IN THE MATTER OF THE	:	**STATE OF NEW JERSEY**
PROVISION OF BASIC	:	**BOARD OF PUBLIC**
GENERATION SERVICE	:	**UTILITIES**
FOR THEPERIOD	:	
BEGINNING JUNE 1, 2011	:	**Docket No. ER10040287**

ATLANTIC CITY ELECTRIC COMPANY

BASIC GENERATION SERVICE
COMMENCING JUNE 1, 2011

COMPANY-SPECIFIC ADDENDUM
COMPLIANCE FILING
November 24, 2010

ATLANTIC CITY ELECTRIC COMPANY'S
COMPANY-SPECIFIC ADDENDUM

The following contains the company-specific material (referred to herein as the "Addendum") of Atlantic City Electric Company ("ACE" or the "Company") for the joint compliance filing made with the New Jersey Board of Public Utilities (the "Board" or "BPU") on this date by the Electric Distribution Companies ("EDCs") in this docket. Capitalized terms have the meanings defined in the joint submission.

As described in the generic section of this filing, two (2) different methods will be utilized for the pricing of Basic Generation Service ("BGS") to customers – fixed energy pricing and variable hourly energy pricing. The fixed energy pricing will be termed "Basic Generation Service – Fixed Pricing" or "BGS-FP," and the hourly energy pricing service will be termed "Basic Generation Service – Commercial and Industrial Energy Pricing" or "BGS-CIEP."

BGS-FP is to be available to all residential and small and medium sized business customers, specifically those customers taking service on Rate Schedules RS, MGS (Secondary and Primary), AGS (Secondary and Primary), DDC, SPL, and CSL. These rate classes comprise the vast majority of ACE's customers and approximately 87% of the eligible BGS-FP usage on the ACE electric system. As described in detail later in this filing, BGS-FP commercial or industrial customers can opt-in to BGS-CIEP.

BGS-CIEP will continue to be the only default supply option available to customers taking service under ACE's Rate Schedule TGS (Transmission General Service). Pursuant to the Board's Order dated December 8, 2005 in connection with BPU Docket No. EO05040317 and the Board's Decision on October 5, 2010 in connection with BPU Docket No. EO10050338, BGS-CIEP will be the only default supply option available to customers on Rate

Schedules MGS Secondary, MGS Primary, AGS Secondary or AGS Primary with an annual peak load share ("PLS") for generation capacity equal to or greater than 750 kW as of November 1 of the year prior to the BGS Auction. There are an estimated 146 eligible CIEP customers representing approximately 13% of the usage on the ACE electric system, whose only default supply option is BGS-CIEP. As described in detail later in this filing, BGS-CIEP will also be available to any commercial or industrial customer on a voluntary basis regardless of such customer's regular rate schedule.

The Company was ordered by the Board on October 5, 2010 in Docket No. EO10050338 to no longer charge the 5 mill Retail Margin effective June 1, 2011. The Board also ordered the Company to lower the CIEP threshold from 1,000 kWs PLC to 750 kWs PLC effective June 1, 2011.

The 2008 BGS FP Supplier Master Agreements ("SMA") allowed for Suppliers of the ACE 2008 BGS FP Auction to be credited a pro-rata share of the Interruptible Load for Reliability ("ILR") credit received from PJM ILR credits from any ACE ILR credited program(s) as configured June 1, 2008[1], to parties of the 2008 BGS-FP SMAs based upon each supplier's responsibility share(s). ACE ILR credits (e.g. the ILR credit associated with supplier responsibility shares) arising from the 2009 or 2010 BGS Auctions or any ACE demand response programs with credits resulting from programs initiated after June 1, 2008 will not be provided to winning suppliers for the associated portion of BGS. ACE 2009 and forward BGS Auctions until ordered to change by the NJ BPU will not provide to the BGS Suppliers any PJM credit issued as a result of demand response programs. ACE expects to propose additional

[1] There were no ACE programs or MWs of ILR configured with PJM ILR Credits for the June 1, 2008 period.

demand response programs to the Board that may become eligible for PJM credits. Any such current or future credit received by ACE will be credited to the clause designated by the Board through orders authorizing such demand response programs.

A. COMMITTED SUPPLY

"Committed Supply" means power supplies to which ACE has an existing physical or financial entitlement. For ACE, Committed Supply includes its Non-Utility Generation ("NUG") contracts, including any restructured replacement power contracts, which may extend into or through the BGS bid period. ACE retains the right to negotiate changes in, and operational control over, all of its NUG contracts.

As a result of the Board's December 18, 2002 Order in Docket Nos. EX01110754 and EO02070384, (the "BGS Orders"), effective August 1, 2003, ACE's NUG-related Committed Supply (capacity, energy, and ancillaries [if any]) is being sold in the wholesale markets. NUG-related capacity, energy, and ancillaries (if any) will continue to be sold in the wholesale markets. These sales shall be considered prudent unless and until the Board determines that a different protocol is appropriate. Just as they are currently, ACE's actual above-market NUG contract costs will continue to be charged to the Non-Utility Generation Charge ("NGC") clause, with full and timely cost recovery assured, and subject to deferral in accordance with ACE's restructuring order. In setting the NGC, the actual NUG contract costs will be offset with revenues received from the sale of the NUG power in the wholesale markets.

In the event that ACE is required to invoke the Contingency Plan (discussed at length below), Committed Supply may be used to offset requirements associated with the Contingency Plan.

Any generation from ACE's Committed Supply which qualifies as a Class I or Class II renewable resource will be used to meet the Renewable Portfolio Standards requirements, and, since ACE has no BGS supply requirements, it will, to the extent permitted by applicable regulatory and contractual provisions, be credited on a pro-rata basis to winning BGS-FP and BGS-CIEP suppliers. This will assure that these environmental benefits are retained by BGS customers in ACE's service territory. Winning BGS-FP and BGS-CIEP suppliers will be responsible for obtaining and providing related verification information to ACE for the minimum Class I and Class II percentages required by the Renewable Portfolio Standards associated with the tranches they serve, net of renewable attributes of the Committed Supply energy proportionately applied, subject to the foregoing limitations, to each supplier's tranches.

B. <u>CONTINGENCY PLANS</u>

While not every contingency can be anticipated, ACE can differentiate four (4) time periods of concern:

a) there are an insufficient numbers of bids to provide for a fully-subscribed Auction Volume either for the BGS-FP auction or the BGS-CIEP auction;

b) a default by one of the winning bidders prior to June 2011;

c) a default during the June 1, 2011 – May 31, 2012 supply period, under the BGS-CIEP contracts entered into for twelve (12) months; and/or

d) a default during the June 1, 2011 - May 31, 2014 supply period, under the BGS-FP contracts entered into for thirty-six (36) months.

1. <u>Insufficient Number of Bids in Auction</u>

In order to ensure that the auction process achieves the best price for customers, the degree of competition in the auction must be sufficient. To ensure a sufficient degree of competition, the volume of BGS-FP and BGS-CIEP Load purchased at each auction will be finally decided after the first round bids are received. Provided that there are sufficient bids at the starting prices, the auctions will be held for 100 percent of BGS-FP and BGS-CIEP Loads.

It is possible that the amount of initial bids will not result in a competitive auction for 100 percent of the BGS-FP or BGS-CIEP Load. This determination will be made by the Auction Manager in consultation with the EDCs, and the Board Advisor.

In the event that the Auction Volume is reduced to less than 100 percent of BGS-FP or BGS-CIEP Load, ACE, at its option, will implement a Contingency Plan for the remaining tranches. Under that plan, ACE will purchase necessary services (including but not limited to network transmission, capacity, energy and ancillary services, and any required Renewable Portfolio Standard Renewable Energy Certificate) for the remaining tranches through PJM-administered markets until May 31, 2011 and may retain Committed Supply to serve these tranches. Any unsubscribed tranches for the period after May 31, 2011 may be included in a subsequent auction or treated as in part 4 of the Contingency Plan described below. This Contingency Plan will alert bidders that, in order to secure BGS-FP and BGS-CIEP prices from New Jersey BGS customers for their supply, it will be necessary to bid in the auctions.

Since the Contingency Plan calls for the purchase of BGS supply in PJM-administered markets, it is considered 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 ACE, on behalf of its customers, would seek to acquire BGS supplies, the incentive to participate in the auctions and the incentive to offer the best deal in the auctions would be diminished.

2. **Defaults Prior to June 1, 2011**

If a winning bidder defaults prior to the beginning of the BGS service, then, at the option of ACE, the open tranches may first be offered to the other winning bidders or will be filled as provided in (3), below. Additional costs incurred by ACE in implementing the Contingency Plan will be assessed against the defaulting suppliers' credit security.

3. **Defaults during the June 1, 2011 - May 31, 2012 Supply Period**

If a default occurs during the June 1, 2011 - May 31, 2012 period, for those contracts entered into for twelve (12) months, at the option of ACE, the tranches supplied by the defaulting supplier may be offered to the other winning bidders, bid out, or procured from PJM-administered markets, and Committed Supply may be retained to serve these tranches. Additional costs incurred by ACE in implementing the Contingency Plan will be assessed against the defaulting suppliers' credit security.

If circumstances are such that it is not practical to find another such supplier, ACE proposes to utilize a process similar to the "flexible portfolio approach" for BGS wholesale supply, as previously described in the ACE's filing in BPU Docket No. EM00080604, as noted in the Board's November 29, 2000 Order in that docket. This approach relies on a combination of competitive sources for BGS power, including RFPs, broker markets, capacity costs based on the PJM Reliability Pricing Model (RPM) and the PJM spot energy market.

4. **Defaults during the June 1, 2011 - May 31, 2014 Supply Period**

If a default occurs during the June 1, 2011 - May 31, 2014 period, for those contracts entered into for thirty-six (36) months, at the option of ACE, the tranches supplied by the defaulting supplier may be offered to the other winning bidders, bid out or procured from PJM-administered markets, and Committed Supply may be retained to serve these tranches. Among the options for bidding out the tranches, ACE may include such tranches in the next BGS procurement. Additional costs incurred by ACE in implementing the Contingency Plan will be assessed against the defaulting suppliers' credit security.

If circumstances are such that it is not practical to find another such supplier, ACE proposes to utilize a process similar to the "flexible portfolio approach" for BGS wholesale supply, as previously described in the ACE's filing in BPU Docket No. EM00080604, as noted in the Board's November 29, 2000 Order in that docket. This approach relies on a combination of competitive sources for BGS power, including RFPs, broker markets, capacity costs based on the PJM Reliability Pricing Model (RPM) and the PJM spot energy market.

C. ACCOUNTING AND COST RECOVERY

The accounting and cost recovery that ACE will use for its BGS service is summarized in this section. These provisions are intended to be applicable to ACE only. Each EDC will provide individual BGS cost recovery methodologies.

ACE’s BGS accounting will account for BGS-FP revenues and BGS-CIEP revenues individually as follows:

1. BGS-FP and BGS-CIEP revenues will be tracked using established accounting procedures and recorded separately as BGS-FP revenue and BGS-CIEP revenue. Transmission revenues from BGS-FP and BGS-CIEP customers are also tracked using established accounting procedures.

2. As previously established for ACE, uncollectible revenues are recovered through a component of ACE's Societal Benefits Charge (the “SBC”).

ACE will account for BGS-FP and BGS-CIEP costs individually as the sum of the following:

1. All payments made to winning BGS bidders for the provision of BGS-FP and BGS-CIEP service, including CIEP Standby Fee payments.

2. Any administrative costs associated with the provision of BGS-FP and BGS-CIEP service.

3. Any cost for procurement of capacity, energy, ancillary service, transmission and other expenses related to the Contingency Plan and any payments to the winners of a subsequent bid process to cover defaults made under the Contingency Plan, less any payments recovered from defaulting bidders. In the event that the Contingency Plan is required for BGS CIEP load, CIEP Standby Fee payments will be tracked separately.

BGS-FP and BGS-CIEP rates will be subject to deferred accounting since there will be differences between the BGS costs (as defined above) and BGS-related revenues (including transmission revenues). Adjustment type charges (also subject to deferred accounting) are necessary in order to balance out the difference between the amount paid to the BGS-FP and BGS-CIEP supplier(s) for BGS-FP and BGS-CIEP supply and the revenue from customers for BGS-FP and BGS-CIEP services. These reconciliation charge rates, including interest, will be calculated periodically for BGS-FP and BGS-CIEP on a cents per kWh basis and the respective rates will be applied to all BGS-FP and BGS-CIEP kWh. These charges will be combined with the fixed, seasonally differentiated BGS-FP and hourly BGS-CIEP charges for billing although they will be published in ACE's Rider BGS as separate BGS-FPRC and BGS-CIEPRC rates that will be revised periodically.

A BGS deferral/credit will be determined individually for the BGS-FP and BGS-CIEP rates as the difference between recorded BGS-FP or BGS-CIEP revenue and the total BGS-FP or BGS-CIEP cost. The individual BGS deferrals will be accounted for in the following manner:

1. If individual BGS costs, as defined above, are higher than individual BGS recorded revenue, the difference will be charged on a monthly basis to the cost deferral to be reconciled and recovered from customers, with interest, on a periodic basis through the BGS-FPRC and/or the BGS-CIEPRC.

2. If individual BGS costs, as defined above, are lower than individual BGS recorded revenue, the difference will be credited monthly to the cost deferral to be reconciled and returned to customers, with interest, on a periodic basis through the BGS-FPRC and/or BGS-CIEPRC.

An additional deferred balance will be maintained individually for the BGS-FPRC and BGS-CIEPRC rates to ensure full recovery of all of the costs associated with the provision of BGS service.

In the event that the Contingency Plan is required to serve BGS-CIEP load, the difference between CIEP Standby Fee revenues and CIEP Standby Fee payments made to winning BGS-CIEP Auction bidders will be maintained in a separate deferred balance account. Interest on this account will be accrued monthly, using the same methodology and interest rate as those for the BGS-FP and BGS-CIEP deferred balances. Any debit/credit balance in this account at the end of the BGS period of June 1, 2011 through May 31, 2012 will be applied as a $/kWh adjustment to the CIEP Standby Fee for the next BGS-CIEP annual period. In this manner, the mechanism to reconcile any CIEP Standby Fee deferred balance is applied, to the greatest extent practicable, to all BGS-CIEP eligible customers who paid the CIEP Standby Fee, and not only to those taking BGS-CIEP Service.

With the exception of any adjustment to the CIEP Standby Fee which may be required, ACE will follow the following schedule for the periodic reconciliation of its BGS-FP and BGS-CIEP rates:

1. For BGS-FPRC and BGS-CIEPRC rates effective June 1, the actual data for the months of August through March will be used.

2. For BGS-FPRC and BGS-CIEPRC rates effective October 1, the actual data for the months of April through July will be used.

ACE will file formula-based BGS-FPRC and BGS-CIEPRC rates with the Board at least 30 days in advance of the date upon which they are requested to be effective. The filed rates will become effective 30 days after filing, absent a determination of manifest error by the Board.

System Control Charge ("SCC")

The SCC will be calculated annually on a cents per kWh basis and the charge will be applied to all of the Company's electric customers. These charges will be published as a separate rate on the Rider BGS tariff sheets. A draft of these tariff sheets is attached. Final tariff sheets will be filed with the Board. The SCC currently provides recovery for appliance cycling load management costs. The charge will be set initially to recover estimated annual expenditures as approved by the Board. The SCC will be subject to deferred accounting with interest at the interest rate applicable to deferred balances previously set by the Board.

D. DESCRIPTION OF BGS TARIFF SHEETS

This section describes the proposed tariff sheets needed to implement ACE's BGS proposal. The proposed tariff sheets for Tariff Rider Basic Generation Service (Rider BGS) are included as Attachment 1. Rider BGS provides the rates, terms and conditions for customers being served under the BGS-FP or BGS-CIEP pricing mechanisms

a. BGS-FP

BGS-FP is to be available to all customers served on Rate Schedules RS, DDC, SPL and CSL. BGS-FP is also available to customers with a Peak Load Share ("PLS") less than 750 kW who are served under Rate Schedules MGS Secondary, MGS Primary, AGS Secondary and AGS Primary. On any meter reading date, and with prior requisite notice, a customer taking supply service under BGS-FP may switch to third-party supply service, and a customer taking third-party supply service may switch to BGS-FP supply service.

As indicated on the proposed tariff sheets, BGS-FP is made up of two components: BGS Supply Charges and the BGS Reconciliation Charge. Additionally, each BGS customer is subject to transmission charges as discussed below.

a. <u>BGS Supply Charges</u>

The values of the BGS Supply charges applicable to Rate Schedules RS, MGS Secondary, MGS Primary, AGS Secondary, AGS Primary, DDC, SPL and CSL include the costs related to energy, generation capacity, ancillary services and administration. This is a continuation of the current approved methodology of recovering all electric supply service costs in the kilowatt-hour charges for these rate schedules.

The specific values that will be utilized for the BGS Supply Charges will be calculated as the tranche weighted average of the winning BGS-FP bid prices for the ACE zone adjusted for the seasonal payment factors for ACE's Atlantic Electric zone, less transmission costs, adjusted by the appropriate factor (multiplier and constant, if applicable) as shown on Table #17 of the Development of Post Transition Period BGS Cost and Bid Factor Tables, included in Attachment 2. Transmission charges will continue to be billed under the rates currently in effect for these Rate Schedules of the ACE Tariff for Electric Service.

It is the intent of ACE that the factors in the tables will be applied to the tranche weighted average of the winning BGS-FP bid prices adjusted for the seasonal payment factors. For the period beginning June 1, 2009, the pricing will be based on the 36-month auction price, the 36-month price from the auction held in February 2008 and the 36-month price from the auction held in February 2007. The tables will be updated annually prior to future BGS auctions and will be utilized to develop customer charges for a related annual period in a similar manner as described 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 load eligible for the BGS-FP class.

b. <u>BGS Reconciliation Charges</u>

This is the implementation of the BGS Reconciliation Charge for BGS-FP as explained in the Accounting and Cost Recovery section of this Addendum.

c. <u>Transmission Charges</u>

Transmission service will continue to be billed under the rates, terms and conditions of the customer's applicable Rate Schedule of the ACE Tariff for Electric Service. The transmission charges applicable to ACE’s BGS FP customers are based on the annual transmission rate for network service for the ACE zone, as stated in PJM’s Open Access Transmission Tariff (“OATT”). As part of a settlement approved by the Federal Energy Regulatory Commission (“FERC”) on August 9, 2004, certain transmission owners in PJM, including ACE, agreed to reexamine their existing rates and to propose a method (such as a formula rate) to harmonize new and existing transmission investments by January 31, 2005, with such new rate (if any) to go into effect June 1, 2005. The objective of the formula rate filing is to establish a just and reasonable method for determining the transmission revenue requirements for the affected transmission pricing zones which would reflect both existing and new investment on a current basis. The formula rate tracks increases and decreases in costs such that no under- and no over-recovery of actual costs will occur. The formula rate protocols include provisions for an annual update to the rate based on current levels of costs and reconciliation of prior period costs and revenues. Pursuant to the protocols established in the settlement, the Company will file updates to the formula rate at FERC on or about May 15 of each year to be effective on June 1. The Company will make corresponding filings with the Board each year seeking approval of the formula rates on a retail level, pursuant to the requirements of the Supplier Master Agreements.

In addition to the formula rate protocols described above, the transmission charge may change from time to time as FERC approves other changes in the PJM OATT and related charges. In compliance with the BGS-FP Supplier Agreements, the transmission cost component of the BGS-FP charges to customers will change from time to time as FERC approves changes in the Network Integration Transmission Service rates for the ACE zone in the PJM OATT, or the FERC approves other network transmission-related charges in the PJM OATT.

ACE will provide the basis for any transmission cost adjustment, and will file supporting documentation from the OATT, as well as any rate translation spreadsheets used.

2. BGS-CIEP

BGS-CIEP will be the only default supply option available to customers served on Rate Schedule TGS (Transmission General Service) and to customers served on Rate Schedules MGS Secondary, MGS Primary, AGS Secondary and AGS Primary with a PLS of 750 kW and higher as of November 1 of the year prior to the BGS auctions. Additionally, BGS-CIEP is available on a voluntary basis to any commercial or industrial customer taking service under the MGS or AGS rate schedules. To be eligible for BGS-CIEP, the customer will need to notify ACE of its choice no later than the second working day of a given year, and must commit to having BGS-CIEP as its default supply service option for a 12-month period commencing June 1st of that year. All commercial and industrial customers taking service under the MGS or AGS rate schedules will be notified of their option to switch to BGS-CIEP through the Company's website and their tariffs. Customers who elected BGS-CIEP in a prior procurement period and who are eligible to receive BGS-FP service may return to BGS-FP if they notify ACE of their intent to return to BGS-FP default service no later than the second working day of January. Such election will be effective on June 1st of that year.

The charges for BGS-CIEP are comprised of three (3) segments: BGS Energy Charges, BGS Capacity Charges and the BGS Reconciliation Charges. Transmission service will continue to be billed under the rates terms and conditions of the customer's applicable Rate Schedule of the ACE Tariff for Electric Service The transmission charges applicable to ACE's BGS CIEP customers are based on the annual transmission rate for network service for the ACE zone, as stated in PJM's OATT. As part of a settlement approved by FERC on August 9, 2004, certain transmission owners in PJM, including ACE, agreed to reexamine their existing rates and to propose a method (such as a formula rate) to harmonize new and existing transmission investments by January 31, 2005, with such new rate (if any) to go into effect June

1, 2005. The objective of the formula rate filing is to establish a just and reasonable method for determining the transmission revenue requirements for the affected transmission pricing zones which would reflect both existing and new investment on a current basis. The formula rate tracks increases and decreases in costs such that no under- and no over-recovery of actual costs will occur. The formula rate protocols include provisions for an annual update to the rate based on current levels of costs and reconciliation of prior period costs and revenues. Pursuant to the protocols established in the settlement, the Company will file updates to the formula rate at FERC on or about May 15 of each year to be effective on June 1. The Company will make corresponding filings with the Board each year seeking approval of the formula rates on a retail level, pursuant to the requirements of the Supplier Master Agreements.

In addition to the formula rate protocols described above, the transmission charge may change from time to time as FERC approves other changes in the PJM OATT and related charges. In compliance with the BGS-CIEP Supplier Agreements, the transmission cost component of the BGS-CIEP charges to customers will change from time to time as FERC approves changes in the Network Integration Transmission Service rates for the ACE zone in the PJM OATT, or the FERC approves other network transmission-related charges in the PJM OATT.

ACE will provide the basis for any transmission cost adjustment, and will file supporting documentation from the OATT, as well as any rate translation spreadsheets used.

a. <u>BGS Energy Charges</u>

One of the primary components of this charge will be the actual real time PJM load weighted average Locational Marginal Price ("LMP") of energy for ACE's Atlantic Electric Transmission Zone. An estimate of the Ancillary Service cost for the ACE zone expressed on a dollar per MWh basis and administrative costs will be added to this. This sum will then be adjusted for losses for service at the rate schedule for which this service is applicable.

b. BGS Capacity Charges

These charges will recover the costs associated with generation capacity. The EDCs have proposed that, effective with the supply period beginning June 1, 2009, the BGS Capacity Charge be based on the results of the BGS-CIEP Auction process. This charge, Sales and Use Tax ("SUT") and the Board Revenue Assessment will be applied to the customer's share of the PJM zonal capacity obligation.

c. BGS Reconciliation Charges

This is the BGS Reconciliation Charge for the BGS-CIEP service as explained in the Accounting and Cost Recovery section of this Addendum.

d. CIEP Standby Fee

For the period June 1, 2011 through May 31, 2012, the EDCs will pay each BGS-CIEP supplier a CIEP Standby Charge equal to the $0.000150 per kWh times their pro-rata share of the total energy usage measured at the meters of all of ACE's BGS-CIEP eligible customers.

The CIEP Standby Fee is a delivery charge that is applicable to all customers having BGS-CIEP as their default supply service. This includes all customers served on Rate Schedules TGS; all customers served on Rate Schedules MGS Secondary, MGS Primary, AGS Secondary and AGS Primary with a peak load share of 750 kW or greater, and all customers on Rate Schedules MGS Secondary, MGS Primary, AGS Secondary and AGS Primary with a peak load share of less than 750 kW that have elected the BGS-CIEP default supply option. Any under- or over-recovery of the CIEP Standby Fee will continue to be subject to deferred accounting.

System Control Charge

In addition to the above BGS-related charges, the SCC is included in the tariff. This charge is in compliance with the Board's Order requiring that the recovery of costs related to the Residential Appliance Cycling be moved from the Energy Efficiency and Renewable Energy programs portion of the SBC to a separate, new non-by passable charge applicable to all customers. The costs recovered through this charge are currently subject to the identical deferred accounting and over/under interest calculations as applicable to deferred balances previously approved by the Board.

E. BGS RATE DESIGN METHODOLOGY

1. ACE BGS-FP Pricing Spreadsheet

The resulting charge for each BGS-FP rate element (i.e., Rate RS summer charge, winter charge, etc.) for the non-hourly BGS-FP supply service will be based on factors applied to the tranche weighted average of the BGS-FP winning bid prices adjusted for the seasonal payment factors. The rate class specific factors have been developed based on the ratios of the estimated underlying market costs of each rate element (for each rate class) to the overall all-in BGS-FP cost. The tables included in Attachment 2 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 applicable rate schedule. 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 based on the most recent available settlement data for current ACE customers.

Table #2 (% Usage During ACE On-Peak Billing Period) contains the percentage of on-peak load, by month, for each applicable rate schedule based on the definitions of time periods as contained in ACE's delivery rate schedules. These percentages are based on usage history for the RS TOU BGS customers for the 36 month period ending December 31, 2008.

Table #3 (Class Usage @ customer) contains the billing month sales forecasted for the period of June 2011 through May 2012.

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 the energy on-peak forwards as of November 11, 2010 for the PJM West trading hub for the period of June 2011 to May 2012, as utilized in BGS marked-to-market calculations, and the historical ratio of actual off-peak to on-peak PJM LMPs for the prior summer and winter periods.

An adjustment of the forward prices contained in Table #4 must be made to correct for the pricing differential between the PJM West trading hub and the ACE zone where the BGS supply will be utilized.

Table #5 (Zone-Hub Basis Differential) contains an estimate of the average zone-hub basis differential 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 the ACE zone.

Table #6 (Losses) The factors utilized for average system losses are inputted in Table #6 (Losses) by rate schedule and voltage level. Loss factors are developed by including losses at the 500kV transmission level as well as losses at lower transmission and distribution voltage levels currently approved for use by the Board.

Table #7 (Summary of Average BGS Energy Only Unit Costs @ customer – PJM Time Periods) is the calculation of the energy only costs by rate, 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) corrected for zone-hub basis differential (from Table #5), losses (from Table #6), and monthly time period weights (from Table #1). These average costs do not include the costs associated with Ancillary Services, Generation Obligation or Transmission costs, which will be considered in subsequent calculations.

Table #8 (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 #7, the monthly time period weights from Table #1 and the total sales to customers from Table #3. Since the end result of these calculations are to be utilized in the development of retail BGS rates, the rates utilizing time of day pricing must be developed based upon the time periods as defined for billing.

Table #9 (Summary of Average BGS Energy Only Unit Costs @ Customer – ACE Time Periods) shows the result of the corrections for the RS TOU BGS rate. These values are calculated based on the assumption that the MWhs included in the PJM on-peak time period and not included in the ACE on-peak time periods are at the average of the on- and off-peak PJM prices.

Table #10 (Generation & Transmission Obligations and Costs and Other Adjustments) The next steps set up the values necessary for the inclusion of the costs of the Generation Capacity and Transmission obligations. The top portion of Table #10 shows the total obligations, by applicable rate schedule, that are currently being utilized in the year 2009. The middle portion of this table shows the number of summer and winter days and months that are used in this analysis. The bottom portion of this table shows the annual market price for transmission service and a seasonally differentiated market price of generation capacity. The cost of transmission service is equal to the current rate for the ACE OATT for network transmission service. The generation capacity costs are based on an estimate of the relevant current wholesale market price.

Table #11 (Ancillary Services) An estimate of the effects of the costs of ancillary services is included in Table #11. Since the actual costs are a complex combination of many factors, an estimate of the overall annual average value, expressed on a dollar per MWh basis, is used as a reasonable and practical alternative.

Table #12 (Summary of Obligation Costs Expressed as $/MWh @ customer) shows the result of the allocation of both the transmission and generation costs on a per kWh basis to all rate schedules. For RS TOU BGS, the per kWh Generation Capacity Obligation Costs are based on the on-peak usage only.

Table #13 (Summary of BGS Unit Costs @ customer) is the result of the inclusion of the transmission, generation capacity, and Ancillary Services costs to the energy only costs shown in Table #9. This table shows the total estimated all-in costs for BGS, based on the assumptions utilized in the above tables, and the average per unit cost, as measured at the customer meters or the bulk system meters.

Table #14 (Ratio of BGS Unit Costs @ customer to All-In Average Cost @ bulk system) indicates the ratio of the individual rate element costs from Table #13 to the overall all-in cost as measured at the bulk system, plus constants, where applicable.

Table #15 (Summary of BGS Unit Costs Less Transmission @customer) provides the BGS-FP unit costs as developed in Table #13, with the exception of transmission. The bottom portion of the table shows the total estimated costs for BGS-FP less transmission costs and the average unit cost as measured at the customer meters or the bulk system. ACE developed this table since retail customers will be billed for transmission service based on existing transmission rates in their applicable Rate Schedule. For that reason, the cost of transmission needs to be excluded from the calculation of the retail BGS rates. To develop retail BGS rates, a series of ratios excluding the transmission cost is developed.

Table #16 (Ratio of BGS Unit Costs less transmission to All-in Average Cost) indicates the ratio 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-FP prices to retail customers.

Table #17 (Summary of Total BGS Costs by Season) show the calculation of the total BGS Costs, utilizing the total customer usage from Table #3 and the all-in unit costs from Table #13. The lower left portion of the table indicates the relative percentage of total costs by season for all rate schedules, while the center shows the calculation of the overall average all-in seasonal unit costs on a dollar per MWh basis. The ratio of these overall average seasonal costs to the overall total cost, shown in the lower right hand portion of Table #17, are the seasonal payment ratios upon which payments to the winning bidders are based.

Table #18 (Retail Rates Charged to BGS FP Customers), shows the calculation of retail rates to be charged to the FP customers for their BGS services. This table utilizes the information computed in Table #16 (Ratio of BGS Unit Costs) and applies the applicable ratios for each rate class to the BGS average price which, in turn, is based on the weighted average winning bids less transmission charges. The upper left portion of this table provides the information on the calculation of the BGS average price.

Table #19 (Retail Rates Charged to BGS FP Customers Including Revenue Assessment and SUT), shows the BGS FP customer rates inclusive of Board and RPA revenue assessments as well as SUT. This table utilizes the information provided in Table #18 and applies the applicable revenue assessment factor to derive the tax effected BGS FP customer's rates.

The final section summarizes some of the most important assumptions utilized in the above calculations.

The second spreadsheet used in the calculation of the final BGS-FP rates is included as Attachment #3, and is entitled "Calculation of June 2011 to May 2012 BGS-FP Rates." 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 (6) tables, labeled as Table A through F, is as follows:

Table A (Auction Results) contains the results of the prior two (2) BGS auctions, as well as the results of the current auction. From these values, the weighted average annual bid price (shown on line #13) is calculated. All of the formulas used in this table are shown in the right hand column of this table, under the head of "Notes."

Table B (Ratio of BGS Unit Costs @ Customer to All-In Average Cost @ Bulk System) is a repeat of the values shown in Table #14 from Attachment 2, the bid factors calculated based on current market conditions.

Table C (Preliminary Resulting BGS Rates) contains the preliminary customer BGS-FP rates as the product of the weighted average bid price (from Table A) and the Bid Factors from Table B.

Table D (Revenue Recovery Calculations) contains a comparison of the total anticipated rate revenue billed to customers based on the preliminary BGS-FP rates developed in Table C and the anticipated total season payments to BGS suppliers, based on the data in Table A. The calculation of the kWh Rate Adjustment Factors are also done in this table, which 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 Resulting 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 kWh Rate Adjustment Factors that were developed in Table D.

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.

Attachment 1

RIDER (BGS)
Basic Generation Service (BGS)

Basic Generation Service (BGS) will be arranged for any customer taking service under Electric Rate Schedules RS, MGS Secondary, MGS Primary, AGS Secondary, AGS Primary, TGS, DDC, SPL, and CSL who has not notified the Company of an Alternative Electric Supplier choice. BGS is also available to customers whose arrangements with Alternative Electric Suppliers have terminated for any reason, including nonpayment.

BGS is offered under two different terms of service; Basic Generation Service - Fixed Price (BGS-FP) and Basic Generation Service -Commercial and Industrial Energy Pricing (BGS-CIEP). BGS-FP is offered to customers on Rate Schedules RS, DDC, SPL and CSL. BGS-FP is also offered to customers on Rate Schedules MGS Secondary, MGS Primary, AGS Secondary, AGS Primary with an annual peak load share (“PLS”) for generation capacity of less than 750 kW as of November 1 or each year. Additionally, BGS customers on Rate Schedule RS have the option of taking BGS-FP on a time of use basis.

BGS Customers on Rate Schedule TGS and BGS customers on Rate Schedules MGS Secondary, MGS Primary, AGS Secondary or AGS Primary with a PLS for generation capacity equal to or greater than 750 kW as of November 1 of each year are required to take service under BGS-CIEP.

Customers on Rate Schedules MGS Secondary, MGS Primary, AGS Secondary or AGS Primary with a PLS of less than 750 kW, have the option of taking either BGS-FP or BGS-CIEP service. Customers who elect BGS-CIEP must notify the Company of their selection no later than the second working day of January of the year they wish to begin BGS-CIEP service. Such election will be effective on June 1 of that year and remain as the customer’s default supply for the following twelve months. Customers electing BGS-CIEP as their default supply in a prior procurement period and who are otherwise eligible to return to BGS-FP may return to BGS FP by notifying the Company no later than the second working day of January of the year that they wish to return to BGS-FP service. Such election shall be effective on June 1 of that year.

BGS-FP Supply Charges ($/kWh):

Rate Schedule	SUMMER June Through September	WINTER October Through May
RS		$ x.xxxxxx
<=750 kwhs summer	$ x.xxxxxx	
> 750 kwh summer	$ x.xxxxxx	
RS TOU BGS Option		
On Peak (See Note 1)	$ x.xxxxxx	$ x.xxxxxx
Off Peak (See Note 1)	$ x.xxxxxx	$ x.xxxxxx
MGS-Secondary	$ x.xxxxxx	$ x.xxxxxx
MGS-Primary	$ x.xxxxxx	$ x.xxxxxx
AGS-Secondary	$ x.xxxxxx	$ x.xxxxxx
AGS-Primary	$ x.xxxxxx	$ x.xxxxxx
DDC	$ x.xxxxxx	$ x.xxxxxx
SPL/CSL	$ x.xxxxxx	$ x.xxxxxx

Note 1: On Peak hours are considered to be 8:00 AM to 8:00 PM, Monday through Friday.

The above Basic Generation Service Energy Charges reflect costs for Energy, Generation Capacity, Ancillary Services and Administrative Charges pursuant to N.J.S.A. 48:2-60 plus New Jersey Sales and Use Tax as set forth in Rider SUT.

RIDER (BGS) continued
Basic Generation Service (BGS)

BGS Reconciliation Charge ($/kWh):
The above charge shall recover the difference between the monthly amount paid to Basic Generation Service (BGS) suppliers and the total revenue from customers for BGS for the preceding months for the applicable BGS supply. These charges include New Jersey Sales and Use Tax as set forth in Rider SUT and are changed on June 1 and October 1 of each year.

Rate Schedule	Charge($ per kWh)
RS	$ x.xxxxxx
MGS Secondary, AGS Secondary, SPL/CSL, DDC	$ x.xxxxxx
MGS Primary, AGS Primary	$ x.xxxxxx

BGS-CIEP

Energy Charges
BGS Energy Charges for Rate Schedule TGS, AGS and MGS customers with a Peak Load Share (PLS) of 1,000 kW or more, and AGS and MGS customers with a PLS of less than 1,000 kW who have elected BGS-CIEP are hourly and are provided at the real time PJM Load Weighted Average Locational Marginal Prices for the Atlantic Electric Transmission Zone, adjusted for losses, plus administrative charges pursuant to N.J.S.A. 48:2-60 and New Jersey Sales and Use Tax as set forth in Rider SUT.

Generation Capacity Obligation Charge

	Summer	Winter
Charge per kilowatt of Generation Obligation ($ per kW per day)	$ x.xxxxxx	$ x.xxxxxx

This charge is equal to the winning bid price from the BGS-CIEP default service auction plus administrative charges pursuant to N.J.S.A. 48:2-60 and New Jersey Sales and Use Tax as set forth in Rider SUT. The above charge shall be applied to each Customer's annual peak load share ("PLS") for generation capacity, adjusted for the applicable PJM-determined Zonal Scaling Factor and the applicable PJM-determined capacity reserve margin factor, on a daily basis for each day in each customer's respective billing cycle.

Ancillary Service Charge

	Charge ($ per kWh)
Service taken at Secondary Voltage	$ x.xxxxxx
Service taken at Primary Voltage	$ x.xxxxxx
Service taken at Sub-Transmission Voltage	$ x.xxxxxx
Service taken at Transmission Voltage	$ x.xxxxxx

This charge represents the average annual cost of Ancillary Services in the Atlantic Electric Transmission zone adjusted for losses, plus administrative charges pursuant to N.J.S.A. 48:2-60 and New Jersey Sales and Use Tax as set forth in Rider SUT.

BGS Reconciliation Charge:

	Charge ($ per kWh)
Service taken at Secondary Voltage	$ x.xxxxxx
Service taken at Primary Voltage	$ x.xxxxxx
Service taken at Sub-Transmission Voltage	$ x.xxxxxx
Service taken at Transmission Voltage	$ x.xxxxxx

The above charge shall recover the difference between the monthly amount paid to Basic Generation Service (BGS) suppliers and the total revenue from customers for BGS for the preceding months for the applicable BGS supply. These charges include administrative charges pursuant to N.J.S.A. 48:2-60 and New Jersey Sales and Use Tax as set forth in Rider SUT and are changed on June 1 and October 1 of each year.

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RIDER (BGS) continued
Basic Generation Service (BGS)

CIEP Standby Fee $ x.xxxxxx per kWh
This charge recovers the costs associated with the winning BGS-CIEP bidders maintaining the availability of the hourly priced default electric supply service plus administrative charges pursuant to N.J.S.A. 48:2-60 and New Jersey Sales and Use Tax as set forth in Rider SUT. This charge is assessed on all kWhs delivered to all CIEP- eligible customers on Rate Schedules MGS Secondary, MGS Primary, AGS Secondary, AGS Primary or TGS.

System Control Charge (SCC) $ x.xxxxxx per kWh
This charge provides for recovery of appliance cycling load management costs. This charge includes administrative charges pursuant to N.J.S.A. 48:2-60 and New Jersey Sales and Use Tax as set forth in Rider SUT. This charge is assessed on all kWhs delivered to all electric customers.

Transmission Enhancement Charge
This charge reflects Transmission Enhancement Charges (“TECs”), implemented to compensate transmission owners for the annual transmission revenue requirements for “Required Transmission Enhancements” (as defined in Schedule 12 of the PJM OATT) that are requested by PJM for reliability or economic purposes and approved by the Federal Energy Regulatory Commission (FERC). The TEC charge (in $ per kWh by Rate Schedule), including administrative charges pursuant to N.J.S.A. 48:2-60 and New Jersey Sales and Use Tax as set forth in Rider SUT, is delineated in the following table.

	Rate Class							
	RS	**MGS Secondary**	**MGS Primary**	**AGS Secondary**	**AGS Primary**	**TGS**	**SPL/CSL**	**DDC**
VEPCo	0.000035	0.000025	0.000026	0.000024	0.000018	0.000013	-	0.000013
TrAILCo	0.000132	0.000132	0.000154	0.000136	0.000126	0.000091	-	0.000068
PSE&G	0.000366	0.000250	0.000265	0.000242	0.000194	0.000129	-	0.000136
PATH	0.000057	0.000039	0.000041	0.000037	0.000030	0.000020	-	0.000021
PPL	0.000007	0.000007	0.000010	0.000009	0.000007	0.000005	-	0.000004
Pepco	0.000022	0.000022	0.000027	0.000024	0.000021	0.000016	-	0.000012
Delmarva	0.000003	0.000003	0.000004	0.000003	0.000003	0.000002	-	0.000002
AEP - East	0.000002	0.000002	0.000002	0.000002	0.000002	0.000001	-	0.000001
Total	0.000624	0.000480	0.000529	0.000477	0.000401	0.000277	-	0.000257

Date of Issue: **Effective Date:**

Issued by:

Revised Attachment 2

Table #1 **% usage during PJM On-Peak period**
(data rounded to nearest %)

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

	RS	RS TOU - BGS	MGS - SEC	MGS - PRI	AGS - SEC	AGS - PRI	SPL/CSL	DDC
January	50.10%	50.15%	56.76%	56.65%	54.98%	52.57%	34.51%	46.89%
February	48.27%	48.25%	55.05%	57.80%	54.91%	51.52%	35.20%	47.52%
March	47.87%	47.82%	56.24%	58.07%	55.56%	53.23%	29.32%	46.96%
April	48.30%	48.21%	55.49%	60.47%	54.20%	53.46%	29.16%	45.59%
May	49.41%	49.62%	57.14%	56.70%	55.21%	54.35%	26.40%	46.28%
June	53.33%	53.27%	57.18%	62.01%	54.64%	54.69%	26.35%	45.69%
July	51.69%	51.64%	55.07%	58.11%	53.09%	53.08%	24.65%	44.67%
August	56.75%	57.50%	59.80%	62.47%	56.67%	57.03%	28.55%	48.58%
September	46.92%	47.04%	51.97%	52.05%	49.59%	51.48%	26.18%	42.05%
October	54.35%	54.30%	59.71%	59.90%	56.86%	58.47%	31.71%	49.01%
November	48.19%	48.31%	55.89%	57.87%	54.29%	54.93%	36.27%	46.53%
December	45.26%	45.26%	51.77%	52.55%	50.32%	49.80%	33.07%	42.39%

Table #2 **% Usage During ACECO On-Peak Billing Period**

	RS TOU - BGS
January	33.22%
February	32.31%
March	31.07%
April	31.20%
May	31.11%
June	22.40%
July	36.20%
August	37.14%
September	35.79%
October	22.16%
November	32.72%
December	32.93%

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

		RS	RS TOU - BGS	MGS - SEC	MGS - PRI	AGS - SEC	AGS - PRI	SPL/CSL	DDC	Total
	Jan-12	395,545	377	103,263	1,474	160,187	11,890	11,649	1,159	685,543
	Feb-12	382,427	381	101,803	1,174	155,705	8,982	10,384	1,095	661,950
	Mar-12	340,456	334	98,725	1,130	150,818	10,880	10,051	1,130	613,523
	Apr-12	299,961	272	92,852	1,036	150,882	13,558	9,039	1,155	568,756
	May-12	266,920	188	91,080	1,142	150,717	12,256	7,812	1,087	531,202
1,748,630	Jun-11	314,607	196	103,302	1,598	159,926	13,442	7,245	1,080	601,396
0.402959984	Jul-11	458,908	272	133,863	2,059	178,305	16,156	7,270	1,079	797,911
	Aug-11	525,274	327	140,972	2,229	181,235	12,656	7,826	1,066	871,586
	Sep-11	449,841	285	134,297	2,385	180,513	12,392	8,468	1,129	789,310
	Oct-11	305,164	228	104,613	1,862	164,599	2,834	9,075	1,109	589,485
	Nov-11	270,493	254	90,975	1,690	151,128	12,242	9,785	1,131	537,698
	Dec-11	329,866	329	107,068	1,577	122,440	12,598	10,995	1,278	586,152
Total		4,339,462	3,444	1,302,812	19,355	1,906,455	139,884	109,601	13,499	7,834,511

Table #4 **Forwards Prices - Energy Only @ bulk system**
($/MWH)

Table #5 **Zone-Hub Basis Differential** **'Based on 3 Year Average**

	On-Peak	Off/On Pk LMP ratio	Off-Peak	Table #5 On-Peak	Table #5 Off-Peak
Jan-12	52.83	0.749	39.57	112%	109%
Feb-12	52.83	0.749	39.57	112%	109%
Mar-12	48.88	0.749	36.62	112%	109%
Apr-12	48.88	0.749	36.62	112%	109%
May-12	46.80	0.749	35.06	112%	109%
Jun-11	49.03	0.659	32.29	124%	116%
Jul-11	60.05	0.659	39.55	124%	116%
Aug-11	60.05	0.659	39.55	124%	116%
Sep-11	48.46	0.659	31.92	124%	116%
Oct-11	45.87	0.749	34.36	112%	109%
Nov-11	45.87	0.749	34.36	112%	109%
Dec-11	45.87	0.749	34.36	112%	109%

Table #6

Losses	**RS**	**RS TOU - BGS**	**MGS - SEC**	**MGS - PRI**	**AGS - SEC**	**AGS - PRI**	**SPL/CSL**	**DDC**
Delivery Loss Factor	7.8715%	7.8715%	7.8715%	5.0738%	7.8715%	5.0738%	7.8715%	7.8715%
Loss Factors + EHV Losses =	8.3464%	8.3464%	8.3464%	5.5631%	8.3464%	5.5631%	8.3464%	8.3464%
Expansion Factor =	1.09106	1.09106	1.09106	1.05891	1.09106	1.05891	1.09106	1.09106
Marginal Loss Factor (w/ EHV Losses) =	2.0027%	2.0027%	2.0027%	2.0027%	2.0027%	2.0027%	2.0027%	2.0027%
Loss Factor w/o Marginal Loss =	6.4733%	6.4733%	6.4733%	3.6332%	6.4733%	3.6332%	6.4733%	6.4733%
Expansion Factor w/o Marginal Loss =	1.06921	1.06921	1.06921	1.03770	1.06921	1.03770	1.06921	1.06921

Table #7 **Summary of Average BGS Energy Only Unit Costs @ customer - PJM Time Periods**
based on Forwards @ PJM West - corrected for congestion & losses
in $/MWh

	RS	**RS TOU - BGS**	**MGS - SEC**	**MGS - PRI**	**AGS - SEC**	**AGS - PRI**	**SPL/CSL**	**DDC**
Summer - all hrs	$ 60.77	$ 60.74	$ 61.47	$ 60.08	$ 60.48	$ 59.02	$ 52.55	$ 57.90
On Peak	$ 74.67	$ 74.58	$ 74.14	$ 71.75	$ 73.80	$ 71.75	$ 73.28	$ 73.51
Off Peak	$ 45.54	$ 45.44	$ 45.36	$ 43.78	$ 45.18	$ 44.05	$ 45.10	$ 45.02
Winter - all hrs	$ 51.49	$ 51.62	$ 52.33	$ 50.70	$ 52.17	$ 50.38	$ 48.60	$ 50.70
On Peak	$ 59.82	$ 60.01	$ 59.47	$ 57.37	$ 59.54	$ 57.76	$ 59.71	$ 59.43
Off Peak	$ 43.50	$ 43.62	$ 43.24	$ 41.70	$ 43.27	$ 42.04	$ 43.32	$ 43.16
Annual	$ 55.23	$ 54.48	$ 55.92	$ 54.71	$ 55.22	$ 53.75	$ 49.71	$ 53.02

System Average Cost @ customer - (limited to classes shown above) = $ 55.23

Table #8 **Summary of Average BGS Energy Only Costs @ customer - PJM Time Periods**
based on Forwards prices corrected for congestion & losses
in $1000

		RS	**RS TOU - BGS**	**MGS - SEC**	**MGS - PRI**	**AGS - SEC**	**AGS - PRI**	**SPL/CSL**	**DDC**
Summer - all hrs		$ 106,267	$ 66	$ 31,502	$ 497	$ 42,336	$ 3,225	$ 1,619	$ 252
	PJM on pk	$ 68,261	$ 42	$ 21,270	$ 346	$ 27,620	$ 2,118	$ 597	$ 145
	PJM off pk	$ 38,006	$ 23	$ 10,232	$ 151	$ 14,717	$ 1,107	$ 1,022	$ 107
Winter - all hrs		$ 133,394	$ 122	$ 41,358	$ 562	$ 62,940	$ 4,294	$ 3,830	$ 464
	PJM on pk	$ 75,851	$ 69	$ 26,313	$ 365	$ 39,275	$ 2,613	$ 1,516	$ 252
	PJM off pk	$ 57,543	$ 53	$ 15,044	$ 197	$ 23,665	$ 1,682	$ 2,314	$ 212
Annual		$ 239,660	$ 188	$ 72,859	$ 1,059	$ 105,276	$ 7,519	$ 5,449	$ 716
System Total		$ 432,726							

Table #9

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

		RS	RS TOU - BGS	MGS - SEC	MGS - PRI	AGS - SEC	AGS - PRI	SPL/CSL	DDC
Summer - all hrs		$ 60.77	$ 60.74	$ 61.47	$ 60.08	$ 60.48	$ 59.02	$ 52.55	$ 57.90
	ACECO On pk		$ 82.59						
	ACECO Off pk		$ 49.55						
Winter - all hrs		$ 51.49	$ 51.62	$ 52.33	$ 50.70	$ 52.17	$ 50.38	$ 48.60	$ 50.70
	ACECO On pk		$ 64.62						
	ACECO Off pk		$ 45.71						
Annual Average		$ 55.23	$ 54.48	$ 55.92	$ 54.71	$ 55.22	$ 53.75	$ 49.71	$ 53.02
System Average		$ 55.23							

Table #10

Generation & Transmission Obligations and Costs and Other Adjustments
obligations - values effective June 2009; costs are market estimates

in MW	RS	RS TOU - BGS	MGS - SEC	MGS - PRI	AGS - SEC	AGS - PRI	SPL/CSL	DDC	Total
Gen Load - MW	1,431.9	1.0	349.3	3.3	387.4	25.7	0.0	1.6	2,200.0
Gen Obl - MW	1,449.4	1.0	353.5	3.3	392.2	26.0	0.0	1.6	2,227.0
Trans Obl - MW	1,457.8	1.0	363.0	1.9	398.8	24.0	0.0	1.7	2,248.1

\# of Months and Days used in this analysis

# of summer days =	122	# of summer months =	4
# of winter days =	243	# of winter months =	8
		total # months =	12

Transmission Cost $ 28,374 per MW-yr

Generation Capacity Cost	Summer	$161.88	$/MW/day	Summer Total	$ 43,980,581
	Winter	$ 161.88	$/MW/day	Winter Total	$ 87,600,666
				Annual Total	$ 131,581,247

Residential Inversion Determination

---------- Rate RS ----------

	Charges	% usage		
Block 1 (0-750 kWh/m)	5.480200	60.70%	SUM 'First 750 KWh	1,116,528,467
Block 2 (>750 kWh/m)	6.345400	39.30%	WIN' First 500 KWh	1,496,055,055
Calculated inversion =	0.865200		SUM '> 750 KWh	722,784,858
			WIN > 500 KWh	1,056,590,671

Table #11

Ancillary Services
forecasted overall annual average $ 3.00

Table #12

Summary of Obligation Costs expressed as $/MWh @ customer

	RS	RS TOU - BGS	MGS - SEC	MGS - PRI	AGS - SEC	AGS - PRI	SPL/CSL	DDC	Total
Transmission Obl - yr round	$ 9.53	$ 7.93	$ 7.91	$ 2.74	$ 5.94	$ 4.87	$ -	$ 3.53	$ 8.14
Generation Obl -									
per annual MWh	$ 19.73	$ 17.16	$ 16.03	$ 10.07	$ 12.15	$ 10.98	$ -	$ 7.00	
recovery per summer MWh	$ 16.37	$ 34.81	$ 13.62	$ 7.88	$ 11.07	$ 9.40	$ -	$ 7.26	
recovery per winter MWh	$ 22.01	$ 32.49	$ 17.59	$ 11.71	$ 12.79	$ 12.00	$ -	$ 6.88	

Table #13 **Summary of BGS Unit Costs @ customer**
Includes energy, G&T obligations, and Ancillary Services
in $/MWh

		RS	RS TOU - BGS	MGS - SEC	MGS - PRI	AGS - SEC	AGS - PRI	SPL/CSL	DDC
Summer - all hrs		$ 89.95	$ 106.76	$ 86.28	$ 73.88	$ 80.76	$ 76.45	$ 55.83	$ 71.96
	ACECO On-Peak		$ 128.61						
	ACECO Off-Peak		$ 60.75						
	Block 1 (0-750 kWh/m)	$ 86.55							
	Block 2 (>750 kWh/m)	$ 95.20							
Winter - all hrs		$ 86.30	$ 95.31	$ 81.10	$ 68.33	$ 74.16	$ 70.42	$ 51.88	$ 64.39
	ACECO On-Peak		$ 108.32						
	ACECO Off-Peak		$ 56.92						
Annual		$ 87.77	$ 82.84	$ 83.14	$ 70.70	$ 76.58	$ 72.78	$ 52.99	$ 66.83

Grand Total Cost in $1000 = $ 653,778

All In Average cost for rates shown (@ customer) = $ 83.45
All In Average costs for rates shown (@ bulk system) = $ 78.09

Table #14 **Ratio of BGS Unit Costs @ customer to All In Average Cost @ bulk system (rounded to 3 decimal places)**
Includes energy, G&T obligations, and Ancillary Services - unadjusted for billing vs. PJM time period differences

		RS	RS TOU - BGS	MGS - SEC	MGS - PRI	AGS - SEC	AGS - PRI	SPL/CSL	DDC
Summer - all hrs			**1.367**	**1.105**	**0.946**	**1.034**	**0.979**	**0.715**	**0.921**
	On-Peak		**1.647**						
	Off-Peak		**0.778**						
	All usage Multiplier	**1.152**							
	Constant	**$ (3.40)**		for Block 1 (0-750 kWh/m) usage					
	Constant	**$ 5.25**		for Block 2 (>750 kWh/m) usage					
Winter - all hrs		**1.105**	**1.220**	**1.038**	**0.875**	**0.950**	**0.902**	**0.664**	**0.824**
	On-Peak		**1.387**						
	Off-Peak		**0.729**						
Annual		**1.124**	**1.061**	**1.065**	**0.905**	**0.981**	**0.932**	**0.679**	**0.856**

Table #15 **Summary of BGS Unit Costs Less Transmission @ customer**

Includes energy, Generation capacity obligations, and Ancillary Services - unadjusted for billing vs. PJM time period differences. Transmission billed at retail tariff level.
in $/MWh

		RS	RS TOU - BGS	MGS - SEC	MGS - PRI	AGS - SEC	AGS - PRI	SPL/CSL	DDC
Summer - all hrs		$ 80.41	$ 98.82	$ 78.37	$ 71.14	$ 74.82	$ 71.59	$ 55.83	$ 68.43
	On-Peak		$ 120.67						
	Off-Peak		$ 52.82						
	Block 1 (0-750 kWh/m)	$ 77.01							
	Block 2 (>750 kWh/m)	$ 85.67							
Winter - all hrs		$ 76.77	$ 87.38	$ 73.19	$ 65.59	$ 68.23	$ 65.56	$ 51.88	$ 60.85
	On-Peak		$ 100.38						
	Off-Peak		$ 48.99						
Annual		$ 78.24	$ 74.91	$ 75.23	$ 67.96	$ 70.65	$ 67.91	$ 52.99	$ 63.30
	Grand Total Cost in $1000 =	$ 589,885							

All In (Less Transmission) Average cost for rates shown (@ customer) =	$ 75.29
All In (Less Transmission) Average costs for rates shown (@ bulk system) =	$ 70.46

Table #16 **Ratio of BGS Unit Costs @ customer to All In Average Cost Less Transmission @ bulk system (rounded to 3 decimal places)**

Includes energy, Generation capacity obligations, and Ancillary Services - unadjusted for billing vs. PJM time period differences.
Transmission billed at retail tariff level.

		RS	RS TOU - BGS	MGS - SEC	MGS - PRI	AGS - SEC	AGS - PRI	SPL/CSL	DDC
Summer - all hrs			**1.402**	**1.112**	**1.010**	**1.062**	**1.016**	**0.792**	**0.971**
	On-Peak		**1.713**						
	Off-Peak		**0.750**						
	All usage Multiplier	**1.141**							
	Constant **$**	**(3.40)**		for Block 1 (0-750 kWh/m) usage					
	Constant **$**	**5.25**		for Block 2 (>750 kWh/m) usage					
Winter - all hrs		**1.089**	**1.240**	**1.039**	**0.931**	**0.968**	**0.930**	**0.736**	**0.864**
	On-Peak		**1.425**						
	Off-Peak		**0.695**						
Annual		**1.110**	**1.063**	**1.068**	**0.965**	**1.003**	**0.964**	**0.752**	**0.898**

Table #17 **Summary of Total BGS Costs by Season**

	RS	RS TOU - BGS	MGS - SEC	MGS - PRI	AGS - SEC	AGS - PRI	SPL/CSL	DDC
Total Costs by Rate - in $1000								
Summer	$ 157,282	$ 115	$ 44,211	$ 611	$ 56,527	$ 4,178	$ 1,720	$ 313
Winter	$ 223,583	$ 225	$ 64,098	$ 757	$ 89,477	$ 6,003	$ 4,087	$ 589
Total	$ 380,865	$ 341	$ 108,310	$ 1,368	$ 146,004	$ 10,181	$ 5,807	$ 902
% of Annual Total $ by Rate								
Summer	41%	34%	41%	45%	39%	41%	30%	35%
Winter	59%	66%	59%	55%	61%	59%	70%	65%

Total Costs - in $1000						
Summer	$ 264,958					
Winter	$ 388,820					
Total	$ 653,778					
% of Annual Total $		If total $ were split on a per MWh basis (on bulk system MWhs):				
Summer	41%	$ 81.03 per MWh @ bulk system	Ratio to All-In Cost	>>>	Summer	**1.0376**
Winter	59%	$ 76.21 per MWh @ bulk system	(rounded to 4 decimal places)		Winter	**0.9759**

Assumptions:

Gen Cost =	$ 161.88	per MW-day summer
=	$ 161.88	per MW-day winter
Trans cost =	$ 28,374	per MW-yr
Ancillary Services =	$ 3.00	per MWH
Energy Prices =	Quotes for the period June 1, 2007 to May 30, 2008 - corrected for hub-zone basis differential.	
Usage patterns =	forecasted energy use by class, on/off % from 2001 - 2003 class load profiles	
Obligations =	class totals as of June 2006	
Losses =	existing loss factors as approved in previous LEAC cases	
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	

Table #18 **Retail Rates Charged to BGS FP Customers**

Includes energy, Generation Obligations, and Ancillary Services - Transmission billed at current Tariff Rates
in $/MWh

Weighted Avg. Winning Bid >>>>	**$**	**100.720**
Less Transmission >>>>>>>>>	**$**	**7.467**
BGS Avg. Price >>>>>>>>>>>	**$**	**93.25**

		RS	RS TOU - BGS	MGS - SEC	MGS - PRI	AGS - SEC	AGS - PRI	SPL/CSL	DDC
Summer - all hrs			$ 133.096	$ 105.565	$ 95.882	$ 100.819	$ 96.452	$ 75.187	$ 92.180
	On-Peak		$ 162.620						
	Off-Peak		$ 71.200						
	Block 1 (0-750 kWh/m)	$ 104.857							
	Block 2 (>750 kWh/m)	$ 113.665							
Winter - all hrs		$ 100.315	$ 114.225	$ 95.709	$ 85.761	$ 89.169	$ 85.668	$ 67.798	$ 79.589
	On-Peak		$ 131.266						
	Off-Peak		$ 64.021						
Annual		$ 103.511	$ 99.128	$ 99.595	$ 89.989	$ 93.533	$ 89.896	$ 70.127	$ 83.741
		12.16	11.51	11.56	9.97	10.70	10.19	7.54	9.39

Table #19 **Retail Rates Charged to BGS FP Customers including Revenue Assessment and SUT**

Includes energy, Generation Obligations, and Ancillary Services - Transmission billed at current Tariff Rates
in $/kWh

Revenue Assessment Factor 1.005025126
(BPU, RPA Assessments)

		RS	RS TOU - BGS	MGS - SEC	MGS - PRI	AGS - SEC	AGS - PRI	SPL/CSL	DDC
Summer - all hrs				$ 0.113522	$ 0.103109	$ 0.108418	$ 0.103722	$ 0.080854	$ 0.099128
	On-Peak		$ 0.174878						
	Off-Peak		$ 0.076566						
	Block 1 (0-750 kWh/m)	$ 0.112761							
	Block 2 (>750 kWh/m)	$ 0.122233							
Winter - all hrs		$ 0.107876		$ 0.102923	$ 0.092225	$ 0.095890	$ 0.092126	$ 0.072908	$ 0.085588
	On-Peak		$ 0.141161						
	Off-Peak		$ 0.068847						
Annual		$ 0.111314	$ 0.106600	$ 0.107102	$ 0.096773	$ 0.100583	$ 0.096672	$ 0.075412	$ 0.090054

Revised
Attachment 3

Atlantic City Electric Company
Calculation of June 2011to May 2012 BGS-FP Rates
based on results of February 2010 BGS FP Auction

Table A **Auction Results**

line #	**Payment Identifier >>**	*remaining portion of 36 month bid - 2009/10 filing*	*remaining portion of 36 month bid - 2010/11 filing*	*36 month bid - 2011/12 filing*	*Notes:*
1	Winning Bid - in $/MWh	$ 105.36	$ 98.56	$ 98.56	winning Bids
2	# of Traunches for Bid	7	7	8	from then current Bid
3	Total # of Traunches	22	22	22	from then current Bid
	Payment Factors				
4	Summer	1.0818	1.0504	1.0376	from then current Bid Factor Spreadsheet
5	Winter	0.9473	0.9679	0.9759	from then current Bid Factor Spreadsheet
	Applicable Customer Usage @ bulk system - in MWh				
6	Summer MWh	3,270,029			from current Bid Factor Spreadsheet
7	Winter MWh	5,101,721			
	Total Payment to Suppliers - in $1000				
8	Summer	$ 118,590	$ 107,717	$ 121,604	= (1) * (2)/(3) * (4) * (6)
9	Winter	$ 162,015	$ 154,854	$ 178,439	= (1) * (2)/(3) * (5) * (7)
10	Total	$ 280,606	$ 262,571	$ 300,044	
	Average Payment to Suppliers - in $/MWh				
11	Summer	$ 106.39			= sum(line 8) / (6) - rounded to 2 decimal places
12	Winter	$ 97.09			= sum(line 9) / (7) - rounded to 2 decimal places
13	Total weighted average	**$ 100.72**	<<< used in calculation of Customer Rates		= sum(line 10) / [(6) + (7)] rounded to 2 decimal places
	Reconciliation of amounts - in $1000				
14	Weighted avg * Total MWh =	$ 843,203			= (13) * [(6)+(7)] / 1000
15	Total Payment to Suppliers =	$ 843,220			= sum (line 10)
16	Difference =	$ (17)			= line (14) - line (15)

Atlantic City Electric Company
Calculation of June 2011to May 2012 BGS-FP Rates
based on results of February 2010 BGS FP Auction

Table B **Ratio of BGS Unit Costs @ customer to All-In Average Cost @ bulk system** *from Table #14 of the bid factor spreadsheet --- round to 3 decimal places*

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

		RS	RS TOU - BGS	MGS - SEC	MGS - PRI	AGS - SEC	AGS - PRI	SPL/CSL	DDC	Total
Summer - all hrs			**1.367**	**1.105**	**0.946**	**1.034**	**0.979**	**0.715**	**0.921**	
	On-Peak		**1.647**							
	Off-Peak		**0.778**							
	All usage Multiplier	**1.152**								
	Constant	**(3.400)**	for Block 1 (0-750 kWh/m) usage							
	Constant	**5.252**	for Block 2 (>750 kWh/m) usage							
Winter - all hrs		**1.105**	**1.220**	**1.038**	**0.875**	**0.950**	**0.902**	**0.664**	**0.824**	
	On-Peak		**1.387**							
	Off-Peak		**0.729**							
Annual - all hrs		**1.124**	**1.061**	**1.065**	**0.905**	**0.981**	**0.932**	**0.679**	**0.856**	

Table C **Preliminary Resulting BGS Rates (in cents per kWh) -** *equal to bid factors times weighted average bid price rounded to 4 decimal places*

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

		RS	RS TOU - BGS	MGS - SEC	MGS - PRI	AGS - SEC	AGS - PRI	SPL/CSL	DDC
Summer - all hrs			***13.7684***	***11.1296***	***9.5281***	***10.4144***	***9.8605***	***7.2015***	***9.2763***
	On-Peak		***16.5886***						
	Off-Peak		***7.8360***						
for Block 1 (0-750 kWh/m) usage		***11.2630***							
for Block 2 (>750 kWh/m) usage		***12.1282***							
Winter - all hrs		***11.1296***	***12.2878***	***10.4547***	***8.8130***	***9.5684***	***9.0849***	***6.6878***	***8.2993***
	On-Peak		***13.9699***						
	Off-Peak		***7.3425***						

Atlantic City Electric Company
Calculation of June 2011to May 2012 BGS-FP Rates
based on results of February 2010 BGS FP Auction

Table D **Revenue Recovery Calculations -** *Reconciliation of seasonal Customer Revenue and Supplier Payments, based on actual anticipated revenues and payments*

	RS	RS TOU - BGS	MGS - SEC	MGS - PRI	AGS - SEC	AGS - PRI	SPL/CSL	DDC
Total Rate Revenue - in $1000								
Summer	$ 202,893	$ 134	$ 57,032	$ 788	$ 72,898	$ 5,388	$ 2,219	$ 404
Winter	$ 288,349	$ 250	$ 82,632	$ 977	$ 115,441	$ 7,744	$ 5,269	$ 759
Total	$ 491,243	$ 384	$ 139,664	$ 1,765	$ 188,339	$ 13,132	$ 7,488	$ 1,163
Total Summer	$ 341,757							
Total Winter	$ 501,420							
Grand Total	$ 843,178							

Total Supplier Payment - in $1000			
Summer	$ 347,911		
Winter	$ 495,308		
Total	$ 843,220		<u>% difference</u>
Differences - in $1000			
Summer	$ 6,154	1.01801	1.7689%
Winter	$ (6,112)	0.98781	-1.2339%
Total	$ 42		0.0050%

kWh Rate Adjustment <u>Factors</u> *rounded to 5 decimal places*
1.01801
0.98781

Note: These differences are due to rounding and seasonal differences in Bidder Payments (which are based on prior wining bids and Seasonal Payment Factors) and current Rates (based on current seasonal market differentials)

Atlantic City Electric Company
Calculation of June 2011to May 2012 BGS-FP Rates
based on results of February 2010 BGS FP Auction

Table E **Final Resulting BGS Rates (in cents per kWh) -** *with preliminary kWh rates adjusted by the kWh Rate Adjustment Factor rounded to 4 decimal places*

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

	RS	RS TOU - BGS	MGS - SEC	MGS - PRI	AGS - SEC	AGS - PRI	SPL/CSL	DDC
Summer - all hrs		***14.0164***	***11.3300***	***9.6997***	***10.6020***	***10.0381***	***7.3312***	***9.4434***
On-Peak		***16.8874***						
Off-Peak		***7.9771***						
for Block 1 (0-750 kWh/m) usage	***11.4658***							
for Block 2 (>750 kWh/m) usage	***12.3466***							
Winter - all hrs	***10.9939***	***12.1380***	***10.3273***	***8.7056***	***9.4518***	***8.9742***	***6.6063***	***8.1981***
On-Peak		***13.7996***						
Off-Peak		***7.2530***						

Table F **Spreadsheet Error Checking** - *Checking of seasonal Customer Revenue and Supplier Payments, based on final actual anticipated revenues and payments*

	RS	RS TOU - BGS	MGS - SEC	MGS - PRI	AGS - SEC	AGS - PRI	SPL/CSL	DDC
Total Rate Revenue - in $1000								
Summer	$ 206,547	$ 137	$ 58,059	$ 802	$ 74,212	$ 5,485	$ 2,259	$ 411
Winter	$ 284,834	$ 247	$ 81,625	$ 965	$ 114,034	$ 7,649	$ 5,205	$ 750
Total	$ 491,380	$ 384	$ 139,683	$ 1,767	$ 188,245	$ 13,135	$ 7,464	$ 1,161
Total Summer	$ 347,912							
Total Winter	$ 495,308							
Grand Total	$ 843,220							
Total Supplier Payment - in $1000								
Summer	$ 347,911							
Winter	$ 495,308							
Total	$ 843,220							
Differences - in $1000								
Summer	$ 0							
Winter	$ (0)							
Total	$ (0)							