorily mandated rate reductions. Section 4.j.; N.J.S.A. 48:3-52.j.¹ At the same time, EDECA provides (at § 9.a.) that each EDC shall provide basic generation service (“BGS”) for at least three years after the start date for retail choice and thereafter until the State of New Jersey Board of Public Utilities (“Board” or “NJBPU”) determines otherwise. N.J.S.A. 48:3-57.a. BGS is defined by the EDECA as electric generation service that is provided to any customer that has not chosen an alternative electric power supplier, whether or not such customer has received offers as to competitive supply options. N.J.S.A. 48:3-51. Section 9.c. of EDECA requires the Board to decide whether to make available the opportunity to provide BGS on a competitive basis within three years of the start date for retail choice.

After an extensive proceeding, the Board, by Order dated December 11, 2001, determined that for the fourth year of Transition Period, consisting of August 1, 2002 through August 1, 2003 (“Year 4”), the electric utilities should continue to provide BGS, with the procurement of supply to meet the full electricity requirements of BGS customers to be achieved via an auction process. The Board also determined that a further review as to whether to make BGS available on a competitive basis for the

¹ The New Jersey EDCs are Public Service Electric and Gas Company (“PSE&G”); Jersey Central Power and Light Company (“JCP&L”); Atlantic City Electric Company, d/b/a Conectiv (“Conectiv”); and Rockland Electric Company (“RECO”).

period beginning August 1, 2003 (“post-Transition Period”) would be undertaken pursuant to a separate scheduling order.

By Order dated January 10, 2002, the Board solicited information from interested parties so that it could make a timely decision whether BGS should be provided on a competitive basis for the post-Transition Period, and the appropriate pricing mechanism for BGS after August 1, 2003. After receiving comments from interested parties and holding various working group meetings, by Order dated June 6, 2002 (“June 6 Order”), the Board ordered the EDCs and other interested parties to file formal proposals by July 1, 2002 on how BGS should be procured for the post-Transition Period.

In response to the June 6 Order, RECO voluntarily joined in the July 1, 2002 generic filing submitted by the other New Jersey EDCs (“EDC Filing”) by which the EDCs proposed to conduct two simultaneous, multi-round, descending clock auctions (“Auction”) for the procurement of supply to meet the full electricity requirements (i.e., energy, capacity, ancillary services, transmission, etc.) of retail customers that have not chosen a Third Party Supplier (“TPS”).

One Auction would be to procure service for the approximately 1,750 largest customers on the utility systems of Conectiv, JCP&L and PSE&G (“BGS-CIEP Auction”). The EDCs propose to move these largest customers to hourly pricing, using interval meters. This category is referred to as the Commercial and Industrial Energy Pricing (“CIEP”) class and represents approximately 2,460 MW of load to be procured through bidding on approximately 49, 50MW tranches. RECO did not propose to have a CIEP pricing class of customers.

The second Auction would be to procure BGS service for all other customers of all four EDCs (“BGS-FP Auction”) representing approximately 15,460 MW of load to be procured through approximately 154,100MW full-service tranches. These customers would be priced at fixed tariff rates determined by converting the auction prices to BGS-FP rates in a manner that reflects rate class and seasonal load characteristics and market prices.

Along with the EDC Filing, RECO also filed a RECO specific addendum that contained a request for proposal process (“RFP”) to secure a fixed price supply for its Western and Central Divisions, which are served through the New York Independent System Operator (“NYISO”). As the Western and Central Divisions are not part of the Pennsylvania, Jersey, Maryland Interconnect (“PJM”), they cannot participate in the regular BGS-FP and BGS-CIEP Auction processes.

The Board issued a Decision and Order (“Decision and Order”) approving the EDCs’ proposal and EDC-specific addendums as modified therein, and required (at 32) the EDCs to make compliance filings, including any changes consistent with the Decision and Order, by November 15, 2002. This document constitutes RECO’s company-specific portion of the compliance filing mandated by the Board’s Decision and Order. RECO’s filing also includes and incorporates by reference the November 15, 2002 filing by New Jersey’s four EDCs (“EDC Compliance Filing”) that includes: the EDC Proposal Objectives (Part I), the EDC Proposal (Part II), and the BGS Supplier Master Agreements.

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 equates to approximately 5 MW) as a member of the Orange and Rockland System², of several NUG contracts. The Crossroads Cogeneration Project, located in RECO's Eastern Division, is the only NUG project located in the RECO service territory. Since the output from the Crossroads Cogeneration Project is physically delivered into RECO's Eastern Division, RECO proposes to net the output from the Crossroads Cogeneration Project (i.e., approximately 4 MW) from the BGS Load of RECO's Eastern Division. RECO would net its share of the output from the remaining NUG projects, allocated to RECO pursuant to the terms of the FERC-approved Power Supply Agreement between RECO and Orange and Rockland Utilities, Inc, from the BGS Load of RECO's Central and Western Divisions.

RECO's above-market NUG contract costs will continue to be charged to its customers through its Energy Cost Adjustment ("ECA"), with full and timely recovery assured, and subject to deferral in accordance with both RECO's Summary Order issued by the Board on July 28, 1999 ("Summary Order"), and RECO's Final Decision and Order issued by the Board on July 22, 2002 ("Final Decision") in In the Matter of Rockland Electric Company's Rate Unbundling, Stranded Costs and Restructuring Filings, BPU Docket Nos. EO97070464, EO97070465, EO97070466 ("Summary Order").

² The Orange and Rockland System is comprised of RECO, Orange and Rockland Utilities, Inc., and Pike County Light & Power Company.

Any generation from RECO's Committed Supply that qualifies as a Class I or Class II renewable resource will continue to be used to meet the New Jersey Renewable Portfolio Standards' requirements for RECO's Central and Western Divisions.

C. RECO Tranche Configuration

The Decision and Order required RECO to participate in the BGS-CIEP Auction. Specifically, the Board determined that RECO should include its 18 customers, currently in SC 7, in the BGS-CIEP Auction. RECO will comply with this directive and include these customers as one tranche in the BGS-CIEP Auction.

As to the BGS-FP Auction, in the Decision and Order, the Board determined that two-thirds of the BGS-FP load should be auctioned for a ten-month period, and the remaining one-third of the BGS-FP load should be auctioned for a 34-month period. Accordingly, RECO will include three ten-month tranches and one 34-month tranche in the BGS-FP Auction.

D. Contingency Plans

While not every contingency can be anticipated, the following three time 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 August 2003; and
- (c) A default during the August 1, 2003 – July 31, 2004 supply period.

(a) Insufficient Number of Bids

A viable Auction Process requires a sufficient degree of competition. To ensure 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 (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 all tranches of RECO's BGS Load will not 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 will purchase that percentage of BGS Load, not met through the Auction Process, in PJM administered markets. This purchase is a strong feature of the Auction proposal because it provides bidders a strong incentive to participate in the Auction Process. If bidders were to believe that a less than fully subscribed auction would lead to a negotiation or a secondary market in which EDCs, on behalf of their customers would seek to acquire fixed priced supplies, the incentive to offer the best deal in the Auction might be diminished.

(b) Defaults prior to August 1, 2003.

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 August 1, 2003-July 31, 2004 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 one 34-month BGS-FP tranche, RECO only will seek replacement supply from PJM administered markets until May 31, 2004. For the remainder of the 34-month period, RECO will seek replacement supply through whatever process is implemented by the Board for the period commencing June 1, 2004.

Additional costs will be assessed against the defaulting company's BGS credit security.

E. Accounting and Cost Recovery

RECO proposes the following accounting and cost recovery with respect to post-Transition BGS.

RECO will track and defer separately for the BGS-FP and BGS-CIEP classes of customers, on a monthly basis, any differences between BGS revenue³ and BGS costs.

BGS costs are comprised of the following:

1. Payments made to BGS-FP and BGS-CIEP suppliers;

³ Retail Margin revenues will be tracked using established accounting procedures and recorded separately as Retail Margin revenue and shall not be included in the calculations of reconciliation charges.

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 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.
5. Any incremental administrative costs 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. These tariff sheets 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 and will be determined individually as set forth below:

The BGS-FP and BGS-CIEP Reconciliation Charges will be used to true up two items relating to 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:

1. The first difference is 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 second difference is 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 actual BGS kWh in month “ x ”.⁴

In connection with this filing, RECO is requesting the Board to make the following findings and issue an Order with respect to BGS accounting and cost recovery consistent with RECO’s Board-approved Plan:

1. RECO’s proposed accounting for BGS is approved by the Board for purposes of accounting and BGS cost recovery.
2. RECO’s Contingency Plan is approved by the Board, and, the costs incurred as a result of this Contingency Plan are presumptively

⁴ Since the BGS-FP and BGS-CIEP Reconciliation Charges are collected/refunded on a two-month lag, the Company is not seeking interest on the differences between BGS Costs and BGS revenues from customers. Should the Board order a greater time lag on the Company’s disposition of these differences, the Company requests interest, at the Company’s Board-approved overall rate of return, on such differences from the time they are incurred until the time they are collected/refunded.

prudent, subject to deferral, and approved for full and timely recovery.

3. The RECO-specific statewide Auction results for the 90% portion of the load, as well as the RECO RFP results for the 10% portion of the load, are approved and produce BGS supply costs that are reasonable and prudent, subject to deferral, and approved for full and timely recovery.

In connection with this filing, RECO is requesting the Board to make the following determination with respect to BGS accounting and cost recovery:

1. RECO's proposed accounting for BGS is approved by the Board for purposes of accounting and BGS cost recovery.
2. The proposed BGS Contingency Plan is approved by the Board and 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 and the related Contingency Plan.

F. Description of BGS Tariff Changes

General

As described above, RECO will be offering both the BGS-FP and the BGS-CIEP alternatives to its BGS customers, the details of which are discussed in the EDC Filing.

The following section briefly describes the tariff changes that will be needed to implement RECO's BGS proposal. These tariff changes will be filed with the Board upon its approval of the post-Transition Year One BGS Auction Process.

BGS-FP

BGS-FP service is proposed to be available to all RECO Service Classification Nos. 1, 2, 3, 4, 5 and 6 customers. BGS-FP service is comprised of three

components: BGS Energy Charges, BGS Capacity Charges and the BGS-FP Reconciliation Charge. Transmission service will continue to be billed to customers under the rates terms and conditions of the applicable Service Classification of RECO's Schedule for Electric Service, P.U.C. No. 2 – Electricity ("Tariff"). A description of BGS-FP service will be added to General Information Section No. 28, Basic Generation Service of the Tariff. Draft Tariff provisions for BGS-FP service are included on page 2 of Attachment A.

BGS Energy Charges

The values of the BGS Energy Charges applicable to Service Classification Nos. 1, 3, 4, 5 and 6 include the costs related to energy, Ancillary Services and generation capacity. This is a continuation of the current approved methodology of recovering all BGS costs in the kilowatthour charges for these service classifications. Generation capacity costs are proposed to be recovered through demand charges for customers in Service Classification No. 2. The resulting BGS Energy Charges applicable to this latter set of customers thus do not include the costs related to generation capacity.

BGS Capacity Charges

These charges are the demand charges previously mentioned that are designed to recover the costs associated with generation capacity for customers served under Service Classification No. 2. These charges are expressed on a per kW basis, and will be those values that appear on the right hand portion of previously referenced Table #15 of Attachment C.

The specific values that will be utilized for the BGS Energy Charges will be calculated as the weighted average of the winning BGS-FP bid prices for RECO's

zone, less transmission costs, and the winning bid price for the RECO RFP, adjusted by the appropriate factor (multiplier and constant, if applicable) as shown on Table #15 of the Development of Post Transition Period BGS Cost and Bid Factor Tables, included as page 9 of Attachment C. The tables will be updated annually prior to future BGS auctions and utilized to develop BGS charges for a related annual period in a similar manner as discussed above. The updates will reflect then current factors such as updated futures prices, factors based on 12-month data, and any changes in the customer groups and loads eligible for the BGS-FP class.

BGS-FP Reconciliation Charge

The implementation of the BGS-FP Reconciliation Charge is explained in the prior Section E - Accounting and Cost Recovery.

BGS-CIEP

The Tariff provisions for BGS-CIEP are included on page 3 of Attachment A. The BGS-CIEP default service is proposed to be available to customers served under Service Classification No. 7.

Similar to the BGS-FP, the charges for BGS-CIEP are comprised of several components: BGS Energy Charges, BGS Capacity Charges, and the BGS-CIEP Reconciliation Charge.

BGS Energy Charges

The primary component of this charge will be the actual real time PJM load weighted average Locational Marginal Price (LMP) of energy for the RECO Transmission Zone. To this will be added an estimate of the Ancillary Service costs (including PJM Administrative Costs) for the RECO zone expressed on a dollar per MWh basis. This sum will then be adjusted for losses for the service classification to

which this service is applicable. A retail margin per kWh, as determined by the Board, will then be added to this total for all metered kWh use.

BGS Capacity Charges

These charges will recover the costs associated with generation capacity. The BGS Capacity Charge is the bid component for the BGS-CIEP bid, and thus the charge will be set equal to the BGS-CIEP Auction capacity clearing price.. These charges are expressed on a per kW basis.

BGS-CIEP Reconciliation Charge

The implementation of the BGS-CIEP Reconciliation Charge is explained in the prior Section E - Accounting and Cost Recovery.

Default Supply Service Availability Charge (“DSSAC”)

As described on the Tariff leaf, included as page 5 of Attachment A, the DSSAC is a Delivery Charge that will be applicable to all customers served under Service Classification No. 7. This charge is equal to \$0.00015 per kWh and is as determined by the Board. The intent of this charge is to recover a portion the costs associated with the winning BGS-CIEP bidders maintaining the availability of the hourly priced BGS service for all customers in the applicable service classifications whether they are purchasing electric supply via BGS-CEIP or in the competitive market from a Third Party Supplier. All revenue resulting from the DSSAC will be paid directly to the winning BGS-CIEP bidders. There will be no true-ups of this charge as per the conditions of the BGS-CIEP bid arrangements.

Retail Margin

In accordance with the Decision and Order, a retail margin of \$0.005 per kWh will be added to BGS-CIEP energy charges beginning in post-Transition Year One.

Other Tariff Changes

In addition to the Tariff changes shown in Attachment A, all service classifications will be modified to remove the existing BGS rates and to reference General Information Section No. 28. Service Classification No. 7 will also be modified to reference General Information Section No. 28A.

G. RECO RFP

RECO proposes to issue an RFP for two separate financial swaps, one pertains to the forecasted capacity requirement (i.e., 80 MW) for RECO's BGS customers located in its non-PJM areas (i.e., RECO's Central and Western Divisions). The other financial swap pertains to the full energy requirements of RECO's BGS customers located in RECO's Central and Western Divisions. Previously, RECO proposed that the bids would be opened the day after the BGS-FP Auction closes and the successful bid presented to the Board for approval. If approved by the Board, the Rockland RFP price would be averaged with the Rockland BGS-FP price to determine the rates for those customers taking BGS-FP service.

While in the Decision and Order the Board agreed with the RFP process proposed by Rockland to secure electric for its non-PJM load, it accepted Staff's recommendation that the RECO RFP be due prior to the BGS-FP Auction. The Board expressed a concern that, under Rockland's proposed timeline, bidders in the Rockland RFP process who also bid in the BGS-FP Auction might have information, which would

provide them with an advantage over other RFP bidders who did not also participate in the BGS-FP Auction. Accordingly, RECO will issue the RECO RFP on or about the first week of December 2002. A copy of the RECO RFP is attached as Attachment B to this filing. RECO is still finalizing the Agreement that is referred to as Exhibit II in the RECO RFP. RECO intends for the Agreement to set out the fixed price (the fixed price is what is to be bid by Proposers), the floating price, the notional quantity, and the period covered as explained above, and expects that the Agreement will incorporate at least some provisions of the ISDA Master Agreement or comparable provisions. The bids submitted in response to the RECO RFP shall be submitted electronically simultaneously to both RECO and the Board's representatives (i.e., Charles River Associates), on January 7, 2003. Thereafter, RECO will consult with the Board's representatives as necessary. The Board will either accept or reject the winning bid at its meeting on January 9, 2003.

H. BGS Rate Design Methodology

RECO BGS Pricing Spreadsheet

As described in the EDC Filing, the resulting charge for each BGS rate element (i.e. Service Classification No. 1 summer charge, winter charge, etc.) for BGS supply service will be based on a factor applied to the final winning bid price. 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 C 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 2001 based on load research data.

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 2002 (excluding June and July).

Table #4 (Forwards Prices – Energy Only @ bulk system) contains the forwards prices for energy, by time period and month for the post transition BGS analysis period. These values are a weighted average forecast of PJM and NYISO energy prices as calculated in Table #20. The PJM values are the published energy on-peak forwards as of May 7th for the PJM West trading hub for the period of June 2002 to May 2003, and an estimate of the unpublished costs 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 forwards prices used to calculate the prices contained in Table #4 must be made to correct for the effects of transmission congestion

in the PJM system between the PJM West trading hub and the RECO zone where the BGS supply will be utilized. Table #20 contains an estimate of the average congestion factors, 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.

The factors utilized for average system losses and unaccounted for supply are inputted in Table #5 (Losses) by service classification and voltage level. Loss factors are those in RECO's current, Board approved, Third Party Supplier Agreement.

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 forwards 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 revenue shortfalls when applied to RECO's Service Classification Nos. 3 and 7 peak and off-peak kWh consumption. To correct for these differences, the shortfalls, by service classification, are divided by the total kWh for each service classification 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 2002. 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 Open Access Transmission Tariff for network transmission service. The generation capacity costs are based on an estimate of the relevant current wholesale market prices in the PJM and NYISO zones as calculated in Table #20. 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 post transition 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 RECO's estimate of Ancillary Services costs in its PJM and NYISO zones 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 all-in costs for the residential non-time of day service classifications, Service Classification Nos. 1 and 5, are blocked in the summer based on the current level of BGS blocking inputted in Table #9 so as to maintain the same rate differential that currently exists. 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 @ bulk system) 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) 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.

Table #18 (Determination of Retail Rates to be Charged to BGS Customers) provides an illustrative example of the BGS rate calculation based on the methodology developed in this worksheet. This calculation utilizes the factors established in Table 15 and the all in bid price, adjusted to remove transmission costs, to establish retail rates to all customers.

Table #19 (Reconciliation of Customer Revenue and Supplier Payments) verifies that this methodology produces BGS revenues that match supplier payments.

Table #20 (Forward Energy Prices) shows the calculation of weighted average prices for energy, generation capacity and ancillary services based on estimates for RECO's PJM and NYISO zones.

ROCKLAND ELECTRIC COMPANY
P.U.C. NO. 2 ELECTRICITY

2nd REVISED LEAF NO. 13
SUPERSEDING 1st REVISED LEAF NO. 13

GENERAL INFORMATION

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

Under this provision, the Company will provide electric power supply to customers that:

- (a) are not offered Competitive Energy Supply by an electric generation supplier;
- (b) choose not to obtain Competitive Energy Supply from an electric generation supplier;
- (c) return to the Company's service after having previously obtained Competitive Energy Supply; or
- (d) contract for Competitive Energy Supply with an electric generation supplier that fails to deliver.

Each month, all costs incurred by the Company in providing electric power supply to the above-referenced customers ("BGS Costs") shall be accumulated and reconciled to the revenues being recovered through the BGS charges in each Service Classification. Any over/under collection will be ~~recovered through the BGS reconciliation charges as described in General Information Section No. 28(C), deferred, with interest, for future recovery in accordance with the Company's Plan for Resolution of Proceedings approved by the Board in its Summary Order dated July 28, 1999 in Docket Nos. EO97070464, EO97070465 and EO97070466.~~ BGS Costs shall include costs associated with Non-Utility Generator ("NUG") contracts less Above-Market NUG Costs as defined in General Information Section 30, ENERGY COST ADJUSTMENT.

~~On July 1 of each year of the Transition Period, the Company shall file with the Board its BGS rates to become effective the following August 1. Such rates shall be set to the levels approved by the Board in its Summary Order dated July 28, 1999 in Docket Nos. EO97070464, EO97070465 and EO97070466.~~

~~On April 1, 2003, and on April 1 in each year thereafter, the Company shall file with the Board its BGS rates for the twelve-month period commencing the following August 1. Such rates shall be set to amortize any over- or under-recovered balances and to provide current BGS cost recovery over the twelve-month period commencing the following August 1.~~

ISSUED:

EFFECTIVE:

ISSUED BY: Stephen B. Bram, President
Saddle River, New Jersey 07458

**ROCKLAND ELECTRIC COMPANY
P.U.C. NO. 2 ELECTRICITY**

ORIGINAL LEAF NO. 13A

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, 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.xxxx ¢	x.xxxx ¢
1 – Over 250 kWh	x.xxxx ¢	x.xxxx ¢
2 – All kWh	x.xxxx ¢	x.xxxx ¢
3 – Peak	x.xxxx ¢	x.xxxx ¢
3 – Off-Peak	x.xxxx ¢	x.xxxx ¢
4 – All kWh	x.xxxx ¢	x.xxxx ¢
5 – First 250 kWh	x.xxxx ¢	x.xxxx ¢
5 – Next 450 kWh	x.xxxx ¢	x.xxxx ¢
5 – Over 700 kWh	x.xxxx ¢	x.xxxx ¢
6 – All kWh	x.xxxx ¢	x.xxxx ¢

Applicable to Service Classification No. 2:

	<u>Summer Months*</u>	<u>Other Months</u>
Demand Charges		
First 5 kW (\$/kW)	No Charge	No Charge
Over 5 kW (\$/kW)	x.xx	x.xx
Usage Charges		
All kWh (¢/kWh)	x.xxx ¢	x.xxx ¢

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

In accordance with P.L. 1997, c. 192, 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.

* Definition of Summer Billing Months
June through September

(Continued)

ISSUED:

EFFECTIVE:

ISSUED BY: Stephen B. Bram, President
Saddle River, New Jersey 07458

GENERAL INFORMATION

No. 28 BASIC GENERATION SERVICE (“BGS”): (Continued)

(B) BASIC GENERATION SERVICE – COMMERCIAL AND INDUSTRIAL ENERGY PRICING (BGS-CIEP) Applicable to Service Classification No. 7

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 \$x.xxxx per kilowatthour, adjusted for losses, plus a retail margin at the rate of \$0.0050 per kilowatthour and applicable taxes.

BGS Capacity Charges:

Charges per kilowatt of Billing Demand:

Charge applicable in all 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.

The customer’s installed capacity obligation, in kilowatts, is determined by the Company no less frequently than once per year. The installed capacity obligation for existing customers or for new customers utilizing an existing building or premise is based upon the customer’s share of the overall summer peak load assigned to the Company by PJM as adjusted by PJM assigned capacity related factors. The installed capacity obligation for customers taking service in a new facility, as determined by the Company, is based upon the load requirements, as estimated by the Company, of the customer’s building or premise. More specifically, the customer’s installed capacity obligation is established based upon the following: 1) an estimate of the customer’s peak demand, based upon the load shape of a representative sample of customers served under the same service classification, in conjunction with the actual or estimated, as applicable, summer energy use of that customer, or on the customer’s actual or estimated, as applicable, summer peak demand, depending on the type of metering equipment installed by the Company, and 2) the aforementioned PJM assigned capacity related factors which are established no less frequently than once per year.

In accordance with P.L. 1997, c. 192, the above charges include provision for the New Jersey Sales and Use Tax. When billed to customers exempt from this tax, as set forth in Rider SUT, such charges will be reduced by the relevant amount of such tax included therein.

(Continued)

ISSUED:

EFFECTIVE:

ISSUED BY: Stephen B. Bram, President
Saddle River, New Jersey 07458

GENERAL INFORMATION

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

(C) BGS RECONCILIATION CHARGES

Separate BGS-FP and BGS-CIEP reconciliation charges shall be computed monthly and assessed on all BGS-FP and BGS-CIEP customers. The reconciliation charges shall recover the differences between amounts paid to BGS suppliers and BGS revenue for the preceding months for the applicable BGS supply. These charges include all applicable taxes and are charged on a monthly basis for all usage billed in the month indicated.

BGS-FP Reconciliation Charge.....x.xxx ¢/kWh

BGS-CIEP Reconciliation Chargex.xxx ¢/kWh

In accordance with P.L. 1997, c. 192, 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.

ISSUED:

EFFECTIVE:

ISSUED BY: Stephen B. Bram, President
Saddle River, New Jersey 07458

GENERAL INFORMATION

No. 28A DEFAULT SUPPLY SERVICE AVAILABILITY CHARGE:

A Default Supply Service Availability Charge shall be assessed on all kWh delivered under Service Classification No. 7. This charge shall recover costs associated with the administration, maintenance and availability of BGS-CIEP service as described in General Information Section No. 28.

Default Supply Service Availability Charge..... 0.0159 ¢/kWh

In accordance with P.L. 1997, c. 192, the above charge includes provision for the New Jersey Sales and Use Tax. When billed to customers exempt from this tax, as set forth in Rider SUT, such charge will be reduced by the relevant amount of such tax included therein.

ISSUED:

EFFECTIVE:

ISSUED BY: Stephen B. Bram, President
Saddle River, New Jersey 07458

**DRAFT****Request-For-Proposals: Financial Swaps for the Period
August 1, 2003 to May 31, 2004****1. Scope of Proposal**

In this Request-For-Proposals (“RFP”) Rockland Electric Company (“RECO”) is seeking competitive proposals from qualified parties (“Proposers”) for two separate “fixed for floating” financially-settled swap transactions.

The first swap pertains to the forecasted capacity requirement for RECO’s Basic Generation Service (“BGS”) Customers located in RECO’s Central Division in Passaic County, New Jersey and RECO’s Western Division in Sussex County, New Jersey (both of which are located in New York Independent System Operator (“NYISO”) Zone G (Hudson Valley)) for the period August 1, 2003 through May 31, 2004. Proposers are to bid the fixed price for this swap. RECO will be the fixed price payer under this swap. The floating price will be the applicable NYISO Pre-Capability Strip Auction Market Clearing price. Proposers will be the floating price payer. Proposers may choose either 50% or 100% of the forecasted 80 MW capacity requirement for the BGS Customers located in RECO’s Central and Western Divisions as the notional quantity for this swap. The term of this swap will be from August 1, 2003 through May 31, 2004.

The second swap pertains to the full energy requirements of RECO’s BGS customers located in RECO’s Central and Western Divisions. Proposers are to bid the fixed price for this swap. RECO will be the fixed price payer under this swap. The floating price will be based on the applicable NYISO Day Ahead Market Zone G hourly prices. Proposers will be the floating price payer. The notional quantity for this swap will be the actual load of the BGS Customers located in RECO’s Central and Western Divisions as reported by the NYISO. The term of this swap will be from August 1, 2003 through May 31, 2004.

Proposers are required to submit bids for both the swap pertaining to capacity and the swap pertaining to energy, but, as explained above, Proposers have the option of selecting either 40 MW or 80 MW as the notional quantity for the swap pertaining to capacity. Bids must be set forth on the Form of Proposal attached as Exhibit I.

Proposers must execute the attached Confidentiality Agreement as soon as possible. The New Jersey Board of Public Utilities’ consultant, Charles River Associates, will execute a similar confidentiality agreement. Upon the receipt of the executed Confidentiality Agreement, RECO will provide the monthly data regarding the load shapes for the BGS Customers.

Proposers are encouraged to review the provisions of the *New York ISO Tariffs*, *The NYISO Installed Capacity Requirements Manual* and all other relevant NYISO rules, procedures and guidelines, prior to submitting their bids.

2. Proposal Conditions

Successful Proposers will be required to enter into swap agreements (collectively, the “Agreement”) in the form attached as Exhibit II. *[Note: RECO has not finally determined the form of Agreement that will be used, but intends for the Agreement to set out the fixed price (the fixed price is what is to be bid by Proposers), the floating price, the notional quantity, and the period covered as explained above and expects that the Agreement will incorporate at least some provisions of the ISDA Master Agreement or comparable provisions. The form of Agreement is intended to be attached to this RFP when it is submitted to Proposers.]* Changes to the Agreement are discouraged and may put a Proposer at a disadvantage compared to other Proposers. Requested changes to the Agreement must be submitted electronically to Jack Carley (CarleyJ@ConEd.com) with a copy to Joseph Holtman (HoltmanJ@ConEd.com) a week prior to the time for submitting the priced proposal. Requested changes that are not timely submitted will not be considered.

Any information specified by the Proposer in writing as “confidential” and/or “proprietary” will be kept confidential and will not be disclosed by RECO or its consultants to others, except for disclosure to the New Jersey Board of Public Utilities or Charles River Associates and except to the extent that disclosure is required by applicable law, regulation or legal process. However, requests for clarification or additional information by Proposers will not be kept confidential.

Prior to the execution, or during the term, of the Agreement, RECO may require any Proposer to provide financial information, such as, financial statements, annual reports or other publicly available reports or filings, bank and trade references to evaluate the Proposer’s creditworthiness.

Following the evaluation of the Proposer’s creditworthiness, the Proposer may be required to provide 1) a guaranty in the form attached hereto as Exhibit IV from its corporate parent (“Guarantor”); or 2) an irrevocable transferable standby Letter of Credit issued by a major United States commercial bank or a foreign bank with a United States branch office with a credit rating of at least “A-“ by S&P and “A3” by Moody’s in a form and in an amount reasonably acceptable to RECO. Any Letter of Credit provided shall comply with the requirements of Exhibit III. The request for, the form of, and the determination of, the amounts of any support requirements shall be at the sole discretion of RECO. Failure to comply with RECO’s requirements may result in disqualification of the Proposer.

All costs and expenses associated with developing and/or submitting a proposal in response to this RFP and/or any related activity following the submission of any such proposal shall be borne by Proposers. While RECO has endeavored to supply useful information in connection with this RFP, RECO makes no representation or warranty, express or implied, as to the accuracy or completeness of any information contained herein or otherwise provided to any Proposer by or on behalf of RECO. RECO shall have no liability relating to or arising from any such information or the use thereof. Proposers are encouraged to conduct their own investigation and analysis of any and all information contained herein or otherwise provided by or on behalf of RECO. This RFP is not an offer or commitment and is not capable of being accepted to form a binding agreement. RECO reserves the right, in its sole discretion, to withdraw or modify this RFP at any time, to reject any or all proposals for any reason, and to enter into further discussions or negotiations with any one or more Proposers.

3. Instructions

Proposals must be submitted electronically to Joseph Holtman (HoltmanJ@ConEd.com) and to Charles River Associates [**Insert Address**] and be received by 1:00 PM, January 7, 2003. The Proposer's electronic submittal to this RFP shall remain open and available to RECO until noon EPT on January 10, 2002.

By 5:00 PM EPT on January 8, 2003, RECO must receive from the Proposer a notarized copy of the above electronically submitted proposal, signed by an official authorized to bind the supplying entity, and addressed to:

Joseph Holtman
Director, Electricity Supply
Consolidated Edison Company of New York, Inc.
4 Irving Place (Room 1310-S)
New York, NY 10003

Questions regarding this RFP should be directed to Joseph Holtman by phone at (212) 460-3321 or by e-mail address: HoltmanJ@ConEd.com. Proposers are also requested to submit the name, telephone number and e-mail address of the person to contact if RECO needs additional information or clarification regarding their proposals.

Exhibit I

<u>Month</u>	<u>Form of Proposal</u>			
	<u>Offered Energy Quantity (1)</u> <u>(MW)</u>	<u>Energy Charge (1)</u> <u>(\$/MWh)</u>	<u>Offered ICAP (2)</u> <u>(MW)</u>	<u>Capacity Charge(2)</u> <u>(\$/kW-month)</u>
Aug-03				
Sep-03				
Oct-03				
Nov-03				
Dec-03				
Jan-04				
Feb-04				
Mar-04				
Apr-04				
May-04				

NOTES:

- (1) The Proposer will offer a fixed price financial swap to provide price coverage for either full or one half of the BGS Customers *actual* energy requirements. The forecasted BGS Customers peak load is 70 MW.
- (2) The Proposer will offer a fixed price financial swap for the *forecasted* amount of UCAP requirements for the BGS Customers load, i.e., either 80 MW of ROS (Rest-of-State) UCAP (full requirement) or 40 MW of ROS UCAP (one half requirement).

Exhibit III

LETTER OF CREDIT PROVISIONS

Performance Assurance provided by one party ("X") for the benefit of the other ("Y") in the form of a Letter of Credit shall be subject to the following provisions.

- (a) Any Letter of Credit shall be delivered by X to such address as Y shall specify and shall be maintained for the benefit of Y or its designee. X or the issuer of the Letter of Credit shall (i) renew or cause the renewal of each outstanding Letter of Credit on a timely basis as provided in the relevant Letter of Credit, (ii) if the bank that issued an outstanding Letter of Credit has indicated its intent not to renew such Letter of Credit, provide either a substitute Letter of Credit or other Performance Assurance, in each case at least twenty (20) days prior to the expiration of the outstanding Letter of Credit, and (iii) if a bank issuing a Letter of Credit shall fail to honor Y's properly documented request to draw on an outstanding Letter of Credit, provide for the benefit of Y either a substitute Letter of Credit that is issued by a bank acceptable to Y or other Performance Assurance, in each case within two (2) Business Days after such refusal.
- (b) Upon the occurrence of a Letter of Credit Default, X agrees to deliver to Y either a substitute Letter of Credit or other Performance Assurance, in each case on or before the second Business Day after the occurrence thereof. "**Letter of Credit Default**" shall mean with respect to an outstanding Letter of Credit, the occurrence of any of the following events: (i) the issuer of such Letter of Credit shall fail to maintain a Credit Rating of at least "A-" by S&P and "A3" by Moody's; in the event of an inconsistency in ratings assigned by S&P or Moody's (a "split rating"), the lowest rating assigned shall control. (ii) the issuer of the Letter of Credit shall fail to comply with or perform its obligations under such Letter of Credit if such failure shall be continuing after the lapse of any applicable grace period; (iii) the issuer of such Letter of Credit shall disaffirm, disclaim, repudiate or reject, in whole or in part, or challenge the validity of, such Letter of Credit; (iv) such Letter of Credit shall expire or terminate, or shall fail or cease to be in full force and effect at any time during the term of this Agreement; provided, however, that no Letter of Credit Default shall occur in any event with respect to a Letter of Credit after the time such Letter of Credit is required to be canceled or returned to X in accordance with the terms of this Agreement.
- (c) As one method of providing additional Performance Assurance, X may increase the amount of an outstanding Letter of Credit or establish one or more additional Letters of Credit.
- (d) (i) A Letter of Credit shall provide that Y may draw upon the Letter of Credit in an amount that is equal to all amounts that are due and owing from X but have not been paid to Y within the time allowed for such payments under this Agreement. A Letter of Credit shall provide that a drawing may be made on the Letter of Credit upon submission to the bank issuing the Letter of Credit of one or more certificates of Y in accordance with the specific requirements of the Letter of Credit.

- (ii) Upon or at any time after the occurrence of an Event of Default with respect to X, Y may draw on the entire, undrawn portion of any outstanding Letter of Credit upon submission to the bank issuing such Letter of Credit of one or more certificates in accordance with the specific requirements of the Letter of Credit. Cash proceeds received from drawing upon the Letter of Credit shall be deemed Performance Assurance and shall be applied against all amounts that are due and owing from X but have not been paid to Y within the time allowed for such payments under this Agreement. Notwithstanding Y's receipt of Cash under the Letter of Credit, X shall remain liable to Y for any failure to transfer sufficient Performance Assurance to Y in accordance with the terms herein. In addition, X shall remain liable for any amounts owing to Y and remaining unpaid after the application of the amounts so drawn by Y.

- (e) Upon or at any time after the occurrence or deemed occurrence of an Termination Date as a result of an Event of Default and the failure of X to make all payments due and owing to Y in accordance with the terms of this Agreement, Y may draw on any outstanding Letter of Credit in an amount equal to such amounts owing to it. X shall remain liable for any amounts owing to Y and remaining unpaid after the application of the amounts so drawn by Y.

EXHIBIT IV

PAYMENT GUARANTEE

_____, 2003

To: Rockland Electric Company

Ladies and Gentlemen:

From time to time, _____ (“Principal”) and Rockland Electric Company, a New Jersey corporation (“Counterparty”) may enter into one or more transactions for the sale and/or purchase of energy, unforced capacity, installed capacity and ancillary services based on such terms and conditions as to which Principal and Counterparty may agree (such transactions are collectively referred to herein as the "Agreement"). In consideration of Counterparty entering into and/or continuing to do business under the Agreement with Principal, _____ (“Guarantor”), a _____ and the parent of Principal, to the extent of \$ _____ (_____ DOLLARS) (the “Guarantee Limit”), hereby irrevocably and unconditionally guarantees to Counterparty, with effect from the date hereof, the due and punctual payment of all amounts payable by Principal under the Agreement when the same shall become due and payable, whether on scheduled payment dates, upon oral or written demand, upon declaration of termination or otherwise, in accordance with the terms of the Agreement and giving effect to any applicable grace or cure period. Upon failure of Principal punctually to pay any such amounts, and upon written demand by Counterparty to Guarantor at its address set forth in the signature block of this Guarantee (or to such other address as Guarantor may specify in writing to Counterparty), Guarantor, subject to the Guarantee Limit, agrees to pay or cause to be paid such amounts within 10 days of its receipt of a written demand from Counterparty; provided that delay by Counterparty in giving such demand shall in no event affect Guarantor’s obligations under this Guarantee. This is a guarantee of payment and not of collection.

Guarantor hereby agrees that its obligations hereunder shall not be affected by the Agreement's validity, enforceability or the lack of authority of Principal to execute, deliver, or perform the Agreement, or any change in or amendment to the Agreement.

Guarantor hereby waives diligence, presentment, and demand on Principal for payment or otherwise (except as provided hereinabove), filing of claims, requirement of a prior proceeding against Principal and protest or notice, except as provided for in the Agreement with respect to amounts payable by Principal. Should Principal become the subject of a bankruptcy, insolvency, reorganization or similar proceeding, the failure of Counterparty to file any claim in such proceeding shall not affect Guarantor’s obligations hereunder to Counterparty. If at any time payment by Principal to Counterparty under the Agreement is rescinded or must be otherwise restored or returned by Counterparty to Principal due to the insolvency, bankruptcy or reorganization of Principal or Guarantor or otherwise, Guarantor's obligations hereunder with respect to such payment shall be reinstated upon such restoration or return to Principal being made by Counterparty.

Guarantor represents to Counterparty as of the date hereof, that:

1. it is duly organized and validly existing under the laws of the jurisdiction of its incorporation and has full power and legal right to execute and deliver this Guarantee and to perform the provisions of this Guarantee on its part to be performed;
2. its execution, delivery and performance of this Guarantee have been and remain duly authorized by all necessary corporate action and do not contravene any provision of its certificate of incorporation or by-laws or any law, regulation or contractual restriction binding on it or its assets;
3. all consents, authorizations, approvals and clearances (including, without limitation, any necessary exchange control approval) and notifications, reports and registrations requisite for its due execution, delivery and performance of this Guarantee have been obtained from or, as the case may be, filed with the relevant governmental authorities having jurisdiction and remain in full force and effect and all conditions thereof have been duly complied with and no other action by, and no notice to or filing with, any governmental authority having jurisdiction is required for such execution, delivery or performance; and
4. this Guarantee is its legal, valid and binding obligation enforceable against it in accordance with its terms except as enforcement hereof may be limited by applicable bankruptcy, insolvency, reorganization or other similar laws affecting the enforcement of creditors' rights or by general equity principles.

In the event of any default by Principal, Counterparty shall have the right to proceed first and directly against Guarantor under this Guarantee without proceeding against any other person or entity or exhausting any other remedies which it may have and without resorting to any other security held by it.

No provision of this Guarantee may be amended or waived except by a written instrument executed by Guarantor and Counterparty. This Guarantee shall bind and benefit the successors and assigns of Guarantor and Counterparty; provided that Guarantor may not assign this Guarantee without Counterparty's consent, which consent shall not unreasonably be withheld. Prompt notice shall be furnished to the other party of any such assignment or succession. This Guarantee shall not be deemed to benefit any person except Guarantor, Counterparty and their respective successors and assigns.

This Guarantee shall expire on _____. However this Guarantee may be terminated prior to said date upon at least 15 days' prior written notice to that effect being actually received by Counterparty. Such expiration or termination shall not, however, affect or reduce Guarantor's obligation hereunder for any liability of Principal pursuant to the Agreement incurred prior to such expiration or termination.

In case any clause, provision, or section of this Guarantee, or any application thereof, is for any reason held to be illegal, invalid or inoperable, such illegality, invalidity or inoperability shall not affect the remainder thereof or any other clause, provision, or section, and each such clause, provision, or section shall be deemed to be effective and operative in the manner and to the full extent permitted by law.

This Guarantee shall be governed by and construed in accordance with the laws of the State of New Jersey, without reference to its choice of law doctrine. _____

By: _____
Name:
Title:
Address:

Accepted:

Rockland Electric Company

By: _____
Name:
Title:
Address:

**Development of Post Transition Period BGS Cost and Bid Factors
Adjusted to Billing Time Periods**

Based on 2001 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

(data rounded to nearest %)	Profile Meter Data SC1	Profile Meter Data SC5	Profile Meter Data SC3	Profile Meter Data SC2 ND	--- Other Analysis --- SC4	SC6	Profile Meter Data SC2 Dem
January	52.5%	50.0%	47.9%	56.6%	30.2%	30.2%	56.6%
February	51.7%	48.9%	47.4%	57.5%	30.0%	30.0%	57.5%
March	51.0%	42.3%	48.8%	57.5%	27.8%	27.8%	57.5%
April	47.8%	37.0%	48.4%	55.3%	29.1%	29.1%	55.3%
May	50.2%	46.3%	51.9%	59.8%	23.2%	23.2%	59.8%
June	53.3%	61.2%	52.3%	59.4%	19.8%	19.8%	59.4%
July	47.6%	54.8%	49.7%	55.6%	20.2%	20.2%	55.6%
August	55.6%	58.2%	56.0%	60.6%	22.8%	22.8%	60.6%
September	47.2%	41.4%	46.0%	54.4%	26.7%	26.7%	54.4%
October	54.4%	41.8%	50.9%	61.2%	30.2%	30.2%	61.2%
November	51.9%	41.6%	45.6%	56.5%	28.3%	28.3%	56.5%
December	47.9%	40.2%	45.1%	53.1%	29.5%	29.5%	53.1%

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

On-Peak periods as defined in specified rate schedule

(data rounded to nearest %)	N/A SC1	N/A SC5	SC3	N/A SC2 ND	N/A SC4	N/A SC6	N/A SC2 Dem
January	---	---	41%	---	---	---	---
February	---	---	37%	---	---	---	---
March	---	---	37%	---	---	---	---
April	---	---	35%	---	---	---	---
May	---	---	37%	---	---	---	---
June	---	---	42%	---	---	---	---
July	---	---	46%	---	---	---	---
August	---	---	42%	---	---	---	---
September	---	---	40%	---	---	---	---
October	---	---	36%	---	---	---	---
November	---	---	43%	---	---	---	---
December	---	---	40%	---	---	---	---

Table #3 Class Usage @ customer
calendar month sales forecasted for 2002
in MWh

	SC1	SC5	SC3	SC2 ND	SC4	SC6	SC2 Dem
January	50,456	1,770	31	9,016	678	470	47,332
February	51,205	1,796	32	10,335	599	416	45,532
March	49,786	1,746	31	8,064	590	410	46,793
April	44,917	1,576	28	6,280	501	348	45,621
May	47,074	1,651	29	5,799	489	340	45,066
June							
July							
August	73,694	2,585	46	5,819	541	376	54,169
September	66,590	2,336	41	7,115	507	352	52,673
October	54,728	1,920	34	5,245	656	455	47,200
November	43,928	1,541	27	6,093	680	472	45,544
December	<u>46,568</u>	<u>1,633</u>	<u>29</u>	<u>7,414</u>	<u>692</u>	<u>480</u>	<u>47,917</u>
Total	528,946	18,554	328	71,180	5,933	4,119	477,847

Table #4 Forwards Prices - Energy Only @ bulk system
in \$/MWh (See Table 20)

	On-Peak	Off-Peak
January	39.80	23.68
February	39.80	23.68
March	35.96	23.68
April	35.96	23.68
May	39.88	23.68
June	47.71	23.68
July	59.06	23.68
August	59.06	23.68
September	37.21	23.68
October	35.55	23.68
November	35.55	23.68
December	35.55	23.68

Table #5 Losses

	SC1	SC5	SC3	SC2 ND	SC4	SC6	SC2 Dem
Expansion Factor =	1.07987	1.07987	1.07987	1.07987	1.07611	1.07611	1.07987

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

		SC1	SC5	SC3	SC2 ND	SC4	SC6	SC2 Dem
Summer - all hrs	\$	40.00	\$ 40.12	\$ 40.05	\$ 40.36	\$ 31.84	\$ 31.85	\$ 41.23
	PJM on pk	\$ 53.53	\$ 54.54	\$ 53.80	\$ 51.43	\$ 51.25	\$ 51.26	\$ 52.78
	PJM off pk	\$ 25.57	\$ 25.57	\$ 25.57	\$ 25.57	\$ 25.48	\$ 25.48	\$ 25.57
Winter - all hrs	\$	33.08	\$ 32.06	\$ 32.68	\$ 34.09	\$ 29.65	\$ 29.65	\$ 33.96
	PJM on pk	\$ 40.28	\$ 40.45	\$ 40.29	\$ 40.51	\$ 39.98	\$ 39.98	\$ 40.24
	PJM off pk	\$ 25.57	\$ 25.57	\$ 25.57	\$ 25.57	\$ 25.48	\$ 25.48	\$ 25.57
Annual	\$	34.91	\$ 34.20	\$ 34.64	\$ 35.23	\$ 30.03	\$ 30.03	\$ 35.58
System Total	\$	35.17						

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

		SC1	SC5	SC3	SC2 ND	SC4	SC6	SC2 Dem
Summer - all hrs	\$	5,612	\$ 197	\$ 3	\$ 522	\$ 33	\$ 23	\$ 4,405
	PJM on pk	\$ 3,876	\$ 135	\$ 2	\$ 380	\$ 13	\$ 9	\$ 3,245
	PJM off pk	\$ 1,736	\$ 63	\$ 1	\$ 142	\$ 20	\$ 14	\$ 1,160
Winter - all hrs	\$	12,855	\$ 437	\$ 8	\$ 1,986	\$ 145	\$ 101	\$ 12,598
	PJM on pk	\$ 7,988	\$ 241	\$ 5	\$ 1,346	\$ 56	\$ 39	\$ 8,535
	PJM off pk	\$ 4,867	\$ 196	\$ 3	\$ 640	\$ 89	\$ 62	\$ 4,063
Annual	\$	18,467	\$ 635	\$ 11	\$ 2,508	\$ 178	\$ 124	\$ 17,003
System Total	\$	38,926						

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

	SC1	SC5	SC3	SC2 ND	SC4	SC6	SC2 Dem
Summer - all hrs	\$ 40.00	\$ 40.12	\$ 40.05	\$ 40.36	\$ 31.84	\$ 31.85	\$ 41.23
RECO On pk			\$ 56.72				
RECO Off pk			\$ 28.49				
Winter - all hrs	\$ 33.08	\$ 32.06	\$ 32.68	\$ 34.09	\$ 29.65	\$ 29.65	\$ 33.96
RECO On pk			\$ 41.78				
RECO Off pk			\$ 27.06				
Annual Average	\$ 34.91	\$ 34.20	\$ 34.64	\$ 35.23	\$ 30.03	\$ 30.03	\$ 35.58
System Average	\$ 35.17						

Table #9 Generation & Transmission Obligations and Costs and Other Adjustments
obligations - annual average forecasted for 2002; costs are market estimates in MW

	SC1	SC5	SC3	SC2 ND	SC4	SC6	SC2 Dem
Gen Obl - MW	228.7	11.3	0.1	13.0	0.0	0.0	162.0
Trans Obl - MW	215.6	10.7	0.1	12.3	0.0	0.0	152.7

of Months and Days used in this analysis

# of summer days =	61	# of summer months =	2
# of winter days =	243	# of winter months =	8
		total # months =	10

Transmission Cost \$ 32,114 per MW-yr

Generation Capacity cost	summer	\$25.08	\$/MW/day	Resulting avg gen cap cost =	summer >>	\$ 9.15	per kW/yr
	winter	\$22.68	\$/MW/day		winter >>	\$ 8.28	per kW/yr
					annual >>	\$ 8.57	per kW/yr

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

	----- SC1 -----		----- SC5 -----		
	Charges	% usage	Chgs (¢/kWh)	Differences	% usage
Block 1 (0-250 kWh/month)	4.350 ¢/kWh	21.80%	4.303		31.45%
Block 2 (>250 kWh/m)	4.907 ¢/kWh	78.20%	4.863	0.560	35.38%
Calculated inversion =	0.557 ¢/kWh		5.240	0.937	33.17%

Table #10 Ancillary Services
forecasted overall annual average \$1.89 /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	\$ 10.91	\$ 15.43	\$ 8.16	\$ 4.62	\$ -	\$ -
Generation Obl -						
per annual MWh	\$ 3.04	\$ 4.29	\$ 2.15	\$ 1.29	\$ -	\$ -
per summer MWh	\$ 3.40	\$ 4.80	\$ 2.40	\$ 1.46	\$ -	\$ -
per winter MWh	\$ 2.91	\$ 4.11	\$ 2.05	\$ 1.25	\$ -	\$ -

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	\$ 56.20	\$ 62.25	\$ 52.50	\$ 48.33	\$ 33.73	\$ 33.74
RECO On pk			\$ 72.63			
RECO Off pk			\$ 38.54			
Block 1	\$ 51.85	\$ 57.16				
Block 2	\$ 57.42	\$ 62.76				
Block 3		\$ 66.53				
Winter - all hrs	\$ 48.78	\$ 53.50	\$ 44.78	\$ 41.86	\$ 31.54	\$ 31.54
RECO On pk			\$ 57.19			
RECO Off pk			\$ 37.11			
Annual -all hrs	\$ 50.76	\$ 55.81	\$ 46.83	\$ 43.03	\$ 31.92	\$ 31.92

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

	SC2 Dem	PLUS:
Summer - all hrs	\$ 43.12	<u>Gen Cost (per kW of Billed Demand/Month)</u>
RECO On pk		
RECO Off pk		
Winter - all hrs	\$ 35.85	summer \$ 0.93
RECO On pk		winter \$ 0.80
RECO Off pk		
Annual - all hrs per MWh only	\$ 37.47	<u>Trans cost</u>
		all months \$ 2.68 per kW of T obl /month

Table #12 (Continued)

Including T&G Obligation \$

Summer - all hrs \$ 53.40
 RECO On pk
 RECO Off pk

Note: Obligation \$ included in On pk costs

Winter - all hrs \$ 46.99
 RECO On pk
 RECO Off pk

Annual - including T&G Obl \$ \$ 48.42

ALL RATES

Grand Total Cost in \$1000 = \$ 54,420

All-In Average cost @ customer = \$ 49.16 per MWh at customer (per customer metered MWh)

All-In Average costs @ bulk system = \$ 45.53 per MWh at bulk system (per bulk system metered MWh)

Table #13 Ratio of BGS Unit Costs @ customer to All-In Average Cost @ bulk system

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				1.06	0.74	0.74
RECO On pk			1.60			
RECO Off pk			0.85			
All usage Multiplier	1.23	1.37				
Constant Blk 1 \$	(4.36) \$	(5.09)				
Constant Blk 2 \$	1.21 \$	0.51				
Constant Blk 3	NA \$	4.28				
Winter - all hrs	1.07	1.18		0.92	0.69	0.69
RECO On pk			1.26			
RECO Off pk			0.82			
Annual - all hrs	1.11	1.23	1.03	0.95	0.70	0.70

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	PLUS:	
Summer - all hrs	1.17	\$ (10.29)	<u>Gen Cost (per kW of Billed Demand/Month)</u>	
RECO On pk			SC2 Dem	
RECO Off pk			summer \$	0.93
Winter - all hrs	1.03	\$ (11.14)	winter \$	0.80
RECO On pk			<u>Trans cost</u>	
RECO Off pk			all months \$	2.68 per kW of T obl /month
Annual - including T&G Obl \$	1.06			

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	\$ 45.29	\$ 46.81	\$ 44.34	\$ 43.71	\$ 33.73	\$ 33.74
RECO On pk			\$ 64.48			
RECO Off pk			\$ 30.38			
Block 1	\$ 40.94	\$ 41.72				
Block 2	\$ 46.51	\$ 47.32				
Block 3		\$ 51.09				
Winter - all hrs	\$ 37.88	\$ 38.06	\$ 36.62	\$ 37.23	\$ 31.54	\$ 31.54
RECO On pk			\$ 49.03			
RECO Off pk			\$ 28.95			
Annual -all hrs	\$ 39.85	\$ 40.38	\$ 38.67	\$ 38.41	\$ 31.92	\$ 31.92

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		PLUS:
Summer - all hrs	\$ 43.12		<u>Gen Cost (per kW of Billed Demand/Month)</u>
RECO On pk			
RECO Off pk			SC2 Dem
Winter - all hrs	\$ 35.85	summer \$	0.93
RECO On pk		winter \$	0.80
RECO Off pk			
Annual - all hrs per MWh only	\$ 37.47		
<u>Including Generation Obligation \$</u>			
Summer - all hrs	\$ 45.75		
RECO On pk			
RECO Off pk			
Winter - all hrs	\$ 38.18		
RECO On pk			
RECO Off pk			
Annual - including T&G Obl \$	\$ 39.87		

Note: Obligation \$ included in On pk costs

ALL RATES

Grand Total Cost in \$1000 =	\$ 43,945		
All-In Average cost @ customer =	\$ 39.70	per MWh at customer (per customer metered MWh)	
All-In Average costs @ bulk system =	\$ 36.77	per MWh at bulk system (per bulk system metered MWh)	

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

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				1.19	0.92	0.92
RECO On pk			1.75			
RECO Off pk			0.83			
All usage Multiplier	1.23	1.27				
Constant Blk 1 \$	(4.36)	\$ (5.09)				
Constant Blk 2 \$	1.21	\$ 0.51				
Constant Blk 3	NA	\$ 4.28				
Winter - all hrs	1.03	1.04		1.01	0.86	0.86
RECO On pk			1.33			
RECO Off pk			0.79			
Annual - all hrs	1.08	1.10	1.05	1.04	0.87	0.87

DEMAND RATES

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

	SC2 Dem Multiplier	SC2 Dem Constant	PLUS:
Summer - all hrs	1.24	\$ (2.64)	<u>Gen Cost (per kW of Billed Demand/Month)</u>
RECO On pk			
RECO Off pk			
Winter - all hrs	1.04	\$ (2.33)	
RECO On pk			summer \$ 0.93
RECO Off pk			winter \$ 0.80
Annual - including T&G Obl \$	1.08		

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	\$ 7,884	\$ 306	\$ 5	\$ 625	\$ 35	\$ 25	\$ 5,706	
Winter	\$ 18,960	\$ 729	\$ 11	\$ 2,438	\$ 154	\$ 107	\$ 17,433	
Total	\$ 26,845	\$ 1,036	\$ 15	\$ 3,063	\$ 189	\$ 131	\$ 23,138	
% of Annual Total \$ by Rate								
Summer	29%	30%	30%	20%	19%	19%	25%	
Winter	71%	70%	70%	80%	81%	81%	75%	
Total Costs - in \$1000								
Summer	\$ 14,586							
Winter	\$ 39,832							
Total	\$ 54,418							
% of Annual Total \$								
Summer	27%	If total \$ were split on a per MWh basis (on bulk system MWhs):					<u>Ratio to All-In Cost</u>	
Winter	73%	\$ 50.62	per MWh @ bulk system				Summer	1.111807
		\$ 43.91	per MWh @ bulk system				Winter	0.964434

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	\$ 6,354	\$ 230	\$ 4	\$ 565	\$ 35	\$ 25	\$ 4,889	
Winter	\$ 14,721	\$ 519	\$ 9	\$ 2,169	\$ 154	\$ 107	\$ 14,163	
Total	\$ 26,845	\$ 749	\$ 13	\$ 2,734	\$ 189	\$ 131	\$ 19,052	
% of Annual Total \$ by Rate								
Summer	24%	31%	30%	21%	19%	19%	26%	
Winter	55%	69%	70%	79%	81%	81%	74%	
Total Costs - in \$1000								
Summer	\$ 12,102							
Winter	\$ 31,841							
Total	\$ 43,943							
% of Annual Total \$								
Summer	28%	If total \$ were split on a per MWh basis (on bulk system MWhs):					<u>Ratio to All-In Cost</u>	
Winter	72%	\$ 42.00	per MWh @ bulk system				Summer	1.1423
		\$ 35.10	per MWh @ bulk system				Winter	0.9547

Table #18 Determination of Retail Rates to be Charged to BGS Customers

All-In Average costs @ bulk system =	\$	45.53 /MWh
Less Transmission	\$	<u>(8.76) /MWh</u>
BGS Cost	\$	36.77 /MWh

Retail BGS Rates (excl SUT) (¢/kWh)

	SC1	SC5	SC3	SC2 ND	SC4	SC6	SC2 Dem
<u>Summer</u>							
All kWh (¢/kWh)				4.371	3.373	3.374	4.312
Peak kWh (¢/kWh)			6.448				
Off-Peak kWh (¢/kWh)			3.038				
Block1	4.094	4.172					
Block2	4.651	4.732					
Block3	NA	5.109					
Demand Charge (\$/kW)							0.93
<u>Winter</u>							
All kWh (¢/kWh)	3.788	3.806		3.723	3.154	3.154	3.585
Peak kWh (¢/kWh)			4.903				
Off-Peak kWh (¢/kWh)			2.895				
Demand Charge (\$/kW)							0.80

Table #19 Reconciliation of Customer Revenue and Supplier Payments

Assumed Winning Bid Price = \$ 45.53
 Payment Ratio - Summer = 1.111807
 Payment Ratio - Winter = 0.964434
 Supplier Price - Summer = 50.6196
 Supplier Price - Winter = 43.9098

	SC1	SC5	SC3	SC2 ND	SC4	SC6	SC2 Dem
Total BGS Revenue (Excl SUT) - in \$1000							
Summer	\$ 6,354	\$ 230	\$ 4	\$ 565	\$ 35	\$ 25	\$ 4,889
Winter	\$ 14,723	\$ 519	\$ 9	\$ 2,168	\$ 154	\$ 107	\$ 14,164
Total	\$ 21,077	\$ 749	\$ 13	\$ 2,733	\$ 189	\$ 132	\$ 19,053
Total							
Summer	\$ 12,102						
Winter	\$ 31,844						
Total	\$ 43,946						
Transmission Revenue							
Summer	\$ 2,095						
Winter	\$ 8,380						
Total	\$ 10,475						
Total Revenue - BGS and Transmission							
Summer	\$ 14,197						
Winter	\$ 40,224						
Total	\$ 54,421						

	SC1	SC5	SC3	SC2 ND	SC4	SC6	SC2 Dem
Total Supplier Payment - in \$1000							
Summer	\$ 7,668	\$ 269	\$ 5	\$ 707	\$ 57	\$ 40	\$ 5,840
Winter	\$ 18,429	\$ 646	\$ 11	\$ 2,762	\$ 231	\$ 160	\$ 17,592
Total	\$ 26,097	\$ 915	\$ 16	\$ 3,469	\$ 288	\$ 200	\$ 23,432
Total							
Summer	\$ 14,586						
Winter	\$ 39,832						
Total	\$ 54,418						
	\$ (3)						

Table #20 Forward Energy Prices

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

	On-Peak	Off-Peak
January	34.15	19.90
February	34.15	19.90
March	31.30	19.90
April	31.30	19.90
May	34.25	19.90
June	41.13	19.90
July	51.30	19.90
August	51.30	19.90
September	32.13	19.90
October	30.63	19.90
November	30.63	19.90
December	30.63	19.90

PJM Congestion Factors

	On-Peak	Off-Peak
January	114.9%	114.9%
February	114.9%	114.9%
March	114.9%	114.9%
April	114.9%	114.9%
May	114.9%	114.9%
June	114.9%	114.9%
July	114.9%	114.9%
August	114.9%	114.9%
September	114.9%	114.9%
October	114.9%	114.9%
November	114.9%	114.9%
December	114.9%	114.9%

PJM Forward Prices (incl congestion) in \$/MWh

	On-Peak	Off-Peak
January	39.24	22.87
February	39.24	22.87
March	35.96	22.87
April	35.96	22.87
May	39.35	22.87
June	47.26	22.87
July	58.94	22.87
August	58.94	22.87
September	36.92	22.87
October	35.19	22.87
November	35.19	22.87
December	35.19	22.87

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

	On-Peak	Off-Peak
January	45.25	31.50
February	45.25	31.50
March	36.00	31.50
April	36.00	31.50
May	45.00	31.50
June	52.00	31.50
July	60.25	31.50
August	60.25	31.50
September	40.00	31.50
October	39.00	31.50
November	39.00	31.50
December	39.00	31.50

Weighted Average Forward Prices - Energy Only @ bulk system (90.6% PJM - 9.4% NYISO)
in \$/MWh

	On-Peak	Off-Peak
January	39.80	23.68
February	39.80	23.68
March	35.96	23.68
April	35.96	23.68
May	39.88	23.68
June	47.71	23.68
July	59.06	23.68
August	59.06	23.68
September	37.21	23.68
October	35.55	23.68
November	35.55	23.68
December	35.55	23.68

Table #21 Generation Capacity Prices (\$/MW/Day)

	<u>PJM</u> <u>90.6%</u>	<u>NYISO</u> <u>9.4%</u>	<u>Weighted</u> <u>Average</u>
Summer	\$20.00	\$74.00	\$25.08
Winter	\$20.00	\$48.55	\$22.68

Table #22 Ancillary Services (percent of energy cost including congestion)

	<u>PJM</u> <u>90.6%</u>	<u>NYISO</u> <u>9.4%</u>	<u>Weighted</u> <u>Average</u>
	\$1.75	\$3.25	\$1.89

Assumptions:

- Gen Cost = \$ 9.15 per kW-yr in summer
- \$ 8.28 per kW-yr in winter
- Trans cost = \$ 32,114 per MW-yr
- Analysis time period = 2 summer months
- 8 winter months
- Ancillary Services = \$ 1.89 /MWh
- Energy Costs = based on 6/02 to 5/03 Forwards @ PJM West - corrected for congestion
- Usage patterns = forecasted 2002 energy use by class, PJM on/off % from 2001 class load profiles,
RECO billing on/off % from 2002 forecasted data
- Obligations = class totals for 2002
- Losses = per RECO's Third Party Supplier Agreement
- 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