IN THE MATTER OF THE	**:**	**STATE OF NEW JERSEY**
PROVISION OF BASIC	**:**	**BOARD OF PUBLIC**
GENERATION SERVICE	**:**	**UTILITIES**
FOR THEPERIOD	**:**	
BEGINNING JUNE 1, 2012	**:**	**DOCKET NO. EO11040250**

ATLANTIC CITY ELECTRIC COMPANY

BASIC GENERATION SERVICE COMMENCING JUNE 1, 2012

COMPANY-SPECIFIC ADDENDUM COMPLIANCE FILING

November 21, 2011

ATLANTIC CITY ELECTRIC COMPANY'S

<u>COMPANY-SPECIFIC ADDENDUM</u>

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 under 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 86% of the total eligible load share 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, BGS-CIEP will be the only default supply option available to customers under 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 145 eligible CIEP customers representing approximately **13**% of the total load share on the ACE electric system, whose only default supply option is BGS-CIEP. As detailed herein, BGS-CIEP will also be available to any commercial or industrial customer on a voluntary basis regardless of such customer's regular rate schedule.

On October 5, 2010, the Company was ordered by the Board in Docket No. EO10050338 to cease charging, as of June 1, 2012, the 5 mill Retail Margin on any commercial or industrial customer taking service under the BGS-CIEP supply option or with a PLS of 750 kW or greater. The Board also ordered the Company to lower the CIEP threshold from 1,000 kWs PLC to 750 kWs PLC.

The 2008 BGS-FP Supplier Master Agreement ("SMA") allowed Suppliers of the ACE 2008 BGS-FP Auction to be credited a pro-rata share of the PJM Interconnection, L.L.C. ("PJM") Interruptible Load for Reliability ("ILR") credits received through ACE ILR credited program(s) configured as of June 1, 2008.[1] 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's BGS Auctions from 2009 and forward do not provide BGS Suppliers any PJM credit issued as a result of demand response programs. ACE expects to propose additional demand response

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

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's authorization of 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"), ACE's NUG-related Committed Supply (capacity, energy, and any ancillaries) is being sold in the wholesale markets. ACE will continue such sales unless and until the Board determines that a different protocol is appropriate. 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 ER02080510 dated July 8, 2004 (ACE Final 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 that qualifies as a Class I or Class II renewable resource will be used to meet the Renewable Portfolio Standards ("RPS") requirements. Additionally, because ACE has no BGS supply requirements, any such resource will be credited on a pro-rata basis to winning BGS-FP and BGS-CIEP suppliers. This will assure that the environmental benefits are retained by ACE's BGS customers. Winning BGS-FP and BGS-CIEP suppliers will be responsible for obtaining and providing to ACE related verification information for the minimum Class I and Class II percentages required by the RPS associated with the tranches each supplier serves.

B. Contingency Plans

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

a) 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 2012;

c) a default during the June 1, 2012 – May 31, 2013 supply period, under the BGS-CIEP contracts entered into for twelve (12) months; and/or

d) a default during the June 1, 2012 - May 31, 2015 supply period, under the BGS-FP contracts entered into for thirty-six (36) months.

1. Insufficient Number of Bids in Auction

In order for the auction process to achieve the best price for customers, there must be sufficient competition in the auction. To ensure sufficient competition, the volume of BGS-FP and BGS-CIEP Load purchased at each auction will be determined 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 the Auction Volume needs to be reduced to less than 100 percent of BGS-FP or BGS-CIEP Load in order to maintain sufficient competition, ACE may implement a Contingency Plan for the remaining tranches. Under the Contingency Plan, ACE will purchase necessary services (including, but not limited to, network transmission, capacity, energy, and ancillary services, as well as any required RPS Renewable Energy Certificate) for the remaining tranches through PJM-administered markets until May 31, 2012, and may retain Committed Supply to serve these tranches. Any unsubscribed tranches for the period after May 31, 2012 may be included in a subsequent auction or handled according to part 4 of the Contingency Plan, as 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, suppliers must bid into the auctions.

Because the Contingency Plan requires the purchase of BGS supply in PJM-administered markets, it is a necessary feature of the auction proposal because it provides bidders a strong incentive to participate in the auction process. If bidders 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 to offer the best deal would be diminished.

2. <u>Defaults Prior to June 1, 2012</u>

If a winning bidder defaults prior to the beginning of the BGS service, then ACE may offer the open tranches to the other winning bidders or fill such tranches as provided in part 3 of the Contingency Plan. Additional costs incurred by ACE in implementing the Contingency Plan will be assessed against the defaulting suppliers' credit security.

3. <u>Defaults during the June 1, 2012 - May 31, 2013 Supply Period</u>

If a default occurs during the June 1, 2012 - May 31, 2013 period, ACE may: (a) offer the 12 month tranches that were being supplied by the defaulting supplier to the other winning bidders; (b) bid out such tranches to all suppliers willing to provide service; (c) procure necessary supply from PJM-administered markets; or (d) retain Committed Supply 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 impractical to find another 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 dated November 29, 2000. 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. <u>Defaults during the June 1, 2012 - May 31, 2015 Supply Period</u>

If a default occurs during the June 1, 2012 - May 31, 2015 period, ACE may: (a) offer the 36 month tranches that were being supplied by the defaulting supplier to the other winning bidders; (b) bid out such tranches to all suppliers willing to provide service; (c) procure necessary supply from PJM-administered markets; or (d) retain Committed Supply to serve these tranches. ACE may also 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 it is impractical 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. This approach relies on a combination of competitive sources for BGS power, including RFPs, broker markets, capacity costs based on the PJM 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 ("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 the procurement of capacity, energy, ancillary service, transmission, and other expenses related to the Contingency Plan, as well as 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 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 because 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) 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 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 June 1, 2012 to May 31, 2013 BGS period 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, not just those taking BGS-CIEP Service.

With the exception of any required adjustment to the CIEP Standby Fee, 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 Board determination of manifest error.

System Control Charge ("SCC")

The SCC will be calculated annually on a cents per kWh basis and 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 as Attachment 1. 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 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 in this filing as Attachment 1. Rider BGS provides the rates, terms, and conditions for customers being served under the BGS-FP or BGS-CIEP pricing mechanisms

1. BGS-FP

BGS-FP will be available to all customers served under Rate Schedules RS, DDC, SPL, and CSL. BGS-FP is also available to customers with a 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 in the proposed tariff sheets, BGS-FP comprises two components: BGS Supply Charges and the BGS Reconciliation Charge. Additionally, each BGS customer is subject to transmission charges, as discussed below.

a. BGS Supply Charges

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 currently-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, which are included in this filing as 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.

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, 2012, the pricing will be based on the 36-month auction price from the auctions held in February 2010 through 2012. 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. 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. BGS Reconciliation Charges

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. Transmission 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-FP customers are based on the annual transmission rate for network service for the ACE zone under the PJM OATT. As part of a settlement approved by the Federal Energy Regulatory Commission ("FERC") on August 9, 2004 **in docket number ER04-457,** certain transmission owners in PJM, including ACE, agreed to reexamine their existing rates and propose by January 31, 2005 a method to harmonize new and existing transmission investments, with a new rate (such as a formula rate), which would into effect June 1, 2005. The objective of this filing was 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 established by the PJM transmission owners tracks increases and decreases in costs such that no under- or 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 files updates to the formula rate at FERC on or about May 15 of each year to be effective on June 1. The Company has made and will continue to 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 under the PJM OATT, or other network transmission-related charges under the PJM OATT.

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

2. BGS-CIEP

BGS-CIEP will be the only default supply option available to customers served under Rate Schedule TGS (Transmission General Service), as well as 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 its 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 no later than the second working day of January. Such election will be effective on June 1st of that year.

BGS-CIEP comprises three (3) charges: 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 under 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 under PJM's OATT. As part of a settlement approved by FERC on August 9, 2004 in Docket No. **ER04-457**, certain transmission owners in PJM, including ACE, agreed to reexamine their existing rates and propose by January 31, 2005 a method to harmonize new and existing transmission investments, with a new rate (such as a formula rate), which would into effect June 1, 2005. The objective of this filing was 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 established by the PJM transmission owners tracks increases and decreases in costs such that no under- or 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 files updates to the formula rate at FERC on or about May 15 of each year to be effective on June 1. The Company has made and will continue to 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 under the PJM OATT, or other network transmission-related charges under 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 applicable rate translation spreadsheets.

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 the average LMP. This sum will then be adjusted for losses for service at the rate schedule for which this service is applicable.

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

These charges will recover the costs associated with generation capacity. The EDCs proposed that, effective with the supply period beginning June 1, 2009, the BGS Capacity Charge would 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, 2012 through May 31, 2013, the EDCs will pay each BGS-CIEP supplier a CIEP Standby Charge equal to $0.000150 per kWh times the supplier's 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, as well as 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 directive 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-bypassable 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 2012 through May 2013.

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 May 17, 2011 for the PJM West trading hub for the period of June 2012 to May 2013, 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 2011. 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 tariff 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 solely on the on-peak usage.

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 because retail customers will be billed for transmission service based on existing transmission rates in their applicable Rate Schedule. Therefore, 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 Division of the Rate Council 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 2012 to May 2013 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. The following is an explanation of each of the six (6) tables, labeled as Table A through F:

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	$ x.xxxxxx	
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	$ (0.002502)
Service taken at Primary Voltage	$ (0.002428)
Service taken at Sub-Transmission Voltage	$ (0.002383)
Service taken at Transmission Voltage	$ (0.002373)

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.

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) **(**$0.000072) 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 Service Charge
The Transmission Service Charge is designed to recover, on an aggregate basis, FERC-approved transmission charges. The retail transmission rate for customers taking service under Rider BGS shall be equal to the customer's transmission peak load contribution multiplied by the Network Integration Transmission Service Rate for the Atlantic City Electric Company's Transmission Zone as defined in the PJM Open Access Transmission Tariff (OATT), 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. The current Transmission Service Charge is $X.XXXXXX per kW-month.

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	0.000199	0.000166	0.000079	0.000123	0.000097	0.000080	-	0.000074
TrAILCo	0.000365	0.000302	0.000144	0.000223	0.000178	0.000146	-	0.000136
PSE&G	0.000356	0.000296	0.000143	0.000219	0.000175	0.000144	-	0.000134
PATH	0.000091	0.000075	0.000036	0.000056	0.000045	0.000036	-	0.000034
PPL	0.000021	0.000018	0.000009	0.000013	0.000011	0.000009	-	0.000007
Pepco	0.000016	0.000014	0.000006	0.000010	0.000009	0.000006	-	0.000006
Delmarva	0.000009	0.000007	0.000003	0.000005	0.000004	0.000003	-	0.000003
AEP - East	0.000003	0.000002	0.000001	0.000002	0.000001	0.000001	-	0.000001
Total	0.001060	0.000880	0.000421	0.000651	0.000520	0.000425	-	0.000395

Attachment 2

Atlantic City Electric Company
Development of Final BGS Rates
June 2012 - May 2013

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-13	314,622	102,269	115,892	735	175,527	47,274	8,220	1,155	765,694
	Feb-13	286,113	99,342	101,891	854	178,222	47,792	7,372	1,125	722,712
	Mar-13	271,485	87,857	98,960	722	169,769	47,663	7,114	1,152	684,721
	Apr-13	241,639	59,278	89,539	686	172,274	47,521	6,289	1,205	618,432
	May-13	230,251	48,224	92,723	728	168,570	48,381	5,537	1,108	595,522
1,544,567	Jun-12	276,292	51,090	106,139	1,048	176,609	55,762	5,192	1,186	673,317
0.420422797	Jul-12	408,220	72,630	128,824	1,479	200,750	58,594	5,342	1,180	877,019
	Aug-12	461,989	83,781	136,544	1,393	203,963	57,229	5,745	1,088	951,732
	Sep-12	398,066	73,760	139,643	982	190,414	57,545	6,404	1,183	867,998
	Oct-12	275,075	52,649	105,963	569	183,132	50,755	7,071	1,137	676,349
	Nov-12	236,360	52,288	92,910	415	166,789	48,061	7,568	1,118	605,508
	Dec-12	273,730	70,211	89,194	548	171,511	50,929	8,484	1,232	665,839
Total		3,673,843	853,379	1,298,223	10,159	2,157,529	617,506	80,337	13,869	8,704,845

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

	On-Peak	Off/On Pk LMP ratio	Off-Peak
Jan-13	56.39	0.783	44.18
Feb-13	56.39	0.783	44.18
Mar-13	50.01	0.783	39.18
Apr-13	50.01	0.783	39.18
May-13	49.14	0.783	38.50
Jun-12	52.16	0.636	33.19
Jul-12	59.62	0.636	37.93
Aug-12	59.62	0.636	37.93
Sep-12	48.54	0.636	30.88
Oct-12	44.40	0.783	34.78
Nov-12	44.70	0.783	35.02
Dec-12	52.85	0.783	41.40

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

	On-Peak	Off-Peak
Jan-13	109%	108%
Feb-13	109%	108%
Mar-13	109%	108%
Apr-13	109%	108%
May-13	109%	108%
Jun-12	114%	110%
Jul-12	114%	110%
Aug-12	114%	110%
Sep-12	114%	110%
Oct-12	109%	108%
Nov-12	109%	108%
Dec-12	109%	108%

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	$ 56.51	$ 56.50	$ 57.07	$ 56.95	$ 56.57	$ 54.87	$ 48.97	$ 54.05
On Peak	$ 69.54	$ 69.47	$ 68.95	$ 67.84	$ 69.10	$ 66.81	$ 68.45	$ 68.75
Off Peak	$ 42.25	$ 42.18	$ 42.00	$ 41.31	$ 42.13	$ 40.82	$ 41.96	$ 41.94
Winter - all hrs	$ 53.45	$ 54.24	$ 54.26	$ 53.36	$ 53.94	$ 52.14	$ 51.08	$ 52.84
On Peak	$ 60.39	$ 61.33	$ 60.22	$ 59.01	$ 60.13	$ 58.16	$ 60.50	$ 60.15
Off Peak	$ 46.78	$ 47.46	$ 46.65	$ 45.69	$ 46.51	$ 45.20	$ 46.59	$ 46.52
Annual	$ 54.74	$ 54.98	$ 55.37	$ 55.09	$ 54.88	$ 53.15	$ 50.48	$ 53.24
System Average Cost @ customer - (limited to classes shown above) =					$ 54.74			

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		$ 87,286	$ 15,891	$ 29,172	$ 279	$ 43,655	$ 12,572	$ 1,111	$ 251
	PJM on pk	$ 56,140	$ 10,253	$ 19,709	$ 196	$ 28,544	$ 8,275	$ 411	$ 144
	PJM off pk	$ 31,147	$ 5,638	$ 9,463	$ 83	$ 15,111	$ 4,297	$ 700	$ 107
Winter - all hrs		$ 113,810	$ 31,029	$ 42,709	$ 280	$ 74,750	$ 20,250	$ 2,945	$ 488
	PJM on pk	$ 63,012	$ 17,135	$ 26,591	$ 179	$ 45,462	$ 12,096	$ 1,126	$ 257
	PJM off pk	$ 50,798	$ 13,894	$ 16,118	$ 102	$ 29,288	$ 8,154	$ 1,819	$ 230
Annual		$ 201,096	$ 46,920	$ 71,881	$ 560	$ 118,405	$ 32,822	$ 4,056	$ 738
System Total		$ 476,479							

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		$ 56.51	$ 56.50	$ 57.07	$ 56.95	$ 56.57	$ 54.87	$ 48.97	$ 54.05
	ACECO On pk		$ 76.97						
	ACECO Off pk		$ 46.02						
Winter - all hrs		$ 53.45	$ 54.24	$ 54.26	$ 53.36	$ 53.94	$ 52.14	$ 51.08	$ 52.84
	ACECO On pk		$ 65.24						
	ACECO Off pk		$ 49.24						
Annual Average		$ 54.74	$ 54.98	$ 55.37	$ 55.09	$ 54.88	$ 53.15	$ 50.48	$ 53.24
System Average		$ 54.74							

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	1,364.2	0.9	352.5	2.8	383.9	24.1	0.0	1.6	2,129.9
Gen Obl - MW	1,381.0	0.9	356.8	2.8	388.6	24.4	0.0	1.6	2,156.1
Trans Obl - MW	1,680.0	1.1	367.3	3.2	401.4	24.1	0.0	1.6	2,478.6

\# 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		$ 25,813	per MW-yr		
Generation Capacity Cost	Summer	$170.28	$/MW/day	Summer Total	$ 44,791,247
	Winter	$ 170.28	$/MW/day	Winter Total	$ 89,215,353
				Annual Total	$ 134,006,600

Residential Inversion Determination

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

	Charges	% usage		
Block 1 (0-750 kWh/m)	5.480200	59.38%	SUM 'First 750 KWh	1,203,019,186
Block 2 (>750 kWh/m)	6.345400	40.62%	WIN' First 500 KWh	1,713,691,222
Calculated inversion =	0.865200		SUM '> 750 KWh	822,927,954
			WIN > 500 KWh	889,639,989
				4,629,278,351

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	$ 11.80	$ 0.03	$ 7.30	$ 8.03	$ 4.80	$ 1.01	$ -	$ 3.05	$ 7.35
Generation Obl -									
per annual MWh	$ 23.36	$ 0.07	$ 17.08	$ 17.13	$ 11.19	$ 2.46	$ -	$ 7.17	
recovery per summer MWh	$ 18.57	$ 0.13	$ 14.50	$ 11.86	$ 10.46	$ 2.21	$ -	$ 7.17	
recovery per winter MWh	$ 26.84	$ 0.13	$ 18.76	$ 22.04	$ 11.60	$ 2.60	$ -	$ 7.17	

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		$ 90.16	$ 59.93	$ 82.15	$ 80.02	$ 75.10	$ 61.26	$ 52.25	$ 67.54
	ACECO On-Peak		$ 80.40						
	ACECO Off-Peak		$ 49.32						
	Block 1 (0-750 kWh/m)	$ 86.65							
	Block 2 (>750 kWh/m)	$ 95.30							
Winter - all hrs		$ 95.36	$ 57.67	$ 83.60	$ 86.60	$ 73.62	$ 58.92	$ 54.35	$ 66.33
	ACECO On-Peak		$ 68.67						
	ACECO Off-Peak		$ 52.54						
Annual		$ 93.18	$ 58.35	$ 83.03	$ 83.43	$ 74.15	$ 59.79	$ 53.76	$ 66.74

Grand Total Cost in $1000 = $ 702,952

All In Average cost for rates shown (@ customer) = $ 80.75
All In Average costs for rates shown (@ bulk system) = $ 75.69

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			**0.792**	**1.085**	**1.057**	**0.992**	**0.809**	**0.690**	**0.892**
	On-Peak		**1.062**						
	Off-Peak		**0.652**						
	All usage Multiplier	**1.191**							
	Constant **$**	**(3.51)**		for Block 1 (0-750 kWh/m) usage					
	Constant **$**	**5.14**		for Block 2 (>750 kWh/m) usage					
Winter - all hrs		**1.260**	**0.762**	**1.105**	**1.144**	**0.973**	**0.778**	**0.718**	**0.876**
	On-Peak		**0.907**						
	Off-Peak		**0.694**						
Annual		**1.231**	**0.771**	**1.097**	**1.102**	**0.980**	**0.790**	**0.710**	**0.882**

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		$ 78.36	$ 59.90	$ 74.85	$ 71.99	$ 70.30	$ 60.26	$ 52.25	$ 64.49
	On-Peak		$ 80.37						
	Off-Peak		$ 49.29						
	Block 1 (0-750 kWh/m)	$ 74.84							
	Block 2 (>750 kWh/m)	$ 83.50							
Winter - all hrs		$ 56.72	$ 57.51	$ 57.54	$ 56.53	$ 57.21	$ 55.32	$ 54.35	$ 56.11
	On-Peak		$ 68.51						
	Off-Peak		$ 52.51						
Annual		$ 81.37	$ 58.32	$ 75.72	$ 75.40	$ 69.35	$ 58.79	$ 53.76	$ 63.69

Grand Total Cost in $1000 = $ 532,872

All In (Less Transmission) Average cost for rates shown (@ customer) = $ 61.22
All In (Less Transmission) Average costs for rates shown (@ bulk system) = $ 57.37

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			**1.044**	**1.304**	**1.255**	**1.225**	**1.050**	**0.911**	**1.124**
	On-Peak		**1.401**						
	Off-Peak		**0.859**						
	All usage Multiplier	**1.366**							
	Constant **$**	**(3.51)**		for Block 1 (0-750 kWh/m) usage					
	Constant **$**	**5.14**		for Block 2 (>750 kWh/m) usage					
Winter - all hrs		**0.989**	**1.002**	**1.003**	**0.985**	**0.997**	**0.964**	**0.947**	**0.978**
	On-Peak		**1.194**						
	Off-Peak		**0.915**						
Annual		**1.418**	**1.016**	**1.320**	**1.314**	**1.209**	**1.025**	**0.937**	**1.110**

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	$ 139,264	$ 16,856	$ 41,990	$ 392	$ 57,960	$ 14,037	$ 1,185	$ 313
Winter	$ 203,057	$ 32,993	$ 65,798	$ 455	$ 102,021	$ 22,884	$ 3,134	$ 612
Total	$ 342,320	$ 49,849	$ 107,788	$ 848	$ 159,982	$ 36,921	$ 4,319	$ 926
% of Annual Total $ by Rate								
Summer	41%	34%	39%	46%	36%	38%	27%	34%
Winter	59%	66%	61%	54%	64%	62%	73%	66%

Total Costs - in $1000						
Summer	$ 271,998					
Winter	$ 430,954					
Total	$ 702,952					
% of Annual Total $		If total $ were split on a per MWh basis (on bulk system MWhs):				
Summer	39%	$ 75.64 per MWh @ bulk system	Ratio to All-In Cost	>>>	Summer	**1.0000**
Winter	61%	$ 75.72 per MWh @ bulk system	(rounded to 4 decimal places)		Winter	**1.0000**

Assumptions:

Gen Cost =	$ 170.28	per MW-day	summer
=	$ 170.28	per MW-day	winter
Trans cost =	$ 25,813	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 >>>>	**$**	**100.180**
Less Transmission >>>>>>>>>	**$**	**6.751**
BGS Avg. Price >>>>>>>>>>>	**$**	**93.43**

		RS	**RS TOU - BGS**	**MGS - SEC**	**MGS - PRI**	**AGS - SEC**	**AGS - PRI**	**SPL/CSL**	**DDC**
Summer - all hrs			$ 99.963	$ 124.858	$ 120.166	$ 117.293	$ 100.537	$ 87.228	$ 107.623
	On-Peak		$ 134.145						
	Off-Peak		$ 82.249						
	Block 1 (0-750 kWh/m)	$ 127.193							
	Block 2 (>750 kWh/m)	$ 136.059							
Winter - all hrs		$ 90.271	$ 91.458	$ 91.549	$ 89.906	$ 91.002	$ 87.990	$ 86.438	$ 89.267
	On-Peak		$ 108.983						
	Off-Peak		$ 83.517						
Annual		$ 132.482	$ 94.924	$ 123.326	$ 122.766	$ 112.956	$ 95.765	$ 87.543	$ 103.706
		15.52	10.21	14.05	14.07	12.66	10.41	9.41	11.48

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				$ 0.134269	$ 0.129224	$ 0.126135	$ 0.108115	$ 0.093803	$ 0.115735
	On-Peak		$ 0.144257						
	Off-Peak		$ 0.088449						
	Block 1 (0-750 kWh/m)	$ 0.136780							
	Block 2 (>750 kWh/m)	$ 0.146315							
Winter - all hrs		$ 0.097076		$ 0.098450	$ 0.096683	$ 0.097861	$ 0.094622	$ 0.092953	$ 0.095996
	On-Peak		$ 0.117198						
	Off-Peak		$ 0.089812						
Annual		$ 0.142468	$ 0.102079	$ 0.132622	$ 0.132019	$ 0.121470	$ 0.102983	$ 0.094142	$ 0.111523

Attachment 3

Atlantic City Electric Company
Calculation of June 2012 to May 2013 BGS-FP Rates
based on results of February 2011 BGS FP Auction

Table A **Auction Results**

line #	**Payment Identifier >>**	*remaining portion of 36 month bid - 2010/11 filing*	*remaining portion of 36 month bid - 2011/12 filing*	*36 month bid - 2012/13 filing*	*Notes:*
1	Winning Bid - in $/MWh	$ 98.56	$ 100.95	$ 100.95	winning Bids
2	# of Traunches for Bid	7	8	7	from then current Bid
3	Total # of Traunches	22	22	22	from then current Bid
	Payment Factors				
4	Summer	1.0504	1.0385	1.0000	from then current Bid Factor Spreadsheet
5	Winter	0.9679	0.9753	1.0000	from then current Bid Factor Spreadsheet
	Applicable Customer Usage @ bulk system - in MWh				
6	Summer MWh	3,595,948			from current Bid Factor Spreadsheet
7	Winter MWh	5,691,614			
	Total Payment to Suppliers - in $1000				
8	Summer	$ 118,452	$ 137,086	$ 115,503	= (1) * (2)/(3) * (4) * (6)
9	Winter	$ 172,760	$ 203,773	$ 182,817	= (1) * (2)/(3) * (5) * (7)
10	Total	$ 291,212	$ 340,859	$ 298,321	
	Average Payment to Suppliers - in $/MWh				
11	Summer	$ 103.18			= sum(line 8) / (6) - rounded to 2 decimal places
12	Winter	$ 98.28			= sum(line 9) / (7) - rounded to 2 decimal places
13	Total weighted average	**$ 100.18**	<<< 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 =	$ 930,428			= (13) * [(6)+(7)] / 1000
15	Total Payment to Suppliers =	$ 930,392			= sum (line 10)
16	Difference =	$ 36			= line (14) - line (15)

Atlantic City Electric Company
Calculation of June 2012 to May 2013 BGS-FP Rates
based on results of February 2011 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			**0.792**	**1.085**	**1.057**	**0.992**	**0.809**	**0.69**	**0.892**	
	On-Peak		**1.062**							
	Off-Peak		**0.652**							
	All usage Multiplier	**1.191**								
	Constant	**(3.514)**	for Block 1 (0-750 kWh/m) usage							
	Constant	**5.138**	for Block 2 (>750 kWh/m) usage							
Winter - all hrs		**1.260**	**0.762**	**1.105**	**1.144**	**0.973**	**0.778**	**0.718**	**0.876**	
	On-Peak		**0.907**							
	Off-Peak		**0.694**							
Annual - all hrs		**1.231**	**0.771**	**1.097**	**1.102**	**0.980**	**0.790**	**0.710**	**0.882**	

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			***7.9343***	***10.8695***	***10.5890***	***9.9379***	***8.1046***	***6.9124***	***8.9361***
	On-Peak		***10.6391***						
	Off-Peak		***6.5317***						
for Block 1 (0-750 kWh/m) usage		***11.5800***							
for Block 2 (>750 kWh/m) usage		***12.4452***							
Winter - all hrs		***12.6227***	***7.6337***	***11.0699***	***11.4606***	***9.7475***	***7.7940***	***7.1929***	***8.7758***
	On-Peak		***9.0863***						
	Off-Peak		***6.9525***						

Atlantic City Electric Company
Calculation of June 2012 to May 2013 BGS-FP Rates
based on results of February 2011 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	$ 184,289	$ 24,433	$ 55,560	$ 519	$ 76,694	$ 18,570	$ 1,568	$ 414
Winter	$ 268,772	$ 45,738	$ 87,128	$ 602	$ 135,080	$ 30,270	$ 4,147	$ 810
Total	$ 453,061	$ 70,171	$ 142,688	$ 1,122	$ 211,775	$ 48,840	$ 5,715	$ 1,225

Total Summer	$ 362,048
Total Winter	$ 572,548
Grand Total	$ 934,595

Total Supplier Payment - in $1000	
Summer	$ 371,042
Winter	$ 559,350
Total	$ 930,392
Differences - in $1000	
Summer	$ 8,994
Winter	$ (13,198)
Total	$ (4,203)

kWh Rate Adjustment Factors	*rounded to 5 decimal places*	% difference
		2.4241%
		-2.3595%
1.02484		-0.4518%
0.97695		

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 2012 to May 2013 BGS-FP Rates
based on results of February 2011 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		***8.1314***	***11.1395***	***10.8520***	***10.1848***	***8.3059***	***7.0841***	***9.1581***
On-Peak		***10.9034***						
Off-Peak		***6.6939***						
for Block 1 (0-750 kWh/m) usage	***11.8676***							
for Block 2 (>750 kWh/m) usage	***12.7543***							
Winter - all hrs	***12.3317***	***7.4577***	***10.8147***	***11.1964***	***9.5228***	***7.6143***	***7.0271***	***8.5735***
On-Peak		***8.8769***						
Off-Peak		***6.7922***						

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	$ 188,866	$ 25,040	$ 56,940	$ 532	$ 78,600	$ 19,031	$ 1,607	$ 425
Winter	$ 262,576	$ 44,684	$ 85,120	$ 588	$ 131,966	$ 29,572	$ 4,051	$ 791
Total	$ 451,442	$ 69,724	$ 142,059	$ 1,121	$ 210,566	$ 48,603	$ 5,658	$ 1,216
Total Summer	$ 371,041							
Total Winter	$ 559,349							
Grand Total	$ 930,389							
Total Supplier Payment - in $1000								
Summer	$ 371,042							
Winter	$ 559,350							
Total	$ 930,392							
Differences - in $1000								
Summer	$ (1)							
Winter	$ (1)							
Total	$ (3)							

I/M/O the Provision of Basic Generation Service for the
Period Beginning June 1, 2012
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I/M/O the Provision of Basic Generation Service for the
Period Beginning June 1, 2012
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I/M/O the Provision of Basic Generation Service for the
Period Beginning June 1, 2012
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