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BOARD OF PUBLIC UTILITIES
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ACTING GOVERNOR

Kristi Izzo
Secretary of the Board
TEL: (973) 648-3426

December 5, 2005

Re: In the Matter of the Deferred Balances Audit of
Atlantic City Electric Co.
Phase II: August 2002 – July 2003
Docket Nos. EX02060363 and EA02060364

To the Service List:

The Board, at its December 2, 2005 Agenda meeting, acknowledged receipt of the Atlantic City Electric Co. deferred balances Phase II audit report and authorized its release to the public for comment. The report is available on the Board's website at www.bpu.state.nj.us. Hard copies are also available upon request by contacting the Board's Division of Audits at (973) 648-4450.

Interested parties are invited to submit comments by January 10, 2006 and reply comments by January 24, 2006. Thereafter, the matter will be returned to the Board's agenda for further action.

Sincerely,

Kristi Izzo
Secretary of the Board

KI/ac

New Jersey Board of Public Utilities

Atlantic City Electric Company

Audit of Deferred Balances for the period from August 1, 2002 to July 31 2003

Phase II

Mitchell & Titus, LLP

Certified Public Accountants
and Consultants

B W G Barrington-Wellesley Group, Inc.
Management Consultants

Table of Contents

I. Executive Summary 1

A. AUDIT OVERVIEW 1

B. SUMMARY OF ADJUSTMENTS 5

C. SUMMARY OF FINDINGS, OBSERVATIONS AND CONCLUSIONS 5

D. PRUDENCE QUANTIFICATION 9

II. Introduction 1

A. BACKGROUND 1

B. AUDIT SCOPE AND OBJECTIVES 1

III. Basic Generation Service (BGS) Deferral

A. BACKGROUND 1

B. SCOPE AND OBJECTIVES 3

C. EVALUATIVE CRITERIA 4

D. CONCLUSION 4

E. OBSERVATIONS 4

IV. Net Non-Utility Charge (NNC) Deferral

A. BACKGROUND 1

B. SCOPE AND OBJECTIVES 3

C. EVALUATIVE CRITERIA 4

D. FINDINGS 4

E. ADJUSTMENT 4

F. CONCLUSION 4

G. OBSERVATIONS 5

V. Market Transition Charge (MTC) Deferral

A. BACKGROUND 1

B. SCOPE AND OBJECTIVES 6

C. EVALUATIVE CRITERIA 7

D. FINDING 7

E. ADJUSTMENT 7

F. CONCLUSION 7

G. OBSERVATIONS 7

VI. Societal Benefit Charge (SBC) Deferral

A. BACKGROUND....1
B. SCOPE AND OBJECTIVES....4
C. EVALUATIVE CRITERIA....5
D. FINDING....6
E. CONCLUSION....6
F. OBSERVATIONS....6

VII. Interest on Total Deferred Balances

A. BACKGROUND....1
B. FINDINGS....1
C. OBSERVATIONS....1

VIII. BGS Procurement Prudence

A. BACKGROUND....1
B. SCOPE AND OBJECTIVES....4
C. EVALUATIVE CRITERIA....4
D. FINDINGS AND CONCLUSIONS....5
E RECOMMENDATIONS....14

IX. NUG Mitigation

A. BACKGROUND....1
B. SCOPE AND OBJECTIVES....2
C. EVALUATIVE CRITERIA....3
D. FINDINGS AND CONCLUSIONS....3
E. RECOMMENDATIONS....10

I. Executive Summary

This chapter represents the executive summary for the results of the Deferred Balances Audit of Atlantic City Electric Company ("ACE" or the "Company") for the period from August 1, 2002 to July 31, 2003 ("Phase II").

A. AUDIT OVERVIEW

On July 29, 2002, the New Jersey Board of Public Utilities ("Board" or "BPU") issued a Request for Proposals ("RFP") to secure the services of an independent accountant/auditor/consultant ("Contractor") to conduct audits of the restructuring-related deferred balances of New Jersey's four electric utilities ("Utilities"). On October 2, 2002, Mitchell & Titus, LLP ("M&T") and Barrington-Wellesley Group, Inc. ("BWG") were engaged to perform the audit of ACE.

The scope of this audit is ACE's transactions for the period from August 1, 1999 through July 31, 2003 (transition period) as they impact the deferred balance accounts. The audit is conducted in two phases:

- Phase I: Deferred Balances from August 1, 1999 through July 31, 2002
- Phase II: Deferred Balances from August 1, 2002 through July 31, 2003

This report describes the results of Phase II of the audit. A separate report was issued at the conclusion of Phase I of the audit.

The objective of the audit, as clarified by the Board staff in its November 21, 2002 letter, is to provide the Board with a certified opinion as to whether ACE's deferred balances, as of July 31, 2003, are accurately calculated, correctly recorded, fairly stated in all material respects, and in compliance with Board Orders.

As stated in the RFP, for those Utilities that have divested their generation assets, the assignment includes a prudency review of the Utilities' BGS procurement practices for the first three years of the transition period. The audit will also examine the Utilities' mitigation efforts, consistent with applicable law, with respect to the above-market NUG contract costs during the transition period.

To satisfy the objectives of the audit, an examination conducted in accordance with attestation standards established by the American Institute of Certified Public Accountants was performed by M&T and the prudence review by BWG.

The examination report, issued by M&T, is presented in a separate bound report. A detailed description of the examination approach and results are presented in Chapters III – VII. These sections provide the background, scope and objectives, evaluative criteria, findings, adjustments, restatement, conclusions and observations by the following deferred balance components: Basic Generation Service ("BGS") Deferral, Non-Utility Generation Charge ("NNC") Deferral, Societal Benefits Charge ("SBC") Deferral and Market Transition Charge ("MTC") Deferral. ACE's deferred balance for Phase II is reflected in **Exhibit I-1** (page I-3).

The results of the prudence review conducted by BWG are presented in Chapters VIII – IX. These chapters provide a detailed description of the background, scope and objectives, evaluative criteria, findings and conclusions, recommendations and quantification for BGS Procurement and NUG Mitigation.

Exhibit I-1

Atlantic City Electric Company
Schedule of Deferred Balances
For the year ended July 31, 2003
(Dollars in thousands)

Components	Beginning Balance at August 1, 2002 Over (Under) Recovery	Revenue	Cost	Ending Balance at July 31, 2003 Over (Under) Recovery	Adjustment	Adjusted Balance at July 31, 2003 Over (Under) Recovery
Basic Generation Service (BGS") (Note 1)						
BGS Revenues	$ 1,254,808	$ 479,317	$ -	$ 1,734,125	$ -	$ 1,734,125
BGS Costs:						
Contracted NUG BGS Cost (Note 2)	(398,096)	-	(151,420)	(549,516)	-	(549,516)
To Be Divested BGS Cost (Note 3)	(429,564)	-	(101,654)	(531,218)	-	(531,218)
Energy and Capacity Purchases	(565,156)	-	(385,704)	(950,860)	-	(950,860)
Others	44,776	-	178,178	222,954	-	222,954
Total BGS Costs	(1,348,040)	-	(460,600)	(1,808,640)	-	(1,808,640)
Net BGS Deferral	**(93,232)**	**479,317**	**(460,600)**	**(74,515)**	**-**	**(74,515)**
Net Non-Utility Generation Transition Charge ("NNC") (Note 2)						
NNC Revenues	360,101	100,519	-	460,620	-	460,620
Net NUG Costs:						
NUG Contract Cost, net	(324,946)	-	(90,842)	(415,788)		(415,788)
Others	(28,996)	-	(3,624)	(32,620)	-	(32,620)
Net NUG Costs	(353,942)	-	(94,466)	(448,408)	-	(448,408)
Net NNC Deferral	**6,159**	**100,519**	**(94,466)**	**12,212**	**-**	**12,212**

Exhibit I-1
(Con't)

Components	Beginning Balance at August 1, 2002 Over (Under) Recovery	Revenue	Cost	Ending Balance at July 31, 2003 Over (Under) Recovery	Adjustments and Restatement	Adjusted Balance at July 31, 2003 Over (Under) Recovery
Market Transition Charge ("MTC") (Note 3)						
Revenues:						
MTC Revenues	92,211	17,773	-	109,984	-	109,984
Others	7,356	549	-	7,905	-	7,905
Total MTC Revenues	99,567	18,322	-	117,889	-	117,889
MTC Costs:						
To-Be-Divested Units Revenue Requirement, net	(178,970)	-	(53,587)	(232,557)	-	(232,557)
Others	(14,505)	-	(4,064)	(18,569)		(18,569)
Total MTC Costs	(193,475)	-	(57,651)	(251,126)	-	(251,126)
Net MTC Deferral	**(93,908)**	**18,322**	**(57,651)**	**(133,237)**	**-**	**(133,237)**
Societal Benefits Charge ("SBC") (Note 4)						
Demand Side Management	4,274	5,704	(9,294)	684		684
Nuclear Decommissioning	22,118	8,017	-	30,135		30,135
Uncollectable Accounts	(9,024)	6,297	(5,389)	(8,116)	1,485	(6,631)
Net SBC Deferral	**17,368**	**20,018**	**(14,683)**	**22,703**	**1,485**	**24,188**
Deferred Balances	**(163,613)**	**618,176**	**(627,400)**	**(172,837)**	**1,485**	**(171,352)**
Interest on total deferred balances (Note 5)	**(2,180)**	**-**	**(6,600)**	**(8,780)**	**3,587**	**(5,193)**
Total (Note 6)	**$ (165,793)**	**$ 618,176**	**$ (634,000)**	**$ (181,617)**	**$ 5,072**	**$ (176,545)**

B. SUMMARY OF ADJUSTMENTS

1. The over-recovery of $3,586,495 noted above which related to interest calculation was adjusted to the total deferred balances.
2. Based on the estimated loss percentages, the required allowance should have been $6,370,906 instead it was $7,856,233 resulting in a difference of $1,485,327.

C. SUMMARY OF FINDINGS, OBSERVATIONS AND CONCLUSIONS

FINDINGS

Description	Chapter Reference	Over/(Under) Recovery
Deferred Balance Adjustments		
1. ACE computed interest on the deferred balance on a before - tax basis. Had ACE computed the interest on the deferred balance on an after-tax basis, the cumulative interest during the transition period would have been $5,193,174 as against the amount of $8,779,669 recorded by ACE. Pursuant to the Final Decision and Order dated July 21, 2003, ACE was directed to recalculate the interest accrued on its post August 1, 1999 deferred balances on a net of tax basis. As per ACE a Notice of Appeal was filed, in August 2004, with the Appellate Division of the Superior Court of New Jersey on this issue.	VII: Interest on Total Deferred Balances	$3,586,495
2. As of July 31, 2003, the allowance for doubtful accounts amounted to $7,856,233. This amount was exceeded by $1,485,327 when compared to the required allowance of $6,370,906, the calculation of the required allowance was based on the estimated loss percentages (average of 7% from the sample months December 2002 and July 2003) of the month end aging of accounts receivable. Although the Company's management claims to have used a conservative approach in establishing a larger reserve balance, there is uncertainty related to the estimated reserve as the historical information on non-collection would indicate that a smaller amount is warranted. The Company's management contends that the analysis process for estimating the adjustment required for the reserve balance at July 31, 2003 warrants processing six-to-nine month's data. As of the date of this report, that process has not been completed.	VI: SBC Deferral	$1,485,327
Total adjustments		$5,071,822

OBSERVATIONS

Description	Chapter Reference for Details	Results and/or Recommendations
1. Basis of recording the revenue for deferral is different from the basis adopted by ACE under the generally accepted accounting principles (GAAP) for its financial statements. Unbilled revenues were not included as deferred revenue consistent with LEAC accounting and the Final Order (paragraph 43). Under GAAP, the accrual basis of accounting is used. Revenues, billed and unbilled, are recognized when earned.	III, IV, V and VI	The resulting impact on the beginning and ending balances relate to revenues for July 2002 and July 2003. No adjustment is proposed but to emphasize the different treatment between the accrual basis in accordance with GAAP and deferral accounting approved by the Board Orders. The difference is not quantified as the unbilled revenue is calculated in total and does not present the breakdown of each revenue component.
2. Sales support cost was included in the BGS but without specific Board Order. From August 1999 to July 2002, ACE included $1,397,521 sales support charge to energy and capacity purchases. Sales support charge represents labor charges reported through internal order No. 5213762 which are related to conducting the BGS activities which is similar to administration cost. There was no specific Board Order that authorized sales support expenses to be charged to deferred balances.	III: BGS Deferral	In Phase I, it was recommended that ACE seek the Board's approval and reclassify the reporting from energy and capacity purchases to BGS administration cost. ACE stated that the sales support costs are true BGS cost and that recovery has been sought as such in the on-going NJ Distribution Base Rate Case.
3. In developing the net BGS price throughout the transition period, ACE used slightly different and inconsistent approach from the Final Order (page 87, paragraph 7).	III: BGS Deferral	No impact on total deferred balance. The amounts calculated added to BGS costs and taken out from the NNC and MTC deferral would have been different.
4. In May 2003, ACE received a partial payment of $4.6 million relating to Logan arbitration which was applied to reduce the BGS deferred balance.	IV: NNC Deferral	This was a finding in Phase I of the audit. ACE subsequently received payment in May 2003.
5. The investment tax credits as of August 1, 1999, in the aggregate amount of approximately $8.6 million[1], relating to the nuclear plants, were not deducted from the calculation of the stranded costs. The	V: MTC Deferral	During Phase I, it was established that ACE should file a ruling request to confirm whether the nuclear facilities ceased to be " public utility property" on August 1, 1999, the Virtual Close

[1] From ACE ruling request filed to the Internal Revenue Service (IRS).

Description	Chapter Reference for Details	Results and/or Recommendations
ruling requests that the Internal Revenue Service ("IRS") determine whether the nuclear facilities ceased to be "public utility property" on August 1, 1999, the Virtual Close Date (October 2000) or Actual Sale Date (October 2001). Upon receipt of the IRS ruling to determine the treatment, the amount will be re-determined depending on the relevant date and, when appropriate, ACE will update the calculation of the stranded costs. The estimated adjustment to the MTC deferral is uncertain pending the outcome of the IRS ruling.		Date (October 2000) or Actual Sale Date (October 2001). A determination as to whether there was need for an adjustment to be made was dependent on the outcome of the IRS Ruling. As per ACE, the Company did file a ruling request on December 12, 2002. After researching this matter, it has been determined that the Internal Revenue Service (IRS) will not be issuing a ruling letter on this issue. The IRS will, however, issue guidance for utilities on the treatment of these deferred tax amounts on the stranded cost balance.
6. The restructuring-related capital expenditures ("transition costs") were based on the estimated costs set forth in Schedule C of the Stipulation of Settlement. These estimated amounts were used in the amortization of transition costs. ACE has submitted the actual amounts as part of its deferral rate case and may consider the true-up or reconciliation to be reflected in the deferral for Phase II. During Phase II the Company continued to amortize the estimated costs into the MTC Deferral. As per ACE, the difference between the amount being amortized and the actual capital costs for the items on Schedule C of the Stipulation will need to be added to the deferred balance when a final determination of the recoverable Transition Period deferred balance is made.	V: MTC Deferral	The impact on deferred balances is immaterial (monthly amortization of transition cost based on estimated amount is $188,000). This was a finding in Phase I.
7. Compensation benefits of 30% of the basic salaries were applied for the years 2000, 2001, 2002 and 2003. The 30% was an estimate although there are certain months where the actual benefits incurred were less than 30%.	V. MTC Deferral	The selected month showed that the actual benefits incurred represent 25.8% of the basic salaries. No quantification of the difference was performed as the difference is estimated to be immaterial. The difference in the

Description	Chapter Reference for Details	Results and/or Recommendations
		percentages of 4.2% results in an estimated overstatement of $30,000 for the B.L. England plant which is the plant that has the highest plant cost (i.e. $700, 000 of the $3 million in average monthly operating and maintenance cost). Per ACE, the actual rate for 2003 was 25%. Benefit expenses were adjusted downward in June of 2003. A portion of the adjustment was allocated to ACE-TUB based on people count. The credits for ACE-TUB were then allocated to BL England, Deepwater and the jointly owned units. ACE stated that the portion allocated to BL England and the jointly owned units was appropriately considered in the deferral.
8. The costs incurred for CEP and USF amounting to $3.4 million and $0.6 million, respectively, were not included in the SBC deferral as at July 31, 2002. These costs were being held in deferred orders for future recovery. ACE has requested approval of its proposed recovery of all CEP and USF related costs incurred through the transition period	VI: SBC Deferral	The Board addressed the treatment of costs incurred for CEP and USF in its Final Decision and Order. The CEP cost recovery was approved by the Board. ACE has been directed to recalculate interest accrued on the CEP costs deferred during the transition period so as to reflect the change in the interest calculation methodology. With respect to the USF costs, the Board adopted the RPA's recommendation to offset, with a like portion of the overrecovered SBC deferred balance, the $.6 million of ACE's USF costs incurred and projected to be incurred and deferred during the transition period. ACE was directed to recalculate the interest accrued on the deferred USF costs during the transition period to reflect the change in the interest

Description	Chapter Reference for Details	Results and/or Recommendations
		calculation methodology. Per ACE, the calculation of interest during the Transition Period is under Notice of Appeal. The Notice was filed in August 2004.
9. Interest was calculated on the monthly average of over (under) recovered total deferred balances. The Company maintains that the interest calculation has been performed in accordance with existing Board regulations as published in N.J.A.C. 14:3-13 (Interest on Deferred Balances of LEAC, Levelized Gas Adjustment Clauses, Purchased Water Adjustment Clauses and Purchased Sewerage Treatment Adjustment Clauses).	VII: Interest on Total Deferred Balances	The method of calculation for the deferred balances during the transition period should be approved by the Board. Pursuant to the Final Decision and Order dated July 21, 2003, ACE has been directed to recalculate the interest accrued on its post August 1, 1999 deferred balances on a net of tax basis. As per ACE, a Notice of Appeal was filed, in August 2004, with the Appellate Division of the Superior Court of New Jersey on this issue.
10. In addition, the interest rate used was based on the average rate for the month of August plus 60 basis points instead of the rate on or closest to August 1 of each year plus 60 basis points.	VII: Interest on Total Deferred Balances	Difference in rate was very minimal.

D. PRUDENCE QUANTIFICATION

BGS Procurement

ACE participated in the development of an innovative approach to procuring Basic Generation Services (BGS) supply for Year Four for both itself and for the other EDCs in New Jersey in order to comply with the requirements of the Board's August 1999 Final Decision and Order. On February 15, 2002, the Board certified the final results of the BGS auction for all four New Jersey EDCs for the period August 1, 2002 through July 31, 2003 in their entirety and approved the closing prices for each EDC. ACE managed its participation in the BGS auction in an effective but costly manner. Approximately $217,000 of ACE's BGS administrative costs were associated with the deficient RFP 1 and RFP 2 processes. The recorded costs for Deepwater and CT capacity in the period August 1999 through December 1999 do not reflect needed capacity quantities and the capacity price should be based on the market clearing price for the daily capacity market. The recorded costs for Deepwater and CT capacity in the period January 2000 through July 2000 do not reflect the needed capacity quantities thereby increasing ACE's deferred balance by $438,480.

NUG Mitigation

Notwithstanding its previous inability to interest the owner of the American Ref-Fuel project in a mutually beneficial restructuring, ACE remained in contact with the owner and monitored the project to identify developments which might create new restructuring opportunities. As the lead owner, Carney's Point has reorganized in bankruptcy, ACE has developed restructuring proposals tailored to the owner's changing financial position and is making reasonable progress toward restructuring this contract. ACE believes that a restructuring of Carney's Point will serve as a template for restructuring Logan since NEG is the lead owner of both. ACE has maintained a management and compensation structure that supports its restructuring program. A review of ACE's internal files confirmed that the company explored reasonable opportunities to restructure all of its NUG contracts during both the Phase I and Phase II audit periods. ACE customers have benefited from the company's dedication of power entitlements under NUG contracts to meet a portion of BGS supply needs rather than selling that power into the regional market. ACE made a number of errors in identifying external costs associated with the Logan contract dispute.

II. Introduction

This chapter is organized as follows:

A. Background
B. Audit Scope and Objectives

A. BACKGROUND

In Chapter VIII of the Phase I Report, BWG concluded that: "Throughout the first three years of the transition period, ACE had limited in-house staff and did not have adequate analytical resources to consistently make effective decisions regarding BGS supply procurement." For Year Four, ACE participated in a statewide competitive bidding process which procured the BGS supply for all four electric distribution companies (EDCs) in New Jersey.

In Chapter IX of the Phase I Report, the auditors concluded that ACE had been prudent in its efforts to mitigate stranded costs through restructuring NUG contracts. The report noted that ACE had bought out one of its four contracts and partially restructured a second, producing net present value ("NPV") savings to ratepayers of $92 million. The company was working with the lead owner of the other two projects to explore restructuring opportunities. The auditors also noted that time constraints had prevented them from conducting a review of ACE's internal files to verify information obtained from an interview of company staff and other sources.

B. AUDIT SCOPE AND OBJECTIVES

We reviewed ACE's BGS Procurement Process and its NUG mitigation efforts for the period August 1, 2002 through July 31, 2003. The objective of these reviews was to determine the prudence of the utility's procurement efforts, consistent with applicable law and its mitigation efforts, with respect to the above-market NUG contract costs.

Examination of Deferred Balances
Mitchell & Titus, LLP

III. Basic Generation Service ("BGS") Deferral

A. BACKGROUND

Pursuant to N.J.S.A. 48:3-57(a) and (b)(3), the Company must provide BGS for retail customers who do not choose an alternate supplier during the three-year period ended July 31, 2002. The responsibility for BGS after July 31, 2002 was determined by bid during the third year of the Transition Period.

BGS refers to electric generation service that is provided to any customer who has not chosen an alternative electric power supplier, cannot obtain such service from an electric power supplier for any reason, or has been denied service by an electric power supplier for non-payment for services. BGS is not a competitive service and is fully regulated by the Board. The costs associated with BGS are intended to be recovered through the BGS charge on a customer's bill.

The following excerpts from the Board Orders are relevant to BGS components:

Tariff rate reductions
"In summary, subject to the conditions embodied herein, the rate discounts provided by ACE, all stated relative to current rates, shall be at a minimum as follows:

August 1, 1999	5 %
January 1, 2001	7%
August 1, 2002	10.2%"[2]

BGS Costs
"ACE shall apply both NUG contract power and to-be-divested owned generation power (prior to the closure of the sale of the generation assets) towards the BGS supply requirement, which power shall be credited at the net BGS price (the floor shopping credit less transmission cost, sales and use tax, line losses, ancillary services and capacity reserve margin)."[3]

Deferred accounting basis
"In setting the annual level of charges for BGS during the Transition Period, for any MTC that continues beyond the Transition Period, and for the SBC, NNC and the TBC, the Company will utilize a methodology similar to that currently used for setting its Energy Adjustment clause charges. The BGS, SBC, NNC, MTC and TBC components will be reviewed annually, based upon projections of costs and of sales. Actual costs will be accounted for on a deferred accounting basis, and when the BGS, SBC, NNC, MTC and TBC are set in the following year, each of those rate components will be set to recover any under recovery in the Deferred Balance, as well as the projected costs for the upcoming year."[4]

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[2] Final and Decision Order, In the Matter of Atlantic City Electric Company's Rate Unbundling, Stranded Costs and Restructuring Filings; Docket Nos. EO97070455, EO97070456, EO97070457; Signed March 30, 2001; Page 96; Paragraph 46.
[3] Final and Decision Order, In the Matter of Atlantic City Electric Company's Rate Unbundling, Stranded Costs and Restructuring Filings; Docket Nos. EO97070455, EO97070456, EO97070457; Signed March 30, 2001; Page 87; Paragraph 7.
[4] Final and Decision Order, In the Matter of Atlantic City Electric Company's Rate Unbundling, Stranded Costs and Restructuring Filings; Docket Nos. EO97070455, EO97070456, EO97070457; Signed March 30, 2001; Page 95; Paragraph 43.

Exhibit III-1 below shows the balances of BGS components as at July 31, 2003:

Exhibit III-1
Basic Generation Service ("BGS")
Over/(Under) Recovery
(Dollars in Thousands)

BGS Components	Audited Opening Balance	Revenues	Cost	Ending Balance
BGS Revenues	$1,254,808	$479,317		$1,734,125
BGS Costs:				
Contracted NUG BGS Cost	(398,096)		(151,420)	(549,516)
To Be Divested BGS Cost	(429,564)		(101,654)	(531,218)
Energy and Capacity Purchases	(565,156)		(385,704)	(950,860)
Energy, Capacity and Ancillary Sales	47,234		179,392	226,626
BGS Administration Costs	(2,458)		(1,214)	(3,672)
Total BGS Costs	(1,348,040)		(460,600)	(1,808,640)
Net BGS Deferral	($93,232)	$479,317	($460,600)	($74,515)

Source: ACE's Response to Data Request, excluding interest calculated separately on the total deferred balances (see Chapter VII).

BGS Revenues
This represents the revenues based on approved tariff rates and the kilowatt hours consumed by ratepayers. As at July 31, 2003, ACE implemented each rate reduction at the following effective dates:

August 1, 1999	5% from April 1997 rates
January 1, 2000	1%
January 1, 2001	1%
August 1, 2002	3.2%

Contracted NUG BGS Cost
This represents BGS costs, calculation of which was based on the kilowatt hours purchased from the non-utility generation companies multiplied by the net BGS price (the floor shopping credit less transmission cost, sales and use tax, line losses, ancillary services and capacity reserve margin). This is deducted from the NUG costs and reflected as BGS costs.

To-Be-Divested BGS Cost
This represents BGS costs, calculation of which was based on the kilowatt hours generated by ACE's to-be-divested generating units multiplied by the net BGS price (the floor shopping credit less transmission cost, sales and use tax, line losses, ancillary services and capacity reserve margin). This is deducted from the costs recoverable by the MTC and reflected as BGS costs.

Energy and Capacity Purchases
Energy and capacity purchases are made from PJM (Pennsylvania-New Jersey-Maryland Interconnection) and other second party sources. ACE purchases energy supply from different providers on the open market depending on its energy needs.

Deepwater is excluded from the calculation by segregating from PJM invoices, the revenues and costs associated with Deepwater. Costs relating to combustion turbines as set forth in Schedule B of the Stipulation were recorded separately and excluded from the deferral calculation.

Energy, Capacity and Ancillary Sales
This represents the sale of excess energy and capacity and certain ancillary units to other energy suppliers. Deepwater is excluded by segregating from PJM invoices, the revenues and costs associated with Deepwater. Revenues relating to combustion turbines as set forth in Schedule B of the Stipulation were recorded separately and excluded from deferral.

BGS Administration Costs
This represents costs of administering the BGS supply contracts.

B. SCOPE AND OBJECTIVES

Scope

The scope of our examination of the BGS included a review, on a test basis, of ACE's transactions and supporting calculations and documentation for the period of August 1, 2002 through July 31, 2003 (Phase II transition period) as they relate to BGS costs and revenues presented in Exhibit III-1.

Objectives

The objectives of this phase of our review involved assessing ACE's compliance with the pertinent Board Orders and examining the evidentiary documents supporting the deferred balance to ensure that the deferred balance includes only those revenues and costs that are fairly stated, in all material respects and in compliance with the Board Orders. A summary of the procedures performed are as follows:

- Conducted interviews with ACE personnel responsible for BGS to update our understanding of the compliance requirements; the general, monitoring and specific controls and key processes and procedures in place;

- Obtained, reviewed and documented the pertinent Board Orders;

- Obtained the accounting reports detailing the revenues and costs and compared to the Deferral Filing for accuracy and consistency;

- Reviewed the billing process – automated system ("C3") and manual billing preparation and meter reading system to update our understanding of their applications;
- Reviewed the billing and meter reading system documentation – flowcharts; interfaces; databases; file and table layouts, and processing logic;
- On a sample basis, performed tests of the customer billings and the meter reading;
- Referred to approved tariff rates effective at specific periods;
- Reviewed the results, management responses and the status of recommendations of prior audits performed by external and internal sources;
- On a sample basis, performed tests of BGS cost components to assess the calculation, timing, allocation and recording of expenditures in accordance with management controls and compliance with the Board Orders;

C. EVALUATIVE CRITERIA

Mitchell & Titus, LLP, used the following criteria to analyze ACE's BGS deferred balance:

- Does ACE have effective controls over compliance with the Board Orders and the amounts reported as deferred balances?
- Are the amounts presented as deferred balances in accordance with the Board Orders?
- Are the amounts presented as deferred balances fairly stated, in all material respects?

D. CONCLUSION

In our opinion, ACE's BGS deferred balance is fairly stated, in all material respects.

E. OBSERVATIONS

1. Basis of recording the revenue for deferral is different from the basis adopted by ACE under the accounting principles generally accepted in the United States of America (GAAP) for its financial statements. Unbilled revenues were not included as deferred revenue consistent with LEAC accounting and the Final Order (paragraph 43). Under GAAP, the accrual basis of accounting is used. Revenues, billed and unbilled, are recognized when earned.

   The resulting impact on the beginning and ending balances relate to revenues for August 2002 and July 2003. No adjustment is proposed but to emphasize the different treatment between the accrual basis in accordance with GAAP and deferral accounting approved by the Board Orders. The difference is not quantified as the unbilled revenue is calculated in total and does not present the breakdown of each revenue component.

2. Sales support cost was included in the BGS but without a specific Board Order. From August 2002 to July 2003, ACE included $1,397,521 sales support charge to energy and capacity purchases. Sales support charge represents labor charges reported through internal order no. 5213762 which are related to conducting the BGS activities which is similar to administration cost. There was no specific Board Order that authorized sales support expenses to be charged to deferred balances.

   In Phase I, it was recommended that ACE seek the Board's approval and reclassify the reporting from energy and capacity purchases to BGS administration cost.

   ACE stated that the sales support costs are true BGS cost and that recovery has been sought as such in the on-going NJ Distribution Base Rate Case.

3. In developing the net BGS price for the years 2000, 2001, 2002 and 2003, ACE used a slightly different and inconsistent approach from the Final Order as presented in Exhibit III-2 (following page).

Exhibit III-2
Formula for Net BGS Price
1999-2003

Per Board Order	Years	Shopping Credit	Less Transmission Rate	BGS Rate	Less SUT	Less Losses	Less Ancillary	Less Reserve Margin	
Per ACE	1999	Shopping credit	Less transmission rate	BGS rate	Less SUT	Less Losses	Less Ancillary	Less Reserve Margin	
Per ACE	2000	Shopping credit	Less transmission rate	BGS rate	Less SUT	Less Losses	Less Ancillary		
Per ACE	2001	Shopping credit	Less transmission rate	BGS rate	Less SUT.	Less Admin.	Less Losses	Less Ancillary	
Per ACE	2002	Shopping credit	Less transmission rate	BGS Rate	Less SUT	Less Revenue Assess.	Less Admin.	Less Losses	Less Ancillary
Per ACE	2003	Shopping credit	Less transmission rate	BGS Rate	Less SUT	Less Revenue Assess.	Less Admin.	Less Losses	Less Ancillary

IV. Net Non-Utility Charge ("NNC") Deferral

A. BACKGROUND

The NNC is designed to recover above market costs of power purchased from non-utility generating companies (NUGs) under the long-term contractual power purchase agreements (PPAs).

The following excerpts from the Board Orders are relevant to NNC deferred balances:

Tariff rate reductions
"In summary, subject to the conditions embodied herein, the rate discounts provided by ACE, all stated relative to current rates, shall be at a minimum as follows:

August 1, 1999	5 %
January 1, 2001	7%
August 1, 2002	10.2%"[5]

Contracted BGS Costs
"ACE shall apply both NUG contract power and to-be-divested owned generation power (prior to the closure of the sale of the generation assets) towards the BGS supply requirement, which power shall be credited at the net BGS price (the floor shopping credit less transmission cost, sales and use tax, line losses, ancillary services and capacity reserve margin)."[6]

Deferred accounting basis
"In setting the annual level of charges for BGS during the Transition Period, for any MTC that continues beyond the Transition Period, and for the SBC, NNC and the TBC, the Company will utilize a methodology similar to that currently used for setting its Energy Adjustment clause charges. The BGS, SBC, NNC, MTC and TBC components will be reviewed annually, based upon projections of costs and of sales. Actual costs will be accounted for on a deferred accounting basis, and when the BGS, SBC, NNC, MTC and TBC are set in the following year, each of those rate components will be set to recover any underrecovery in the Deferred Balance, as well as the projected costs for the upcoming year."[7]

PCLP Buyout Interest
"Recoverable interest costs included in the NNC during the period of interim financing would be calculated by applying the interest rate actually incurred on the interim debt to an initial net of tax debt balance that reflects the full tax deduction associated with the termination payment."[8]

"Atlantic is entitled to and shall be allowed full and timely recovery of the $228.5 million termination payment employing the net of tax methodology provided for herein, as well as reasonable and prudently incurred transaction costs at a level to be determined by the Board and interim financing costs in the manner provided for hereinabove."[9]

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[5] Final and Decision Order, In the Matter of Atlantic City Electric Company's Rate Unbundling, Stranded Costs and Restructuring Filings ("Final and Decision Order"); Docket Nos. EO97070455, EO97070456, EO97070457; Signed March 30, 2001; Page 96; Paragraph 46.
[6] Final and Decision Order; Page 87; Paragraph 7.
[7] Final and Decision Order, In the Matter of Atlantic City Electric Company's Rate Unbundling, Stranded Costs and Restructuring Filings; Docket Nos. EO97070455, EO97070456, EO97070457; Signed March 30, 2001; Page 95; Paragraph 43.
[8] November 10, 1999 Decision and Order, In the Matter of the Petition of Atlantic City Electric Company for Approval of an Agreement to Terminate Its Power Purchase Agreement with Pedricktown Cogeneration Limited Partnership; Docket No. EE99090685; Page 9; 2nd Paragraph.
[9] November 10, 1999 Decision Order

Exhibit IV-1 below shows the balances of NNC components as at July 31, 2003:

Exhibit IV-1
Net Non-Utility Charges
Over/(Under) Recovery
(Dollars in Thousands)

NNC Components	Beginning Balance at August 1, 2002	Revenues	Cost	Adjustment	Ending Balance at July 31, 2003
NNC Revenues	$360,101	$100,519			$460,620
Net NUG Costs:					
NUG Contract Payments	(723,042)		(242,262)		(965,304)
PCLP Buyout Interest	(20,585)		(1,526)		(22,111)
Keystone Swap Breakage	(5,993)		(1,998)		(7,991)
Logan Arbitration	(2,418)		(100)		(2,518)
Less Contracted NUG BGS Costs	398,096		151,420		549,516
Net NUG Costs	(353,942)		(94,466)		(448,408)
Net NNC Deferral	$6,159	$100,519	($94,466)		$12,212

Source: ACE's August 30, 2002 Deferral Filings, excluding interest calculated separately on the total deferred balances (see Chapter VII).

NNC Revenues
This represents the revenues based on approved tariff rates and the kilowatt hours consumed by ratepayers. As at July 31, 2003, ACE implemented each rate reduction at the following effective dates:

August 1, 1999	5% from April 1997 rates
January 1, 2000	1%
January 1, 2001	1%
August 1, 2002	3.2%

NUG Contract Cost
This represents the cost of energy and capacity purchases made under PPAs with NUGs based on contract prices with agreed escalations and amendments.

PCLP Buyout Interest
This represents the interest incurred on the net-of-tax buyout costs (ACE's payment in terminating its PPA with Pedricktown Cogeneration Limited Partnership or PCLP) approved by the Board to be included in the NNC deferred balance. The tax represents the refund for tax benefits on the losses incurred by ACE for such buyout cost.

Keystone Swap Breakage
This represents the amortization over a 20-year period, with 8% interest, of $20 million "swap breakage" costs associated with the Keystone project and previously recovered by the LEAC. Approvals were made in the following Board Orders:

- Docket Nos. EM88091074, dated August 12, 1993 for the $20 million amortization;
- Docket Nos. ER94020033, dated July 24, 1994 for the 20-year amortization; and
- Docket Nos. ER94020033, dated March 2, 1995 for the 8% interest.

Logan Arbitration
This represents costs that ACE incurred in settling the dispute regarding Logan Generating Company, L.P. ("Logan") method of billing. The arbitration arises over payments due under the purchase power agreement (PPA) with Logan. The PPA provides that an important variable in the formula for calculating the price of energy, called the Facility Heat Rate Multiplier (FHRM) is to be determined by a test conducted from time to time by Logan. The Company claimed that Logan's test procedures violated the PPA. The FHRM determined by this test shall be applied retroactively for billing purposes effective as of February 9, 2000.

NUG BGS Cost
This calculated BGS cost is deducted from the NUG Contract Cost. Refer to discussion of *Contracted NUG BGS Cost* in Chapter III Section A.

B. SCOPE AND OBJECTIVES

Scope

The scope of our examination of the NNC included a review, on a test basis, of ACE's transactions and supporting calculations and documentation for the year of August 1, 2002 through July 31, 2003 (Phase II transition period) as they relate to NNC costs and revenues presented in Exhibit IV-1.

Objectives

The objectives of this phase of our review involved assessing ACE's compliance with the pertinent Board Orders and examining the evidentiary documents supporting the deferred balance to ensure the deferred balance includes only those revenues and costs that are fairly stated, in all material respects and in compliance with the Board Orders. A summary of the procedures performed are as follows:

- Conducted interviews with ACE personnel responsible for NNC to update our understanding of the compliance requirements; the general, monitoring and specific controls and key processes and procedures in place;

- Obtained, reviewed and documented the pertinent Board Orders;

- Obtained the accounting reports detailing the revenues and program costs and compared to the Deferral Filing for accuracy and consistency;

- Reviewed the billing process – automated system ("C3") and manual billing preparation and meter reading system to update our understanding of their applications;

- Reviewed the billing and meter reading system documentation – flowcharts; interfaces; databases; file and table layouts, and processing logic;

- On a sample basis, performed tests of the customer billings and the meter reading;

- Referred to approved tariff rates effective at specific periods;

- Reviewed the results, management responses and the status of recommendations of prior audits performed by external and internal sources;

- On a sample basis, performed tests of NNC cost components to assess the calculation, timing, allocation and recording of expenditures in accordance with management controls and compliance with the Board Orders;

C. EVALUATIVE CRITERIA

Mitchell & Titus, LLP, used the following criteria to analyze ACE's NNC deferred balance:

- Does ACE have effective controls over compliance with the Board Orders and the amounts reported as deferred balances?

- Are the amounts presented as deferred balances in accordance with the Board Orders?

- Are the amounts presented as deferred balances fairly stated, in all material respects?

D. FINDINGS

None.

E. ADJUSTMENT

None.

F. CONCLUSION

In our opinion, ACE's NNC deferred balance is fairly stated, in all material respects.

G. OBSERVATIONS

1. Basis of recording the revenue for deferral is different from the basis adopted under the GAAP (see Chapter III for details).

2. In May 2003, ACE received the partial payment of $4.6 million relating to Logan arbitration which was applied to reduce the NUG deferred balance. (This was a finding in Phase I of the audit and it represents the receipt of partial payment).

3. In developing the net BGS price for the years 2000, 2001, 2002 and 2003, ACE used a slightly different and inconsistent approach from the Final Order (see Chapter III for details).

4. Logan arbitration cost of $2,518,000 continued to be included in the deferral but without specific Board Order. As the result of this arbitration (discussed in observation no. 2 above) is expected by ACE to be for the benefit of the ratepayers, the Board may allow this cost to be charged to deferral.

V. Market Transition Charge ("MTC") Deferral

A. BACKGROUND

The MTC is a recovery mechanism for the stranded costs of the utility. The difference between revenues generated and actual costs incurred by ACE for the MTC components described below are included in the Deferred Balance.

The following excerpts from The Board Orders are relevant to MTC components:

BGS Costs
"ACE shall apply both NUG contract power and to-be-divested owned generation power (prior to the closure of the sale of the generation assets) towards the BGS supply requirement, which power shall be credited at the net BGS price (the floor shopping credit less transmission cost, sales and use tax, line losses, ancillary services and capacity reserve margin)."[10]

Tariff rate reductions
"In summary, subject to the conditions embodied herein, the rate discounts provided by ACE, all stated relative to current rates, shall be at a minimum as follows:

August 1, 1999	5 %
January 1, 2001	7%
August 1, 2002	10.2%"[11]

Generation related stranded costs
"The Company has made a business decision to divest its interests in the B.L. England, Keystone, Conemaugh, Peach Bottom, Salem and Hope Creek generating stations. Upon approval of the divestiture by the Board, the net divestiture proceeds as determined by the Board will be used to determine the Company's generation related stranded costs. Generation related stranded costs shall mean the excess of net book value as of the closing date(s) of the sale(s) over net divestiture proceeds. The net book value shall reflect the net investment in each facility, reflective of the gross investment less depreciation reserve less accumulated deferred income tax, and investment tax credits, if appropriate, as of the closing date(s). The tax impacts with respect to taxable gains and/or losses will be considered in calculating net stranded costs. Net divestiture proceeds are defined as the excess of the selling price(s) of the generating assets over the transaction costs incurred by the Company. The transaction costs shall be reasonable, verifiable and necessary, and shall include (but not necessarily be limited to) sales and transfer taxes, state, federal and local taxes, as well as reasonable consultants fees, broker commissions, legal fees, investment banking fees, title transfer fees, real estate transfer and related costs, mortgage and financing costs, real estate taxes, transportation and system-separation costs (including outside contractor, engineering, purchased materials and labor costs) associated with the divestiture activities, paid overtime and out-of-pocket expenses for Company employees associated with the divestiture activities, and any arrangements to address direct and

[10] Final and Decision Order, In the Matter of Atlantic City Electric Company's Rate Unbundling, Stranded Costs and Restructuring Filings; Docket Nos. EO97070455, EO97070456, EO97070457; Signed March 30, 2001; Page 87; Paragraph 7.

[11] Final and Decision Order, In the Matter of Atlantic City Electric Company's Rate Unbundling, Stranded Costs and Restructuring Filings; Docket Nos. EO97070455, EO97070456, EO97070457; Signed March 30, 2001; Page 96; Paragraph 46.

indirect employee impacts from the divestiture including retirement, severance and any other employee-related benefit costs, as shall be determined by the Board."[12]

Net Divestiture Proceeds
"Final determination by the Board of the net divestiture proceeds shall be undertaken only upon the completion of the transfer of all of the generation assets listed in paragraph 17 to each purchaser thereof, as set forth herein.

a. Such final determination shall be made within a separate divestiture proceeding, to be filed by ACE pursuant to standards to be set by the Board, subject to the terms of this Order. The final determination of the net divestiture proceeds shall include a determination of actual selling price(s), book value(s) costs."[13]

To-Be Divested ("Owned Generation") Revenue Requirements
During the period between August 1, 1999 and completion of the divestiture of generation assets, MTC revenues shall be applied to owned generation revenue requirements, including continued depreciation of assets, and return on investment, operating and maintenance expenses and fuel expenses, and, between the time of divestiture closing and time of securitization closing, MTC revenues shall be applied to provide a return on the net owned generation stranded costs at 13.0% pre-tax.[14]

Restructuring-related items ("Transition Costs")

"The Company will incur additional costs for restructuring-related items that are capital in nature, the estimated costs of which are set forth in Schedule C of the Stipulation."[15]

"The recovery of restructuring-related costs of an operating nature other than consumer education cost, as listed in Schedule D, of the Stipulation, via the MTC shall be subject to reasonableness and verification review by the Board, and shall be net of other sources of recovery towards such costs, including Third Party Supplier Agreement fees"[16]

Tax on divestiture proceeds
"For ratemaking purposes, all tax expenses for the computation of divestiture proceeds, MTC revenues and NUG buyouts or buydowns shall be determined on a utility standalone basis, and not by imputing the tax effects of a consolidated return."[17]

Deferred accounting basis
"In setting the annual level of charges for BGS during the Transition Period, for any MTC that continues beyond the Transition Period, and for the SBC, NNC and the TBC, the Company will utilize a methodology similar to that currently used for setting its Energy Adjustment clause charges. The BGS, SBC, NNC, MTC and TBC components will be reviewed annually, based upon projections of costs and of sales. Actual costs will be accounted for on a deferred accounting basis, and when the BGS, SBC, NNC, MTC and TBC are set in the following year, each of those rate components will be set to recover any underrecovery in the Deferred Balance, as well as the projected costs for the upcoming year."[18]

[12] Final and Decision Order, In the Matter of Atlantic City Electric Company's Rate Unbundling, Stranded Costs and Restructuring Filings; Docket Nos. EO97070455, EO97070456, EO97070457; Signed March 30, 2001 ("Final and Decision Order"; Page 89; Paragraph 17.
[13] Final and Decision Order; Page 89; Paragraph 18a.
[14] Final and Decision Order; Page 92; Paragraph 22.
[15] Final and Decision Order; Page 91; Paragraph 24.
[16] Final and Decision Order; Page 91; Paragraph 25.
[17] Final and Decision Order; Page 94; Paragraph 36.
[18] Final and Decision Order, In the Matter of Atlantic City Electric Company's Rate Unbundling, Stranded Costs and Restructuring Filings; Docket Nos. EO97070455, EO97070456, EO97070457; Signed March 30, 2001; Page 95; Paragraph 43.

Sale of Nuclear Assets
"In addition, consistent with the Board's prior Orders relating to the sale of a utility's generating assets, the Board HEREBY DIRECTS the Company to file for a private letter ruling with the IRS regarding the treatment of the federal income tax benefits associated with the divested assets, such as the Investment Tax Credit ("ITC"), Excess Deferred Income Taxes ("EDIT") associated with changes in the corporate tax rate, and Accumulated Deferred Income Taxes ("ADIT") associated with timing differences between tax and book accounting, namely, timing differences associated with accelerated tax depreciation."[19]

TELP Lease
"All monthly lease revenues shall be immediately credited against ACE's MTC deferred balance. The Board FURTHER DIRECTS that the one-time credit of $5,000 also be credited to the MTC deferred balance at the time of the closing of the transaction."[20]

Exhibit V-1 below shows the balances of MTC components as at July 31, 2003:

Exhibit V-1
Market Transition Charges
Over/(Under) Recovery
(Dollars in Thousands)

MTC Components	Beginning Balance at August 1, 2002	Revenues	Cost	Ending Balance at July 31, 2003
Revenues:				
MTC Revenues	**$92,211**	**$17,773**		**$109,984**
GRFT Recovery Revenues	**6,156**	**549**		**6,705**
GRFT Audit Settlement	**1,200**			**1,200**
Total MTC Revenues	**99,567**	**18,322**		**117,889**
MTC Costs:				
Consolidated Billing Implementation	**(2,627)**		**(933)**	**(3,560)**
Transition Costs Amortization	**(6,666)**		**(2,254)**	**(9,020)**
Transition Operating Costs	**(5,125)**		**(921)**	**(6,046)**
TELP Lease	**13**		**44**	**57**
To-Be-Divested Units Revenue Requirement ("Revenue Requirement")	**(611,150)**		**(155,243)**	**(766,393)**
Less To-Be-Divested Units included in BGS Costs	**429,563**		**101,656**	**531,219**
Total MTC Costs	**(193,475)**		**(57,651)**	**(135,854)**
Audit adjustment	**2,617**			**2,617**
Net MTC Deferral	**($93,908)**	**$18,322**	**($57,651)**	**($133,237)**

[19] Energy Decision and Order – Sale of Nuclear Assets; Docket No. EM99110870; Signed July 21, 2000; Page 22, 3rd Paragraph and Page 23;
[20] Final Approval of Transfer of Certain Non Utility Property to TELP; Signed December 19, 2001; Docket No. EM00060384;Page 3

Source: ACE's August 30, 2002 Deferral Filings, excluding interest calculated separately on the total deferred balances (see Chapter VII).

MTC Revenues
This represents the revenues based on approved tariff rates and the kilowatt hours consumed by ratepayers. As at July 31, 2003, ACE implemented each rate reduction at the following effective dates:

August 1, 1999	5% from April 1997 rates
January 1, 2000	1%
January 1, 2001	1%
August 1, 2002	3.2%

GRFT Recovery Revenues
This represents the completed amortization of the additional GRFT (included in the Regulatory Asset Recovery Charge) as approved by the Board's Order dated October 20, 1992, in Docket No. ER90091090J. The Board required that at the end of the ten-year amortization period, either an adjustment to rates be made or deferred accounting be implemented to reflect the cessation of the amortization. In December 2001, the recovery of the amortization of this regulatory asset was completed. Effective January 2002, the revenues collected through the RARC related to the amortization of the additional one-time GRFT payment have been applied to the calculation of ACE's MTC deferred balance.

GRFT Audit Settlement
This represents the reduction of the deferred balance by $1.2 million in accordance with the Settlement of the Board's Audit A-2859 adopted by the Board's Order dated June 27, 2000, in Docket No. EA00050299.

Consolidated Billing Implementation
The expenses incurred related to enhancement of the billing systems needed as a result of restructuring.

Transition Costs Amortization
This represents the amortization based on the estimated capital related transition costs set forth in Schedule C of the Stipulation of Settlement. Transition costs are amortized over a period of eight (8) years. A thirteen percent (13%) pre-tax return is calculated on the unamortized balance.

Transition Operating Costs
This represents the on-going transition operating costs related to expenses for customer care, balancing and settlement, load profiling and regulatory proceedings set forth in Schedule D of the Stipulation of Settlement.

TELP Lease
This represents the credit of monthly lease payments as well as the one-time credit to the deferred balance in accordance with the Board's Order dated December 19, 2001, in Docket No. EM00060384.

Revenue Requirement
The revenue requirement from owned generation assets is based on the investment with the 13% pre-tax return ("return on rate base amounts") and operating costs ("operating income requirements"). This also includes the return on nuclear stranded costs after divestiture.

The owned generation assets include the following steam and nuclear plants:

Steam Plants:
- BL England
- Keystone
- Conemaugh

Nuclear Plants:
- Salem
- Peach Bottom
- Hope Creek

The 13% pre-tax return is applied to the net owned generation investment and post-divestiture stranded costs.

The net rate base includes the stranded costs of the nuclear plants sold in October 18, 2001. The net divestiture proceeds as determined by the Board are used to determine the Company's generation related stranded costs. Generation related stranded costs represent the excess of net book value as of the closing date (October 2001) of the sale over net divestiture proceeds. The net book value reflects the net investment in each facility, reflective of the gross investment less depreciation reserve less accumulated deferred income tax as of the closing date. The tax impacts with respect to taxable gains and/or losses are considered in calculating net stranded costs.

The investment cost uses the same methodology in calculating the net rate base, as follows:
- ⇒ Plant cost
- ⇒ Depreciation reserve
- ⇒ Deferred tax benefits
- ⇒ Fuel inventories
- ⇒ Materials and supplies inventories
- ⇒ Cash working capital
- ⇒ Allocation of consolidated tax benefits from losses incurred by ACE's affiliated companies

The operating income requirement includes the following:
- ⇒ Operating and maintenance expense
- ⇒ Fuel expense
- ⇒ Depreciation
- ⇒ Tax benefits

Tax benefits on the operating income were calculated first to cover the benefits from these expenses and recalculated to the pre-tax amount.

To-Be-Divested Units BGS Costs

This calculated BGS cost is deducted from the MTC Revenue Requirement. Refer to discussion of *Contracted NUG BGS Cost* in Chapter III Section A.

B. SCOPE AND OBJECTIVES

Scope

The scope of our examination of the MTC included a review, on a test basis, of ACE's transactions, and supporting calculations and documentation for the period August 1, 2002 through July 31, 2003, (Phase II transition period), as they relate to MTC costs and revenues presented in Exhibit V-1.

Objective

The objectives of this phase of our review involved assessing ACE's compliance with the pertinent Board Orders and examining the evidentiary documents supporting the deferred balance to ensure the deferred balance includes only those revenues and costs that are fairly stated, in all material respects and in compliance with the Board Orders. A summary of the procedures performed are as follows:

- Conducted interviews with ACE personnel responsible for MTC to update our understanding of the compliance requirements; the general, monitoring and specific controls and key processes and procedures in place;

- Obtained, reviewed and documented the pertinent Board Orders;

- Obtained the accounting reports detailing the revenues and program costs and compared to the Deferral Filing for accuracy and consistency;

- Reviewed the billing process – automated system ("C3") and manual billing preparation and meter reading system to update our understanding of their applications;

- Reviewed the billing and meter reading system documentation – flowcharts; interfaces; databases; file and table layouts, and processing logic;

- On a sample basis, performed tests of the customer billings and the meter reading;

- Referred to approved tariff rates effective at specific periods;

- Reviewed the results, management responses and the status of recommendations of prior audits performed by external and internal sources;

- On a sample basis, performed tests of MTC cost components and revenue requirements to assess the calculation, timing, allocation and recording of expenditures in accordance with management controls and compliance with the Board Orders.

C. EVALUATIVE CRITERIA

Mitchell & Titus, LLP, used the following criteria to analyze ACE's MTC deferred balance:

- Does ACE have effective controls over compliance with the Board Orders and the amounts reported as deferred balances?

- Are the amounts presented as deferred balances in accordance with the Board Orders?

- Are the amounts presented as deferred balances fairly stated, in all material respects?

D. FINDING

None.

E. ADJUSTMENT

None.

F. CONCLUSION

In our opinion, ACE's MTC deferred balance is fairly stated, in all material respects.

G. OBSERVATIONS

1. Basis of recording the revenue for deferral is different from the basis adopted under the GAAP (see Chapter III for details).

2. The investment tax credits as of August 1, 1999, in the aggregate amount of approximately $8.6 million[21], relating to the nuclear plants, were not deducted from the calculation of the stranded costs. The ruling requests that the Internal Revenue Service ("IRS") determine whether the nuclear facilities ceased to be "public utility property" on August 1, 1999, the Virtual Close Date (October 2000) or Actual Sale Date (October 2001). Upon receipt of the IRS ruling to determine the treatment, the amount will be re-determined depending on the relevant date and, when appropriate, ACE will update the calculation of the stranded costs.

[21] From ACE ruling request filed to the Internal Revenue Service (IRS).

The estimated adjustment to the MTC deferral is uncertain pending the outcome of the IRS ruling. (This observation is from Phase I of the audit).

During Phase I, it was established that ACE should file a ruling request to confirm whether the nuclear facilities ceased to be "public utility property" on August 1, 1999, the Virtual Close Date (October 2000) or Actual Sale Date (October 2001).

A determination as to whether there was need for an adjustment to be made was dependant on the outcome of the IRS Ruling.

As per ACE, the Company did file a ruling request on December 12, 2002. After researching this matter, it has been determined that the Internal Revenue Service (IRS) will not be issuing a ruling letter on this issue. The IRS will, however, issue guidance for utilities on the treatment of these deferred tax amounts on the stranded cost balance.

3. The restructuring-related capital expenditures ("transition costs) were based on the estimated costs set forth in Schedule C of the Stipulation of Settlement. These estimated amounts were used in the amortization of transition costs. ACE has submitted the actual amounts as part of its deferral rate case and may consider the true-up or reconciliation to be reflected in the deferral for Phase II.

   During Phase II, the Company continued to amortize the estimated costs into the MTC Deferral. As per ACE, the difference between the amount being amortized and the actual capital costs for the items on Schedule C of the Stipulation will need to be added to the deferred balance when a final determination of the recoverable Transition Period deferred balance is made.

   The impact on deferred balances is immaterial (monthly amortization of transition cost based on estimated amount is (188,000). This was a finding in Phase I.

4. Compensation benefits of 30% of the basic salaries were applied for the years 2000, 2001, 2002 and 2003. The 30% was an estimate although there are certain months where the actual benefits incurred were less than 30%.

   The selected month showed that the actual benefits incurred represent 25.8% of the basic salaries. No quantification of the difference was performed as the difference is estimated to be immaterial (e.g. Estimated overstatement is $30,000 for the 4.2% on the average monthly benefits for B.L. England plant (representing the highest plant cost) amount to $700,000 out of the average monthly operating and maintenance cost of $3 million.)

   Per ACE, the actual rate for 2003 was 25%. Benefit expenses were adjusted downward in June of 2003. A portion of the adjustment was allocated to ACE-TUB based on people count. The credits for ACE-TUB were then allocated to BL England, Deepwater and the jointly owned units. ACE stated that the portion allocated to BL England and the jointly owned units was appropriately considered in the deferral.

VI. Societal Benefits Charge (SBC) Deferral

A. BACKGROUND

This mechanism is designed to recover the costs associated with Board-approved programs implemented to achieve specific public policy goals. The difference between actual costs incurred and revenues received by ACE for the SBC components described below, are included in the Deferred Balance.

The Final Decision and Order provides for the following:

SBC components
"Consistent with N.J.S.A. 48:3-60, the Company will establish a Societal Benefits Charge. The SBC will include costs related to: (1) social programs, (2) nuclear plant decommissioning costs, (3) Demand Side Management programs, and (4) consumer education expenses." (page 94, paragraph 34)

Tariff rates
"The SBC will be set at the level of costs for the above items already in rates as of the date of the Board's Summary Order in this matter." (page 94, paragraph 35)

Deferred accounting basis
"In setting the annual level of charges for BGS during the Transition Period, for any MTC that continues beyond the Transition Period, and for the SBC, NNC and the TBC, the Company will utilize a methodology similar to that currently used for setting its Energy Adjustment clause charges. The BGS, SBC, NNC, MTC and TBC components will be reviewed annually, based upon projections of costs and of sales. Actual costs will be accounted for on a deferred accounting basis, and when the BGS, SBC, NNC, MTC and TBC are set in the following year, each of those rate components will be set to recover any under recovery in the Deferred Balance, as well as the projected costs for the upcoming year." (page 95, paragraph 43)

- Social Programs: costs associated with existing social programs including uncollectible customers' accounts (UNC), and the Universal Service Fund ("USF"). Note: There are no USF costs incurred by ACE.

  Under Section 6 of EDECA, "An electric public utility may continue to offer Customer Account Services on a regulated basis subsequent to the effective date of this act."

  The Uncollectible Account Deferral accounting requires an uncollectible reserve account balance to be determined each month. This reserve balance is based on the assumed level of loss percentage applied to the month end aging schedule of Customer Accounts Receivables. The required reserve is compared to the actual, pre-closing reserve (which has been reduced by the month's write-offs and increased by write-off recoveries) and an adjustment is booked to bring the reserve to the required level.

- Nuclear Decommissioning (ND): costs associated with nuclear decommissioning funding requirements necessary to meet Federal and/or State requirements to decommission nuclear units.

Pursuant to N.J.A.C. 14: 5A-2.1, every New Jersey electric public utility having an ownership in one or more nuclear generating stations is required to file with the Board by January 1, 1996, and every four years thereafter, unless otherwise directed by the Board, a "Decommissioning Cost Update" (Update) for the Board's consideration. The primary purpose of N.J.A.C. 14:5A (Chapter 5A) is to assure that secure and adequate funds are provided for the decommissioning of nuclear electric generating facilities. Accurate and timely cost estimates are required for the Board to balance the need for providing sufficient funds for decommissioning and the need to fairly assess current ratepayers for their share of these costs. Decommissioning is the process by which a nuclear facility is safely removed from service and radioactive materials are disposed of without incurring unreasonable risk to public health and safety. The NRC[22] requires that a nuclear facility must be decommissioned once it has reached the end of its useful life.

- Demand Side Management (DSM): DSM costs associated with rebates, grants, program implementation, direct marketing, hardware, administration, measurement and evaluation, customer communication and education, market research, and advertising.

  The Board's DSM regulations require that utilities provide several core programs including:

  ⇒ Home Energy Savings Program (HESP)
  ⇒ Low Income Direct Grant and Seal-up Program
  ⇒ Commercial and Apartment Conservation Service
  ⇒ Energy Efficient New Construction
  ⇒ Information Programs (to foster conservation awareness)
  ⇒ Educational Programs (to present in schools)

- Consumer Education: Board-approved restructuring costs such as educating residential, small business, and special needs consumers about the implications for consumers of the restructuring of the electric power industry.

[22] Nuclear Regulatory Commission

Exhibit VI-1 below shows the balances of SBC components as at July 31, 2003:

Exhibit VI-1
Societal Benefit Charges
Over/(Under) Recovery
(Dollars in Thousands)

SBC Components	Beginning Balance	Revenues	Cost	Ending Balance
DSM	$4,274	$5,704	($9,294)	$ 684
ND	22,118	8,017	0	30,135
UNC	(9,024)	6,297	(5,389)	(8,116)
Total	$17,368	$20,018	($14,683)	$22,703

Source: ACE's Response to Data Request, excluding interest calculated separately on the total deferred balances (see Chapter VII).

There were no consumer education costs incurred by ACE as at July 31, 2003.

SBC tariff rates are as follows:

Exhibit VI-2
SBC Tariff Rates

SBC Components:	DSM	ND	UNC
$/KWH	$0.000633	$0.000889	$0.000699

Source: ACE's Tariff Rate for Electric Service

1. DSM

- DSM revenues were based on ACE's tariff rates approved by the Board prior to transition period (see Exhibit VI-2 above).
- DSM expenses represent valid expenses related to the programs under the Board's DSM regulations.

2. ND

- ND revenues were based on ACE's tariff rates approved by the Board prior to transition period (see Exhibit VI-2 above).
- No ND expenses are recorded during the transition period.
- Any over-recoveries are included in the revenues reported in the deferred balances.

⇒ The tariff rate for nuclear decommissioning ($0.000889/kwh) was set to recover the annual expense of $6.4 million paid to the trust fund. The tariff rate has been constant. As kilowatt hours continue to grow during the transition period, nuclear decommissioning revenues generated were greater than the $6.4 annual payment to the trust fund.

⇒ During the period from August 1, 1999 thru July 31, 2002, ND revenues based on flat tariff rates and reported as deferred amounted to $22 million

3. UNC

- Revenues stated to recover uncollectible balances were based on ACE's tariff rates approved by the Board prior to the transition period (see Exhibit VI-2 above).

- ACE determined uncollectible expenses as follows:

ACE's credit and collection department is responsible for the collection and determination of delinquent accounts except for the following:

⇒ Residential accounts are referred to a collection agency 60 days after the final bill is mailed.

⇒ Some customers such as nursing homes, daycare centers and hospitals are referred to ACE's commercial account representative.

ACE's methodology of estimating the ultimate collection/non-collection of accounts, the collection process and actual write-off process is a six-to-nine- month process.

Prior to October 2001, the uncollectible expenses were recognized based on the actual monthly write-offs, net of recoveries. Thereafter, the uncollectibles were based on the change in the required reserve balance. This reserve balance is based on the assumed level of loss percentage applied to the month end aging schedule of customer accounts receivables. ACE applied different percentages depending on the status and age of the accounts receivables. These percentages were estimated based on the historical write-offs during the years 1998-2000 adjusted by the increased level of actual write-offs in subsequent years. The required reserve is compared to the actual, pre-closing reserve (which has been reduced by the month's write-offs and increased by write-off recoveries) and an adjustment is booked to bring the reserve to the required level.

B. SCOPE AND OBJECTIVES

Scope

The scope of our examination of the SBC included a review, on a test basis, of ACE's transactions, and supporting calculations and documentation for the period August 1, 2002 through July 31, 2003, (Phase II transition period), as they relate to SBC costs and revenues presented in Exhibit III-1.

Objective

The objectives of this phase of our review involved assessing ACE's compliance with the pertinent Board Orders and examining the evidentiary documents supporting the deferred balance to ensure the deferred balance includes only those revenues and costs that are fairly stated, in all material respects and in compliance with the Board Orders. A summary of the procedures performed are as follows:

- Conducted interviews with ACE personnel responsible for DSM, Nuclear Decommissioning and Uncollectibles to update our understanding of the compliance requirements; the general, monitoring and specific controls and key processes and procedures in place;
- Obtained, reviewed and documented the pertinent Board Orders;
- Obtained the accounting reports detailing the revenues and program costs and compared to the Deferral Filing for accuracy and consistency;
- Reviewed the billing process – automated system ("C3") and manual billing preparation and meter reading system to update our understanding of their applications;
- Reviewed the billing and meter reading system documentation – flowcharts; interfaces; databases; file and table layouts, and processing logic;
- On a sample basis, performed tests of the customer billings and the meter reading;
- Referred to approved tariff rates effective at specific periods;
- Reviewed the results, management responses and the status of recommendations of prior audits performed by external and internal sources;
- On a sample basis, performed tests of DSM program expenditures to assess the calculation, timing, allocation and recording of expenditures in accordance with management controls and compliance with the Board Orders;
- Reviewed the basis of recording uncollectible expenses;

C. EVALUATIVE CRITERIA

Mitchell & Titus, LLP, used the following criteria to analyze ACE's SBC deferred balance:

- Does ACE have effective controls over compliance with the Board Orders and the amounts reported as deferred balances?

- Are the amounts presented as deferred balances in accordance with the Board Orders?

- Are the amounts presented as deferred balances fairly stated, in all material respects?

D. FINDING

As of July 31, 2003, the allowance for doubtful accounts amounted to $7,856,233. This amount exceeded by $1,485,327 compared to the required allowance of $6,370,906 based on the estimated loss percentages (average of 7% from the sample months December 2002 and July 2003) of the month end aging accounts receivable.

Although ACE used a conservative approach in establishing a larger reserve balance, there is uncertainty related to the estimated reserve as the historical information on non-collection demonstrated a lower amount. As a result, ACE may have to adjust the reserve balance once the actual amount of write-off or percentage of non-collection for July 2003 and future periods is determined.

E. CONCLUSION

In our opinion, except for the uncertainty of the matter noted above, ACE's SBC deferred balance is fairly stated, in all material respects.

F. OBSERVATIONS

1. Basis of recording the revenue for deferral is different from the basis adopted under the GAAP (see Chapter III for details).

2. The costs incurred for CEP and USF amounting to $3.4 million and $0.6 million, respectively, were not included in the SBC deferral as at July 31, 2002. These costs were being held in deferred orders for future recovery. ACE has requested approval of its proposed recovery of all CEP and USF related costs incurred through the transition period.

   The Board addressed the treatment of costs incurred for CEP and USF in its Final Decision and Order.

   The CEP cost recovery was approved by the Board. ACE has been directed to recalculate interest accrued on the CEP costs deferred during the transition period so as to reflect the change in the interest calculation methodology.

   With respect to the USF costs, the Board adopted the RPA's recommendation to offset, with a like portion of the overrecovered SBC deferred balance, the $.6 million of ACE's USF costs incurred and projected to be incurred and deferred during the transition period. ACE was directed to recalculate the interest accrued on the deferred USF costs during the transition period to reflect the change in the interest calculation methodology.

Per ACE, the calculation of interest during the Transition Period is under Notice of Appeal. This Notice was filed in August 2004.

VII. Interest on Total Deferred Balances

A. BACKGROUND

Interest is adjusted on August 1 of each year of the Transition Period and accrued on any under or over recovered balances. The interest rate is based on seven year constant maturity treasuries as shown in the Federal Reserve Statistical Release on or closest to August 1 of each year plus sixty basis points.[23]

Interest rates used during Phase II was 4.48%. M&T traced the interest rates used to the Federal Reserve Statistical Release on or closest to August 1, 2002 plus sixty basis points and compared with the interest rates used by ACE. In addition, M&T recalculated the interest following the method applied by ACE.

The interest calculated on the total deferred balances as of July 31, 2003 amounted to $5,193,174.

B. FINDING

During the transition period, August 1, 1999 to July 31, 2003, ACE did not compute the interest on the deferred balances on an after-tax basis. Had ACE calculated the interest on an after-tax basis, the cumulative interest would have been $5,193,174 compared to $8,779,669 which ACE applied to the deferred balance.

C. OBSERVATIONS

1. ACE applied interest on the average monthly under or over recoveries of all the deferred balance components.

   The Company maintains that the interest calculation has been performed in accordance with existing Board regulations as published in N.J.A.C. 14:3-13 (Interest on Deferred Balances of LEAC, Levelized Gas Adjustment Clauses, Purchased Water Sewerage Treatment Adjustment Clauses).

The method of calculation for the deferred balances during the transition period should be approved by the Board.

Pursuant to the Final Decision and Order dated July 21, 2003, ACE was directed to recalculate the interest accrued on its post August 1, 1999 deferred balances on a net of tax basis. As per ACE, a Notice of Appeal was filed, in August 2004, with the Appellate Division of the Superior Court of New Jersey on this issue.

[23] Final and Decision Order, In the Matter of Atlantic City Electric Company's Rate Unbundling, Stranded Costs and Restructuring Filings; Docket Nos. EO97070455, EO97070456, EO97070457; Signed March 30, 2001; Page 82.

2. ACE used the interest rate based on the average business days for the month of August, 2002 instead of the interest rate on or closest to August 1, 2002. Difference is very minimal as shown below:

Date	Interest Rate Plus 60 Basis Points		Difference Over (under)
	Monthly Average Rate	On or closest to August 1	
August 2002	4.48	4.64	(0.16)

Prudence Review
Barrington-Wellesley Group, Inc.

CHAPTER VIII. BGS PROCUREMENT PRUDENCE

A. BACKGROUND

In Chapter VIII of the Phase I Report, BWG concluded that: "Throughout the first three years of the transition period, ACE had limited in-house staff and did not have adequate analytical resources to consistently make effective decisions regarding BGS supply procurement." For Year Four, ACE participated in a statewide competitive bidding process which procured the BGS supply for all four electric distribution companies (EDCs) in New Jersey. **Exhibit I-1** provides a timeline of the key events that led to the statewide auction.

Exhibit I-1
BGS Procurement Year Four Timeline

June 6, 2001	Board directed the EDCs to file proposals to implement an RFP process for Year Four BGS.
June 29, 2001	EDCs filed a generic proposal recommending a simultaneous, multi-round, descending clock auction format. The EDCs developed the proposal with the assistance of its consultant, National Economic Research Associates (NERA).
August 29, 2001	Staff recommended and the Board approved hiring Charles River Associates (CRA) to review the EDCs' proposal and provide oversight of the auction process.
December 11, 2001	Board approved with modifications and clarifications, the EDC's BGS auction proposal, and directed the EDCs to make compliance filings on this matter consistent with Board Order dated December 11, 2001, no later than December 12, 2001.
December 12, 2001	EDCs jointly filed a revised Proposal for Auction of Basic Generation Service Rights and Responsibilities, Parts I and II, and Part III, a revised BGS Master Agreement. The EDCs also jointly filed amended BGS Auction Proposal Confidential Information.
December 14, 2001	Board approved the EDC's Compliance Filing, finding it to be consistent with the Board's Order and directed the EDCs to provide supplemental attachments B, C and D to the BGS Master Agreement within five business days.
December 18, 2001	EDCs filed Compliance filing incorporating the final amendments.
February 4 – 13, 2002	The auction was held. It was administered by NERA and was continuously monitored by BPU Staff from the Chief Economist's Office and the Division of Energy, and by the Board's consultant, CRA.
February 15, 2002	The Board certified the final results of the BGS auction in their entirety.

Under the EDC proposal, Year Four BGS supply would be procured through a simultaneous statewide competitive bidding process, the Simultaneous Descending Clock Auction (SDCA) process, conducted under the supervision of the Board. Bidders would bid for the right to serve full requirements tranches (or slices) of BGS load. Tranches would be identical and uniform within each EDC and would represent a fixed percentage of each EDC's total BGS load. Tranches would be set so that the size of the obligation for a tranche for all EDCs would be equal. Since each tranche would represent a small equal percentage of an EDC's total BGS load, rather than a specific block of customers, the size of each tranche would only be affected by that percentage of any change in total BGS load. **Exhibit I -2** provides the tranche sizes and numbers:

Exhibit I-2

Tranche Sizes and Numbers

	BGS Peak Load Share (MW)	Number of Tranches	Size of tranche (MW)	Size of tranche (% of BGS Peak Load Share)
PSE&G	9,608.4	96	100.09	1.042%
JCP&L	5,146.1	51	100.90	1.96
AECO (1)	2,369.7	19	98.81	4.17
RECO	440.0	4	110.00	25.0
Total	**17,564.2**	**170**		

(1) AECO had 24 tranches in total. It served five of its own tranches and put 19 tranches up for bid.

Source: Statewide Auction of New Jersey Basic Generation Service (BGS) Bidder Information Material.

A full requirements tranche meant that providers would be responsible for fulfilling all the requirements of a PJM Load Serving Entity (LSE) including capacity, energy, ancillary services, transmission and any other services as may be required by PJM. Winning bidders would fulfill these requirements for the percentage of each EDCs load that they serve. Additionally, the providers assumed any risk of migration between BGS and Third Party Suppliers (TPS). To minimize costs and risks, the EDCs proposed changes to the switching rules whereby a customer on BGS on August 1, 2002 would be committed to remain on BGS through July 31, 2003. With this change, bidders were no longer subject to the risk that Commercial & Industrial (C&I) customers would migrate into BGS during higher cost peak periods and leave during lower cost non-peak periods.

Subsequent to the Board's approval of the EDC's proposal in December, 2001, the auction proceeded in a series of rounds in February 2002. The auction began on February 4, 2002 and ended in round 73 on February 13, 2002. The auction was administered by NERA and was continuously monitored by BPU Staff from the Chief Economist's Office and the Division of Energy and by the Board's consultant, CRA. The auction filled all of the EDC's 170 tranches. In each round, bidders stated how many tranches of each EDC they stood ready to serve at the prices in force during that round of the auction. As the auction progressed, prices gradually fell until the amount to which bidders subscribed just equaled the load to be procured. The annual BGS load was divided into four products, one product representing the BGS load of one EDC. An auction participant could bid to supply a portion of the load (number of tranches) of one or more EDC. At the end of the bidding of a round, the Auction Manager (NERA) reduced the price for the tranches of an EDC by a decrement if the bidders together subscribed to more tranches for that EDC than were available. If the tranches of an EDC were just subscribed or were under-subscribed, the announced price of a tranche for that EDC did not change. The auction continued and the prices continued to tick down until, for each EDC's system, the total number of tranches subscribed fell to the point where it equaled the number available. The prices as the auction closed were the clearing or final auction prices. The bidders that hold the final bids when the auction closed were the winning bidders. All winners for an EDC's tranches received the same final price for that EDC.

If the target auction volume was restricted to less than 100 percent of the BGS load for all EDCs, each EDC would have implemented a Contingency Plan for the remaining tranches. Under the Contingency Plans, the EDCs would have purchased necessary services including installed capacity, energy and ancillary service through PJM-administered markets.

On February 15, 2002 the Board certified the final results of the BGS auction in their entirety and approved the following closing prices as indicated in **Exhibit I-3** for each EDC:

Exhibit I-3
Approved Closing Prices
(Cents per kilowatt)

EDC	Closing Price
PSE&G	5.11
JCP&L	4.87
AECO	5.12
RECO	5.82

Source: February 15, 2002 Order I/M/O The Provision of Basic Generation Service Pursuant to The Electric Discount And Energy Competition Act, N.J.S.A. 48:3-49 et seq. BGS Auction Results (Data Response DA-PS-28).

The Board, in its July 2003 Summary Order, identified several items as follow-up issues from Phase I. Among those items needing further review was $3.5 million in BGS administrative costs.[24] These were costs associated with obtaining electric supply, through competitive bidding and auction processes (Requests for Proposals or RFPs), to provide electric supply to customers who did not chose an alternative supplier. In the Phase I report, BWG concluded that RFPs I and II were deficient. During the Phase I Deferred Balance Proceeding, a BWG witness testified that ACE should not be compensated for the administrative costs associated with those two RFP processes. The Staff subsequently directed BWG to determine the administrative costs associated with RFPs I and II.

[24] NJBPU Order Clarifying Issues and Directing the Filing of Supplemental Testimony, December 5, 2003, Docket Nos. ER02080510, et. al., page 3.

In the Phase I report, BWG found that ACE's use of Deepwater and Combustion Turbines (CT) capacity for basic generation supply (BGS) in the August 1999 through July 2000 period was not in compliance with the Final Order that requires the capacity to be offered to PJM at market prices. Paragraph 21 of the Final Order states:

> As a condition of the transfer during the Transition Period, ACE's affiliate shall offer capacity from the transferred units for sale within the PJM control area at market prices, and if the capacity is sold outside the PJM control area, the Company's affiliate shall make the capacity subject to recall by PJM during system emergencies.

While the sale of the capacity to ACE was within the PJM control area, BWG found that the recorded cost of the 1999 capacity from these units did not reflect market prices. The 1999 capacity from these units was priced at $79.90 per MW, based on the price of an annual capacity purchase for the PJM planning period from June 1999 though May 2000. According to ACE personnel, the 2000 Deepwater and CT capacity costs were trued up to reflect PJM capacity prices and appropriate volumes in a November 2000 adjustment; however no similar adjustment was made for the 1999 capacity costs. While BWG did not review details of the adjustment during Phase I, it recommended that ACE make an adjustment to reduce the 1999 Deepwater and CT capacity costs to reflect PJM capacity prices. BWG further recommended that as part of this adjustment, ACE should demonstrate that the capacity provided by these units was needed for BGS in the period August 1999 to July 2000, and exclude the costs associated with any capacity that was not needed.

B. SCOPE AND OBJECTIVES

We reviewed ACE's BGS Procurement Process for the period August 1, 2002 through July 31, 2003. We also reviewed BGS administrative costs and Deepwater and CT capacity costs. In addition we analyzed the difference between the actual cost of ACE's BGS purchases during years one to three and the cost of energy and capacity based on concurrent PJM market prices. The objective of our review was to determine the prudence of the utility's procurement efforts, consistent with applicable law.

C. EVALUATIVE CRITERIA

BWG used the following criteria in its evaluation of ACE's BGS Procurement:

- Did ACE develop its BGS supply program for Year Four of the transition period in accordance with the requirements of the Board's August 1999 Final Decision and Order?
- Did the auction process accomplish its objectives?
- Did ACE manage its participation in the BGS auction in an effective manner?
- What portion of BGS administrative costs were related to RFP 1 and RFP 2?
- Did the recorded costs for Deepwater and CT capacity reflect needed capacity quantities at market prices?

D. FINDINGS AND CONCLUSIONS

1. ACE participated in the development of an innovative approach to procuring BGS supply for Year Four for both itself and for the other EDCs in New Jersey in order to comply with the requirements of the Board's August 1999 Final Decision and Order.

- In concert with NERA and the other EDCs, ACE participated in the development of a simultaneous statewide competitive bidding process, the SDCA.
- Each winning bidder was required to assume PJM Load Serving Entity (LSE) responsibility for the portion of BGS Load it was to serve. In exchange for taking on the obligations of BGS supply, winning bidders were granted a prorated share of the capacity credits associated with each EDC's Committed Supply and Active Load Management Credits (ALM).
    - ACE's Committed Supply consisted of its NUG contracts, including any restructured replacement power contracts, and any wholesale purchases previously contracted for by ACE. ACE did not include its to-be-divested plants as part of the Committed Supply for the purposes of the BGS auction.[25]
    - ACE provided winning bidders with capacity credits it had purchased through its RFP process for August and September 2002 on a pro rata basis, based on tranches won to total trances bid.[26]
    - As required by the Final Order, ACE used its NUG-related committed supply to serve BGS load by reserving a fixed percentage of its BGS load for which it continued to be the LSE.[27]
- The SDCA proposal was subsequently adopted and approved by the BPU.

2. On February 15, 2002, the Board certified the final results of the BGS auction for all four New Jersey EDCs for the period August 1, 2002 through 2003 in their entirety and approved the closing prices for each EDC.

- Based on independent reports from the EDCs Auction Manager, NERA, and the Board's consultant, Charles River Associates (CRA), the Board found that:
    - bidders had sufficient information to prepare for the auction
    - no procedural problems nor errors were observed during the auction

[25] Data Response ACE-II-3.6. Proposal for Auction of Basic Generation Service Rights and Responsibilities, ACE, Company Specific Addendum, Compliance Filing, December 12, 2001
[26] Data Response ACE-II-3.6. Proposal for Auction of Basic Generation Service Rights and Responsibilities, ACE, Company Addendum, Compliance Filing, December 12, 2001
[27] Data Response ACE-II-3.6. Proposal for Auction of Basic Generation Service Rights and Responsibilities, ACE, Company Addendum, Compliance Filing, December 12, 2001

- o all communication protocols were followed
- o no hardware or software problems with the auction and communication system were observed
- o no security breaches were observed during the auction process
- o all guidelines for setting the auction volume were followed
- o there was no evidence of confusion nor misunderstanding on the part of the bidders, nor were any complaints received from the bidders
- o the auction was carried out in a fair and transparent manner
- o there was no evidence of collusion nor gaming by the bidders
- o The auction generated a result that was consistent with competitive bidding, market determined prices, and efficient allocation of the BGS load.

- In the BGS auction, ACE's 2,370 MW BGS peak load share was divided into 24 tranches of 98.8 MW. Nineteen of these tranches were supplied by the auction bidders, at an average cost of $51.2/MWH. ACE served five of its own tranches, or 494 MW.

3. ACE managed its participation in the BGS auction in an effective, but costly manner.

- ACE had a dedicated group of full-time personnel who supported its participation in the Year Four BGS auction. Additionally, this group was supported by legal, accounting and credit professionals from throughout Conectiv as required.
- The professionals involved were knowledgeable about power supply, regulatory and financial issues. They worked closely with NERA, the other EDCs and the Board and its staff to develop the auction process for the state.
- ACE's costs to administer its participation in the BGS auctions compare unfavorably to those of the other two large New Jersey electric utilities. ACE's administrative costs for supporting the BGS auction process approximate $1 million per year. JCP&L's and PSE&G's costs were $640,000 and $750,000 per year, respectively.
- BWG believes that, based on its size relative to JCP&L and PSE&G, ACE's administrative costs for supporting the BGS auction process should not have exceeded the $640,000 amount incurred by JCP&L.

4. Approximately $217 thousand of ACE's BGS administrative costs were associated with the deficient RFP 1 and RFP 2 processes.

- As indicated in **Exhibit I-4**, ACE charged approximately $3.4 million of BGS administrative costs to the deferred balance accounts for all four RFP processes.[28] These charges included costs for:
    - Consultants engaged to provide: forecasts of energy and capacity market prices and guidance to the Company in developing and evaluating the RFPs.
    - Legal services associated with the filing and review of various legal matters pertaining to BGS, such as the RFPs submitted to the Board for approval, the filing and litigation of the BGS Auction process, and BGS supplier agreement development.
    - A consultant who served as the Board's BGS auction advisor.
    - Internal charges such as labor and other expenses pertaining to the ACE personnel assigned the various BGS activities, such as buying and/or selling capacity, contract administration and accounting for BGS transactions.
    - Tranche fees, paid to ACE by successful bidders during the BGS auction, were posted as credits to BGS administrative costs.
- In posting BGS administrative costs to the deferred balance account, ACE did not identify the RFP for which each charge was incurred.[29] As summarized in **Exhibit I-5**, BWG estimated the administrative costs associated with RFPs I and II as follows:
    - Contractors – RFPs I and II covered the period January 1, 2000 through August 31, 2000. Work on these two RFP's began in May 1999 and ended in May 2000. ACE used two consultants in support of RFPs I and II, the Wayfinder Group and Lexecon.[30] Wayfinder's charges, posted in June and September 2000, amounted to $24,266.86, and Lexecon's charges during that same period were $102,845.27 for a total of $127, 112.13.[31]
    - Legal – Outside counsel fees of $16,047.62 were posted in June 2000.[32]
    - Internal Labor – ACE charged a total of $1,281,780.92 in BGS administrative costs for all four RFPs and the BGS auction.[33] ACE indicated that $73,912.60 of the total was associated with RFPs I and II.[34]

[28] Testimony of C. Morgan, April 15, 2003.
[29] C. Morgan interview 9-1-04.
[30] Audit of Deferred Balances Atlantic City Electric Company Phase I, page VIII-7
[31] RAR-MTC-II-1
[32] RAR-MTC-II-2
[33] RAR-MTC-II-4
[34] Telephone Conversation with C. Morgan, 11-1-04.

Exhibit I-4
BGS Administrative Costs

Cost Category	Amount
Contractors	$1,989,766.34
Legal Fees	$506,840.64
Internal Labor	$1,281,780.92
Software, System and IT Expenses	$52,203.86
BGS Auction Advisor	$123,000.00
Other	$23,922.70
Tranche Fees	$532,000.00
Total	$3,445,514.46

- Source: C. Morgan Testimony and RAR-MTC-II-1, 2, 4, 5 and 6

Exhibit I-5
BGS Administrative Cost Adjustment

Category	Amount
Contractors	$127,112.13
Legal Fees	$16,047.62
Internal Labor	$73,912.60
Total	$217,017,35

5. The recorded costs for Deepwater and CT capacity in the period August 1999 through December 1999 do not reflect needed capacity quantities and the capacity price should be based on the market clearing price for the daily capacity market.

- As shown in **Exhibit I-6**, the capacity quantities used to determine the 1999 costs recorded exceed both the available and "used" Deepwater and CT capacity quantities as put forth in Exhibit CFM-6 to the Company's Phase II direct testimony dated April 15, 2004.

Exhibit I-6
Comparison of Deepwater and CT Capacity Quantities Used to Determine BGS Costs, Available Capacity, and "Used" Capacity
(MW)

Period	Basis for Recorded Costs	Available Capacity	"Used" Capacity
8/1/99 – 8/31/99	636.0	615.2	597.9
9/1/99 – 9/30/99	636.0	566.8	541.8
10/1/99 – 10/31/99	636.0	567.4	Daily quantities range from 544.2 MW to 544.7 MW
11/1/99 – 11/30/99	636.0	569.0	569.0
12/1/99 - 12/28/99	636.0	579.6	Daily quantities range from 538.9 MW to 574.5 MW
12/29/99 - 12/31/99	636.0	481.3	481.3

Note: The quantities used as the basis for the recorded costs also exceed the First of Each Month Capacity Position data provided in Document Response DR-ACE-37.3.

Source: 1999 Capacity Cost True-Up (Data Response RAR-MTC-II-82); ACE Capacity (Exhibit CFM-6 to Morgan Phase II Direct Testimony dated April 15, 2004.)

- To comply with the Phase I BWG recommendation, ACE should only include the cost of capacity that was needed. In response to a Phase II data request, ACE calculated a final true-up adjustment for 2000 Deepwater and CT capacity costs using the "used" capacity quantity as the "needed" quantity.[35] Following this same methodology, the cost of needed capacity should be calculated using the "used" capacity amounts listed in Exhibit I-6. "Used" does not necessarily equate to "needed." ACE would incur capacity deficiency charges if it were capacity deficient. In August 1999 through May 2000, these deficiency charges were $176.83/Mw-Day. While it is unreasonable to expect that ACE should have matched its daily capacity supply to its capacity requirement, it is possible that it could have sold some of its capacity in the PJM market on those days or months when it had excess capacity.

- ACE set the transfer price at $79.90/MW-Day, in part, to meet the Order requirements. ACE considered several alternatives before electing to use the CTs and Deepwater to fulfill its BGS capacity obligations at a price of $79.90/MW-Day. As documented in a memo dated August 26, 1999, ACE considered four options for BGS capacity supply, and concluded that "with all the price and market information that we have, using the retained assets priced at $79.90/MW-Day is the best option for supplying the BGS commitment.[36]

[35] Data Response RAR-MTC-II-81.
[36] August 26, 1999 Memo From R.K. Douglass, To: W.H. Spence. Subject: Recommendation on Ace/BGS Capacity Obligation.

- The memo addressed four options:
  - Purchase capacity via the PJM auction process.
  - Purchase capacity via bi-lateral contracts.
  - Continue to allocate capacity from the retained assets.
  - Allocate any excess capacity from DP&L to ACE.
- In its August 1999 memo, ACE explained its decision to use capacity from the retained assets at a price of $79.90/MW-Day.

> The recommended option for supplying the BGS capacity is Option 3 because it avoids the price rise caused by PJM load growth and purchasing 500-600 MW in the relatively thin PJM auction and bi-lateral markets. The transfer price for this capacity should be $79.90/MW-day, the PJM clearing price for the only auction held for the PJM planning year. This establishes a market price consistent with the BPU stipulation and order. The prices for shorter-term markets have been from $89/MW-day to $162/MW-day, but none of them have been for 500 MW. If we went into the PJM market to buy 500 MW, the clearing prices would have been much higher to transact this relatively large quantity, probably approaching the high side of the offer prices.
>
> Also... in surveying the bi-lateral market for a wholesale sale, the offers were from $85 to $96/MW-day for 200 MW for calendar year 2000 which is $5 to $15 higher than the proposed price. Finally, this market rate of $79.90/Mw-day is lower than the capacity rate included in the BGS charge, which is above $100/MW-day. With all the price and market information that we have, using the retained assets priced at $79.90/MW-day is the best option for supplying the BGS commitment.[37]

- There is no clear definition of the term "market prices" in the Final Order. PJM has both daily and monthly (and multi-monthly) capacity markets.
- The $79.90/MW-Day used by ACE is in fact a market price, but it is only for 20 MW of capacity, rather than for the 480 to 615 MW provided by the CTs and Deepwater in the last five months of 1999.
  - As shown in the Multi-Monthly Capacity Credit Market Statistics for PJM East which were provided in the Company's rebuttal Exhibit CFM-5, this was the only sale of capacity which covered the entire planning period from June 1999 to May 2000.
  - ACE explains the consideration of Deepwater and CTs as capacity resources for the entire PJM planning period in the August 26, 1999 memo: "...capacity obligations/resources have already been set for the PJM planning year, which

[37] August 26, 1999 Memo From R.K. Douglass, To: W.H. Spence. Subject: Recommendation on Ace/BGS Capacity Obligation

began June 1, 1999. Since the BPU Order was significantly delayed beyond June, Conectiv was required to identify its dedicated capacity resources in late May."[38]

- The use of the $79.90 PJM auction clearing price for capacity in the period May 1999 through June 2000 is not consistent with the PJM daily market capacity price cost methodology that ACE used in 2000, and that it adopted in its 2004 Phase II Rebuttal Testimony regarding 2000 Deepwater and CT capacity costs.

- As shown in **Exhibit I-7**, the adjustment for ACE's 1999 Deepwater and CT capacity costs is $7.5 million based on the determination that the term "market price" as used in the Final Order should be interpreted as the market clearing price for the daily capacity market.

Exhibit I-7
1999 Deepwater and CT Capacity Cost Adjustments to Correct Capacity Quantities and Prices
(Dollars)

	PJM Daily Capacity Clearing Price	PJM Auction Price for Planning period ($79.90/MW-Day)
Originally Recorded	7,774,909	7,774,909
Cost per Adjusted Quantities and Prices	274,109	6,856,363
1999 Correcting Adjustment Required	**(7,500,800)**	**(918,546)**

Source: Data Response RAR-MTC-II-82, Phase II Direct Testimony Exhibit CFM-6; BWG analysis.

6. The recorded costs for Deepwater and CT capacity in the period January 2000 through July 2000 do not reflect the needed capacity quantities thereby increasing ACE's deferred balance by $438,480.

- In January 2000, ACE revised its methodology to determine the Deepwater and CT capacity costs. A comparison of the 1999 and 2000 methodologies is shown in **Exhibit I-8**.

[38] August 26, 1999 Memo from R.K. Douglass, To: W.H. Spence. Subject: Recommendation on Ace/BGS Capacity Obligation

Exhibit I-8
Bases for Deepwater and CT Capacity Cost Calculation
August 1999 to July 2000

Item	**Basis for Capacity Cost Calculation**		
	Original Deferred Balances Account Entry	**October/November 2000 Adjustment**	**September 2004 ACE Rebuttal Testimony**
August 1999 - December 1999			
MW	Total Deepwater and CT installed capacity.	No 1999 adjustment	
Price	PJM planning year auction clearing price (auction on May 17, 1999.)		
January 2000 - July 2000			
MW	Monthly projected Deepwater and CT quantities based on projected load.	Daily Deepwater and CT quantities.	Revised values for Daily Deepwater and CT quantities based on actual load.
Price	Monthly average of PJM daily market capacity price.	PJM daily market capacity price.	PJM daily market capacity price.

- In 1999, the price ACE used to record costs in the deferred balance was $79.90. This was the clearing price for capacity in the period May 1999 through June 2000 based on a May 1999 PJM auction (see further discussion below). Beginning in January 2000, the price ACE used was the monthly of average of daily PJM capacity prices. .[39 40 41]

- In 1999, the capacity quantity was based on the units' installed capacity (636 MW). Starting in January 2000 the capacity was based on a monthly projection of the capacity needs (projected monthly requirements ranged from 173 MW to 513 MW.)[42 43 44]

- ACE's explanations for the January 2000 change in its determination of the Deepwater and CT capacity costs include:

  - ACE management decided that retail choice was active and that customers were taking service with alternative suppliers.[45] Prior to November 17, 1999, ACE was

[39]ACE Response to Phase II Audit Informal Data Request Item #8, October 4, 2004.
[40]ACE Rebuttal Testimony Exhibit CFM-7.
[41] Data Response RAR-MTC-II-78.
[42] ACE response to Phase II Audit Informal Data Request Item #8, October 4, 2004.
[43]ACE Rebuttal Testimony Exhibit CFM-7.
[44] Data Response RAR-MTC-II-78.
[45] ACE response to Phase II Audit Informal Data Request Item #8, October 4, 2004 (Explanation of change in methodology in 2000.)

the only load serving entity in the ACE zone so that the entire retail peak load contribution was assigned to ACE. After retail choice started on November 17, the peak load contribution was allocated to each load serving entity in the Atlantic zone. As retail choice became more wide-spread in the late 1999 to July 2000 time period, the peak load contribution allocated to ACE for BGS purposes was reduced.[46]

- By January, the rules for the retail suppliers within PJM were known, there was more certainty also within PJM itself as to the process they were following in moving the load responsibilities.[47]

- The energy and capacity markets were becoming more known to all suppliers in the PJM ISO. Hence there was more certainty in both the retail load migration as well as the mechanism inside PJM.[48]

- ACE made adjustments to the costs originally recorded in the deferred balance in October and November 2000 in order to revise the capacity quantities and prices. However, subsequent analysis by ACE (presented in Rebuttal Schedule CFM-7) indicates that an adjustment is required to reflect the needed capacity and PJM daily market clearing prices.

- The necessary adjustment to 2000 Deepwater and CT capacity costs is $438,480 as shown in **Exhibit I-9**.

Exhibit I-9
2000 Deepwater and CT Capacity Cost Adjustments to Correct Capacity Quantities and Prices
(Dollars)

Item	Dollars
Cost per Adjusted Volumes and Prices	$ 1,861,551
Originally Recorded	6,438,293
Difference	(4,576,742)
October/November 2000 Adjustment	(5,015,222)
2000 Correcting Adjustment Required	**$ 438,480**

Source: ACE Phase II Rebuttal Exhibit CFM-7; October/November 2000 Cost Adjustment Work Papers; BWG Analysis (ACE response to Phase II Audit Informal Data Request Item #4).

[46] ACE response to Phase II Audit Informal Data Request Item #6, September 9, 2004 (Source of Peak Load Contribution Values.)
[47] ACE response to Phase II Audit Informal Data Request Item #8, October 4, 2004 (Explanation of change in methodology in 2000.)
[48] ACE response to Phase II Audit Informal Data Request Item #8, October 4, 2004 (Explanation of change in methodology in 2000.)

E. RECOMMENDATIONS

1. Remove an additional $360,000 from the deferred balance for BGS administrative costs for excess costs incurred in administering the BGS auction in order to bring ACE's costs in line with those of the other large electric utilities in the state. (Refers to Conclusion 3.)

2. Remove $217,017.35 from the deferred balance for BGS administrative costs associated with RFPs I and II. (Refers to Conclusion 4.)

3. Disallow $7.5 million of 1999 Deepwater and CT capacity costs by based on the determination that the term "market price" as used in the Final Order should be interpreted as the market clearing price for the daily capacity market. Offset the $7.5 million by $0.4 million for a net disallowance of $7.1 million to reflect a reduction in the adjustment to the year 2000 purchases previously made. (Refers to Conclusions 5 and 6.)

CHAPTER IX NUG Mitigation

A. BACKGROUND

In Chapter IX of the Phase I Report, the auditors concluded that Atlantic City Electric Company ("ACE") had been prudent in its efforts to mitigate stranded costs through restructuring NUG contracts.[49] The report noted that ACE had bought out one of its four contracts and partially restructured a second, producing net present value ("NPV") savings to ratepayers of $ 92 million.[50] The company was working with the lead owner of the other two projects to explore restructuring opportunities. The auditors also noted that time constraints had prevented them from conducting a review of ACE's internal files to verify information obtained from an interview of company staff and other sources.[51]

Accordingly, the Phase II investigation included an examination of ACE's efforts to mitigate NUG contract costs in the remaining twelve months of the transition period (August 1, 2002 through July 31, 2003); and a review of ACE's internal files for the entire transition period (August 1, 1999 through July 31, 2003).

Phase II included a review of ACE's efforts to maximize value from remaining NUG entitlements. In its Orders in ACE's pending rate case and related proceedings, the BPU indicated its concern about this issue by adopting a Staff recommendation to require the company to file

> " monthly reports with the Board that show, for each NUG project, the energy and capacity purchased (Mwh and Mw) the amount paid for the energy and capacity, the disposition of the energy and capacity, (i.e. whether it was sold in the wholesale power market or otherwise), the amount received from the sale of the energy and capacity, as well as the value of the energy if it were priced at the average monthly PJM LMP and capacity deficiency rates, and the value if it were priced at the rate payable for BGS supply obtained pursuant to the Statewide auction."[52]

While these reports were to begin after the conclusion of the Phase II period, the BPU requested that the auditors examine ACE's record in managing NUG power sales during Phase II.

Finally, the auditors were asked to undertake a review of the expenses incurred by ACE in the arbitration of a contract dispute with the owners of the Logan NUG project.

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[49] While the company now operates under the name Conectiv, for convenience we continue to identify it by the (abbreviated) name used in the Phase I Report, ACE.
[50] Phase I Report, p. IX-10.
[51] *Ibid.*
[52] Docket Nos. ER02080510 et al., I/M/O Verified Petition of Atlantic City Electric Company d/b/a Conectiv Power Delivery for Approval of its Tariff to Provide for an Increase in Rates for Electric Service, Summary Order (July 31, 2003), p. 7. The Board reaffirmed this requirement with minor modifications in its Final Order July 8, 2004), p. 118.

The three active projects during the Phase II period were American Ref-Fuel, Carney's Point, and Logan. The Phase I Report described the status of these projects as follows:

American Ref-Fuel. ....ACE ... explored restructuring opportunities with American Ref-Fuel. Those discussions resulted in an understanding that ACE and American Ref-Fuel would conduct an auction to solicit proposals for ACE to assign the PPA to a third party, without recourse, in return for an upfront lump sum payment by ACE. The auction took place, resulting in identification of several creditworthy and experienced bidders. Following due diligence and negotiations with two bidders, American Ref-Fuel withdrew its support for the effort, insisting on substituting itself for the winning bidder. This led to a breakdown in the negotiations with American Ref-Fuel in early 2000... [Citation omitted.] Concurrent with ACE's negotiation efforts, PJM instituted an open access tariff, in accordance with FERC requirements. This tariff applied to deliveries from NUG plants. However, American Ref-Fuel was also paying for transmission under a wheeling agreement with an intervening utility, PECO. As PECO was, in effect, recovering the PECO transmission costs through the PPA, ACE took the position that it was paying twice for transmission of power from the NUG. ACE succeeded in negotiating an agreement with American Ref-Fuel under which it paid American Ref-Fuel to buy out its transmission agreement with PECO, and share the resultant savings through lower power prices under the PPA. That agreement, which yielded customer benefits of $8.2 million, was approved by the BPU [citation omitted]. .... ACE attempted to resume negotiations with American Ref-Fuel on a comprehensive restructuring of the PPA in 2001. Those discussions continued over the course of a year, and were complicated by ownership and management changes at American Ref-Fuel. Ultimately, American Ref-Fuel insisted on too high a price, and the discussions terminated in August 2002.

Logan and Carney's Point. National Energy Group (NEG), a subsidiary of Pacific Gas &Electric Company owns 50 percent of both the Logan and Carney's Point projects. Accordingly, ACE faced dealing with the same party to pursue a restructuring of both plants. In response to ACE's overture, NEG offered to explore renegotiation of the Logan project first, since NEG deemed it a better candidate for restructuring. Negotiations took place from 1998 to early 1999, when they reached an impasse over pricing. At the same time, ACE informed NEG that it intended to press an open issue concerning the pricing formula for contract energy in order to mitigate contract costs. NEG responded by invoking the arbitration provisions of the contract to resolve the pricing issue. ACE was advised by its counsel to cease restructuring negotiations about Logan until the arbitration was completed. The arbitration took more than two years, and resulted in a ruling in ACE's favor.

With the arbitration preventing further progress on the Logan project, ACE got NEG to begin negotiations on a possible restructuring of the Carney's Point contract. Those negotiations were making significant progress when NEG began experiencing severe financial pressures in the summer of 2002. This led NEG to request a change in the structure of the deal under consideration. ACE agreed with the request, and NEG is currently considering ACE's Proposal.[53]

B. SCOPE AND OBJECTIVES

We reviewed ACE's NUG mitigation efforts during the period August 1, 2002 through July 31, 2003. The objective of this review was to determine the prudence of the utility's mitigation efforts, consistent with applicable law, with respect to the above-market NUG contract costs during this portion of the transition period. We also conducted a review of the company's internal files to verify information supplied by the company with respect to its mitigation efforts in Phases I and II. We also examined ACE's record in managing NUG power sales during Phase II and reviewed the expenses incurred by ACE in the arbitration of a contract dispute with the owners of the Logan NUG project.

[53] Phase I Report, pp. IX-4-5.

C. EVALUATIVE CRITERIA

BWG used the following criteria in its evaluation of ACE's NUG mitigation efforts:

- Did ACE maintain a reasonable and prudent program to mitigate its NUG contracts?
- Has ACE taken a proactive approach to the mitigation of NUG costs and taken advantage of all reasonably available opportunities to mitigate NUG costs?
- Did ACE manage its NUG power sales appropriately in Phase II?
- Were the expenses incurred by ACE in the arbitration of a contract dispute with the owners of the Logan NUG project appropriate?

D. FINDINGS AND CONCLUSIONS

1. The regulatory requirements are unchanged from the Phase I report.

2. Notwithstanding its previous inability to interest the owner of the American Ref-Fuel project in a mutually beneficial restructuring, ACE remained in contact with the owner and monitored the project to identify developments which might create new restructuring opportunities.

   - In early 2003, ACE learned that Duke Energy, a 50 percent owner of the project, was planning to sell its project share to Donaldson, Lufkin and Jenrette, an investment firm, and AIG, an insurance company.
   - When the ownership transfer occurred, ACE contacted the project management to inquire as to whether the new owners would be receptive to a contract buyout. Project management responded that the new owners preferred to continue receiving the income stream generated under the contract. Accordingly, while ACE continues to monitor the contract, no opportunity to restructure exists at this time.[54]

3. As the lead owner of the Carney's Point project has reorganized in bankruptcy, ACE has developed restructuring proposals tailored to the owner's changing financial position and is making reasonable progress toward restructuring this contract.

   - The Phase I Report noted that ACE's negotiations with NEG to restructure Carney's Point were complicated when NEG began experiencing financial difficulties. NEG's financial condition worsened and the company filed for bankruptcy in late 2002. Over the winter of 2002 - 2003, ACE monitored the bankruptcy proceedings. After it became apparent that the project would not be sold as part of the bankruptcy resolution, ACE resumed restructuring discussions with NEG in March 2003.

[54] Interview of Mark Hollern, October 15, 2003 ("Hollern Interview").

- While NEG is receptive to ACE's interest, ACE has had to tailor its approach to NEG's business model, which has changed as a result of its reorganization in bankruptcy. To the extent ACE finds it necessary to finance any restructuring payment, ACE may need to address limitations on the amount of debt it is permitted to maintain in its capital structure under the Public Utilities Holding Company Act (PUHCA).[55]

- Another development relating to the possible restructuring of Carney's Point is the recent sale by GE Capital of its 40 percent ownership interest in the contract to ArcLight Capital Partners, which is majority-owned by the John Hancock Mutual Life Insurance Company.[56] A former partner with McManus & Miles, the firm which has provided consulting advice to ACE in connection with its NUG restructuring program, has joined the management team at ArcLight. This development may facilitate ACE's efforts to interest the project owners in restructuring the contract, since the individual formerly with McManus & Miles is familiar with the potential advantages to project owners (as well as the utility) of restructurings.[57]

4. ACE believes that a restructuring of Carney's Point will serve as a template for restructuring Logan since NEG is the lead owner of both.[58]

- ACE's efforts to pursue restructuring of the Logan contract were stalled in the Phase I period while the parties arbitrated a dispute over a contract pricing term. The arbitrators ruling in ACE's favor did not fully resolve the dispute. As part of their decision, the arbitrators ordered the project owners to undertake a heat rate test on the plant. Thereafter, a dispute arose as to the methodology to be used for the test, and the matter was returned to arbitration. As was the case in the earlier phase of the arbitration, counsel advised ACE management not to conduct restructuring negotiations while the arbitration proceedings were under way. As those proceedings continued through the Phase II audit period, restructuring negotiations did not progress.

- Nonetheless, ACE attempted to formulate an approach to restructuring the Carney's Point contract that might serve as a template for restructuring the Logan contract once the arbitration is resolved.

5. ACE has maintained a management and compensation structure that supports its restructuring program.

- On August 1, 2002, Conectiv merged with Potomac Electric Company, resulting in the formation of a new holding company, Pepco Holdings, Inc. ("PHI").[59] This merger resulted in organizational changes that affected the management of ACE's NUG restructuring activities. While the same individual is assigned (on a full-time basis) to

[55] *Ibid.*
[56] See http://www.bizjournals.com/boston/stories/2002/09/30/daily11.html.
[57] Hollern Interview.
[58] *Ibid.*
[59] See http://www.pepcoholdings.com/news/news_release.html.

manage the restructuring efforts, PHI has transferred that individual's function from the energy division to the power delivery division of Conectiv. Senior management oversight of restructuring policies, which formerly resided with Conectiv officials, now takes place at a regulatory policy committee made up of senior officers of PHI. While this creates an additional layer of management review, the regulatory policy committee recognizes the continued importance of attempting to mitigate NUG contract costs, and regularly includes contract restructuring issues on its meeting agendas.[60]

- The budget for restructuring NUG contracts is essentially unchanged from its level prior to the acquisition of Conectiv by PHI, and continues to fund both the full-time position of the program manager and the ongoing retainer of McManus & Miles to provide consulting services.[61]

- As an employee of the energy division, the program manager for NUG contract mitigation was eligible for special performance bonuses for successfully restructuring contracts. The power delivery division in which he now works does not include special performance bonuses in its incentive compensation policy. However, up to 20 percent of the program manager's compensation remains tied to success in achieving performance goals, which include targets relating to contract restructuring.

- The contract with McManus & Miles also incorporates financial incentives tied to the level of NPV ratepayer savings resulting from contract restructurings, as it did during the Phase I period.[62]

6. A review of ACE's internal files confirmed that the company explored reasonable opportunities to restructure all of its NUG contracts during both the Phase I and Phase II audit periods.

- The auditors conducted an on-site review of ACE's internal files, including hard-copy and electronic documents. The company's program manager assisted in locating and identifying relevant materials. The files include detailed draft proposals and financial analyses relating to restructuring each of the contracts, as well as records of regular (in many cases daily) communication with the project owners and the consultant.

- The review confirmed that the program manager, with support from McManus & Miles, diligently pursued restructuring efforts throughout the Phase I and Phase II periods.

7. ACE customers have benefited from the company's dedication of power entitlements under NUG contracts to meet a portion of BGS supply needs rather than selling that power into the regional market.

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[60] Hollern Interview.

[61] *Ibid.*
[62] *Ibid.*

- In the Final Decision and Order in ACE's Restructuring case, the BPU directed ACE to apply NUG power toward its BGS supply requirement.[63] The BPU reiterated this point in its Order establishing auction procedures for the fourth year of the Transition Period (Phase II):

> [R]ecognizing that Conectiv has a Final Order which calls for it to use the power from its non-utility generation ("NUG") contracts to serve BGS load, Conectiv should reserve a fixed percentage of BGS load and to serve that load by applying its NUG related power (capacity, energy and ancillary services), using as necessary the procedures previously approved by the Board, to serve that percentage of the BGS load; thus Conectiv would provide full requirements service to a fixed percentage of its BGS load.[64]

- The Final Decision and Order also directed ACE to credit its NNC account for the use of this power "at the net BGS price (the floor shopping credit less transmission cost, sales and use tax, line losses, ancillary services and capacity reserve margin)."[65]

- NUG power dedicated to meeting BGS supply needs was credited at $0.04563 per kWh from August 1, 2002 through December 31, 2002, and at $0.045738 per kWh from January 1, 2003 through the end of Phase II.[66] **Exhibit II-1** indicates how the credits were derived.

Exhibit II-1
Derivation of NNC Credit for NUG Power ($kWh)

		Aug-Dec. 2002	Jan-July 2003
A	Shopping Credit	$0.058347	$0.058411
B	Transmission Rate	0.004680	0.004680
C	**BGS Rate (A-B)**	**0.053667**	**0.053731**
D	Sales +Use Tax	0.003037	0.003041
E	BPU assessment	0.00018	0.000085
F	Admin. Cost	0.000193	0.000149
G	Losses	0.003426	0.003434
H	Ancillary Serv.	0.001284	0.001284
I	**Net BGS Credit (C-D-E-F-G-H)**	**$0.045643**	**$0.045738**

Source: Response to DR-ACE-II-22, Request No. 4

- As shown in the next **Exhibit II-2**, average real-time spot market prices over this period were about $7.00 per mWh, or 16 percent, lower than the BGS credit. Accordingly, using NUG power to offset BGS supply needs was more beneficial to customers than selling that power into the real time market. While a precise

[63] Docket Nos. 9707455 et al., I/M/O Atlantic City Electric Company—Rate Unbundling, Stranded Cost and Restructuring Filings, Final Decision and Order (March 30, 2001), p. 87 ("Final Decision and Order").
[64] Docket Nos. EX01050303 et al., I/M/O The Provision of Basic Generation Service Pursuant to the Electric Discount and Energy Competition Act, N.J.S.A. 3-49 et seq. (Dec. 11, 2001), p. 25.
[65] Final Decision and Order, p. 87.
[66] Response to DR-ACE-II-22, Request No. 4.

quantification is not possible from available data, that benefit was on the order of $13 million in the Phase II period.[67]

Exhibit II-2
Comparison of ACE Zonal LMPs to BGS Credits

Monthly Avg. Real Time LMP ($/mWh)		BGS RATE ($/mWh)
2002		
Aug.	$43.587	$44.056
Sept.	32.360	45.643
Oct.	29.938	45.643
Nov.	24.797	45.643
Dec.	32.542	45.643
2003		
Jan.	45.560	45.738
Feb.	49.157	45.738
Mar.	55.223	45.738
April	37.738	45.738
May	31.175	45.738
June	32.323	45.738
July	43.139	45.738
Avg.	**$38.128**	**$45.566**

Sources: PJM Website (www.PJM.com);
Response to DR-ACE-22, Request No. 3.

- Because ACE's supply entitlements (including NUG PPAs) exceeded 20 percent of BGS load (the percentage that ACE committed to meet with those entitlements), the company was not required to make any supplemental purchases of power from PJM to meet its share of BGS load responsibility.[68]

- The crediting of entitlements to BGS supply requirements takes place through the PJM routine balancing and settlement processes. It was handled internally at ACE by the same personnel who are generally responsible for PJM billing, and did not require any additional personnel. Costs of accounting for PJM billing for BGS supply are charged to the BGS deferral accounts at cost, including overhead, benefits and other loaders, but

[67] This estimate was derived by assuming that all NUG energy devoted to meet 20% of BGS supply would have been sold or credited at the average ACE zonal LMP or BGS rate, respectively. The volume of energy equivalent to 20 percent of BGS supply was assumed to be 1752 gWh, based on the average BGS volume in three preceding years. See Docket Nos. ER02080510 et al., I/M/O Verified Petition of Atlantic City Electric Company d/b/a Conectiv Power Delivery for Approval of its Tariff to Provide for an Increase in Rates for Electric Service, Final Order (July 8,2004), Exhibit 1. A more accurate calculation would require knowledge of hourly sales volumes and individual pricing nodes for individual NUGs in the Phase II period. In addition, no attempt was made to determine the potential value of selling NUG capacity in the wholesale market. That capacity was credited to auction bidders, presumably thereby lowering their bid prices.

[68] Response to DR-ACE-II-22 Request No. 2.

without a profit. ACE's accounts do not sub-divide BGS labor between PJM billing work relating to credited entitlements and other BGS supply sources, so the company's cost of managing the crediting of entitlements in the PJM balancing and settlement process is not readily available.[69]

8. ACE made a number of errors in identifying external costs associated with the Logan contract dispute.
   - Correction of those errors resulted in a reduction in recoverable costs of $83,614.63. The auditors understand that the company accepted these corrections in rebuttal testimony filed in its pending rate case.[70] The auditors also note an outstanding issue with respect to the company's right to defer internal Logan dispute costs.
   - The company submitted an itemized list of Logan dispute costs of $3,298,882.77 million on June 23, 2004.[71] Of that figure, ACE identified $2,849,506.03 as external costs and $449,376.74 as internal costs. The auditors conducted a limited review of these costs, based on the characterization and amounts of the invoices and journal entries, and telephone conversations with company staff and an outside attorney. The auditors did not review the invoices themselves.
   - The auditors' review of the external costs discovered an erroneous duplicate billing of $13,353.02 for services of the law firm of Pepper Hamilton & Scheetz in the month of July 2002. In addition, the auditors determined that all invoices for services of the law firm of Nixon Peabody LLP, amounting in total to $70,261.61, were improperly charged to the deferral account.[72]
   - Several items in the itemized list of external costs were labeled in an incorrect or misleading manner, but nonetheless do not appear to have been improperly charged to the deferral account. They are:

     a. Westcott Enterprises was an arbitrator, not a consultant.
     b. Joseph Isabella, identified in RAR-MTC-II-27 as a contractor, was a former ACE employee, who was deposed about the original Logan PPA negotiations. He insisted on being paid in order to testify.
     c. James Diefenderfert, identified in RAR-MTC-II-27 as a separate contractor, is from the same firm as Analytical Applications.
     d. Kathy Gordon, who appeared from RAR-MTC-II-27 to be an attorney, is an ACE employee who handles NUG billing. Her name appears in the data response only because she was responsible for reclassifying some expenses.

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[69] Response to DR-ACE-II-22 Request No. 1; e-mail of Charles Morgan to Arthur Adelberg (October 14, 2004).
[70] Docket No, ER03020110, I/M/O the Petition of Atlantic City Electric Company d/b/a Conectiv Power Delivery for Approval to Increase Base Rates for Electric Service, Phase II.
[71] Response to RAR-MTC-27, Attachment 1.
[72] Telephone conversation with MaryAnn Abdul, Conectiv Power Delivery (August 10, 2004); e-mail from Charles Morgan to Arthur Adelberg (Sept. 13, 2004); e-mail from MaryAnn Abdul to Arthur Adelberg (August 13, 2004).

e. Expenses identified in RAR-MTC-II-27 as "reclass Contr-Out-Counsel/LgSchutz-reclass" are Analytical Consulting and Pepper Hamilton legal costs, reclassified by an ACE employee named Schultz. [73]

- The overall level of external costs, while substantial, appears to be justified in light of the complexity of the dispute. Evidently, the Logan PPA itself was not clear as to what was a proper method to test the plant's actual heat rate, and ACE had to do considerable investigative work, including combing through prior test data, to come up with a theory as to why they were being overcharged. ACE also had to reconstruct what billings would have been had Logan done its testing as ACE believed it should.

- The arbitration award itself left details of the revised test methodology and the calculation of damages to subsequent negotiation between the parties. These proved to be very controversial, leading to many months of tests, discussions and negotiations, and ultimately an agreed upon testing protocol in excess of 100 pages. In the arbitration proceeding, Logan's lawyers, from the firm of Kirkland & Ellis, took very aggressive positions, requiring many minor issues to be litigated at length. ACE required separate experts to address different aspects of the case. PriceWaterhouseCoopers was retained to examine several matters, including the accuracy of Logan's coal cost numbers, coal quantities, and what billings would have been had Logan used the testing methodology advocated by ACE. McHale was retained after the award to monitor Logan's testing. Analytical Applications was used to analyze data from Logan's prior tests.[74]

- The BPU has raised the issue in a pending ACE rate case of whether the internal costs were properly deferred by the company.[75] The auditors issued data requests to ascertain the company's basis for deferring these costs.[76] The response suggests that the company is relying on equitable considerations rather than a specific accounting order or statutory authorization:

> As indicated on page 92 of the Board's March 30, 2001 Final Order in Docket Nos. EO97070455, et. al., for the Company the NUG stranded costs are considered to be the above market costs associated with the NUG contracts. These above market costs are recovered through the NNC rate, which is subject to deferred accounting. Since the impact of the Logan arbitration is a reduction in the above market NUG costs that will be charged to customers through the NNC, it is appropriate that the costs incurred to achieve those savings be also accounted for through the NNC.
> EDECA also permits transaction costs incurred in a NUG buyout or buydown that reduces stranded costs to be included in the determination of savings to be passed through to customers (N.J.S.A. 48:3-61(l)). The impact of the Logan arbitration is comparable to a NUG buydown. The Company has incurred costs in order to achieve savings for customers. Those costs must be

[73] Telephone conversations with Charles Morgan and MaryAnn Abdul, Conectiv Power Delivery (August 10 and 11, 2004).
[74] Telephone conversation with MaryAnn Abdul, Conectiv Power Delivery, and Ken Levin, Pepper Hamilton & Scheetz (August 11, 2004).
[75] Docket No. ER0208510, supra, Order Clarifying Issues and Directing the Filing of Supplemental Testimony (Dec. 12, 2003), p. 3; id., Final Decision and Order (July 8, 2004), pp. 116-17.
[76] DR-ACE-II-21, Requests No. 1, 2.

netted against the savings resulting from the Company's actions with the resulting savings being passed through to customers on a full and timely basis.[77]

E. RECOMMENDATIONS

1. Reduce recoverable costs associated with the Logan contract dispute by $83,614.63, as already agreed to by the company. [Finding No. 7]

2. If the BPU determines that internal costs associated with the Logan contract dispute were not properly deferred, reduce recoverable costs by $449,376.74. [Finding No. 7]

[77] Response to DR-ACE-II-21, Request No. 1.

Atlantic City Electric Company

Schedule of Deferred Balances and Attachments
For the Year Ended July 31, 2003

And Independent Accountants' Report

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Independent Accountants' Report

To Atlantic City Electric Company and
New Jersey Board of Public Utilities:

We have examined the Atlantic City Electric Company's ("ACE" or the "Company") compliance with the New Jersey Board of Public Utilities ("Board") Orders[1] and schedule of deferred balances[2] for the year ended July 31, 2003 ("Phase II"). The management of the Company is responsible for compliance with Board Orders as well as the balances and amounts presented in the accompanying schedule of deferred balances. Our responsibility is to express an opinion on the Company's compliance with the Board Orders and schedule of deferred balances based on our examination.

Our examination was conducted in accordance with attestation standards established by the American Institute of Certified Public Accountants and, accordingly, included examining, on a test basis, evidence about the Company's compliance with the Board Orders and performing such other procedures as we considered necessary in the circumstances. We believe that our examination provides a reasonable basis for our opinion. Our examination does not provide a legal determination on the Company's compliance with the Board Orders.

Our examination disclosed the following matters of material non-compliance:

- We noted that during the transition period from August 1, 1999 to July 31, 2003, the Company calculated the interest on the deferred balances on a before-tax basis. Had ACE computed interest on the deferred balance on an after-tax basis, the cumulative interest would have been $5,193,174 compared to $8,779,669 which ACE applied to the deferred balance.

  Pursuant to the Final Decision and Order dated July 21, 2003, ACE was directed to recalculate the interest accrued on its post August 1, 1999 deferred balances on a net of tax basis. As per ACE, a Notice of Appeal was filed, in August 2004, with the Appellate Division of the Superior Court of New Jersey on this issue.

- As of July 31, 2003, the allowance for doubtful accounts amounted to $7,856,233. This amount was exceeded by $1,485,327 when compared to the required allowance of $6,370,906. The calculation of the required allowance was based on the estimated loss

[1] See Attachment I for the listing of Board Orders subjected to this examination.
[2] See Attachment II for the schedule of deferred balances and accompanying notes to the schedule of deferred balances.

percentages (average of 7% from the sample months of December 2002 and July 2003) of the month end aging of accounts receivable.

Although the Company's management claims to have used a conservative approach in establishing a larger reserve balance, there is uncertainty related to the estimated reserve as the historical information on non-collection would indicate that a smaller amount is warranted. The Company's management contends that the analysis process for estimating the adjustment required for the reserve balance at July 31, 2003 warrants processing six-to-nine month's data. As of the date of this report, that process has not been completed.

In our opinion, except for the matters of material noncompliance noted above, the Company complied, in all material respects, with the Board Orders regarding the deferred balances for Phase II.

This report is intended solely for the information and use of New Jersey Board of Public Utilities and the management of the Company and is not intended and should not be used by anyone other than these specified parties. Since this report is a matter of public record, its distribution is not limited.

Mitchell & Titus, LLP

September 26, 2005

Atlantic City Electric Company ("ACE")

Excerpts from the New Jersey Board of Public Utilities ("Board") Orders
For the year ended July 31, 2003

Board Order, Date and Docket No.	Page and/or Paragraph No.	Excerpt
Final Decision and Order Agenda Date: July 15, 1999 Signed March 30, 2001 Docket Nos. EO97070455, EO97070456, EO97070457 ("Final Decision and Order")	Page 82 3rd Paragraph	With respect to the Deferred Balance, the Board FINDS that this should more appropriately be referred to as "Deferred Costs," rather than "Deferred Revenues" as proposed in Stipulation I, to better reflect the nature of the deferral, whereby deferral of recovery of some portion of MTC costs, NUG stranded costs and BGS costs may be necessary to achieve the rate reductions ordered herein, depending on market price conditions and subject to the provisions of this Order. Consistent with our determinations in the PSE&G and GPU cases, the Board FINDS that the appropriate interest rate thereon, for underrecovered balances is the interest rate on seven-year constant maturity treasuries, as shown in the Federal Reserve Statistical Release on or closest to August 1st of each year, plus sixty basis points best reflecting the time period over which the balance of deferred costs will likely be financed. Given the legislatively-imposed rate caps during the Transition Period, there is the potential, particularly if market prices were to escalate such that BGS rates are increased over an extended period of time, that ACE would not be able to fully recover MTC, NNC and/or BGS costs during this timeframe, and that the Deferred Balance could grow as a result to a level that could lead to post-Transition Period spikes as those costs are later recovered. Accordingly, in order to avoid such circumstances, it is appropriate that ACE pursue BGS cost hedging mechanisms and that the Deferred Balance be recoverable, with interest, over a reasonable period of time post-Transition Period as may be determined by the Board.
Final Decision and Order	Pages 83-84 Paragraph 1	Electric rate reductions shall be implemented as follows to comply with the provisions of N.J.S.A. 48:3-52(d). The initial aggregate rate reduction, inclusive of all unbundled rate components, to be implemented effective August 1, 1999 shall be 5% from current rates. The average distribution rate for the Company effective on August 1, 1999 shall be 2.1384 cents per kwh. The MTC shall be set as the residual amount necessary to achieve the rate reduction, after accounting for other unbundled rate components established pursuant to this Order, including the distribution rate, regulatory asset charge, State energy taxes including Sales and Use Tax, Corporate Business Tax and TEFA, SBC, NNC, and BGS charge. The DSM and LEAC overrecovery balances, including accrued interest, shall not be utilized to offset regulatory asset charges but shall instead be credited to, and become the starting balance of, the Deferred Balance established pursuant to paragraph 27. Effective no later than January 1, 2001, the Company shall implement a further aggregate rate reduction of at least 2% relative to current rates (bringing the total rate reduction to at least 7%). However, to the extent that the Company completes the divestiture of generating assets and securitization of net owned generation stranded costs, or successfully completes a NUG contract(s) restructuring, buyout or buydown

Atlantic City Electric Company ("ACE")

Excerpts from the New Jersey Board of Public Utilities ("Board") Orders
For the year ended July 31, 2003

Board Order, Date and Docket No.	Page and/or Paragraph No.	Excerpt
		and securitization of net NUG stranded costs prior to January 1, 2001, it shall implement a rate reduction reflecting the full resultant savings no later than the date of the establishment of the resultant TBC. To the extent that such savings result in the implementation of a further rate reduction of less than 2%, ACE shall in any event reduce rates effective January 1, 2001, to achieve the 7% total rate reduction as of that date. To the extent that the savings resulting from divestiture and securitization of net owned generation stranded costs, and/or NUG restructuring buyout or buydown and securitizaton exceeds 2%, ACE shall implement a rate reduction beyond 7% to fully pass such savings on to customers, upon the date of the establishment of the resultant TBC. To the extent that the sum of the unbundled rate components as of July 31, 2002 exceeds the price cap resulting from the implementation of a 10% aggregate rate reduction relative to April 30, 1997 rates, which unbundled rate components are to reflect any savings which have resulted from the buyout, buydown, or restructuring and securitization of NUG contracts implemented pursuant to this paragraph, the Company shall, consistent with the provisions of this Order, implement an additional reduction in the MTC as necessary in order to achieve effective August 1, 2002, the mandated 10% aggregate rate reduction relative to April 30, 1997 rates. ACE shall make a filing, no later than August 1, 2002, as to the proposed level of all unbundled rate components beginning August 1, 2003, so that the Board may consider this matter prior to the end of the transition period. All parties will be afforded an opportunity to participate in this proceeding. In order to fund and sustain the rate reductions and the rate credit set forth in paragraphs 1(a) through 1(d) above, it may be necessary for the Company to defer the recovery of revenues associated with BGS, NUG costs, or other costs. No portion of the costs for BGS shall be deferred prior to the deferral of any other deferrable cost, as more specifically set forth in paragraph 27.
Final Decision and Order	Page 84 Paragraph 2	The initial 5% (August 1, 1999) and final 10% (August 1, 2002) rate reductions are required by the Act, and shall not be contingent upon divestiture and securitization of generation assets.

Atlantic City Electric Company ("ACE")

Excerpts from the New Jersey Board of Public Utilities ("Board") Orders
For the year ended July 31, 2003

Board Order, Date and Docket No.	Page and/or Paragraph No.	Excerpt
Final Decision and Order	Page 87 Paragraph 7	ACE shall apply both NUG contract power and to-be-divested owned generation power (prior to the closure of the sale of the generation assets) towards the BGS supply requirement, which power shall be credited at the net BGS price (the floor shopping credit less transmission cost, sales and use tax, line losses, ancillary services and capacity reserve margin). Such credited prices shall be employed for purposes of establishing the level of the NNC and establishing the level of owned generation revenue requirement recovery (prior to the completion of divestiture), in accordance with this Order. During the first three years of the Transition Period, up to and including July 31, 2002, ACE shall solicit requests for proposals ("RFP Process") for the provision of wholesale supply for BGS in twelve month pricing cycles, or such other cycles as ACE deems necessary or prudent. ACE will submit its plans for the RFP Process to the BPU by September 15, 1999. ACE shall commence the RFP Process as soon as practicable after such date and approval of the plan by the BPU, with the goal of concluding such process and entering into a contract for BGS supply by December 15, 1999. Any agreements for the provision of BGS shall be presented to, and subject to the approval of, the BPU.
Final Decision and Order	Page 89 Paragraph 17	The Company has made a business decision to divest its interests in the B.L. England, Keystone, Conemaugh, Peach Bottom, Salem and Hope Creek generating stations. Upon approval of the divestiture by the Board, the net divestiture proceeds as determined by the Board will be used to determine the Company's generation related stranded costs. Generation related stranded costs shall mean the excess of net book value as of the closing date(s) of the sale(s) over net divestiture proceeds. The net book value shall reflect the net investment in each facility, reflective of the gross investment less depreciation reserve less accumulated deferred income tax, and investment tax credits, if appropriate, as of the closing date(s). The tax impacts with respect to taxable gains and/or losses will be considered in calculating net stranded costs. Net divestiture proceeds are defined as the excess of the selling price(s) of the generating assets over the transaction costs incurred by the Company. The transaction costs shall be reasonable, verifiable and necessary, and shall include (but not necessarily be limited to) sales and transfer taxes, state, federal and local taxes, as well as reasonable consultants fees, broker commissions, legal fees, investment banking fees, title transfer fees, real estate transfer and related costs, mortgage and financing costs, real estate taxes, transportation and system-separation costs (including outside contractor, engineering, purchased materials and labor costs) associated with the divestiture activities, paid overtime and out-of-pocket expenses for Company employees associated with the divestiture activities, and any arrangements to address direct and indirect employee impacts from the divestiture including retirement, severance and any other employee-related benefit costs, as shall be determined by the Board.
Final Decision and Order	Page 89	Final determination by the Board of the net divestiture proceeds shall be undertaken only upon the

Atlantic City Electric Company ("ACE")

Excerpts from the New Jersey Board of Public Utilities ("Board") Orders
For the year ended July 31, 2003

Board Order, Date and Docket No.	Page and/or Paragraph No.	Excerpt
	Paragraph 18a	completion of the transfer of all of the generation assets listed in paragraph 17 to each purchaser thereof, as set forth herein. a. Such final determination shall be made within a separate divestiture proceeding, to be filed by ACE pursuant to standards to be set by the Board, subject to the terms of this Order. The final determination of the net divestiture proceeds shall include a determination of actual selling price(s), book value(s) costs. The Board is not pre-judging at this time ACE's prudence in implementing the RFP and selecting a winning bidder(s). Such final judgment will come at the conclusion of the separate divestiture proceedings.
Final Decision and Order	Page 91 Paragraph 21	The Company agreed in Stipulation I to forego recovery of $9 million in net stranded costs associated with its Deepwater Station and its Combustion Turbines, as set forth in Schedule B of the Stipulation ("Transferred Units").
Final Decision and Order	Page 92 Paragraph 22	During the period between August 1, 1999 and completion of the divestiture of generation assets, MTC revenues shall be applied to owned generation revenue requirements, including continued depreciation of assets, and return on investment, operating and maintenance expenses and fuel expenses, and, between the time of divestiture closing and time of securitization closing, MTC revenues shall be applied to provide a return on the net owned generation stranded costs at 13.0% pre-tax. At time of the termination of the MTC (upon the establishment of the TBC), total MTC revenues and market revenues received from the crediting of owned generation power to BGS in accordance with paragraph 7 (as modified) will be reconciled to the amounts indicated, including a review of the prudence and reasonableness of the Company's operation of the units, and the Deferred Balance will be reconciled accordingly to reflect a resulting shortfall or excess.
Final Decision and Order	Page 92 Paragraph 23	The Company is entitled to full and timely recovery of 100% of the costs associated with its NUG purchased power contract, in accordance with the provision of N.J.S.A. 48:3-61, which contracts have been previously reviewed and approved for full and timely recovery by the Board. Therefore, consistent with N.J.S.A. 48:3-61(a)(3) and other applicable law, the Company shall be permitted to fully recover, dollar-for-dollar, the costs associated with its NUG contracts, over the life of each such contract. The Company shall utilize a Net Non-Utility Generator Charge as a component of the MTC to recover the stranded costs associated with the purchase of power from NUGs. The NNC shall be equal to the difference between the cost of the NUG-contract purchased power and either (a) the proceeds realized by the Company from the sale of that NUG-contract power in the competitive wholesale market, (b) the pricing set forth in paragraph 7, to the extent NUG resources are utilized as set forth in paragraph 7, or (c) the pricing set forth in

Atlantic City Electric Company ("ACE")

Excerpts from the New Jersey Board of Public Utilities ("Board") Orders
For the year ended July 31, 2003

Board Order, Date and Docket No.	Page and/or Paragraph No.	Excerpt
		paragraph 9, to the extent NUG resources are utilized as set forth in paragraph 9. Such proceeds will be adjusted to reflect a deduction for the reasonable marketing and administrative costs associated with the sale of the NUG-contract power into the wholesale market to the extent such power is indeed sold in the wholesale market. The NNC shall also include swap breakage costs incurred in connection with a previous amendment to one of its NUG contracts, which costs have been recovered to date through the Energy Adjustment clause charge. The NNC shall continue over the actual term of each of the Company's NUG contracts, and shall be applied as a non-bypassable wires charge to retail customers. In the event of a NUG-contract buyout, buydown or restructuring, and to the extent that a 10% aggregate rate reduction relative to April 30, 1999 rates is achieved without the use of cost deferrals, the Company will be provided with an incentive for such restructuring. This incentive shall amount to ten (10) percent of the net savings in excess of the 10% rate reduction, except for the Pedricktown Project for which the incentive will be 5% of such savings, and the NNC shall be adjusted accordingly. Upon application by ACE and a determination by the Board that the conditions of EDECA are met, the Board will issue a financing order consistent with the provisions of the Act, permitting securitization over the remaining contract term, of the costs associated with any buyout, buydown or restructuring of the Company's NUG power contracts which the Board approves and finds to be consistent with the standards in N.J.S.A. 48:3-61 and 62. In the event of such approved buyout, buydown, or restructuring, and prior to the securitization of the costs for same, the Company shall include such costs in its MTC recovery and concurrently reflect in rates any power purchase cost savings resulting therefrom.
Final Decision and Order	Page 92 Paragraph 24	The Company will incur additional costs for restructuring-related items that are capital in nature, the estimated costs of which are set forth in Schedule C of the Stipulation. The Company has proposed to recover these costs through securitization of up to 75% of total capital expenses for terms up to 15 years. The Board renders no determination at this time with respect to any such request for the securitization of restructuring-related costs of a capital nature. The recovery of restructuring-related costs of a capital nature via the MTC shall be subject to a reasonableness and verification review by the Board, and shall be net of other sources of recovery towards such costs including Third Party Supplier Agreement fees. If approved, such costs will be amortized over a period not to exceed eight years. The rate of return on unamortized restructuring-related costs collected via the MTC shall be 13.0% pre-tax.

Atlantic City Electric Company ("ACE")

Excerpts from the New Jersey Board of Public Utilities ("Board") Orders
For the year ended July 31, 2003

Board Order, Date and Docket No.	Page and/or Paragraph No.	Excerpt
Final Decision and Order	Page 93 Paragraph 25	The recovery of restructuring-related costs of an operating nature other than consumer education cost, as listed in Schedule D, of the Stipulation, via the MTC shall be subject to reasonableness and verification review by the Board, and shall be net of other sources of recovery towards such costs, including Third Party Supplier Agreement fees.
Final Decision and Order	Page 93 Paragraph 27	As described in paragraph 1 above, the Board recognizes that the Company may have to defer recovery of some portion of its costs in order to achieve and/or sustain rate reductions through the end of the Transition Period. The costs which may be so deferred (the "Deferred Costs") are those incurred during the Transition Period to meet the costs of BGS (as set pursuant to paragraph 6), the NNC (as set pursuant to paragraph 23), and the costs recoverable through the MTC (set forth in paragraph 25). Therefore, during the Transition Period, the Company will utilize a deferred accounting mechanism for any Deferred Costs. Revenues for BGS will only be deferred to the extent necessary to fund and sustain the rate reductions set forth in paragraph 1 and then only after the deferral of any other item of Deferred Costs, as set forth in this paragraph. Any Deferred Costs, together with a return on the unrecovered balance, will be audited by the Board and will be recoverable at the end of the Transition Period in a manner and timeframe to be determined by the Board.
Final Decision and Order	Page 94 Paragraph 34	Consistent with N.J.S.A. 48:3-60, the Company will establish a Societal Benefits Charge. The SBC will include costs related to: (1) social programs, (2) nuclear plant decommissioning costs, (3) Demand Side Management programs, and (4) consumer education expenses.
Final Decision and Order	Page 94 Paragraph 35	The SBC will be set at the level of costs for the above items already in rates as of the date of the Board's Summary Order in this matter. During the Transition Period, the funding of SBC initiatives may vary from the level of funding currently in rates. An annual true-up process will be established to provide for the full and timely recovery of SBCs. To the extent that full and timely recovery of the SBC costs prevents the Company from achieving the rate reductions described in paragraph 1 above, the Company will defer a portion of the SBC cost recovery subject to the same terms and conditions as described in paragraph 27.
Final Decision and Order	Page 94 Paragraph 36	For ratemaking purposes, all tax expenses for the computation of divestiture proceeds, MTC revenues and NUG buyouts or buydowns shall be determined on a utility standalone basis, and not by imputing the tax effects of a consolidated return. Such treatment has no precedential value with regard to future rate cases pertaining to the regulated rates of ACE.
Final Decision and Order	Pages 95 and 96	Expenses to redeem and retire outstanding capital in connection with the recovery of stranded costs shall be

The Board Orders should be read in their entirety regarding the Deferred Balances.

Atlantic City Electric Company ("ACE")

**Excerpts from the New Jersey Board of Public Utilities ("Board") Orders
For the year ended July 31, 2003**

Board Order, Date and Docket No.	Page and/or Paragraph No.	Excerpt
	Paragraph 43	recognized as stranded costs, and may be included in the MTC for recovery. Recovery via the MTC of expenses to redeem or retire outstanding capital in connection with the recovery of stranded costs is subject to Board review that such costs have been reasonably and prudently incurred. The Board also notes that reasonably and prudently incurred capital retirement and redemption expenses associated with a securitization financing are included the definition of bondable stranded costs in the Act and upon application by ACE and a determination by the Board that the conditions of EDECA are met, may be securitized to the extent permitted by EDECA and recovered via the TBC. In setting the annual level of charges for BGS during the Transition Period, for any MTC that continues beyond the Transition Period, and for the SBC, NNC and the TBC, the Company will utilize a methodology similar to that currently used for setting its Energy Adjustment clause charges. The BGS, SBC, NNC, MTC and TBC components will be reviewed annually, based upon projections of costs and of sales. Actual costs will be accounted for on a deferred accounting basis, and when the BGS, SBC, NNC, MTC and TBC are set in the following year, each of those rate components will be set to recover any underrecovery in the Deferred Balance, as well as the projected costs for the upcoming year. The setting of the BGS, SBC, NNC and MTC shall be subject to providing the rate reductions as set forth in paragraph 1, the Deferred Costs provisions of paragraphs 27-29, and the provisions of the Act. Accordingly, notwithstanding the above and in order to satisfy the rate reduction provisions of the Act, the Board may or may not actually adjust the indicated charges (other than the TBC and the BGS price as provided in the Act and/or elsewhere in this Order) during the Transition Period. Any overrecoveries in the Deferred Balances for the BGS, SBC, NNC or MTC will be applied as a credit to the respective rate components in the same manner. The same procedure will be followed for each year in which the BGS, SBC, NNC, MTC and TBC charges are to be set.
Final Decision and Order	Page 96 Paragraph 46	In summary, subject to the conditions embodied herein, the rate discounts provided by ACE, all stated relative to current rates, shall be at a minimum as follows: August 1, 1999, 5 % January 1, 2001, 7% August 1, 2002, 10.2%

The Board Orders should be read in their entirety regarding the Deferred Balances.

Atlantic City Electric Company ("ACE")

Excerpts from the New Jersey Board of Public Utilities ("Board") Orders
For the year ended July 31, 2003

Board Order, Date and Docket No.	Page and/or Paragraph No.	Excerpt
November 10, 1999 Decision and Order Docket No. EE99090685 ("November 10, 1999 Order")	Pages 9 2nd paragraph	In each case, however, recoverable interest costs included in the NNC during the period of interim financing would be calculated by applying the interest rate actually incurred on the interim debt to an initial net of tax debt balance that reflects the full tax deduction associated with the termination payment. Accordingly, we HEREBY DIRECT the Company to credit the difference between the revenue allowed for buyout costs during the period of interim financing (exclusive of sales tax) and the buyout costs actually incurred (i.e., the short-term debt interest, calculated as just described) to the NNC deferred balance with interest, thereby assuring that ratepayers are fully compensated by this treatment.
November 10, 1999 Order	Page 9 6th paragraph	As to Issue 4, we agree with the Ratepayer Advocate and find that after the closing on the termination agreement, there should be no further recovery of PCLP-related Merrill Creek costs from ratepayers and the Board disallows the inclusion of such costs as part of the Company's stranded cost recovery.
November 10, 1999 Order	Page 11 2nd paragraph	Pursuant to Section 13 (l) 1 of the Act, and based on the ratepayer savings expected to result from the termination agreement presented herein and the rate reduction associated therewith, we HEREBY APPROVE the proposed buy-out of the PCLP PPA. Pursuant to that Section and Sections 13 (a) (3) and 14 (c) (2) of the Act, we additionally HEREBY FIND that Atlantic is entitled to and shall be allowed full and timely recovery of the $228.5 million termination payment employing the net of tax methodology provided for herein, as well as reasonable and prudently incurred transaction costs at a level to be determined by the Board and interim financing costs in the manner provided for hereinabove. Finally, pursuant to Section 14 (c) (2) of the Act, we HEREBY FIND that the termination payment and related transaction costs determined to be recoverable by the Board may in the aggregate either constitute, or may be included as part of the principal amount of transition bonds for which Atlantic may seek approval to issue under the Act.
Energy Decision and Order – Sale of Nuclear Assets Agenda Date: May 10, 2000 Signed July 21, 2000 Docket No. EM99110870 ("July 21, 2000 Order")	Pages 22 (3rd Paragraph) and Page 23	In addition, consistent with the Board's prior Orders relating to the sale of a utility's generating assets, the Board HEREBY DIRECTS the Company to file for a private letter ruling with the IRS regarding the treatment of the federal income tax benefits associated with the divested assets, such as the Investment Tax Credit ("ITC"), Excess Deferred Income Taxes ("EDIT") associated with changes in the corporate tax rate, and Accumulated Deferred Income Taxes ("ADIT") associated with timing differences between tax and book accounting, namely, timing differences associated with accelerated tax depreciation. If favorable, the requested ruling, which could be based on the arguments advanced in a similar request ordered by the Connecticut Department of Utility Control in connection with the divestiture of United Illuminating Company's Bridgeport Harbor and New Haven generating stations, would allow the benefits associated with the remaining balances of deferred income and investment tax credits to continue to flow through to

Atlantic City Electric Company ("ACE")

Excerpts from the New Jersey Board of Public Utilities ("Board") Orders
For the year ended July 31, 2003

Board Order, Date and Docket No.	Page and/or Paragraph No.	Excerpt
		ratepayers. Thus, the Board HEREBY ORDERS the Company to file for a private letter ruling with the IRS regarding these tax issues and accordingly, our final determination of the net proceeds and stranded costs (the closing true-up proposed by the Company on page 26 of the Petition) shall await the outcome of this ruling.
July 21, 2000 Order	Page 23 3rd paragraph	The Board notes that, in either case, the Company's overall rates would not change during the four year transition period and thus the revenues "freed up" by the cessation of decommissioning funding would either serve to reduce the SBC deferral if the SBC were left unchanged, or the Basic Generation Service, Net Non-Utility Generation Charge ("NNC") or Market Transition Charge ("MTC") deferral in the event the SBC were reduced. For that reason, we will allow the Company to maintain the SBC at its current level, recognizing that interest will be accrued on any over-recovered balance that may result, and that the full over-recovered balance with applicable interest shall be applied for the benefit of ratepayers in a manner to be determined by the Board at a future date and shall be netted against all other deferrals for purposes of applying the threshold tests included in paragraphs 27 through 29 of the Stipulation of Settlement as modified by the Board's Summary Order.
Decision and Order - Sale of the Company's Nuclear Generating Units Agenda Date: May 5, 2000 Signed September 17, 2001 Docket No. EM99110870 ("September 17, 2001 Order")	Page 5 4th paragraph	The Board recognizes that the Nuclear Assets-related portion of the Company's interest in Merrill Creek will no longer be used and useful upon the closing of the sale of the Nuclear Assets, as discussed above. The Board FINDS it appropriate to allow certain Merrill Creek expenses, in an approximate amount of $4.7 million, to remain as eligible stranded costs at this time. However, the Board also recognizes that Merrill Creek has potential prospective value for generation facilities that may be constructed in the Delaware River Basin during the term for which ACE has an entitlement to water storage capacity in Merrill Creek. Also, ACE has the duty to mitigate its stranded costs. Therefore, the Company is DIRECTED to use its best efforts to sell or lease all or part of its interest in Merrill Creek so as to mitigate its stranded costs. The Board further DIRECTS that all revenues resulting from any sale or lease shall be returned to customers as a credit against stranded costs charges.
September 17, 2001 Order	Page 5 5th paragraph	As a result of the above adjustments to ACE's proposed level of eligible stranded cost recovery associated with the sale of the Nuclear Assets, the Board HEREBY DETERMINES the amount of stranded costs, eligible for recovery by the Company, as defined by N.J.S.A. 48:3-51, to be approximately $297.9 million as of December 31, 1999, subject to further adjustment at the time of closing and subsequent verification to reflect actual data at the time of closing. Pursuant to N.J.S.A. 48:3-61(a)(1), the Board HEREBY FINDS

Atlantic City Electric Company ("ACE")

Excerpts from the New Jersey Board of Public Utilities ("Board") Orders
For the year ended July 31, 2003

Board Order, Date and Docket No.	Page and/or Paragraph No.	Excerpt
		that the Company shall have the opportunity to recover such eligible stranded costs through the Company's Market Transition Charge, in a time frame and manner to be determined by the Board.
Final Order Approving Transfer Dated and Signed December 19, 2001 Docket No. EM00060384	Page 3 3rd paragraph	The Board HEREBY DIRECTS that all monthly lease revenues shall be immediately credited against ACE's MTC deferred balance. The Board FURTHER DIRECTS that the one-time credit of $5,000 also be credited to the MTC deferred balance at the time of the closing of the transaction. ACE shall notify the Board within five (5) business days of the closing. All other determinations set forth in the Order Conditionally Approving Transfer shall continue to remain in full effect as though set forth herein in their entirety.
Approval of an Amendment to the Agreement for Purchase of Electric Power with American Ref-Fuel Company of Delaware Valley, L.P. December 6, 2000 Docket No. EM00060388	Page 3 4th paragraph	The Board also FINDS it appropriate to permit all reasonable and prudent costs incurred by ACE in fulfilling the terms of the Amendment to be recovered on a full and timely basis through the Company's MTC to its electric customers, and to pass through any savings to its electric customers through the same approved mechanism. However, the Board also recognizes that the Company has provided an insufficient level of detail in support of the claimed transaction costs that it proposes to include in recoverable costs. Accordingly, the Board requires the Company to provide additional supporting information regarding such costs before the Board determines whether such costs can be ultimately found to be reasonable and prudent. At the same time, the Board affirms the recoverability of such costs that are ultimately found to be reasonable and prudent, and not otherwise recoverable in rates. The Board DIRECTS ACE to provide detailed information in support of its transaction costs with thirty (30) days of the conclusion of the transaction.

The Board Orders should be read in their entirety regarding the Deferred Balances.

Atlantic City Electric Company

Schedule of Deferred Balances
For the year ended July 31, 2003
(Dollars in Thousands)

Components	**Unaudited** Beginning Balance at August 1, 2002 Over (Under) Recovery	Revenue	Cost	Ending Balance at July 31, 2003 Over (Under) Recovery	Adjustments and Restatements	Adjusted Balance at July 31, 2003 Over (Under) Recovery
Basic Generation Service ("BGS") (Note 1)						
BGS Revenues	$ 1,254,808	$ 479,317	$ -	$ 1,734,125	$ -	$ 1,734,125
BGS Costs:						
Contracted NUG BGS Cost (Note 2)	(398,096)	-	(151,420)	(549,516)	-	(549,516)
To Be Divested BGS Cost (Note 3)	(429,564)	-	(101,654)	(531,218)	-	(531,218)
Energy and Capacity Purchases	(565,156)	-	(385,704)	(950,860)	-	(950,860)
Others, net	44,776		178,178	222,954	-	222,954
Total BGS Costs	(1,348,040)	-	(460,600)	(1,808,640)	-	(1,808,640)
Net BGS Deferral	**(93,232)**	**479,317**	**(460,600)**	**(74,515)**	-	**(74,515)**
Net Non-Utility Generation Transition Charge ("NNC") (Note 2)						
NNC Revenues	360,101	100,519	-	460,620	-	460,620
Net NUG Costs:						
NUG Contract Cost, net	(324,946)	-	(90,842)	(415,788)	-	(415,788)
Others	(28,996)	-	(3,624)	(32,620)	-	(32,620)
Net NUG Costs	(353,942)	-	(94,466)	(448,408)	-	(448,408)
Net NNC Deferral	**6,159**	**100,519**	**(94,466)**	**12,212**	-	**12,212**

See Notes to the Schedule.

Atlantic City Electric Company

Schedule of Deferred Balances
For the year ended July 31, 2003
(Dollars in Thousands)

Components	Audited Beginning Balance at August 1, 2002 Over (Under) Recovery	Revenue	Cost	Ending Balance at July 31, 2003 Over (Under) Recovery	Adjustments and Restatements	Adjusted Balance at July 31, 2003 Over (Under) Recovery
Market Transition Charge ("MTC") (Note 3)						
Revenues:						
MTC Revenues	$ 92,211	$ 17,773	$ -	$ 109,984	$ -	$ 109,984
Others	7,356	549	-	7,905	-	7,905
Total MTC Revenues	99,567	18,322	-	117,889	-	117,889
MTC Costs:						
To-Be-Divested Units Revenue Requirement, net	(178,970)	-	(53,587)	(232,557)	-	(232,557)
Others	(14,505)	-	(4,064)	(18,569)	-	(18,569)
Total MTC Costs	(193,475)	-	(57,651)	(251,126)	-	(251,126)
Net MTC Deferral	**(93,908)**	**18,322**	**(57,651)**	**(133,237)**	**-**	**(133,237)**
Societal Benefits Charge ("SBC") (Note 4)						
Demand Side Management	4,274	5,704	(9,294)	684	-	684
Nuclear Decommissioning	22,118	8,017	-	30,135	-	30,135
Uncollectable Accounts	(9,024)	6,297	(5,389)	(8,116)	1,485	(6,631)
Net SBC Deferral	**17,368**	**20,018**	**(14,683)**	**22,703**	**1,485**	**24,188**
Deferred Balances	**(163,613)**	**618,176**	**(627,400)**	**(172,837)**	**-**	**(171,352)**
Interest on total deferred balances (Note 5)	**(2,180)**	**-**	**(6,600)**	**(8,780)**	**3,587**	**(5,193)**
Total	**$ (165,793)**	**$ 618,176**	**$ (634,000)**	**$ (181,617)**	**$ 5,072**	**$ (176,545)**

See Notes to the Schedule.

Atlantic City Electric Company
Notes to the Schedule of Deferred Balances
For the year ended July 31, 2003

Note 1. BASIC GENERATION SERVICE ("BGS")

The BGS revenues and costs were provided by the Company in response to the auditors' data request.

Note 2. NON-UTILITY GENERATION CHARGES ("NNC")

The deferred balances for NNC were provided by Company in response to auditors' data request.

Pursuant to the Board Orders[1], the NUG Contract Cost on the schedule of deferred balances was presented after deducting the BGS costs calculated at the net BGS price applied to the kilowatt hours generated by the non-utility generating companies.

Note 3. MARKET TRANSITION CHARGES ("MTC")

The MTC revenues and costs were provided by the Company in response to the auditors' data request.

Pursuant to the Board Orders[1], the calculated revenue requirement on the schedule of deferred balances was presented after deducting the BGS costs calculated at the net BGS price applied to the kilowatt hours generated by the Company-owned generating units.

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[1] Final Decision and Order; In the Matter of Atlantic City Electric Company's Rate Unbundling, Stranded Costs and Restructuring Filings; Dated March 30, 2001; BPU Docket Nos. EO97070455, EO97070456 and EO97070457, Page 87, Paragraph 7.

Atlantic City Electric Company
Notes to the Schedule of Deferred Balances
For the year ended July 31, 2003

Note 4. SOCIETAL BENEFITS CHARGES ("SBC")

The deferred balances for SBC were provided by the Company in response to the auditors' data request.

Note 5. INTEREST

Pursuant to the Board Orders[2], interest adjusted on August 1 of each year of the Transition Period will be accrued on any under or over recovered balances. The interest rate will be based on seven year constant maturity treasuries as shown in the Federal Reserve Statistical Release on or closest to August 1 of each year plus sixty basis points.

The Company applied interest on the monthly average of the under or over recovered deferred balances. The interest rate used during Phase II was 4.48%

Note 6. ENDING BALANCE AT JULY 31, 2003

Ending balance at July 31, 2003, as stated on this schedule, includes two adjustments and restatements from Phase I Audit for a PCLP interest adjustment due to timing in the amount of $459,332 and the "misclassification" of $2.617M of the amortization of the Gross Receipts and Franchise Taxes, which are currently under appeal with the Appellate Division of the Superior Court of New Jersey.

[2] Final Decision and Order; In the Matter of Atlantic City Electric Company's Rate Unbundling, Stranded Costs and Restructuring Filings; Dated March 30, 2001; BPU Docket Nos. EO97070455, EO97070456 and EO97070457, Page 82, 3rd Paragraph.