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An Exelon Company

July 14, 2017

VIA FEDERAL EXPRESS and
ELECTRONIC MAIL
irene.asbury@bpu.nj.gov
board.secretary@bpu. nj.gov

Irene Kim Asbury, Esquire
Secretary of the Board
Board of Public Utilities
44 South Clinton Avenue, 3rd Floor, Suite 314
P.O. Box 350
Trenton, New Jersey 08625-0350

RE: I/M/O the Petition of Atlantic City Electric Company for Approval to Implement FERC-Approved Changes to ACE's Retail Transmission (Formula) Rate Pursuant to Paragraphs 15.9 of the BGS-RSCP and BGS-CIEP Supplier Master Agreements and Tariff Filing Reflecting Changes to Schedule 12 Charges in PJM Open Access Transmission Tariff (2017)
BPU Docket No. ______________________

Dear Secretary Asbury:

The undersigned is Assistant General Counsel to Atlantic City Electric Company ("ACE" or the "Company") in connection with the above referenced matter.

Enclosed herewith for filing are three conformed copies of a Verified Petition and supporting Exhibits seeking Board approval to implement changes to ACE's retail transmission rates charged to suppliers of Residential Small Commercial Pricing and Commercial and Industrial Basic Generation Service.[1] Tariff pages reflecting changes to Schedule 12 charges in the PJM Open Access Transmission Tariff have also been provided.

Kindly file this submission and advise ACE of the assigned docket number at your earliest convenience. Please note that the Company has requested action on this filing by September 1, 2017.

[1] This filing has been made consistent with the Board's Order Waiving Provisions of N.J.A.C. 14:4-2, N.J.A.C. 14:17-4.2(a), N.J.A.C. 14:1-1.6(c), and N.J.A.C. 14:17-1.6(d), issued on July 29, 2016, in connection with *In the Matter of the Board's E-Filing Program*, BPU Docket No. AX16020100.

Thank you for your consideration and courtesies. Feel free to contact me with any questions or if I can be of further assistance.

Respectfully submitted,

/jpr
Philip J. Passanante
An Attorney at Law of the
State of New Jersey

Enclosure

cc: Service List

IN THE MATTER OF THE PETITION OF ATLANTIC CITY ELECTRIC COMPANY FOR APPROVAL TO IMPLEMENT FERC-APPROVED CHANGES TO ACE'S RETAIL TRANSMISSION (FORMULA) RATE PURSUANT TO PARAGRAPHS 15.9 OF THE BGS-RSCP AND BGS-CIEP SUPPLIER MASTER AGREEMENTS (2017)	STATE OF NEW JERSEY BOARD OF PUBLIC UTILITIES BPU Docket No. _______________ VERIFIED PETITION

ATLANTIC CITY ELECTRIC COMPANY (hereinafter referred to as "Petitioner," "ACE" or the "Company"), a public utility corporation of the State of New Jersey, respectfully requests that the Board of Public Utilities ("BPU" or the "Board") approve implementation of changes to the Company's retail transmission (formula) rates filed with the Federal Energy Regulatory Commission ("FERC"), as proposed and outlined herein. In support thereof, Petitioner states as follows:

1. The Company is engaged in the purchase, transmission, distribution, and sale of electric energy to residential, commercial, and industrial customers. ACE's service territory comprises eight counties located in southern New Jersey, and includes approximately 550,000 customers.

2. As part of a settlement approved by FERC on or about August 9, 2004, certain transmission owners in PJM Interconnection, L.L.C. ("PJM"), including ACE, agreed to reexamine their existing rates and propose a method (such as a formula rate) to harmonize new and existing transmission investments by January 31, 2005. It was anticipated that such new rate (if any) would go into effect on or by June 1, 2005.[1] On January 31, 2005, Petitioner, among others, filed a formula rate for determining the wholesale transmission revenue requirements

[1] *See Allegheny Power System Operating Companies, et al.*, 108 FERC ¶61,167 (2004).

applicable in its PJM rate zone pursuant to the PJM tariff, to be effective on or about June 1, 2005.

3. The objective of the formula rate filing was to establish a just and reasonable method for determining transmission revenue requirements for the affected transmission pricing zones which would reflect existing and new investment on a current basis. The formula rate tracks increases and decreases in costs such that no under-recovery and no over-recovery of actual costs will occur. In the formula rate filing, ACE committed to populate the formula with actual data from its filed FERC Form 1 for calendar year 2004, and to post that information on the PJM website no later than May 1, 2004.

4. On March 20, 2006, certain transmission owners within PJM filed an uncontested settlement in Docket No. ER04-515-000 (the "Settlement").[2] The Settlement was approved by FERC on or about April 19, 2006. FERC also accepted the revised tariff sheets for filing effective June 1, 2005. The formula rate implementation protocols included provisions for an annual update to the Annual Transmission Revenue Requirements (the "Transmission Rate") based on current levels of costs and the reconciliation of prior period costs and revenues.

5. The Settlement also provided that, "[o]n or before May 15 of each year [ACE] shall recalculate its [Transmission Rate], produce an "Annual Update" for the upcoming year, and;

> (i) post such Annual Update on PJM's Internet website… and
>
> (ii) file such Annual Update with the FERC as an informational filing."[3]

---

[2] The transmission owners included Baltimore Gas and Electric Company and Pepco Holdings, Inc. ("PHI") and its operating affiliates. The Petitioner is an operating affiliate of PHI, which is now known as Pepco Holdings LLC.

[3] *See* Settlement Agreement, Exhibit B-1 containing PJM Tariff Attachment H1-B, Section 1.b.

6. Pursuant to the implementation protocols established in the Settlement, the Company filed an update to the formula rate at FERC on or about May 12, 2017, to be effective June 1, 2017. The formula rate update also incorporated a number of transmission enhancement projects that are included in Schedule 12 of the PJM Open Access Transmission Tariff ("OATT"). A copy of that update is included as **Exhibit A**.

7. Schedule 12 of the PJM OATT details Transmission Enhancement Charges ("TECs"), which were implemented to compensate transmission owners for the annual transmission revenue requirements for "Required Transmission Enhancements" (again, as defined in the PJM OATT) that are requested by PJM for reliability or economic purposes. TECs are recovered by PJM through an additional transmission charge in the transmission zones assigned cost responsibility for Required Transmission Enhancement projects. By Order dated January 25, 2017 (BPU Docket No. ER16121153), the Board approved and authorized ACE and the other New Jersey electric distribution companies ("EDCs") to recover the FERC-approved TECs found in Schedule 12 of the OATT for the Potomac Appalachian Transmission Highline, L.L.P. ("PATH") project, and for certain projects of Virginia Electric and Power Company ("VEPCo").

8. Commencing on or about April 24, 2017, formula rate update filings were made by Baltimore Gas and Electric Company (April 24, 2017), PPL Electric Utilities Corporation (April 27, 2017), American Electric Power Service Corporation (May 30, 2017), Trans-Allegheny Interstate Line Company (also referred to as "TrAILCo") (May 15, 2017), Delmarva Power & Light Company (May 12, 2017), and Potomac Electric Power Company (May 12, 2017), to be effective June 1, 2017. Each formula rate update filing includes TECs that are applicable to customers in the ACE service territory. Copies of all formula rate updates can be

found on the PJM website at http://www.pjm.com/markets-and-operations/billing-settlements-and-credit/formula-rates.aspx.

9. By Order dated October 22, 2003 (BPU Docket No. EO03050394), the Board authorized the EDCs to recover FERC-approved changes in firm transmission service-related charges. The Board has also authorized recovery of FERC-approved changes in firm transmission service-related charges in subsequent orders approving the Basic Generation Service ("BGS") supply procurement process and the associated Supplier Master Agreement(s) ("SMAs"). Pursuant to these Board Orders, the Company has recovered the TECs as part of its Basic Generation Service-Residential Small Commercial Pricing ("BGS-RSCP") and Basic Generation Service-Commercial and Industrial Energy Pricing ("BGS-CIEP").

10. Through this filing, the Company respectfully requests approval to implement the new transmission rates and TECs effective as of Friday, September 1, 2017. Proposed tariffs containing the revised rates for transmission service are attached as **Exhibit B**. Also included in **Exhibit B** are tariff pages showing additions and deletions to the current tariff pages. The revised tariff sheets reflect changes in BGS-RSCP and BGS-CIEP charges to customers resulting from a change in FERC-approved Transmission Rates.

11. **Exhibit C** provides the proposed adjustment to the overall retail transmission rate to incorporate the TECs for projects outside of the ACE Zone in PJM. Additionally, as indicated previously, a number of TEC-related projects have been approved within the ACE Zone. The revenue requirements associated with these projects are delineated in Attachment 7 to the Company's formula rate filing. **Exhibit D** to this filing provides the treatment for incorporating the cost responsibilities and revenue credits for these projects in the development of the ACE

retail transmission rates. The Company's work papers, which set forth the details of the rate design calculations, are provided as **Exhibit E**.

12. The Transmission Rates reported herein have been modified in accordance with the Board-approved methodology contained in the Company-Specific Addenda provided pursuant to the BGS proceedings referenced in this Petition.

13. Petitioner further respectfully requests that the effected BGS suppliers receive the appropriate compensation for the rate adjustment(s) detailed herein, subject to the terms and conditions of the appropriate BGS-RSCP and/or BGS-CIEP SMAs.

14. This Petition satisfies the requirements of ¶¶ 15.9(a)(i) and (ii) of the BGS-RSCP SMAs and ¶¶ 15.9(a)(i) and (ii) of the BGS-CIEP SMAs, which mandate that BGS suppliers be notified of rate increases or decreases in the Transmission Rate, and that the Company file for and obtain the Board's approval to implement changes in retail rates commensurate with the FERC-implemented Transmission Rate change. An adjustment to BGS supplier accounts for the period June 1, 2017 through May 31, 2018 will be made upon the Board's approval of this request. For the period beginning June 1, 2017, Petitioner will track amounts associated with the rate change to BGS suppliers in accordance with ¶¶ 15.9(a)(iii) and (iv) of the BGS-RSCP and BGS-CIEP SMAs until receipt of final FERC action on the informational filing referenced in Paragraph 6 above.

15. Communications and correspondence regarding this matter should be sent to Petitioner and its counsel at the following addresses:

Philip J. Passanante, Esquire
Assistant General Counsel
Atlantic City Electric Company
92DC42
500 North Wakefield Drive
Newark, Delaware 19702

Post Office Box 6066
Newark, Delaware 19714-6066

with copies to the following representatives of the Company:

Joseph F. Janocha
Manager, Retail Rates
Atlantic City Electric Company - 63ML38
5100 Harding Highway
Mays Landing, New Jersey 08330

and

Roger E. Pedersen
Manager, Regulatory Affairs
Atlantic City Electric Company - 63ML38
5100 Harding Highway
Mays Landing, New Jersey 08330

and

Daniel A. Tudor
Senior Energy Acquisition Analyst
EP6412
Pepco Holdings, LLC/Atlantic City Electric Company
701 Ninth Street, N.W.
Washington, D.C. 20068-0001

WHEREFORE, the Petitioner, **ATLANTIC CITY ELECTRIC COMPANY**, respectfully requests that the Board of Public Utilities:

A. permit the Company to implement changes to Petitioner's retail transmission (formula) rates as detailed in this filing;

B. authorize appropriate adjustments to BGS suppliers subject to the terms and conditions of the BGS-RSCP and/or BGS-CIEP SMAs; and

C. grant such other or further relief as may be just and appropriate.

Respectfully submitted,

ATLANTIC CITY ELECTRIC COMPANY

Dated: July 14, 2017

/jpr

PHILIP J. PASSANANTE
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Assistant General Counsel to
Atlantic City Electric Company

IN THE MATTER OF THE PETITION OF ATLANTIC CITY ELECTRIC COMPANY FOR APPROVAL TO IMPLEMENT FERC-APPROVED CHANGES TO ACE'S RETAIL TRANSMISSION (FORMULA) RATE PURSUANT TO PARAGRAPHS 15.9 OF THE BGS-RSCP AND BGS-CIEP SUPPLIER MASTER AGREEMENTS (2017)	STATE OF NEW JERSEY BOARD OF PUBLIC UTILITIES

AFFIDAVIT OF VERIFICATION

KEVIN M. McGOWAN, being duly sworn, upon his oath deposes and says:

1. I am the Vice President of Regulatory Policy and Strategy of Atlantic City Electric Company ("ACE"), the Petitioner named in the foregoing Verified Petition. I am duly authorized to make this Affidavit of Verification on ACE's behalf.

2. I have read the contents of the foregoing Verified Petition by ACE for Approval to Implement FERC-Approved Changes to Its Retail Transmission (Formula) Rate Pursuant to Paragraphs 15.9 of the BGS-RSCP and BGS-CIEP Supplier Master Agreements. I verify that the statements of fact and other information contained therein are true and correct to the best of my knowledge, information, and belief.

KEVIN M. McGOWAN

SWORN TO AND SUBSCRIBED before me this 5th day of July, 2017.

DOROTHY M. BONDS
NOTARY
Exp. - 10/14/2021
PUBLIC
DISTRICT OF COLUMBIA

Notary Public
My Commission Expires: 10/14/2021

Exhibit A

ATTACHMENT H-1A

	Atlantic City Electric Company Formula Rate - Appendix A		Notes	FERC Form 1 Page # or Instruction	2016
	Shaded cells are input cells				
	Allocators				
	Wages & Salary Allocation Factor				
1	Transmission Wages Expense			p354.21.b	$ 2,935,059
2	Total Wages Expense			p354.28b	$ 34,528,085
3	Less A&G Wages Expense			p354.27b	$ 1,327,463
4	Total			(Line 2 - 3)	33,200,622
5	Wages & Salary Allocator			(Line 1 / 4)	8.8404%
	Plant Allocation Factors				
6	Electric Plant in Service		(Note B)	p207.104g (see Attachment 5)	$ 3,340,259,698
7	Common Plant In Service - Electric			(Line 24)	0
8	Total Plant In Service			(Sum Lines 6 & 7)	3,340,259,698
9	Accumulated Depreciation (Total Electric Plant)			p219.29c (see Attachment 5)	$ 734,424,845
10	Accumulated Intangible Amortization		(Note A)	p200.21c	$ 15,119,930
11	Accumulated Common Amortization - Electric		(Note A)	p356	$ -
12	Accumulated Common Plant Depreciation - Electric		(Note A)	p356	$ -
13	Total Accumulated Depreciation			(Sum Lines 9 to 12)	749,544,775
14	Net Plant			(Line 8 - 13)	2,590,714,923
15	Transmission Gross Plant			(Line 29 - Line 28)	1,150,457,660
16	Gross Plant Allocator			(Line 15 / 8)	34.4422%
17	Transmission Net Plant			(Line 39 - Line 28)	910,994,675
18	Net Plant Allocator			(Line 17 / 14)	35.1638%
	Plant Calculations				
	Plant In Service				
19	Transmission Plant In Service		(Note B)	p207.58.g	$ 1,124,448,196
20	For Reconciliation only - remove New Transmission Plant Additions for Current Calendar Year		For Reconciliation Only	Attachment 6 - Enter Negative	$ -
21	New Transmission Plant Additions for Current Calendar Year (weighted by months in service)			Attachment 6	14,359,330
22	Total Transmission Plant In Service			(Line 19 - 20 + 21)	1,138,807,526
23	General & Intangible			p205.5.g & p207.99.g (see Attachment 5)	$ 131,783,286
24	Common Plant (Electric Only)		(Notes A & B)	p356	$ -
25	Total General & Common			(Line 23 + 24)	131,783,286
26	Wage & Salary Allocation Factor			(Line 5)	8.84037%
27	General & Common Plant Allocated to Transmission			(Line 25 * 26)	11,650,135
28	Plant Held for Future Use (Including Land)		(Note C)	p214	782,029
29	TOTAL Plant In Service			(Line 22 + 27 + 28)	1,151,239,689
	Accumulated Depreciation				
30	Transmission Accumulated Depreciation		(Note B)	p219.25.c	$ 234,966,564
31	Accumulated General Depreciation			p219.28.c (see Attachment 5)	$ 35,742,413
32	Accumulated Intangible Amortization			(Line 10)	15,119,930
33	Accumulated Common Amortization - Electric			(Line 11)	0
34	Common Plant Accumulated Depreciation (Electric Only)			(Line 12)	0
35	Total Accumulated Depreciation			(Sum Lines 31 to 34)	50,862,343
36	Wage & Salary Allocation Factor			(Line 5)	8.84037%
37	General & Common Allocated to Transmission			(Line 35 * 36)	4,496,421
38	TOTAL Accumulated Depreciation			(Line 30 + 37)	239,462,985
39	TOTAL Net Property, Plant & Equipment			(Line 29 - 38)	911,776,704
	Adjustment To Rate Base				
	Accumulated Deferred Income Taxes				
40	ADIT net of FASB 106 and 109			Attachment 1	-293,036,751
41	Accumulated Investment Tax Credit Account No. 255	Enter Negative	(Notes A & I)	p266.h	0
42	Net Plant Allocation Factor			(Line 18)	35.16%
43	Accumulated Deferred Income Taxes Allocated To Transmission			(Line 41 * 42) + Line 40	-293,036,751
43a	Transmission Related CWIP (Current Year 12 Month weighted average balances)		(Note B)	p216.43.b as Shown on Attachment 6	0
	Transmission O&M Reserves				
44	Total Balance Transmission Related Account 242 Reserves		Enter Negative	Attachment 5	-2,251,848
	Prepayments				
45	Prepayments		(Note A)	Attachment 5	7,568,786
46	Total Prepayments Allocated to Transmission			(Line 45)	7,568,786
	Materials and Supplies				
47	Undistributed Stores Exp		(Note A)	p227.6c & 16.c	0
48	Wage & Salary Allocation Factor			(Line 5)	8.84%
49	Total Transmission Allocated			(Line 47 * 48)	0
50	Transmission Materials & Supplies			p227.8c	$ 1,943,868
51	Total Materials & Supplies Allocated to Transmission			(Line 49 + 50)	1,943,868
	Cash Working Capital				
52	Operation & Maintenance Expense			(Line 85)	25,079,904
53	1/8th Rule			x 1/8	12.5%
54	Total Cash Working Capital Allocated to Transmission			(Line 52 * 53)	3,134,988
	Network Credits				
55	Outstanding Network Credits		(Note N)	From PJM	0
56	Less Accumulated Depreciation Associated with Facilities with Outstanding Network Credits		(Note N)	From PJM	0
57	Net Outstanding Credits			(Line 55 - 56)	0
58	TOTAL Adjustment to Rate Base			(Line 43 + 43a + 44 + 46 + 51 + 54 - 57)	-282,640,957
59	Rate Base			(Line 39 + 58)	629,135,747

O&M

	Transmission O&M				
60	Transmission O&M			p321.112.b (see Attachment 5)	$ 18,775,954
61	Less extraordinary property loss			Attachment 5	0
62	Plus amortized extraordinary property loss			Attachment 5	0
63	Less Account 565			p321.96.b	$ -
64	Plus Schedule 12 Charges billed to Transmission Owner and booked to Account 565		(Note O)	PJM Data	$ -
65	Plus Transmission Lease Payments		(Note A)	p200.3c	$ -
66	Transmission O&M			(Lines 60 - 63 + 64 + 65)	18,775,954
	Allocated General & Common Expenses				
67	Common Plant O&M		(Note A)	p356	$ -
68	Total A&G			p323.197.b (see Attachment 5)	$ 73,069,738
68a	For informational purposes: PBOB expense in FERC Account 926		(Note S)	Attachment 5	$ 1,000,545
69	Less Property Insurance Account 924			p323.185b	$ 468,644
70	Less Regulatory Commission Exp Account 928		(Note E)	p323.189b	$ 4,153,916
71	Less General Advertising Exp Account 930.1			p323.191b	$ 363,930
72	Less DE Enviro & Low Income and MD Universal Funds			p335.b	$ -
73	Less EPRI Dues		(Note D)	p352-353	$ 138,757
74	General & Common Expenses			(Lines 67 + 68) - Sum (69 to 73)	67,944,491
75	Wage & Salary Allocation Factor			(Line 5)	8.8404%
76	General & Common Expenses Allocated to Transmission			(Line 74 * 75)	6,006,547
	Directly Assigned A&G				
77	Regulatory Commission Exp Account 928		(Note G)	p323.189b	132,610
78	General Advertising Exp Account 930.1		(Note F)	p323.191b	0
79	Subtotal - Transmission Related			(Line 77 + 78)	132,610
80	Property Insurance Account 924			p323.185b	$ 468,644
81	General Advertising Exp Account 930.1		(Note K)	p323.191b	0
82	Total			(Line 80 + 81)	468,644
83	Net Plant Allocation Factor			(Line 18)	35.16%
84	A&G Directly Assigned to Transmission			(Line 82 * 83)	164,793
85	Total Transmission O&M			(Line 66 + 76 + 79 + 84)	25,079,904

Depreciation & Amortization Expense

	Depreciation Expense				
86	Transmission Depreciation Expense			p336.7b&c	26,123,416
87	General Depreciation			p336.10b&c	6,240,883
88	Intangible Amortization		(Note A)	p336.1d&e	139,483
89	Total			(Line 87 + 88)	6,380,366
90	Wage & Salary Allocation Factor			(Line 5)	8.8404%
91	General Depreciation Allocated to Transmission			(Line 89 * 90)	564,048
92	Common Depreciation - Electric Only		(Note A)	p336.11.b	0
93	Common Amortization - Electric Only		(Note A)	p356 or p336.11d	0
94	Total			(Line 92 + 93)	0
95	Wage & Salary Allocation Factor			(Line 5)	8.8404%
96	Common Depreciation - Electric Only Allocated to Transmission			(Line 94 * 95)	0
97	Total Transmission Depreciation & Amortization			(Line 86 + 91 + 96)	26,687,464

Taxes Other than Income

98	Taxes Other than Income			Attachment 2	1,148,903
99	Total Taxes Other than Income			(Line 98)	1,148,903

Return / Capitalization Calculations

	Long Term Interest				
100	Long Term Interest			p117.62c through 67c	65,599,295
101	Less LTD Interest on Securitization Bonds		(Note P)	Attachment 8	8,290,626
102	Long Term Interest			"(Line 100 - line 101)"	57,308,669
103	Preferred Dividends		enter positive	p118.29c	$ -
	Common Stock				
104	Proprietary Capital			p112.16c	$ 1,033,261,076
105	Less Preferred Stock		enter negative	(Line 114)	0
106	Less Account 216.1		enter negative	p112.12c	$ -
107	Common Stock			(Sum Lines 104 to 106)	1,033,261,076
	Capitalization				
108	Long Term Debt			p112.17c through 21c	$ 1,103,448,302
109	Less Loss on Reacquired Debt		enter negative	p111.81.c	$ (6,020,831)
110	Plus Gain on Reacquired Debt		enter positive	p113.61.c	$ -
111	Less ADIT associated with Gain or Loss		enter negative	Attachment 1	2,459,510
112	Less LTD on Securitization Bonds	(Note P)	enter negative	Attachment 8	-66,433,302
113	Total Long Term Debt			(Sum Lines Lines 108 to 112)	1,033,453,679
114	Preferred Stock			p112.3c	$ -
115	Common Stock			(Line 107)	1,033,261,076
116	Total Capitalization			(Sum Lines 113 to 115)	2,066,714,755
117	Debt %	Total Long Term Debt	(Note Q)	(Line 113 / 116)	50%
118	Preferred %	Preferred Stock	(Note Q)	(Line 114 / 116)	0%
119	Common %	Common Stock	(Note Q)	(Line 115 / 116)	50%
120	Debt Cost	Total Long Term Debt		(Line 102 / 113)	0.0555
121	Preferred Cost	Preferred Stock		(Line 103 / 114)	0.0000
122	Common Cost	Common Stock	(Note J)	Fixed	0.1050
123	Weighted Cost of Debt	Total Long Term Debt (WCLTD)		(Line 117 * 120)	0.0277
124	Weighted Cost of Preferred	Preferred Stock		(Line 118 * 121)	0.0000
125	Weighted Cost of Common	Common Stock		(Line 119 * 122)	0.0525
126	Total Return (R)			(Sum Lines 123 to 125)	0.0802
127	Investment Return = Rate Base * Rate of Return			(Line 59 * 126)	50,473,530

Composite Income Taxes					
	Income Tax Rates				
128	FIT=Federal Income Tax Rate				35.00%
129	SIT=State Income Tax Rate or Composite		(Note I)		9.00%
130	p	(percent of federal income tax deductible for state purposes)		Per State Tax Code	0.00%
131	T	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =			40.85%
132	T/ (1-T)				69.06%
	ITC Adjustment		(Note I)		
133	Amortized Investment Tax Credit		enter negative	p266.8f	$ (378,101)
134	T/(1-T)			(Line 132)	69.06%
135	Net Plant Allocation Factor			(Line 18)	35.1638%
136	ITC Adjustment Allocated to Transmission			(Line 133 * (1 + 134) * 135)	-224,776
137	Income Tax Component =	CIT=(T/1-T) * Investment Return * (1-(WCLTD/R)) =		[Line 132 * 127 * (1-(123 / 126))]	22,810,824
138	Total Income Taxes			(Line 136 + 137)	22,586,049
REVENUE REQUIREMENT					
	Summary				
139	Net Property, Plant & Equipment			(Line 39)	911,776,704
140	Adjustment to Rate Base			(Line 58)	-282,640,957
141	Rate Base			(Line 59)	629,135,747
142	O&M			(Line 85)	25,079,904
143	Depreciation & Amortization			(Line 97)	26,687,464
144	Taxes Other than Income			(Line 99)	1,148,903
145	Investment Return			(Line 127)	50,473,530
146	Income Taxes			(Line 138)	22,586,049
147	Gross Revenue Requirement			(Sum Lines 142 to 146)	125,975,850
	Adjustment to Remove Revenue Requirements Associated with Excluded Transmission Facilities				
148	Transmission Plant In Service			(Line 19)	1,124,448,196
149	Excluded Transmission Facilities		(Note M)	Attachment 5	0
150	Included Transmission Facilities			(Line 148 - 149)	1,124,448,196
151	Inclusion Ratio			(Line 150 / 148)	100.00%
152	Gross Revenue Requirement			(Line 147)	125,975,850
153	Adjusted Gross Revenue Requirement			(Line 151 * 152)	125,975,850
	Revenue Credits & Interest on Network Credits				
154	Revenue Credits			Attachment 3	2,509,943
155	Interest on Network Credits		(Note N)	PJM Data	-
156	Net Revenue Requirement			(Line 153 - 154 + 155)	123,465,907
	Net Plant Carrying Charge				
157	Net Revenue Requirement			(Line 156)	123,465,907
158	Net Transmission Plant			(Line 19 - 30)	889,481,632
159	Net Plant Carrying Charge			(Line 157 / 158)	13.8807%
160	Net Plant Carrying Charge without Depreciation			(Line 157 - 86) / 158	10.9437%
161	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes			(Line 157 - 86 - 127 - 138) / 158	2.7300%
	Net Plant Carrying Charge Calculation per 100 Basis Point increase in ROE				
162	Net Revenue Requirement Less Return and Taxes			(Line 156 - 145 - 146)	50,406,328
163	Increased Return and Taxes			Attachment 4	78,377,717
164	Net Revenue Requirement per 100 Basis Point increase in ROE			(Line 162 + 163)	128,784,045
165	Net Transmission Plant			(Line 19 - 30)	889,481,632
166	Net Plant Carrying Charge per 100 Basis Point increase in ROE			(Line 164 / 165)	14.4786%
167	Net Plant Carrying Charge per 100 Basis Point increase in ROE without Depreciation			(Line 163 - 86) / 165	11.5416%
168	Net Revenue Requirement			(Line 156)	123,465,907
169	True-up amount			Attachment 6	12,398,602
170	Plus any increased ROE calculated on Attachment 7 other than PJM Sch. 12 projects			Attachment 7	372,518
171	Facility Credits under Section 30.9 of the PJM OATT and Facility Credits paid to Vineland per settlement in ER05-515 (Note R)			Attachment 5	-
172	Net Zonal Revenue Requirement			(Line 168 - 169 + 171)	136,237,027
	Network Zonal Service Rate				
173	1 CP Peak		(Note L)	PJM Data	2,673
174	Rate ($/MW-Year)			(Line 172 / 173)	50,960
175	Network Service Rate ($/MW/Year)			(Line 174)	50,960

Notes

A Electric portion only
B Exclude Construction Work In Progress and leases that are expensed as O&M (rather than amortized). New Transmission plant
that is expected to be placed in service in the current calendar year weighted by number of months it is expected to be in-service. New Transmission plant expected
to be placed in service in the current calendar year that is not included in the PJM Regional Transmission Plan (RTEP) must be separately detailed on Attachment 5.
For the Reconciliation, new transmission plant that was actually placed in service weighted by the number of months it was actually in service
CWIP will be linked to Attachment 6 which shows detail support by project (incentive and non-incentive).
C Transmission Portion Only
D All EPRI Annual Membership Dues
E All Regulatory Commission Expenses
F Safety related advertising included in Account 930.1
G Regulatory Commission Expenses directly related to transmission service, RTO filings, or transmission siting itemized in Form 1 at 351.h.
I The currently effective income tax rate, where FIT is the Federal income tax rate; SIT is the State income tax rate, and p =
"the percentage of federal income tax deductible for state income taxes". If the utility includes taxes in more than one state, it must explain in
Attachment 5 the name of each state and how the blended or composite SIT was developed. Furthermore, a utility that
elected to use amortization of tax credits against taxable income, rather than book tax credits to Account No. 255 and reduce
rate base, must reduce its income tax expense by the amount of the Amortized Investment Tax Credit (Form 1, 266.8.f)
multiplied by (1/1-T). A utility must not include tax credits as a reduction to rate base and as an amortization against taxable income.

J The ROE is 10.5% which includes a base ROE of 10.0% ROE per FERC order in Docket No. EL13-48 and a 50 basis point RTO membership adder as authorized by FERC: provided, that the projects identified in Docket Nos. ER08-686
and ER08-1423 have been awarded an additional 150 basis point adder and, thus, their ROE is 12.0%.
K Education and outreach expenses relating to transmission, for example siting or billing
L As provided for in Section 34.1 of the PJM OATT and the PJM established billing determinants will not be revised or updated in the annual rate reconciliations per settlement in ER05-515.
M Amount of transmission plant excluded from rates per Attachment 5.
N Outstanding Network Credits is the balance of Network Facilities Upgrades Credits due Transmission Customers who have made lump-sum payments
(net of accumulated depreciation) towards the construction of Network Transmission Facilities consistent with Paragraph 657 of Order 2003-A.
Interest on the Network Credits as booked each year is added to the revenue requirement to make the Transmisison Owner whole on Line 155.
O Payments made under Schedule 12 of the PJM OATT that are not directly assessed to load in the Zone under Schedule 12 are included in Transmission O&M.
If they are booked to Acct 565, they are included in on line 64
P Securitization bonds may be included in the capital structure per settlement in ER05-515.
Q ACE capital structure is initially fixed at 50% common equity and 50% debt per settlement in ER05-515 subject to moratorium provisions in the settlement.
R Per the settlement in ER05-515, the facility credits of $15,000 per month paid to Vineland will increase to $37,500 per month (prorated for partial months)
effective on the date FERC approves the settlement in ER05-515.
S See Attachment 5 - Cost Support, section entitled "PBOP Expense in FERC Account 926" for additional information per FERC orders in Docket Nos. EL13-48 , EL15-27 and ER16-456.

Atlantic City Electric Company

Attachment 1- Accumulated Deferred Income Taxes (ADIT) Worksheet

	Only Transmission Related	*Plant Related*	*Labor Related*	*Total ADIT*
ADIT- 282	-	(859,350,629)	-	
ADIT-283	(2,677,716)	(18,810)	(39,070,805)	
ADIT-190	1,702,752	19,543,357	7,312,797	
Subtotal	(974,964)	(839,826,082)	(31,758,008)	
Wages & Salary Allocator			8.8404%	
Gross Plant Allocator		34.4422%		
ADIT	(974,964)	(289,254,261)	(2,807,527)	(293,036,751)

Note: ADIT associated with Gain or Loss on Reacquired Debt is included in Column A here and included in Cost of Debt on Appendix A, Line 111.
Amount (2,459,510)

In filling out this attachment, a full and complete description of each item and justification for the allocation to Columns C-F and each separate ADIT item will be listed. Dissimilar items with amounts exceeding $100,000 will be listed separately.

	A	B Total	C	D	E	F	G
ADIT-190			Gas, Prod or Other Related	Only Transmission Related	Plant	Labor	Justifications
190	1999 AMT	364,878	-	-	364,878	-	Reflects the deferred tax asset related to New Jersey Alternative Minimum Assessment (AMA) credit. Relates to both Transmission and Distribution.
190	Accrual Labor Related	7,207,952	-	-	-	7,207,952	Represents deferred income taxes on labor related book accruals that are only deductible for tax purposes as economic performance occurs. The deferred taxes are related to Company personnel across all functions.
190	Accrued Liab - Auto	105,853	-	-	-	105,853	These deferred taxes are the result of a deduction taken for book purposes to set aside a reserve for Auto liability claims. For tax, no deduction is permitted until the "all events" test is met, typically when payment is made. The deferred taxes related to Company personnel across all functions.
190	Accrued Liab - Misc.	10,155,988	8,846,865	-	1,310,131	(1,008)	Represents accrued book liabilities that can not be deducted for tax purposes until the "all events" test is met. Amounts in Gas, Production or Other Related represent deferred taxes on Unbilled Revenues which are retail related. Deferred taxes on Other Miscellaneous Accrued Liabilities relate to both Transmission and Distribution and are being allocated using both the Plant and Labor allocators.
190	Accrued Liability - General	9,023,000	8,191,010	-	831,990	-	Amounts in Gas, Production or Other Related represent deferred income taxes on Accrued Merger Commitments made as part of the 2016 merger with Exelon that have not been paid to date. These amounts are excluded from Rate Base. Other General Accrued liabilities are related to both Transmission and Distribution and are being allocated using the Plant Allocator.
190	Accumulated Deferred Investment Tax Credit	1,658,779	-	-	1,658,779	-	Pursuant to the requirements of FAS 109, ACE's accumulated deferred income taxes must encompass all timing differences regardless of whether the difference is normalized or flowed-through. These balances represent the deferred taxes on the Investment Tax Credit regulatory liability. Related to all plant. These amounts are removed below.
190	BAD DEBT RESERVE	13,075,318	13,075,318	-	-	-	Under the Tax Reform Act of 1986, taxpayers were required to account for bad debts using the specific write-off method. The reserve method is used for book purposes. The amount represents the deferred tax asset related to the add-back of book reserves for tax purposes.. The deferred tax asset is retail related.
190	Charitable Contribution Limit	5,051,297	5,051,297	-	-	-	ACE accrued Charitable Contribution Commitments made as part of the 2016 merger with Exelon that have not been paid to date. In addition, ACE has deducted Charitable Contributions for book purposes that could not be used in ACE's federal income tax return because of limitations caused by its tax net operating losses. Charitable Contributions are not included in Operating Income and any related deferred income taxes are excluded from Rate Base.
190	ENVIRONMENTAL EXPENSE	276,963	276,963	-	-	-	These deferred taxes are the result of a deduction taken for book purposes to set aside a reserve for environmental site clean-up expenses. For tax, no deduction is permitted until the "all events" test is met, typically when economic performance has occurred. This book reserve is primarily related to Deepwater and BL England sites which should not be in transmission service. It is Generation related.
190	OPEB	13,737,414	-	-	-	13,737,414	FAS No. 106 requires accrual basis instead of cash basis accounting for post retirement health care and life insurance benefits for book purposes. Amounts paid to participants or funded through the VEBA or 401(h) accounts are currently deductible for tax purposes. Affects Company personnel across all functions.
190	Reg Asset - FERC Formula Rate Adj. Trans. Svc	1,702,752	-	1,702,752	-	-	When a regulatory asset/liability is established, books credit/debit income, which for tax purposes needs to be reversed along with the associated amortization. The deferred tax asset is 100% Transmission related.
190	Stranded Costs	1,231,720	1,231,720	-	-	-	Stranded Costs incurred when Generation was deregulated were deferred for book purposes pending collection from/refund to customers in the future. These amounts were included for tax purposes when incurred. The deferred tax asset is Generation related.
190	Federal NOL	(2,644,331)	(2,547,383)	-	(96,948)	-	Represents the deferred tax asset related to federal net operating loss carryforwards (offset by the federal benefit of state NOL carryforwards) available to offset future federal taxable income. Related to both Transmission and Distribution.
190	State NOL	24,411,544	7,278,238	-	17,133,306	-	Represents the deferred tax asset related to state net operating loss carryforwards available to offset future state taxable income. Related to both Transmission and Distribution.
190	FAS 109 Deferred Taxes - 190	1,145,580	-	-	1,145,580	-	Pursuant to the requirements of FAS 109, ACE's accumulated deferred income taxes must encompass all timing differences regardless of whether the difference is normalized or flowed-through. These balances represent the tax gross-up necessary for full recovery of the prior flow-through amounts. Related to all plant.
190	Subtotal - p234	86,504,707	41,404,028	1,702,752	22,347,716	21,050,211	
	Less FASB 109 Above if not separately removed	2,804,359	-	-	2,804,359	-	
190	Less FASB 106 Above if not separately removed	13,737,414	-	-	-	13,737,414	FAS No. 106 requires accrual basis instead of cash basis accounting for post retirement health care and life insurance benefits for book purposes. Amounts paid to participants or funded through the VEBA or 401(h) accounts are currently deductible for tax purposes. Affects company personnel across all functions.
190	Total	69,962,934	41,404,028	1,702,752	19,543,357	7,312,797	

Instructions for Account 190:
1. ADIT items related only to Non-Electric Operations (e.g., Gas, Water, Sewer) or Production are directly assigned to Column C
2. ADIT items related only to Transmission are directly assigned to Column D
3. ADIT items related to Plant and not in Columns C & D are included in Column E
4. ADIT items related to labor and not in Columns C & D are included in Column F
5. Deferred income taxes arise when items are included in taxable income in different periods than they are included in rates, therefore if the item giving rise to the ADIT is not included in the formula, the associated ADIT amount shall be excluded.
6. Re: Form 1-F filer: Sum of subtotals for Accounts 282 and 283 should tie to Form No. 1-F, p.113.57.c

	A	B	C	D	E	F	G
ADIT-282		Total	Gas, Prod or Other Related	Only Transmission Related	Plant	Labor	Justifications
282	Plant Related - APB 11 Deferred Taxes	(859,350,629)			(859,350,629)		This deferred tax balance relates to our plant and results from life and method differences. Related to both T & D plant.
282	CIAC	52,779,814	52,779,814				Contributions in Aid of Construction (CIAC) are a reduction to Plant for book accounting purposes, but are included in taxable income and depreciated for income tax purposes. This different book/tax treatment results in deferred income taxes which must be recorded in accordance with SFAS 109. The Company collects an income tax gross-up from the customer which is reimbursement for the time value of money on the additional tax liability incurred until such time as the amounts are fully depreciated for tax purposes. The deferred income tax asset on CIAC's is excluded from Rate Base because the underlying plant is not included in Rate Base.
282	Leased Vehicles	(7,794,621)	(7,794,621)				The Company leases its vehicles under arrangements that are treated as Operating Leases for book purposes, but financing leases for tax purposes. The differing income tax treatment between Rent Expense deducted for book purposes and tax depreciation expense deducted for income tax purposes, results in deferred income taxes being recorded on the books. Since Leased Vehicles are not included in Rate Base, the deferred income taxes are being excluded as well.
282	Plant Related - FAS109 Deferred Taxes	(32,010,736)			(32,010,736)		Pursuant to the requirements of FAS 109, ACE's accumulated deferred income taxes must encompass all timing differences regardless of whether the difference is normalized or flowed-through. These balances represent the deferred taxes on prior flow-through items. Related to all plant. These amounts are removed below.
	Subtotal - p275	(846,376,172)	44,985,193	-	(891,361,365)	-	
	Less FASB 109 Above if not separately removed	(32,010,736)	-	-	(32,010,736)	-	
	Less FASB 106 Above if not separately removed	-					
282	Total	(814,365,436)	44,985,193	-	(859,350,629)	-	

Instructions for Account 282:
1. ADIT items related only to Non-Electric Operations (e.g., Gas, Water, Sewer) or Production are directly assigned to Column C
2. ADIT items related only to Transmission are directly assigned to Column D
3. ADIT items related to Plant and not in Columns C & D are included in Column E
4. ADIT items related to labor and not in Columns C & D are included in Column F
5. Deferred income taxes arise when items are included in taxable income in different periods than they are included in rates, therefore if the item giving rise to the ADIT is not included in the formula, the associated ADIT amount shall be excluded.

6. Re: Form 1-F filer: Sum of subtotals for Accounts 282 and 283 should tie to Form No. 1-F, p.113.57.c

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	A	B	C	D	E	F	G
ADIT-283		Total	Gas, Prod or Other Related	Only Transmission Related	Plant	Labor	Justifications
283	Accrual Labor Related	(4,269,783)	-	-	-	(4,269,783)	Represents deferred income tax liability on Vacation Accrual Regulatory Asset. The deferred taxes are related to Company personnel across all functions.
283	BGS Deferred Related - Retail	(14,428,575)	(14,428,575)	-	-	-	Relates to deferred costs associated with Basic Generation Service. Retail related.
283	Interest on Contingent Taxes	(18,810)	-	-	(18,810)	-	Estimated book interest income on prior year taxes not included in taxable income for tax purposes. Related to both Transmission and Distribution.
283	Loss on Reacquired Debt	(2,459,510)	(2,459,510)	-	-	-	The cost of bond redemption is deductible currently for tax purposes and is amortized over the life of the new bond issue for book purposes. Excluded here since included in Cost of Debt
283	Misc. Deferred Debits - Retail	(23,042)	(23,042)	-	-	-	Represents deferred taxes on miscellaneous deferred debits deducted for tax purposes in advance of book purposes. Retail related.
283	NUG BUYOUT	(11,558,142)	(11,558,142)	-	-	-	These deferred taxes relate to Regulatory Assets created during Generation deregulation. The underlying costs were deducted for tax purposes as incurred. Amortization Expense recorded for book purposes as amounts are collected from customers is reversed for tax purposes. It is Generation related.
283	PENSION PAYMENT RESERVE	(34,801,022)	-	-	-	(34,801,022)	The Company claims tax deductions for payments made to fund its Retirement Income Plan to the extent permitted under the IRC Section 415 contribution limitations. For book purposes, Pension Plan expense is recorded in accordance with SFAS 158. This deferred tax liability reflects the difference between the tax versus book deductions. It affects Company personnel across all functions.
283	Reg Asset - FERC Formula Rate Adj. Trans. Svc	(2,677,716)	-	(2,677,716)	-	-	When a regulatory asset/liability is established, books credit/debit income, which for tax purposes needs to be reversed along with the associated amortization. The deferred tax asset is 100% Transmission related.
283	Reg Asset-NJ Rec-Base	(8,726,472)	(8,726,472)	-	-	-	When a regulatory asset/liability is established, books credit/debit income, which for tax purposes needs to be reversed along with the associated amortization. This deferred tax liability is retail related.
283	Regulatory Asset - NJ RGGI	(173,383)	(173,383)	-	-	-	When a regulatory asset/liability is established, books credit/debit income, which for tax purposes needs to be reversed along with the associated amortization. This deferred tax liability is retail related.
283	Regulatory Asset - SREC Program	(870,712)	(870,712)	-	-	-	Represents deferred income tax liability on the Solar Renewable Energy Certificate Program. Retail related.
283	Stranded Costs	(39,198,946)	(39,198,946)	-	-	-	These deferred taxes relate to Regulatory Assets created during Generation deregulation. The underlying costs were deducted for tax purposes as incurred. Amortization Expense recorded for book purposes as amounts are collected from customers is reversed for tax purposes. It is Generation related.
283	Use Tax reserve	768,182	768,182	-	-	-	For book purposes, SFAS 5 reserves are established for potential prior year sales and use tax liabilities. For tax purposes, these liabilities can only be deducted when the amounts become fixed liabilities and are paid. Related to the retail function.
283	Gross up on FAS 109 Deferred Taxes	(22,088,802)	-	-	(22,088,802)	-	Pursuant to the requirements of FAS 109, ACE's accumulated deferred income taxes must encompass all timing differences regardless of whether the difference is normalized or flowed-through. These balances represent the tax gross-up necessary for full recovery of the prior flow-through amounts. Related to all plant. These amounts are removed below.
283	Subtotal - p277 (Form 1-F filer: see note 6, below)	(140,526,733)	(76,670,600)	(2,677,716)	(22,107,612)	(39,070,805)	
283	Less FASB 109 Above if not separately removed	(22,088,802)	-	-	(22,088,802)	-	
283	Less FASB 106 Above if not separately removed	-					
283	Total	(118,437,931)	(76,670,600)	(2,677,716)	(18,810)	(39,070,805)	

check

Instructions for Account 283:
1. ADIT items related only to Non-Electric Operations (e.g., Gas, Water, Sewer) or Production are directly assigned to Column C
2. ADIT items related only to Transmission are directly assigned to Column D
3. ADIT items related to Plant and not in Columns C & D are included in Column E
4. ADIT items related to labor and not in Columns C & D are included in Column F
5. Deferred income taxes arise when items are included in taxable income in different periods than they are included in rates, therefore if the item giving rise to the ADIT is not included in the formula, the associated ADIT amount shall be excluded.
6. Re: Form 1-F filer: Sum of subtotals for Accounts 282 and 283 should tie to Form No. 1-F, p.113.57.c

ADITC-255			Balance	Amortization
1	Rate Base Treatment			
2	Balance to line 41 of Appendix A	Total		
3	Amortization			
4	Amortization to line 133 of Appendix A	Total	4,060,657	378,101
5	Total		4,060,657	378,101
6	Form No. 1 balance (p.266) for amortization	Total Form No. 1 (p 266 & 267)	4,060,657	378,101
7	Difference /1		-	-

/1 Difference must be zero

Atlantic City Electric Company

Attachment 2 - Taxes Other Than Income Worksheet

	Other Taxes	Page 263 Col (i)	Allocator	Allocated Amount
	Plant Related		***Gross Plant Allocator***	
1	Real property (State, Municipal or Local)	2,718,030		
2	Personal property	-		
3	City License	-		
4	Federal Excise	15,339		
	Total Plant Related	2,733,369	34.4422%	941,431
	Labor Related		***Wages & Salary Allocator***	
5	Federal FICA & Unemployment	2,040,419		
6	Unemployment(State)	295,904		
	Total Labor Related	2,336,323	8.8404%	206,540
	Other Included		***Gross Plant Allocator***	
7	Miscellaneous	2,706		
	Total Other Included	2,706	34.4422%	932
	Total Included			1,148,903
	Excluded			
8	State Franchise tax	-		
9	TEFA	-		
10	Use & Sales Tax	1,203,283		
10	Excluded merger costs in line 5	1,454		
11	Total "Other" Taxes (included on p. 263)	6,277,135		
12	Total "Taxes Other Than Income Taxes" - acct 408.10 (p. 114.14)	6,277,135		
13	Difference	-		

Criteria for Allocation:

A Other taxes that are incurred through ownership of plant including transmission plant will be allocated based on the Gross Plant Allocator. If the taxes are 100% recovered at retail they will not be included

B Other taxes that are incurred through ownership of only general or intangible plant will be allocated based on the Wages and Salary Allocator. If the taxes are 100% recovered at retail they will not be included

C Other taxes that are assessed based on labor will be allocated based on the Wages and Salary Allocator

D Other taxes except as provided for in A, B and C above, that are incurred and (1) are not fully recovered at retail or (2) are directly or indirectly related to transmission service will be allocated based on the Gross Plant Allocator; provided, however, that overheads shall be treated as in footnote B above

E Excludes prior period adjustments in the first year of the formula's operation and reconciliation for the first year

Atlantic City Electric Company

Attachment 3 - Revenue Credit Workpaper

	Account 454 - Rent from Electric Property		
1	Rent from Electric Property - Transmission Related (Note 3)		949,422
2	Total Rent Revenues	(Sum Line 1)	949,422
	Account 456 - Other Electric Revenues (Note 1)		
3	Schedule 1A		$ 848,650
4	Net revenues associated with Network Integration Transmission Service (NITS) for which the load is not included in the divisor (difference between NITS credits from PJM and PJM NITS charges paid by Transmission Owner) (Note 4)		-
5	Point to Point Service revenues for which the load is not included in the divisor received by Transmission Owner (Note 4)		761,122
6	PJM Transitional Revenue Neutrality (Note 1)		-
7	PJM Transitional Market Expansion (Note 1)		-
8	Professional Services (Note 3)		-
9	Revenues from Directly Assigned Transmission Facility Charges (Note 2)		619,380
10	Rent or Attachment Fees associated with Transmission Facilities (Note 3)		-
11	Gross Revenue Credits	(Sum Lines 2-10)	3,178,574
12	Less line 17g		(668,630)
13	Total Revenue Credits		2,509,943

<u>Revenue Adjustment to determine Revenue Credit</u>

14 Note 1: All revenues related to transmission that are received as a transmission owner (i.e., not received as a LSE), for which the cost of the service is recovered under this formula, except as specifically provided for elsewhere in this Attachment or elsewhere in the formula will be included as a revenue credit or included in the peak on line 173 of Appendix A.

15 Note 2: If the costs associated with the Directly Assigned Transmission Facility Charges are included in the Rates, the associated revenues are included in the Rates. If the costs associated with the Directly Assigned Transmission Facility Charges are not included in the Rates, the associated revenues are not included in the Rates.

16 Note 3: Ratemaking treatment for the following specified secondary uses of transmission assets: (1) right-of-way leases and leases for space on transmission facilities for telecommunications; (2) transmission tower licenses for wireless antennas; (3) right-of-way property leases for farming, grazing or nurseries; (4) licenses of intellectual property (including a portable oil degasification process and scheduling software); and (5) transmission maintenance and consulting services (including energized circuit maintenance, high-voltage substation maintenance, safety training, transformer oil testing, and circuit breaker testing) to other utilities and large customers (collectively, products). Company will retain 50% of net revenues consistent with Pacific Gas and Electric Company, 90 FERC ¶ 61,314. Note: in order to use lines 17a - 17g, the utility must track in separate subaccounts the revenues and costs associated with each secondary use (except for the cost of the associated income taxes).

17a	Revenues included in lines 1-11 which are subject to 50/50 sharing.		949,422
17b	Costs associated with revenues in line 17a	Attachment 5 - Cost Support	387,839
17c	Net Revenues (17a - 17b)		561,583
17d	50% Share of Net Revenues (17c / 2)		280,791
17e	Costs associated with revenues in line 17a that are included in FERC accounts recovered through the formula times the allocator used to functionalize the amounts in the FERC account to the transmission service at issue.		-
17f	Net Revenue Credit (17d + 17e)		280,791
17g	Line 17f less line 17a		(668,630)
18	Note 4: If the facilities associated with the revenues are not included in the formula, the revenue is shown here but not included in the total above and is explained in the Cost Support; for example revenues associated with distribution facilities. In addition, Revenues from Schedule 12 are not included in the total above to the extent they are credited under Schedule 12.		10,660,859
19	Amount offset in line 4 above		111,505,353
20	Total Account 454, 456 and 456.1		125,344,786
21	Note 4: SECA revenues booked in Account 447.		

Atlantic City Electric Company

Attachment 4 - Calculation of 100 Basis Point Increase in ROE

	Return and Taxes with 100 Basis Point increase in ROE				
A	100 Basis Point increase in ROE and Income Taxes			(Line 127 + Line 138)	78,377,717
B	100 Basis Point increase in ROE				1.00%
	Return Calculation				
59	Rate Base			(Line 39 + 58)	629,135,747
	Long Term Interest				
100	Long Term Interest			p117.62c through 67c	65,599,295
101	Less LTD Interest on Securitization E (Note P)			Attachment 8	8,290,626
102	**Long Term Interest**			"(Line 100 - line 101)"	57,308,669
103	**Preferred Dividends**		enter positive	p118.29c	0
	Common Stock				
104	Proprietary Capital			p112.16c	1,033,261,076
105	Less Preferred Stock		enter negative	(Line 114)	0
106	Less Account 216.1		enter negative	p112.12c	0
107	**Common Stock**			(Sum Lines 104 to 106)	1,033,261,076
	Capitalization				
108	Long Term Debt			p112.17c through 21c	1,103,448,302
109	Less Loss on Reacquired Debt		enter negative	p111.81.c	-6,020,831
110	Plus Gain on Reacquired Debt		enter positive	p113.61.c	0
111	Less ADIT associated with Gain or Loss		enter negative	Attachment 1	2,459,510
112	Less LTD on Securitization Bonds		enter negative	Attachment 8	-66,433,302
113	Total Long Term Debt			(Sum Lines Lines 108 to 112)	1,033,453,679
114	Preferred Stock			p112.3c	0
115	Common Stock			(Line 107)	1,033,261,076
116	**Total Capitalization**			(Sum Lines 113 to 115)	2,066,714,755
117	Debt %	(Note Q from Appendix A)	Total Long Term Debt	(Line 113 / 116)	50%
118	Preferred %	(Note Q from Appendix A)	Preferred Stock	(Line 114 / 116)	0%
119	Common %	(Note Q from Appendix A)	Common Stock	(Line 115 / 116)	50%
120	Debt Cost		Total Long Term Debt	(Line 102 / 113)	0.0555
121	Preferred Cost		Preferred Stock	(Line 103 / 114)	0.0000
122	Common Cost	(Note J from Appendix A)	Common Stock	Appendix A % plus 100 Basis Pts	0.1150
123	Weighted Cost of Debt		Total Long Term Debt (WCLTD)	(Line 117 * 120)	0.0277
124	Weighted Cost of Preferred		Preferred Stock	(Line 118 * 121)	0.0000
125	Weighted Cost of Common		Common Stock	(Line 119 * 122)	0.0575
126	Total Return (R)			**(Sum Lines 123 to 125)**	**0.0852**
127	Investment Return = Rate Base * Rate of Return			**(Line 59 * 126)**	**53,619,209**
	Composite Income Taxes			(Note L)	
	Income Tax Rates				
128	FIT=Federal Income Tax Rate				35.00%
129	SIT=State Income Tax Rate or Composite				9.00%
130	p = percent of federal income tax deductible for state purposes			Per State Tax Code	0.00%
131	T	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =			40.85%
132	T/ (1-T)				69.06%
	ITC Adjustment				
133	Amortized Investment Tax Credit		enter negative	p266.8f	-378,101
134	T/(1-T)			(Line 132)	69.06%
135	Net Plant Allocation Factor			(Line 18)	35.1638%
136	**ITC Adjustment Allocated to Transmission**		(Note I from Appendix A)	(Line 133 * (1 + 134) * 135)	**-224,776**
137	**Income Tax Component =**	CIT=(T/1-T) * Investment Return * (1-(WCLTD/R)) =			24,983,284
138	**Total Income Taxes**				**24,758,508**

Atlantic City Electric Company

Attachment 5 - Cost Support

Electric / Non-electric Cost Support

Line	Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions	Notes	Form 1 Page	Form 1 Amount	Electric Portion	Non-electric Portion	Details
	Plant Allocation Factors						
10	Accumulated Intangible Amortization	(Note A)	p200.21c	15,119,930	15,119,930	0	Respondent is Electric Utility only.
11	Accumulated Common Amortization - Electric	(Note A)	p356	0	0	0	
12	Accumulated Common Plant Depreciation - Electric	(Note A)	p356	0	0	0	
	Plant In Service						
24	Common Plant (Electric Only)	(Notes A & B)	p356	0	0	0	
	Accumulated Deferred Income Taxes						
41	Accumulated Investment Tax Credit Account No. 255	(Notes A & I)	p266.h	4,060,657	4,060,657	0	Respondent is Electric Utility only.
	Materials and Supplies						
47	Undistributed Stores Exp	(Note A)	p227.6c & 16.c	0	0	0	Respondent is Electric Utility only.
	Allocated General & Common Expenses						
65	Plus Transmission Lease Payments	(Note A)	p200.3c	0			
67	Common Plant O&M	(Note A)	p356	0	0	0	
	Depreciation Expense						
88	Intangible Amortization	(Note A)	p336.1d&e	139,483	139,483	0	Respondent is Electric Utility only.
92	Common Depreciation - Electric Only	(Note A)	p336.11.b	0	0	0	
93	Common Amortization - Electric Only	(Note A)	p356 or p336.11d	0	0	0	

Transmission / Non-transmission Cost Support

Line	Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions	Notes	Form 1 Page	Form 1 Amount	Transmission Related	Non-transmission Related	Details
28	Plant Held for Future Use (Including Land)	(Note C)	p214	12,757,399	782,029	11,975,370	Transmission Right of Way - Carll's Corner to Landis

CWIP & Expensed Lease Worksheet

Line	Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions	Notes	Form 1 Page	Form 1 Amount	CWIP In Form 1 Amount	Expensed Lease in Form 1 Amount	Details
	Plant Allocation Factors						
6	Electric Plant in Service	(Note B)	p207.104g	3,341,206,653	0	0	See ARO Exclusion - Cost Support section below for Electric Plant in Servie without AROs
	Plant In Service						
19	Transmission Plant In Service	(Note B)	p207.58.g	1,124,448,196	0	0	See Form 1
24	Common Plant (Electric Only)	(Notes A & B)	p356	0	0	0	
	Accumulated Depreciation						
30	Transmission Accumulated Depreciation	(Note B)	p219.25.c	234,966,564	0	0	See Form 1

EPRI Dues Cost Support

Line	Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions	Notes	Form 1 Page	Form 1 Amount	EPRI Dues	Details
	Allocated General & Common Expenses					
73	Less EPRI Dues	(Note D)	p352-353	138,757	138,757	See Form 1

Atlantic City Electric Company

Attachment 5 - Cost Support

Regulatory Expense Related to Transmission Cost Support

	Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions			Form 1 Amount	Transmission Related	Non-transmission Related	Details
	Allocated General & Common Expenses						
70	Less Regulatory Commission Exp Account 928	(Note E)	p323.189b	4,153,916	132,610	4,021,306	FERC Form 1 page 351 line 3 (h) through 6 (h)
	Directly Assigned A&G						
77	Regulatory Commission Exp Account 928	(Note G)	p323.189b	4,153,916	132,610	4,021,306	FERC Form 1 page 351 line 3 (h) through 6 (h)

Safety Related Advertising Cost Support

	Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions			Form 1 Amount	Safety Related	Non-safety Related	Details
	Directly Assigned A&G						
81	General Advertising Exp Account 930.1	(Note K)	p323.191b	363,930	-	363,930	None

MultiState Workpaper

	Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions			State 1	State 2	State 3	State 4	State 5	Details
	Income Tax Rates								
				NJ	PA				Enter Calculation
129	SIT=State Income Tax Rate or Composite	(Note I)	9.0000%	9.00%	9.990%				Apportioned: NJ 100.0000%, PA 0.0000%

Education and Out Reach Cost Support

	Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions			Form 1 Amount	Education & Outreach	Other	Details
	Directly Assigned A&G						
78	General Advertising Exp Account 930.1	(Note F)	p323.191b	363,930	-	363,930	None

Excluded Plant Cost Support

	Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions			Excluded Transmission Facilities	Description of the Facilities
	Adjustment to Remove Revenue Requirements Associated with Excluded Transmission Facilities				
149	Excluded Transmission Facilities	(Note M)	Attachment 5	-	General Description of the Facilities
	Instructions:			Enter $	None
1	Remove all investment below 69 kV or generator step up transformers included in transmission plant in service that are not a result of the RTEP Process				
2	If unable to determine the investment below 69kV in a substation with investment of 69 kV and higher as well as below 69 kV,			Or	
	the following formula will be used:	Example		Enter $	
A	Total investment in substation	1,000,000			
B	Identifiable investment in Transmission (provide workpapers)	500,000			
C	Identifiable investment in Distribution (provide workpapers)	400,000			
D	Amount to be excluded (A x (C / (B + C)))	444,444			
					Add more lines if necessary

Atlantic City Electric Company

Attachment 5 - Cost Support

Outstanding Network Credits Cost Support

	Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions			Outstanding Network Credits	Description of the Credits
	Network Credits			Enter $	
55	Outstanding Network Credits	(Note N)	From PJM	0	General Description of the Credits
					None
56	Less Accumulated Depreciation Associated with Facilities with Outstanding Network Credits	(Note N)	From PJM	0	
					None
					Add more lines if necessary

Transmission Related Account 242 Reserves

	Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions	Total	Allocation	Transmission Related	Details
44	Transmission Related Account 242 Reserves (exclude current year environmental site related reserves)	Enter $		Amount	
	Directly Assignable to Transmission	0	100%	-	
	Labor Related, General plant related or Common Plant related	12,977,141	8.84%	1,147,228	
	Plant Related	3,207,174	34.44%	1,104,620	
	Other		0.00%	-	
	Total Transmission Related Reserves	16,184,315		2,251,848	

Prepayments

	Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions					Description of the Prepayments
45	Prepayments					
5	Wages & Salary Allocator			8.840%	To Line 45	
	Pension Liabilities, if any, in Account 242		-	8.840%	-	
	Prepayments	$	423,912	8.840%	37,475	
	Prepaid Pensions if not included in Prepayments	$	85,192,220	8.840%	7,531,310	Prepaid Pension is recorded in FERC account 186 (see FERC Form 1 page 233).
			85,616,132		7,568,786	
						Add more lines if necessary

Extraordinary Property Loss

	Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions		Amount	Number of years	Amortization	w/ interest
61	Less extraordinary property loss	Attachment 5	$ -			
62	Plus amortized extraordinary property loss	Attachment 5		5	$ -	$ -

Atlantic City Electric Company

Attachment 5 - Cost Support

Interest on Outstanding Network Credits Cost Support

Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions				Interest on Network Credits	Description of the Interest on the Credits
	Revenue Credits & Interest on Network Credits				
155	Interest on Network Credits	(Note N)	PJM Data	0	General Description of the Credits
				Enter $	None
					Add more lines if necessary

Facility Credits under Section 30.9 of the PJM OATT and Facility Credits paid to Vineland per settlement in ER05-515 (Note R)

Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions		Amount	Description & PJM Documentation
	Net Revenue Requirement		
171	Facility Credits under Section 30.9 of the PJM OATT and Facility Credits paid to Vineland per settlement in ER05-515 (Note R)	-	Settelement agreement.

PJM Load Cost Support

Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions				1 CP Peak	Description & PJM Documentation
	Network Zonal Service Rate				
173	1 CP Peak	(Note L)	PJM Data	2,673.4	See Form 1

Statements BG/BH (Present and Proposed Revenues)

Customer	Billing Determinants	Current Rate	Proposed Rate	Current Revenues	Proposed Revenues	Change in Revenues
ACE zone						
Total						

Supporting documentation for FERC Form 1 reconciliation

Compliance with FERC Order on the Exelon Merger

Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions			Form 1 Amount	Merger Costs	Non Merger Related
60	Transmission O&M	p321.112.b	19,188,113	412,159	18,775,954
68	Total A&G	p323.197.b	92,346,183	19,276,445	73,069,738

ARO Exclusion - Cost Support

Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions			Form 1 Amount	ARO's	Non-ARO's	
6	Electric Plant in Service	p207.104g	3,341,206,653	946,955	3,340,259,698	Distribution ARO-$850,400 and General & Intangible ARO-$96,555
9	Accumulated Depreciation (Total Electric Plant)	p219.29c	734,520,209	95,364	734,424,845	Distribution ARO-$47,086 and General ARO-$48,278
23	General & Intangible	p205.5.g & p207.99.g	131,879,841	96,555	131,783,286	General & Intangible ARO-$96,555
31	Accumulated General Depreciation	p219.28.c	35,790,691	48,278	35,742,413	General ARO-$48,278

PBOP Expense in FERC 926

Atlantic City Electric Company

Attachment 5 - Cost Support

Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions			Total A&G Form 1 Amount	Account 926 Form 1 Amount	PBOP in FERC 926 current rate year	PBOP in FERC 926 prior rate year	Explanation of change in PBOP in FERC 926
68	Total A&G	Total: p.323.197.b Account 926: p.323.187.b and c	92,346,183	12,070,521	1,000,545	877,444	The actuarially determined amount of OPEB expense in FERC 926 increased $.129 million from the prior year; the increase primarily represents a $0.1 million increase in amortization of unrecognized gain/loss from assumption changes, primarily a change in the census data and decrease in the discount rate from 4.15% in 2015 to 3.80% in 2016, $0.4 million decrease in expected return on plan assets, offset by ($0.4 million) decrease in interest cost.

Attachment 3 - Revenue Credit Workpaper

17b	Costs associated with revenues in line 17a	$	387,839
	Revenue Subject to 50/50 sharing (Attachment 3 - line 17a)	$	949,422
	Federal Income Tax Rate		35.00%
	Federal Tax on Revenue subject to 50/50 sharing		332,298
	Net Revenue subject to 50/50 sharing		617,124
	Composite State Income Tax Rate		9.000%
	State Tax on Revenue subject to 50/50 sharing		55,541
	Total Tax on Revenue subject to 50/50 sharing	$	387,839

Atlantic City Electric Company

Attachment 5a - Allocations of Costs to Affiliate

	Delmarva Power	Atlantic City	Pepco	Non - Regulated	Total
Executive Management	17,888,560	15,212,497	30,153,120	7,412,352	70,666,529
Procurement & Administrative Services	6,791,101	4,845,791	9,935,687	3,926,533	25,499,112
Financial Services & Corporate Expenses	19,012,271	15,407,361	29,313,579	25,623,238	89,356,449
Insurance Coverage and Services	1,053,835	1,059,259	878,771	205,181	3,197,046
Human Resources	6,163,406	4,489,926	9,197,885	4,056,693	23,907,910
Legal Services	1,989,324	1,359,614	3,911,072	7,910,660	15,170,671
Audit Services	235,790	200,263	422,964	21,511	880,528
Customer Services	55,980,435	49,006,144	49,427,135	2,578	154,416,292
Information Technology	17,486,264	13,036,712	32,166,511	1,667,441	64,356,929
External Affairs	3,335,582	2,669,671	5,057,025	694,805	11,757,083
Environmental Services	2,511,651	2,003,017	2,263,716	16,460	6,794,844
Safety Services	421,363	405,808	652,912	-	1,480,083
Regulated Electric & Gas T&D	46,285,265	36,369,629	61,044,684	1,370,583	145,070,161
Internal Consulting Services	520,648	339,645	885,335	-	1,745,628
Interns	165,014	133,506	173,225	-	471,745
Cost of Benefits	13,676,739	8,613,927	23,152,231	-	45,442,897
Building Services	91,882	116,387	4,599,613	-	4,807,882
Total	**$ 193,609,128**	**$ 155,269,158**	**$ 263,235,465**	**$ 52,908,036**	**$ 665,021,787**

Name of Respondent	This Report Is:	Resubmission Date (Mo, Da, Yr)	Year/Period of Report
PHI Service Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	Dec 31, 2016

Schedule XVII - Analysis of Billing – Associate Companies (Account 457)

1. For services rendered to associate companies (Account 457), list all of the associate companies.

Line No.	Name of Associate Company (a)	Account 457.1 Direct Costs Charged (b)	Account 457.2 Indirect Costs Charged (c)	Account 457.3 Compensation For Use of Capital (d)	Total Amount Billed (e)
1	Potomac Electric Power Company	55,777,848	207,249,778	207,839	263,235,465
2	Delmarva Power & Light Company	45,668,170	147,785,802	155,156	193,609,128
3	Atlantic City Electric Company	29,420,467	125,724,641	124,050	155,269,158
4	Exelon Business Services Company, LLC	42,660,634			42,660,634
5	Pepco Energy Services, Inc.	4,221,075	1,906,663	4,801	6,132,539
6	Pepco Holdings LLC	979,497	1,972,619	5,708	2,957,824
7	Thermal Energy Limited Partnership	4,232	407,746	522	412,500
8	ATS Operating Services, Inc.	26	167,526	192	167,744
9	Atlantic Southern Properties, Inc.	3,079	158,479	142	161,700
10	Conectiv Properties & Investments, Inc.	57	121,639	103	121,799
11	Conectiv Thermal Systems, Inc.	1,447	95,441	67	96,955
12	Conectiv, LLC	6,529	79,114	62	85,705
13	Potomac Capital investment Corporation	29,039	36,778	114	65,931
14	Atlantic City Electric Transition Funding, LLC	37,069	7,509	40	44,618
15	ATE Investment, Inc.	87			87
16					
17					
18					
19					
20					
21					
22					
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40	**Total**	178,809,256	485,713,735	498,796	665,021,787

Service Company Billing Analysis by Utility FERC Account
YTD Dec 2016
Total PHI

FERC Accounts	FERC Account Name	DPL	ACE	PEPCO	Non-Utility	Total	Inclusion in ATRR
107	Constr Work In Progress	26,805,795	19,873,552	37,468,781	-	84,148,128	Not included
182.3	Other Regulatory Assets	4,175,575	259,524	8,595,791	-	13,030,891	Not included
184	Clearing Accounts - Other	348,794	92,274	638,660	(253,174)	826,555	Not included
408.1	Taxes other than inc taxes, utility operating inc	2,313	784	1,997	-	5,093	Not included
416-421.2	Other Income -Below the Line	892,977	789,210	1,313,427	53,161,209	56,156,823	Not included
426.1-426.5	Other Income Deductions - Below the Line	1,753,265	1,341,072	2,592,346	-	5,686,683	Not included
430	Interest-Debt to Associated Companies	182,125	145,629	244,108	-	571,862	Not included
431	Interest-Short Term Debt	(26,965)	(21,576)	(36,264)	-	(84,805)	Not included
556	System cont & load dispatch	2,775,119	2,378,381	2,624,428	-	7,777,928	Not included
557	Other expenses	1,275,792	1,012,311	1,550,758	-	3,838,861	Not included
560	Operation Supervision & Engineering	3,003,550	2,801,852	5,088,055	-	10,893,458	100% included
561	Load dispatching		299			299	100% included
561.1	Load Dispatching - Reliability	15,313	13,623	-	-	28,936	100% included
561.2	Load Dispatch - Monitor & Operate Transmission Sys	54,585	28,734	849,068	-	932,386	100% included
561.3	Load Dispatch - Transmission Service & Scheduling	45,300	38,036	50,977	-	134,313	100% included
561.5	Reliability, Planning and Standards	340,515	334,220	131,940	-	806,676	100% included
563	Overhead line expenses	-	-	301	-	301	100% included
562	Station expenses	-	-	11,428	-	11,428	100% included
564	Underground Line Expenses - Transmission	-	-	3,084	-	3,084	100% included
566	Miscellaneous transmission expenses	1,333,901	1,161,236	1,290,926	-	3,786,062	100% included
568	Maintenance Supervision & Engineering	66,861	84,785	507,686	-	659,332	100% included
569.2	Maintenance of Computer Software	840,498	353,031	449,960	-	1,643,489	100% included
570	Maintenance of station equipment	182,130	92,896	379,724	-	654,749	100% included
571	Maintenance of overhead lines	234,450	231,176	548,094	-	1,013,720	100% included
572	Maintenance of underground lines	667	950	11,117	-	12,735	100% included
573	Maintenance of miscellaneous transmission plant	32,488	56,182	171,684	-	260,354	100% included
575.5	Ancillary services market administration	-	-	17,401		17,401	Not included
580	Operation Supervision & Engineering	1,001,036	471,740	1,212,741	-	2,685,517	Not included
581	Load dispatching	1,179,197	535,514	1,475,555	-	3,190,266	Not included
582	Station expenses	897,139	-	105,767	-	1,002,906	Not included
583	Overhead line expenses	95,393	229,072	47,265	-	371,730	Not included
584	Underground line expenses	34,878	-	208,396	-	243,274	Not included
585	Street lighting	4,028	-	43	-	4,071	Not included
586	Meter expenses	800,246	411,127	1,108,564	-	2,319,937	Not included
587	Customer installations expenses	346,745	299,963	893,846	-	1,540,554	Not included
588	Miscellaneous distribution expenses	5,474,825	5,527,826	9,099,689	-	20,102,340	Not included
589	Rents	60,620	2,757	64,590	-	127,967	Not included
590	Maintenance Supervision & Engineering	1,014,077	543,084	431,373	-	1,988,535	Not included
591	Maintain structures	-	-	102	-	102	Not included
592	Maintain equipment	567,892	615,945	1,111,695	-	2,295,532	Not included
593	Maintain overhead lines	1,499,072	1,123,689	1,646,212	-	4,268,974	Not included
594	Maintain underground line	195,257	80,020	610,137	-	885,414	Not included
595	Maintain line transformers	550	200	199,373	-	200,122	Not included
596	Maintain street lighting & signal systems	41,368	40,213	15,904	-	97,486	Not included
597	Maintain meters	110,587	33,666	157,207	-	301,460	Not included
598	Maintain distribution plant	32,930	13,967	560,761	-	607,659	Not included
800-894	Total Gas Accounts	2,419,540	-	-	-	2,419,540	Not included
902	Meter reading expenses	144,919	46,153	123,280	-	314,351	Not included
903	Customer records and collection expenses	51,327,401	49,920,892	48,002,627	-	149,250,920	Not included
907	Supervision - Customer Svc & Information	93,109	89,900	135,212	-	318,221	Not included
908	Customer assistance expenses	2,108,200	754,281	876,429	-	3,738,910	Not included
909	Informational & instructional advertising	204,733	204,651	306,902	-	716,286	Not included
912	Demonstrating and selling expense	140,748	-	-	-	140,748	Not included
913	Advertising expense	43,946	-	-	-	43,946	Not included
920	Administrative & General salaries	367,453	98,423	639,618	-	1,105,493	Wage & Salary Factor
921	Office supplies & expenses	5,082	4,300	6,549	-	15,931	Wage & Salary Factor
923	Outside services employed	67,081,017	56,928,796	110,924,582	-	234,934,395	Wage & Salary Factor
924	Property insurance	(3,103)	(2,499)	(4,305)	-	(9,908)	Net Plant Factor
925	Injuries & damages	467,041	359,075	751,897	-	1,578,013	Wage & Salary Factor
926	Employee pensions & benefits	7,900,160	4,233,882	12,532,015	-	24,666,057	Wage & Salary Factor
928	Regulatory commission expenses	2,081,126	592,263	2,541,328	-	5,214,716	Direct Transmission Only
929	Duplicate charges-Credit	472,389	232,352	1,387,280	-	2,092,021	Wage & Salary Factor
930.1	General ad expenses	-	-	33	-	33	Direct Transmission Only
930.2	Miscellaneous general expenses	643,418	590,393	1,134,900	-	2,368,711	Wage & Salary Factor
935	Maintenance of general plant	421,060	219,332	422,422	-	1,062,814	Wage & Salary Factor
Total		**193,609,128**	**155,269,158**	**263,235,465**	**52,908,036**	**665,021,787**	

Atlantic City Electric Company

Attachment 6 - Estimate and Reconciliation Worksheet

Step	Month	Year	Action
Exec Summary			
1	April	Year 2	TO populates the formula with Year 1 data from FERC Form 1 data for Year 1 (e.g., 2004)
2	April	Year 2	TO estimates all transmission Cap Adds and CWIP for Year 2 weighted based on Months expected to be in service in Year 2 (e.g., 2005)
3	April	Year 2	TO adds weighted Cap Adds to plant in service in Formula
4	May	Year 2	Post results of Step 3 on PJM web site
5	June	Year 2	Results of Step 3 go into effect for the Rate Year 1 (e.g., June 1, 2005 - May 31, 2006)
6	April	Year 3	TO populates the formula with Year 2 data from FERC Form 1 for Year 2 (e.g., 2005)
7	April	Year 3	Reconciliation - TO calculates Reconciliation by removing from Year 2 data - the total Cap Adds placed in service in Year 2 and adding weighted average in Year 2 actual Cap Adds and CWIP in Reconciliation (adjusted to include any Reconciliation amount from prior year)
8	April	Year 3	TO estimates Cap Adds and CWIP during Year 3 weighted based on Months expected to be in service in Year 3 (e.g., 2006)
9	April	Year 3	Reconciliation - TO adds the difference between the Reconciliation in Step 7 and the forecast in Line 5 with interest to the result of Step 7 (this difference is also added to Step 8 in the subsequent year)
10	May	Year 3	Post results of Step 9 on PJM web site
11	June	Year 3	Results of Step 9 go into effect for the Rate Year 2 (e.g., June 1, 2006 - May 31, 2007)

1 April Year 2 TO populates the formula with Year 1 data from FERC Form 1 data for Year 1 (e.g., 2004)

89,969,196 Rev Req based on Year 1 data — Must run Appendix A to get this number (without inputs in lines 20, 21 or 43a of Appendix A)

2 April Year 2 TO estimates all transmission Cap Adds and CWIP for Year 2 weighted based on Months expected to be in service in Year 2 (e.g., 2005)

	(A) Monthly Additions Other Plant In Service	(B) Monthly Additions Other Plant In Service	(C) Monthly Additions MAPP CWIP	(D) Monthly Additions MAPP In Service	(E) Weighting	(F) Other Plant In Service Amount (A x E)	(G) Other Plant In Service Amount (B x E)	(H) MAPP CWIP Amount (C x E)	(I) MAPP In Service Amount (D x E)	(J) Other Plant In Service (F / 12)	(K) Other Plant In Service (G / 12)	(L) MAPP CWIP (H / 12)	(M) MAPP In Service (I / 12)	
Jan					11.5	-	-	-	-	-	-	-	-	
Feb					10.5	-	-	-	-	-	-	-	-	
Mar	5,828,562				9.5	55,371,339	-	-	-	4,614,278	-	-	-	
Apr					8.5	-	-	-	-	-	-	-	-	
May	28,871,397				7.5	216,535,478	-	-	-	18,044,623	-	-	-	
Jun	42,760,597				6.5	277,943,881	-	-	-	23,161,990	-	-	-	
Jul					5.5	-	-	-	-	-	-	-	-	
Aug					4.5	-	-	-	-	-	-	-	-	
Sep					3.5	-	-	-	-	-	-	-	-	
Oct					2.5	-	-	-	-	-	-	-	-	
Nov					1.5	-	-	-	-	-	-	-	-	
Dec	3,235,662				0.5	1,617,831	-	-	-	134,819	-	-	-	
Total	80,696,218	-	-	-		551,468,528	-	-	-	45,955,711	-	-	-	
New Transmission Plant Additions and CWIP (weighted by months in service)										45,955,711	-	-	-	
								Input to Line 21 of Appendix A		45,955,711	-		-	45,955,711
								Input to Line 43a of Appendix A				-		-
								Month In Service or Month for CWIP		5.17	#DIV/0!	#DIV/0!	#DIV/0!	

3 April Year 2 TO adds weighted Cap Adds to plant in service in Formula

$ 45,955,711 Input to Formula Line 21

4 May Year 2 Post results of Step 3 on PJM web site

93,967,438 — Must run Appendix A to get this number (with inputs on lines 21 and 43a of Attachment A)

5 June Year 2 Results of Step 3 go into effect for the Rate Year 1 (e.g., June 1, 2005 - May 31, 2006)

$ 93,967,438

6 April Year 3 TO populates the formula with Year 2 data from FERC Form 1 for Year 2 (e.g., 2005)

122,607,736 Rev Req based on Prior Year data — Must run Appendix A to get this number (without inputs in lines 20, 21 or 43a of Appendix A)

7 April Year 3 Reconciliation - TO calculates Reconciliation by removing from Year 2 data - the total Cap Adds placed in service in Year 2 and adding weighted average in Year 2 actual Cap Adds and CWIP in Reconciliation
(adjusted to include any Reconciliation amount from prior year)

Remove all Cap Adds placed in service in Year 2
For Reconciliation only - remove actual New Transmission Plant Additions for Year 2 $ 170,292,241 Input to Formula Line 20

Add weighted Cap Adds actually placed in service in Year 2

	(A) Monthly Additions Other Plant In Service	(B) Monthly Additions Other Plant In Service	(C) Monthly Additions MAPP CWIP	(D) Monthly Additions MAPP In Service	(E) Weighting	(F) Other Plant In Service Amount (A x E)	(G) Other Plant In Service Amount (B x E)	(H) MAPP CWIP Amount (C x E)	(I) MAPP In Service Amount (D x E)	(J) Other Plant In Service (F / 12)	(K) Other Plant In Service (G / 12)	(L) MAPP CWIP (H / 12)	(M) MAPP In Service (I / 12)	
Jan	12,706,474				11.5	146,124,447	-	-	-	12,177,037	-	-	-	
Feb	3,246,053				10.5	34,083,555	-	-	-	2,840,296	-	-	-	
Mar	1,511,631				9.5	14,360,493	-	-	-	1,196,708	-	-	-	
Apr	26,556,388				8.5	225,729,299	-	-	-	18,810,775	-	-	-	
May	52,012,666				7.5	390,094,996	-	-	-	32,507,916	-	-	-	
Jun	45,875,408				6.5	298,190,155	-	-	-	24,849,180	-	-	-	
Jul	92,900				5.5	510,950	-	-	-	42,579	-	-	-	
Aug	804,570				4.5	3,620,565	-	-	-	301,714	-	-	-	
Sep	1,103,039				3.5	3,860,636	-	-	-	321,720	-	-	-	
Oct	4,192,134				2.5	10,480,335	-	-	-	873,361	-	-	-	
Nov	1,095,520				1.5	1,643,280	-	-	-	136,940	-	-	-	
Dec	21,095,458				0.5	10,547,729	-	-	-	878,977	-	-	-	
Total	170,292,241	-	-	-		1,139,246,440	-	-	-	94,937,203	-	-	-	
New Transmission Plant Additions and CWIP (weighted by months in service)										94,937,203	-	-	-	
								Input to Line 21 of Appendix A		94,937,203	-		-	94,937,203
								Input to Line 43a of Appendix A				-		-
								Month In Service or Month for CWIP		5.31	#DIV/0!	#DIV/0!	#DIV/0!	

115,988,462 Result of Formula for Reconciliation Must run Appendix A with cap adds in line 21 & line 20
(Year 2 data with total of Year 2 Cap Adds removed and monthly weighted average of Year 2 actual Cap Adds added in)

8 April Year 3 TO estimates Cap Adds and CWIP during Year 3 weighted based on Months expected to be in service in Year 3 (e.g., 2006)

	(A) Monthly Additions Other Plant In Service	(B) Monthly Additions Other Plant In Service	(C) Monthly Additions MAPP CWIP	(D) Monthly Additions MAPP In Service	(E) Weighting	(F) Other Plant In Service Amount (A x E)	(G) Other Plant In Service Amount (B x E)	(H) MAPP CWIP Amount (C x E)	(I) MAPP In Service Amount (D x E)	(J) Other Plant In Service (F / 12)	(K) Other Plant In Service (G / 12)	(L) MAPP CWIP (H / 12)	(M) MAPP In Service (I / 12)	
Jan					11.5	-	-	-	-	-	-	-	-	
Feb					10.5	-	-	-	-	-	-	-	-	
Mar	6,321,892				9.5	60,057,974	-	-	-	5,004,831	-	-	-	
Apr	4,268,041				8.5	36,278,349	-	-	-	3,023,196	-	-	-	
May					7.5	-	-	-	-	-	-	-	-	
Jun	11,688,559				6.5	75,975,634	-	-	-	6,331,303	-	-	-	
Jul					5.5	-	-	-	-	-	-	-	-	
Aug					4.5	-	-	-	-	-	-	-	-	
Sep					3.5	-	-	-	-	-	-	-	-	
Oct					2.5	-	-	-	-	-	-	-	-	
Nov					1.5	-	-	-	-	-	-	-	-	
Dec					0.5	-	-	-	-	-	-	-	-	
Total	22,278,492	-	-	-		172,311,956	-	-	-	14,359,330	-	-	-	
New Transmission Plant Additions and CWIP (weighted by months in service)										14,359,330	-	-	-	
123,838,424								Input to Line 21 of Appendix A		14,359,330	-		-	14,359,330
								Input to Line 43a of Appendix A				-		-
								Month In Service or Month for CWIP		4.27	#DIV/0!	#DIV/0!	#DIV/0!	

9 April Year 3 Reconciliation - TO adds the difference between the Reconciliation in Step 7 and the forecast in Line 5 with interest to the result of Step 7 (this difference is also added to Step 8 in the subsequent year)

The Reconciliation in Step 7		The forecast in Prior Year		
115,988,462	-	104,043,298	=	11,945,164

Interest on Amount of Refunds or Surcharges

Interest rate pursuant to 35.19a for March c 0.3000%

Month	Yr	1/12 of Step 9	Interest rate for March of the Current Yr	Months	Interest	Surcharge (Refund) Owed
Jun	Year 1	995,430	0.3000%	11.5	34,342	1,029,773
Jul	Year 1	995,430	0.3000%	10.5	31,356	1,026,786
Aug	Year 1	995,430	0.3000%	9.5	28,370	1,023,800
Sep	Year 1	995,430	0.3000%	8.5	25,383	1,020,814
Oct	Year 1	995,430	0.3000%	7.5	22,397	1,017,827
Nov	Year 1	995,430	0.3000%	6.5	19,411	1,014,841
Dec	Year 1	995,430	0.3000%	5.5	16,425	1,011,855
Jan	Year 2	995,430	0.3000%	4.5	13,438	1,008,869
Feb	Year 2	995,430	0.3000%	3.5	10,452	1,005,882
Mar	Year 2	995,430	0.3000%	2.5	7,466	1,002,896
Apr	Year 2	995,430	0.3000%	1.5	4,479	999,910
May	Year 2	995,430	0.3000%	0.5	1,493	996,923
Total		11,945,164				12,160,176

		Balance	Interest rate from above	Amortization over Rate Year	Balance
Jun	Year 2	12,160,176	0.3000%	1,033,217	11,163,440
Jul	Year 2	11,163,440	0.3000%	1,033,217	10,163,714
Aug	Year 2	10,163,714	0.3000%	1,033,217	9,160,988
Sep	Year 2	9,160,988	0.3000%	1,033,217	8,155,254
Oct	Year 2	8,155,254	0.3000%	1,033,217	7,146,503
Nov	Year 2	7,146,503	0.3000%	1,033,217	6,134,726
Dec	Year 2	6,134,726	0.3000%	1,033,217	5,119,913
Jan	Year 3	5,119,913	0.3000%	1,033,217	4,102,056
Feb	Year 3	4,102,056	0.3000%	1,033,217	3,081,145
Mar	Year 3	3,081,145	0.3000%	1,033,217	2,057,172
Apr	Year 3	2,057,172	0.3000%	1,033,217	1,030,126
May	Year 3	1,030,126	0.3000%	1,033,217	-
Total with interest				12,398,602	

The difference between the Reconciliation in Step 7 and the forecast in Prior Year with interest	12,398,602
Rev Req based on Year 2 data with estimated Cap Adds and CWIP for Year 3 (Step 8)	$ 123,838,424
Revenue Requirement for Year 3	136,237,027

10 May Year 3 ılts of Step 9 on PJM web site

$ 136,237,027

11 June Year 3 r the Rate Year 2 (e.g., June 1, 2006 - May 31, 2007)

$ 136,237,027

Atlantic City Electric Company

Attachment 7 - Transmission Enhancement Charge Worksheet

1 New Plant Carrying Charge

2 **Fixed Charge Rate (FCR) if not a CIAC**

Line		Formula Line		
3		Formula Line		
4	A	160	Net Plant Carrying Charge without Depreciation	10.9437%
5	B	167	Net Plant Carrying Charge per 100 Basis Point increase in ROE without Depreciation	11.5416%
6	C		Line B less Line A	0.5979%

7 **FCR if a CIAC**

Line		Formula Line		
8	D	161	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes	2.7300%

9 **The FCR resulting from Formula in a given year is used for that year only.**
10 **Therefore actual revenues collected in a year do not change based on cost data for subsequent years**

11 **The ROE is 10.5% which includes a base ROE of 10.0% ROE per FERC order in Docket No. EL13-48 and a 50 basis point RTO membership adder as authorized by FERC: provided, that the projects**

Line		Details		B0265 Mickelton	B0276 Monroe	B0211 Union-Corson
12	"Yes" if a project under PJM OATT Schedule 12, otherwise "No"	Schedule 12	(Yes or No)	Yes	Yes	Yes
13	Useful life of project	Life		35	35	35
14	"Yes" if the customer has paid a lump sum payment in the amount of the investment on line 18, Otherwise "No"	CIAC	(Yes or No)	No	No	No
15	Input the allowed ROE Incentive	Increased ROE (Basis Points)		150	0	0
16	From line 4 above if "No" on line 14 and From line 8 above if "Yes" on line 14	Base FCR		10.9437%	10.9437%	10.9437%
17	Line 6 times line 15 divided by 100 basis points	FCR for This Project		11.8406%	10.9437%	10.9437%
18	Columns A, B or C from Attachment 6	Investment		4,854,660 may be weighted average of small projects	7,878,071	13,722,120
19	Line 18 divided by line 13	Annual Depreciation Exp		138,705	225,088	392,061
20	From Columns H, I or J from Attachment 6	Month In Service or Month for CWIP		6.00	6.00	9.00

Line		Invest Yr	Beginning	Depreciation	Ending	Revenue	Beginning	Depreciation	Ending	Revenue	Beginning	Depreciation	Ending	Revenue
39	Base FCR	2017	3,814,376	138,705	3,675,671	540,960	6,189,913	225,088	5,964,825	877,862	10,487,620	392,061	10,095,560	1,496,892
40	W Increased ROE	2017	3,814,376	138,705	3,675,671	573,925	6,189,913	225,088	5,964,825	877,862	10,487,620	392,061	10,095,560	1,496,892
41	Base FCR	2018	3,675,671	138,705	3,536,967	525,781	5,964,825	225,088	5,739,737	853,229	10,095,560	392,061	9,703,499	1,453,986
42	W Increased ROE	2018	3,675,671	138,705	3,536,967	557,502	5,964,825	225,088	5,739,737	853,229	10,095,560	392,061	9,703,499	1,453,986
43	Base FCR	2019	3,536,967	138,705	3,398,262	510,601	5,739,737	225,088	5,514,650	828,596	9,703,499	392,061	9,311,439	1,411,080
44	W Increased ROE	2019	3,536,967	138,705	3,398,262	541,078	5,739,737	225,088	5,514,650	828,596	9,703,499	392,061	9,311,439	1,411,080
45	Base FCR	2020	3,398,262	138,705	3,259,557	495,422	5,514,650	225,088	5,289,562	803,963	9,311,439	392,061	8,919,378	1,368,173
46	W Increased ROE	2020	3,398,262	138,705	3,259,557	524,655	5,514,650	225,088	5,289,562	803,963	9,311,439	392,061	8,919,378	1,368,173
47	Base FCR	2021	3,259,557	138,705	3,120,853	480,242	5,289,562	225,088	5,064,474	779,330	8,919,378	392,061	8,527,317	1,325,267
48	W Increased ROE	2021	3,259,557	138,705	3,120,853	508,231	5,289,562	225,088	5,064,474	779,330	8,919,378	392,061	8,527,317	1,325,267
49	Base FCR	2022	3,120,853	138,705	2,982,148	465,063	5,064,474	225,088	4,839,386	754,697	8,527,317	392,061	8,135,257	1,282,361
50	W Increased ROE	2022	3,120,853	138,705	2,982,148	491,808	5,064,474	225,088	4,839,386	754,697	8,527,317	392,061	8,135,257	1,282,361
51	Base FCR	2023	2,982,148	138,705	2,843,444	449,883	4,839,386	225,088	4,614,299	730,064	8,135,257	392,061	7,743,196	1,239,455
52	W Increased ROE	2023	2,982,148	138,705	2,843,444	475,385	4,839,386	225,088	4,614,299	730,064	8,135,257	392,061	7,743,196	1,239,455
53	Base FCR	2024	2,843,444	138,705	2,704,739	434,704	4,614,299	225,088	4,389,211	705,431	7,743,196	392,061	7,351,136	1,196,549
54	W Increased ROE	2024	2,843,444	138,705	2,704,739	458,961	4,614,299	225,088	4,389,211	705,431	7,743,196	392,061	7,351,136	1,196,549
55	Base FCR	2025	2,704,739	138,705	2,566,035	419,525	4,389,211	225,088	4,164,123	680,798	7,351,136	392,061	6,959,075	1,153,643
56	W Increased ROE	2025	2,704,739	138,705	2,566,035	442,538	4,389,211	225,088	4,164,123	680,798	7,351,136	392,061	6,959,075	1,153,643
57	Base FCR	2026	2,566,035	138,705	2,427,330	404,345	4,164,123	225,088	3,939,035	656,165	6,959,075	392,061	6,567,015	1,110,737
58	W Increased ROE	2026	2,566,035	138,705	2,427,330	426,114	4,164,123	225,088	3,939,035	656,165	6,959,075	392,061	6,567,015	1,110,737
59	Base FCR	2027	2,427,330	138,705	2,288,625	389,166	3,939,035	225,088	3,713,948	631,532	6,567,015	392,061	6,174,954	1,067,831
60	W Increased ROE	2027		138,705	(138,705)	122,281	3,939,035	225,088	3,713,948	631,532	6,567,015	392,061	6,174,954	1,067,831
61		....		....	.....	....	....	....	.....	....	....	....	.....	....
62		....	....	.....	.....	....	....	.....	.....	....	....	.....	.....	....
63														

identified in Docket Nos. ER08-686 and ER08-1423 have been awarded an additional 150 basis point adder and, thus, their ROE is 12.0%.

B0210 Orchard-500kV				B0210 Orchard-Below 500kV				B0277 Cumberland Sub:2nd Xfmr				B1398.5 Reconductor Mickleton - Depford - 230 Kv line				B1398.3.1 Mickleton Dep	
Yes				Yes				Yes				Yes				Yes	
35				35				35				35				35	
No				No				No				No				No	
150				150				150				0				0	
10.9437%				10.9437%				10.9437%				10.9437%				10.9437%	
11.8406%				11.8406%				11.8406%				10.9437%				10.9437%	
26,046,638				18,572,212				6,759,777				4,045,398				13,176,210	
744,190				530,635				193,136				115,583				376,463	
7.00				7				2				5				5	
Beginning	Depreciation	Ending	Revenue	Beginning	Depreciation	Ending	Revenue	Beginning	Depreciation	Ending	Revenue	Beginning	Depreciation	Ending	Revenue	Beginning	Depreciation
19,783,042	744,190	19,038,852	2,827,751	14,106,037	530,635	13,575,403	2,016,290	5,440,011	193,136	5,246,875	767,340	3,942,737	115,583	3,827,154	534,416	12,204,855	376,463
19,783,042	744,190	19,038,852	2,998,498	14,106,037	530,635	13,575,403	2,138,040	5,440,011	193,136	5,246,875	814,396	3,942,737	115,583	3,827,154	534,416	12,204,855	376,463
19,038,852	744,190	18,294,662	2,746,309	13,575,403	530,635	13,044,768	1,958,219	5,246,875	193,136	5,053,738	746,204	3,827,154	115,583	3,711,571	521,767	11,828,392	376,463
19,038,852	744,190	18,294,662	2,910,382	13,575,403	530,635	13,044,768	2,075,210	5,246,875	193,136	5,053,738	791,528	3,827,154	115,583	3,711,571	521,767	11,828,392	376,463
18,294,662	744,190	17,550,473	2,664,866	13,044,768	530,635	12,514,133	1,900,148	5,053,738	193,136	4,860,602	725,068	3,711,571	115,583	3,595,988	509,118	11,451,929	376,463
18,294,662	744,190	17,550,473	2,822,266	13,044,768	530,635	12,514,133	2,012,379	5,053,738	193,136	4,860,602	768,659	3,711,571	115,583	3,595,988	509,118	11,451,929	376,463
17,550,473	744,190	16,806,283	2,583,424	12,514,133	530,635	11,983,499	1,842,077	4,860,602	193,136	4,667,465	703,931	3,595,988	115,583	3,480,405	496,469	11,075,466	376,463
17,550,473	744,190	16,806,283	2,734,149	12,514,133	530,635	11,983,499	1,949,549	4,860,602	193,136	4,667,465	745,791	3,595,988	115,583	3,480,405	496,469	11,075,466	376,463
16,806,283	744,190	16,062,093	2,501,982	11,983,499	530,635	11,452,864	1,784,005	4,667,465	193,136	4,474,329	682,795	3,480,405	115,583	3,364,823	483,820	10,699,003	376,463
16,806,283	744,190	16,062,093	2,646,033	11,983,499	530,635	11,452,864	1,886,719	4,667,465	193,136	4,474,329	722,923	3,480,405	115,583	3,364,823	483,820	10,699,003	376,463
16,062,093	744,190	15,317,904	2,420,540	11,452,864	530,635	10,922,229	1,725,934	4,474,329	193,136	4,281,192	661,659	3,364,823	115,583	3,249,240	471,171	10,322,539	376,463
16,062,093	744,190	15,317,904	2,557,917	11,452,864	530,635	10,922,229	1,823,889	4,474,329	193,136	4,281,192	700,054	3,364,823	115,583	3,249,240	471,171	10,322,539	376,463
15,317,904	744,190	14,573,714	2,339,098	10,922,229	530,635	10,391,595	1,667,863	4,281,192	193,136	4,088,056	640,522	3,249,240	115,583	3,133,657	458,522	9,946,076	376,463
15,317,904	744,190	14,573,714	2,469,801	10,922,229	530,635	10,391,595	1,761,059	4,281,192	193,136	4,088,056	677,186	3,249,240	115,583	3,133,657	458,522	9,946,076	376,463
14,573,714	744,190	13,829,524	2,257,656	10,391,595	530,635	9,860,960	1,609,792	4,088,056	193,136	3,894,919	619,386	3,133,657	115,583	3,018,074	445,873	9,569,613	376,463
14,573,714	744,190	13,829,524	2,381,684	10,391,595	530,635	9,860,960	1,698,229	4,088,056	193,136	3,894,919	654,317	3,133,657	115,583	3,018,074	445,873	9,569,613	376,463
13,829,524	744,190	13,085,335	2,176,214	9,860,960	530,635	9,330,326	1,551,721	3,894,919	193,136	3,701,783	598,250	3,018,074	115,583	2,902,491	433,224	9,193,150	376,463
13,829,524	744,190	13,085,335	2,293,568	9,860,960	530,635	9,330,326	1,635,398	3,894,919	193,136	3,701,783	631,449	3,018,074	115,583	2,902,491	433,224	9,193,150	376,463
13,085,335	744,190	12,341,145	2,094,772	9,330,326	530,635	8,799,691	1,493,649	3,701,783	193,136	3,508,646	577,113	2,902,491	115,583	2,786,909	420,575	8,816,687	376,463
13,085,335	744,190	12,341,145	2,205,452	9,330,326	530,635	8,799,691	1,572,568	3,701,783	193,136	3,508,646	608,580	2,902,491	115,583	2,786,909	420,575	8,816,687	376,463
12,341,145	744,190	11,596,955	2,013,329	8,799,691	530,635	8,269,056	1,435,578	3,508,646	193,136	3,315,510	555,977	2,786,909	115,583	2,671,326	407,926	8,440,224	376,463
12,341,145	744,190	11,596,955	2,117,335	8,799,691	530,635	8,269,056	1,509,738	3,508,646	193,136	3,315,510	585,712	2,786,909	115,583	2,671,326	407,926	8,440,224	376,463
....	....	.....	....	....	....	.....	....	....	....	.....	....	....	....	.....	....	....	....
....	.....	.....	....	....	.....	.....	....	....	.....	.....	....	....	.....	.....	....	....	.....

tford 230kv terminal	B1600 Upgrade Mill T2 138/69 kV Transformer
	Yes
	35
	No
	0
	10.9437%
	10.9437%
	14,841,978
	424,057
	6

Ending	Revenue	Beginning	Depreciation	Ending	Revenue	Total	Incentive Charged	Revenue Credit
11,828,392	1,670,931	14,647,390	424,057	14,223,334	1,980,620	$ 12,713,063		$ 12,713,063
11,828,392	1,670,931	14,647,390	424,057	14,223,334	1,980,620	$ 13,085,580	$ 13,085,580	
11,451,929	1,629,732	14,223,334	424,057	13,799,277	1,934,212	$ 12,369,439		$ 12,369,439
11,451,929	1,629,732	14,223,334	424,057	13,799,277	1,934,212	$ 12,727,547	$ 12,727,547	
11,075,466	1,588,532	13,799,277	424,057	13,375,221	1,887,805	$ 12,025,815		$ 12,025,815
11,075,466	1,588,532	13,799,277	424,057	13,375,221	1,887,805	$ 12,369,514	$ 12,369,514	
10,699,003	1,547,333	13,375,221	424,057	12,951,164	1,841,397	$ 11,682,191		$ 11,682,191
10,699,003	1,547,333	13,375,221	424,057	12,951,164	1,841,397	$ 12,011,481	$ 12,011,481	
10,322,539	1,506,134	12,951,164	424,057	12,527,107	1,794,990	$ 11,338,567		$ 11,338,567
10,322,539	1,506,134	12,951,164	424,057	12,527,107	1,794,990	$ 11,653,448	$ 11,653,448	
9,946,076	1,464,935	12,527,107	424,057	12,103,051	1,748,582	$ 10,994,943		$ 10,994,943
9,946,076	1,464,935	12,527,107	424,057	12,103,051	1,748,582	$ 11,295,414	$ 11,295,414	
9,569,613	1,423,736	12,103,051	424,057	11,678,994	1,702,174	$ 10,651,319		$ 10,651,319
9,569,613	1,423,736	12,103,051	424,057	11,678,994	1,702,174	$ 10,937,381	$ 10,937,381	
9,193,150	1,382,537	11,678,994	424,057	11,254,938	1,655,767	$ 10,307,695		$ 10,307,695
9,193,150	1,382,537	11,678,994	424,057	11,254,938	1,655,767	$ 10,579,348	$ 10,579,348	
8,816,687	1,341,338	11,254,938	424,057	10,830,881	1,609,359	$ 9,964,070		$ 9,964,070
8,816,687	1,341,338	11,254,938	424,057	10,830,881	1,609,359	$ 10,221,315	$ 10,221,315	
8,440,224	1,300,139	10,830,881	424,057	10,406,825	1,562,952	$ 9,620,446		$ 9,620,446
8,440,224	1,300,139	10,830,881	424,057	10,406,825	1,562,952	$ 9,863,282	$ 9,863,282	
8,063,761	1,258,940	10,406,825	424,057	9,982,768	1,516,544	$ 9,276,822		$ 9,276,822
8,063,761	1,258,940	10,406,825	424,057	9,982,768	1,516,544	$ 9,217,839	$ 9,217,839	
…..	….	….	….	…..	….			$ -
…..	….	….	…..	…..	….		$ -	
							$ 217,852,030	$ 210,914,295

Atlantic City Electric Company

Attachment 8 - Company Exhibit - Securitization Workpaper

Line #		
	Long Term Interest	
101	**Less LTD Interest on Securitization Bonds**	8,290,626
	Capitalization	
112	**Less LTD on Securitization Bonds**	66,433,302

Calculation of the above Securitization Adjustments

Inputs from Atlantic City Electric Company 2016 FERC Form 1
Pages 256-257 "Long Term Debt (Account 221, 222, 223, and 224)"
Line 17 "Note Payable to ACE Transition Funding - variable"
LTD Interest on Securitization Bonds in column (i)
LTD on Securitization Bonds in column (h)

Exhibit B

Tariff Sheets

RATE SCHEDULE RS
(Residential Service)

AVAILABILITY
Available for full domestic service to individually metered residential customers, including rural domestic customers, engaged principally in agricultural pursuits.

	SUMMER June Through September	**WINTER** October Through May
Delivery Service Charges:		
Customer Charge ($/Month)	$4.44	$4.44
Distribution Rates ($/kWH)		
First Block	$0.050245	$0.046361
(Summer <= 750 kWh; Winter<= 500kWh)		
Excess kWh	$0.057764	$0.046361
Non-Utility Generation Charge (NGC) ($/kWH)	See Rider NGC	
Societal Benefits Charge ($/kWh)		
Clean Energy Program	See Rider SBC	
Universal Service Fund	See Rider SBC	
Lifeline	See Rider SBC	
Uncollectible Accounts	See Rider SBC	
Transition Bond Charge (TBC) ($/kWh)	See Rider SEC	
Market Transition Charge Tax (MTC-Tax) ($/kWh)	See Rider SEC	
Transmission Service Charges ($/kWh):		
Transmission Rate	$0.019422	$0.019422
Reliability Must Run Transmission Surcharge	$0.000000	$0.000000
Transmission Enhancement Charge ($/kWh)	See Rider BGS	
Basic Generation Service Charge ($/kWh)	See Rider BGS	
Regional Greenhouse Gas Initiative Recovery Charge ($/kWh)	See Rider RGGI	
Infrastructure Investment Surcharge	See Rider IIS	

CORPORATE BUSINESS TAX (CBT)
Charges under this rate schedule include a component for Corporate Business Taxes as set forth in Rider CBT.

NEW JERSEY SALES AND USE TAX (SUT)
Charges under this rate schedule include a component for New Jersey Sales and Use Tax as set forth in Rider SUT.

RATE SCHEDULE MGS-SECONDARY
(Monthly General Service)

AVAILABILITY

Available at any point of Company's system where facilities of adequate character and capacity exist for the entire electric service requirements of any customer delivered at one point and metered at or compensated to the voltage of delivery. This schedule is not available to residential customers.

	SUMMER June Through September	**WINTER** October Through May
Delivery Service Charges:		
Customer Charge		
Single Phase	$5.64	$5.64
Three Phase	$7.05	$7.05
Distribution Demand Charge (per kW)	$1.90	$1.56
Reactive Demand Charge	$0.46	$0.46
(For each kvar over one-third of kW demand**)**		
Distribution Rates ($/kWh)	$0.050434	$0.045558
Non-Utility Generation Charge (NGC) ($/kWH)	See Rider NGC	
Societal Benefits Charge ($/kWh)		
Clean Energy Program	See Rider SBC	
Universal Service Fund	See Rider SBC	
Lifeline	See Rider SBC	
Uncollectible Accounts	See Rider SBC	
Transition Bond Charge (TBC) ($/kWh)	See Rider SEC	
Market Transition Charge Tax (MTC-Tax) ($/kWh)	See Rider SEC	
CIEP Standby Fee ($/kWh)	See Rider BGS	
Transmission Demand Charge ($/kW for each kW in excess of 3 kW)	$3.27	$2.89
Reliability Must Run Transmission Surcharge ($/kWh)	$0.000000	$0.000000
Transmission Enhancement Charge ($/kWh)	See Rider BGS	
Basic Generation Service Charge ($/kWh)	See Rider BGS	
Regional Greenhouse Gas Initiative Recovery Charge ($/kWh)	See Rider RGGI	
Infrastructure Investment Surcharge	See Rider IIS	

The minimum monthly bill will be $7.05 per month plus any applicable adjustment.

Date of Issue: **Effective Date:**

Issued by:

ATLANTIC CITY ELECTRIC COMPANY
BPU NJ No. 11 Electric Service - Section IV Revised Sheet Replaces Revised Sheet No. 14

RATE SCHEDULE MGS-PRIMARY
(Monthly General Service)

AVAILABILITY

Available at any point of Company's system where facilities of adequate character and capacity exist for the entire electric service requirements of any customer delivered at one point and metered at or compensated to the voltage of delivery. This schedule is not available to residential customers.

	SUMMER June Through September	WINTER October Through May
Delivery Service Charges:		
Customer Charge		
Single Phase	$5.32	$5.32
Three Phase	$6.64	$6.64
Distribution Demand Charge (per kW)	$1.53	$1.19
Reactive Demand Charge	$0.43	$0.43
(For each kvar over one-third of kW demand)		
Distribution Rates ($/kWh)	$0.045258	$0.043956
Non-Utility Generation Charge (NGC) ($/kWH)	See Rider NGC	
Societal Benefits Charge ($/kWh)		
Clean Energy Program	See Rider SBC	
Universal Service Fund	See Rider SBC	
Lifeline	See Rider SBC	
Uncollectible Accounts	See Rider SBC	
Transition Bond Charge (TBC) ($/kWh)	See Rider SEC	
Market Transition Charge Tax (MTC-Tax) ($/kWh)	See Rider SEC	
CIEP Standby Fee ($/kWh)	See Rider BGS	
Transmission Demand Charge **($/kW for each kW in excess of 3 kW)**	$3.16	$2.82
Reliability Must Run Transmission Surcharge ($/kWh)	$0.000000	$0.000000
Transmission Enhancement Charge ($/kWh)	See Rider BGS	
Basic Generation Service Charge ($/kWh)	See Rider BGS	
Regional Greenhouse Gas Initiative **Recovery Charge ($/kWh)**	See Rider RGGI	
Infrastructure Investment Surcharge	See Rider IIS	

The minimum monthly bill will be $6.64 per month plus any applicable adjustment.

Date of Issue: **Effective Date:**

Issued by:

ATLANTIC CITY ELECTRIC COMPANY
BPU NJ No. 11 Electric Service - Section IV Revised Sheet Replaces Revised Sheet No. 17

RATE SCHEDULE AGS-SECONDARY
(Annual General Service)

AVAILABILITY

Available at any point of Company's system where facilities of adequate character and capacity exist for the entire electric service requirements of any customer contracting for annual service delivered at one point and metered at or compensated to the voltage of delivery.

MONTHLY RATE

Delivery Service Charges:	
Customer Charge	$151.25
Distribution Demand Charge ($/kW)	$8.82
Reactive Demand (for each kvar over one-third of kW demand)	$0.67
Non-Utility Generation Charge (NGC) ($/kWH)	See Rider NGC
Societal Benefits Charge ($/kWh)	
Clean Energy Program	See Rider SBC
Universal Service Fund	See Rider SBC
Lifeline	See Rider SBC
Uncollectible Accounts	See Rider SBC
Transition Bond Charge (TBC) ($/kWh)	See Rider SEC
Market Transition Charge Tax (MTC-Tax) ($/kWh)	See Rider SEC
CIEP Standby Fee ($/kWh)	See Rider BGS
Transmission Demand Charge ($/kW)	$3.57
Reliability Must Run Transmission Surcharge ($/kWh)	$0.000000
Transmission Enhancement Charge ($/kWh)	See Rider BGS
Basic Generation Service Charge ($/kWh)	See Rider BGS
Regional Greenhouse Gas Initiative Recovery Charge ($/kWh)	See Rider RGGI
Infrastructure Investment Surcharge	See Rider IIS

Date of Issue: **Effective Date:**

Issued by:

RATE SCHEDULE AGS-PRIMARY
(Annual General Service)

AVAILABILITY

Available at any point of Company's system where facilities of adequate character and capacity exist for the entire electric service requirements of any customer contracting for annual service delivered at one point and metered at or compensated to the voltage of delivery.

MONTHLY RATE

Delivery Service Charges:	
Customer Charge	$560.25
Distribution Demand Charge ($/kW)	$7.24
Reactive Demand (for each kvar over one-third of kW demand)	$0.53
Non-Utility Generation Charge (NGC) ($/kWH)	See Rider NGC
Societal Benefits Charge ($/kWh)	
Clean Energy Program	See Rider SBC
Universal Service Fund	See Rider SBC
Lifeline	See Rider SBC
Uncollectible Accounts	See Rider SBC
Transition Bond Charge (TBC) ($/kWh)	See Rider SEC
Market Transition Charge Tax (MTC-Tax) ($/kWh)	See Rider SEC
CIEP Standby Fee ($/kWh)	See Rider BGS
Transmission Demand Charge ($/kW)	$3.58
Reliability Must Run Transmission Surcharge ($/kWh)	$0.000000
Transmission Enhancement Charge ($/kWh)	See Rider BGS
Basic Generation Service Charge ($/kWh)	See Rider BGS
Regional Greenhouse Gas Initiative Recovery Charge ($/kWh)	See Rider RGGI
Infrastructure Investment Surcharge	See Rider IIS

RATE SCHEDULE TGS
(Transmission General Service)
(Sub Transmission Service Taken at 23kV and 34.5 kV)

AVAILABILITY
Available at any point of Company's system where facilities of adequate character and capacity exist for the entire electric service requirements of any customer contracting for annual service delivered at one point and metered at or compensated to the voltage subtransmission level (23 or 34.5 kV).

MONTHLY RATE

Delivery Service Charges:

Customer Charge

Maximum billed demand within the most recent 12 billing months.	
Less than 5,000 kW	$137.29
5,000 – 9,000 kW	$4,546.92
Greater than 9,000 kW	$8,253.86
Distribution Demand Charge ($/kW)	
Maximum billed demand within the most recent 12 billing months.	
Less than 5,000 kW	$3.94
5,000 – 9,000 kW	$3.03
Greater than 9,000 kW	$1.52
Reactive Demand (for each kvar over one-third of kW demand)	$0.54
Non-Utility Generation Charge (NGC) ($/kWH)	See Rider NGC
Societal Benefits Charge ($/kWh)	
Clean Energy Program	See Rider SBC
Universal Service Fund	See Rider SBC
Lifeline	See Rider SBC
Uncollectible Accounts	See Rider SBC
Transition Bond Charge (TBC) ($/kWh)	See Rider SEC
Market Transition Charge Tax (MTC-Tax) ($/kWh)	See Rider SEC
CIEP Standby Fee ($/kWh)	See Rider BGS
Transmission Demand Charge ($/kW)	$1.68
Reliability Must Run Transmission Surcharge ($/kWh)	$0.000000
Transmission Enhancement Charge ($/kWh)	See Rider BGS
Basic Generation Service Charge ($/kWh)	See Rider BGS
Regional Greenhouse Gas Initiative Recovery Charge ($/kWh)	See Rider RGGI
Infrastructure Investment Surcharge	See Rider IIS

RATE SCHEDULE TGS
(Transmission General Service)
(Transmission Service Taken at or above 69kV)

AVAILABILITY
Available at any point of Company's system where facilities of adequate character and capacity exist for the entire electric service requirements of any customer contracting for annual service delivered at one point and metered at or compensated to the voltage at transmission level (69 kV or higher).

MONTHLY RATE

Delivery Service Charges:

Customer Charge		
Maximum billed demand within the most recent 12 billing months.		
Less than 5,000 kW	$133.60	
5,000 – 9,000 kW	$4,424.86	
Greater than 9,000 kW	$20,080.75	
Distribution Demand Charge ($/kW)		
Maximum billed demand within the most recent 12 billing months.		
Less than 5,000 kW	$3.07	
5,000 – 9,000 kW	$2.36	
Greater than 9,000 kW	$0.15	
Reactive Demand (for each kvar over one-third of kW demand)	$0.52	
Non-Utility Generation Charge (NGC) ($/kWH)	See Rider NGC	
Societal Benefits Charge ($/kWh)		
Clean Energy Program	See Rider SBC	
Universal Service Fund	See Rider SBC	
Lifeline	See Rider SBC	
Uncollectible Accounts	See Rider SBC	
Transition Bond Charge (TBC) ($/kWh)	See Rider SEC	
Market Transition Charge Tax (MTC-Tax) ($/kWh)	See Rider SEC	
CIEP Standby Fee ($/kWh)	See Rider BGS	
Transmission Demand Charge ($/kW)	$1.85	
Reliability Must Run Transmission Surcharge ($/kWh)	$0.000000	$0.000000
Transmission Enhancement Charge ($/kWh)	See Rider BGS	
Basic Generation Service Charge ($/kWh)	See Rider BGS	
Regional Greenhouse Gas Initiative Recovery Charge ($/kWh)	See Rider RGGI	
Infrastructure Investment Surcharge	See Rider IIS	

RATE SCHEDULE DDC
(Direct Distribution Connection)

AVAILABILITY

Available at any point of the Company's existing distribution system where facilities of adequate character exist for the connection of fixed, constant and predictable non-residential loads not to exceed one kilowatt

MONTHLY RATES

Distribution:

Service and Demand (per day per connection)	$0.167902
Energy (per day for each kW of effective load)	$0.808718
Non-Utility Generation Charge (NGC) ($/kWH)	See Rider NGC
Societal Benefits Charge ($/kWh)	
Clean Energy Program	See Rider SBC
Universal Service Fund	See Rider SBC
Lifeline See Rider SBC	
Uncollectible Accounts	See Rider SBC
Transition Bond Charge (TBC) ($/kWh)	See Rider SEC
Market Transition Charge Tax (MTC-Tax) ($/kWh)	See Rider SEC
Transmission Rate ($/kWh)	$0.006480
Reliability Must Run Transmission Surcharge ($/kWh)	$0.000000
Transmission Enhancement Charge ($/kWh)	See Rider BGS
Basic Generation Service Charge ($/kWh)	See Rider BGS
Regional Greenhouse Gas Initiative Recovery Charge ($/kWh)	See Rider RGGI
Infrastructure Investment Surcharge	See Rider IIS

CORPORATE BUSINESS TAX (CBT)

Charges under this rate schedule include a component for Corporate Business Taxes as set forth in Rider CBT.

NEW JERSEY SALES AND USE TAX (SUT)

Charges under this rate schedule include a component for New Jersey Sales and Use Tax as set forth in Rider SUT.

LOAD CONSUMPTION

Effective load shall be determined by the Company and be specified in the contract. Effective load is defined as the sum of the products of the connected load in kilowatts times the percent load on at one time. No changes in attached load may be made by the customer without the permission of the Company and customer shall allow the Company access to his premises to assure conformance with this provision.

RIDER STB-STANDBY SERVICE
(Applicable to MGS, AGS, TGS and SPP Rate Schedules)

AVAILABILITY
This rider is available to customers having other sources of electrical energy supply, but who desire to purchase Standby Service from the Company. The terms of this rider shall not be available in any month when the customer's Generation Availability for the current and preceding five (5) months does not exceed 50%.

DEFINITIONS

Standby Service:
Standby Service is defined as the additional electrical capacity available to a customer in the event of a forced outage and during a mutually agreed upon customer's scheduled maintenance shutdown of the customer owned electrical energy source.

Standby Service Capacity:
The Standby Service Capacity shall be the maximum electrical capacity in kW supplied by the customer owned electrical energy source during the current and preceding five (5) months. Such Standby Service Capacity may be revised with Company approval as changes in the customer's load conditions warrant.

Generation Availability:
Generation Availability is defined as the availability of the customer owned electrical energy source during the current and preceding five (5) months and shall be determined by dividing the Kwhrs produced during this period by the product of the Standby Service Capacity times 4380 hours.

MODIFICATION OF DEMAND DETERMINATION
The monthly billing demand shall be as defined under the "Demand Determination" section of the applicable rate schedule.

The Standby Service Demand shall be the "Standby Service Capacity" as defined above.

During the billing months in which a forced outage or mutually agreed upon customer's scheduled maintenance shutdown occurs, the billing demand will be determined by subtracting the Standby Service Capacity from the total demand and waives the minimum charge provision of the applicable rate schedule. Electric service is provided under the terms of the applicable rate schedule. Total demand is defined as the sum of the Company's demand meter plus demand supplied by the other sources of electrical energy, all computed to the nearest whole kilowatt during a fifteen minute period.

STANDBY SERVICE CHARGE
This rider imposes a Standby Service Charge at the following voltage levels:

Tariff	Transmission Stand By Rate ($/kW)	Distribution Stand By Rate ($/kW)
MGS-Secondary	$0.33	$0.10
MGS Primary	$0.32	$0.13
AGS Secondary	$0.36	$0.90
AGS Primary	$0.36	$0.74
TGS Sub Transmission	$0.19	$0.00
TGS Transmission	$0.19	$0.00

RIDER (BGS) continued
Basic Generation Service (BGS)

CIEP Standby Fee $0.000160 per kWh
This charge recovers the costs associated with the winning BGS-CIEP bidders maintaining the availability of the hourly priced default electric supply service plus administrative charges pursuant to N.J.S.A. 48:2-60 and New Jersey Sales and Use Tax as set forth in Rider SUT. This charge is assessed on all kWhs delivered to all CIEP- eligible customers on Rate Schedules MGS Secondary, MGS Primary, AGS Secondary, AGS Primary or TGS.

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

	Rate Class							
	RS	MGS Secondary	MGS Primary	AGS Secondary	AGS Primary	TGS	SPL/CSL	DDC
VEPCo	0.000588	0.000492	0.000531	0.000325	0.000261	0.000250	-	0.000206
TrAILCo	0.000632	0.000498	0.000523	0.000349	0.000294	0.000226	-	0.000209
PSE&G	0.000642	0.000506	0.000531	0.000355	0.000298	0.000228	-	0.000214
PATH	0.000051	0.000041	0.000043	0.000029	0.000024	0.000018	-	0.000017
PPL	0.000238	0.000199	0.000215	0.000131	0.000105	0.000102	-	0.000083
Pepco	0.000021	0.000018	0.000019	0.000012	0.000010	0.000010	-	0.000007
JCP&L	0.000003	0.000003	0.000003	0.000002	0.000002	0.000001	-	0.000001
Delmarva	0.000001	0.000001	0.000001	0.000001	0.000001	0.000001	-	0.000001
BG&E	0.000073	0.000061	0.000066	0.000041	0.000032	0.000031	-	0.000026
AEP - East	0.000106	0.000080	0.000042	0.000048	0.000019	0.000036	-	0.000037
Total	0.002355	0.001899	0.001974	0.001293	0.001046	0.000903	-	0.000801

Exhibit B

Redlined Tariff Sheets

ATLANTIC CITY ELECTRIC COMPANY
BPU NJ No. 11 Electric Service - Section IV ~~Thirty-Seventh~~ Revised Sheet Replaces ~~Thirty-Sixth~~ Revised Sheet No. 5

RATE SCHEDULE RS
(Residential Service)

AVAILABILITY
Available for full domestic service to individually metered residential customers, including rural domestic customers, engaged principally in agricultural pursuits.

	SUMMER June Through September	WINTER October Through May
Delivery Service Charges:		
Customer Charge ($/Month)	$4.44	$4.44
Distribution Rates ($/kWH)		
First Block	$0.050245	$0.046361
(Summer <= 750 kWh; Winter<= 500kWh)		
Excess kWh	$0.057764	$0.046361
Non-Utility Generation Charge (NGC) ($/kWH)	See Rider NGC	
Societal Benefits Charge ($/kWh)		
Clean Energy Program	See Rider SBC	
Universal Service Fund	See Rider SBC	
Lifeline	See Rider SBC	
Uncollectible Accounts	See Rider SBC	
Transition Bond Charge (TBC) ($/kWh)	See Rider SEC	
Market Transition Charge Tax (MTC-Tax) ($/kWh)	See Rider SEC	
Transmission Service Charges ($/kWh):		
Transmission Rate	$0.~~012293~~019422	$0.~~012293~~ 019422
Reliability Must Run Transmission Surcharge	$0.000000	$0.000000
Transmission Enhancement Charge ($/kWh)	See Rider BGS	
Basic Generation Service Charge ($/kWh)	See Rider BGS	
Regional Greenhouse Gas Initiative Recovery Charge ($/kWh)	See Rider RGGI	
Infrastructure Investment Surcharge	See Rider IIS	

CORPORATE BUSINESS TAX (CBT)
Charges under this rate schedule include a component for Corporate Business Taxes as set forth in Rider CBT.

NEW JERSEY SALES AND USE TAX (SUT)
Charges under this rate schedule include a component for New Jersey Sales and Use Tax as set forth in Rider SUT.

Date of Issue: ~~December 8, 2016~~ **Effective Date:** ~~January 1, 2017~~

~~**Issued by: David M. Velazquez, President and Chief Executive Officer – Atlantic City Electric Company**~~
~~**Filed pursuant to Board of Public Utilities of the State of New Jersey directives associated with the BPU Docket No. ER16111054**~~

Issued by:

RATE SCHEDULE MGS-SECONDARY
(Monthly General Service)

AVAILABILITY

Available at any point of Company's system where facilities of adequate character and capacity exist for the entire electric service requirements of any customer delivered at one point and metered at or compensated to the voltage of delivery. This schedule is not available to residential customers.

	SUMMER June Through September	**WINTER** October Through May
Delivery Service Charges:		
Customer Charge		
Single Phase	$5.64	$5.64
Three Phase	$7.05	$7.05
Distribution Demand Charge (per kW)	$1.90	$1.56
Reactive Demand Charge	$0.46	$0.46
(For each kvar over one-third of kW demand)		
Distribution Rates ($/kWh)	$0.050434	$0.045558
Non-Utility Generation Charge (NGC) ($/kWH)	See Rider NGC	
Societal Benefits Charge ($/kWh)		
Clean Energy Program	See Rider SBC	
Universal Service Fund	See Rider SBC	
Lifeline	See Rider SBC	
Uncollectible Accounts	See Rider SBC	
Transition Bond Charge (TBC) ($/kWh)	See Rider SEC	
Market Transition Charge Tax (MTC-Tax) ($/kWh)	See Rider SEC	
CIEP Standby Fee ($/kWh)	See Rider BGS	
Transmission Demand Charge ($/kW for each kW in excess of 3 kW)	$~~2.47~~3.27	$2.~~08~~89
Reliability Must Run Transmission Surcharge ($/kWh)	$0.000000	$0.000000
Transmission Enhancement Charge ($/kWh)	See Rider BGS	
Basic Generation Service Charge ($/kWh)	See Rider BGS	
Regional Greenhouse Gas Initiative Recovery Charge ($/kWh)	See Rider RGGI	
Infrastructure Investment Surcharge	See Rider IIS	

The minimum monthly bill will be $7.05 per month plus any applicable adjustment.

RATE SCHEDULE MGS-PRIMARY
(Monthly General Service)

AVAILABILITY
Available at any point of Company's system where facilities of adequate character and capacity exist for the entire electric service requirements of any customer delivered at one point and metered at or compensated to the voltage of delivery. This schedule is not available to residential customers.

	SUMMER June Through September	**WINTER** October Through May
Delivery Service Charges:		
Customer Charge		
Single Phase	$5.32	$5.32
Three Phase	$6.64	$6.64
Distribution Demand Charge (per kW)	$1.53	$1.19
Reactive Demand Charge	$0.43	$0.43
(For each kvar over one-third of kW demand)		
Distribution Rates ($/kWh)	$0.045258	$0.043956
Non-Utility Generation Charge (NGC) ($/kWH)	See Rider NGC	
Societal Benefits Charge ($/kWh)		
Clean Energy Program	See Rider SBC	
Universal Service Fund	See Rider SBC	
Lifeline	See Rider SBC	
Uncollectible Accounts	See Rider SBC	
Transition Bond Charge (TBC) ($/kWh)	See Rider SEC	
Market Transition Charge Tax (MTC-Tax) ($/kWh)	See Rider SEC	
CIEP Standby Fee ($/kWh)	See Rider BGS	
Transmission Demand Charge ($/kW for each kW in excess of 3 kW)	$~~1.08~~3.16	$~~0.74~~2.82
Reliability Must Run Transmission Surcharge ($/kWh)	$0.000000	$0.000000
Transmission Enhancement Charge ($/kWh)	See Rider BGS	
Basic Generation Service Charge ($/kWh)	See Rider BGS	
Regional Greenhouse Gas Initiative Recovery Charge ($/kWh)	See Rider RGGI	
Infrastructure Investment Surcharge	See Rider IIS	

The minimum monthly bill will be $6.64 per month plus any applicable adjustment.

ATLANTIC CITY ELECTRIC COMPANY
BPU NJ No. 11 Electric Service - Section IV ~~Thirty-Seventh~~ Revised Sheet Replaces ~~Thirty-Sixth~~ Revised Sheet No. 17

RATE SCHEDULE AGS-SECONDARY
(Annual General Service)

AVAILABILITY
Available at any point of Company's system where facilities of adequate character and capacity exist for the entire electric service requirements of any customer contracting for annual service delivered at one point and metered at or compensated to the voltage of delivery.

MONTHLY RATE

Delivery Service Charges:	
Customer Charge	$151.25
Distribution Demand Charge ($/kW)	$8.82
Reactive Demand (for each kvar over one-third of kW demand)	$0.67
Non-Utility Generation Charge (NGC) ($/kWH)	See Rider NGC
Societal Benefits Charge ($/kWh)	
Clean Energy Program	See Rider SBC
Universal Service Fund	See Rider SBC
Lifeline	See Rider SBC
Uncollectible Accounts	See Rider SBC
Transition Bond Charge (TBC) ($/kWh)	See Rider SEC
Market Transition Charge Tax (MTC-Tax) ($/kWh)	See Rider SEC
CIEP Standby Fee ($/kWh)	See Rider BGS
Transmission Demand Charge ($/kW)	$~~2.01~~3.57
Reliability Must Run Transmission Surcharge ($/kWh)	$0.000000
Transmission Enhancement Charge ($/kWh)	See Rider BGS
Basic Generation Service Charge ($/kWh)	See Rider BGS
Regional Greenhouse Gas Initiative Recovery Charge ($/kWh)	See Rider RGGI
Infrastructure Investment Surcharge	See Rider IIS

Date of Issue: ~~December 8, 2016~~ **Effective Date:** ~~January 1, 2017~~

Issued by:
~~**Issued by: David M. Velazquez, President and Chief Executive Officer – Atlantic City Electric Company**~~
~~**Filed pursuant to Board of Public Utilities of the State of New Jersey directives associated with the BPU Docket No. ER16111054**~~

ATLANTIC CITY ELECTRIC COMPANY
~~**ATLANTIC CITY ELECTRIC COMPANY**~~

BPU NJ No. 11 Electric Service - Section IV ~~Thirty-Seventh~~ Revised Sheet Replaces ~~Thirty-Sixth~~ Revised Sheet No. 19

RATE SCHEDULE AGS-PRIMARY
(Annual General Service)

AVAILABILITY

Available at any point of Company's system where facilities of adequate character and capacity exist for the entire electric service requirements of any customer contracting for annual service delivered at one point and metered at or compensated to the voltage of delivery.

MONTHLY RATE

Delivery Service Charges:

Customer Charge	$560.25
Distribution Demand Charge ($/kW)	$7.24
Reactive Demand (for each kvar over one-third of kW demand)	$0.53
Non-Utility Generation Charge (NGC) ($/kWH)	See Rider NGC
Societal Benefits Charge ($/kWh)	
Clean Energy Program	See Rider SBC
Universal Service Fund	See Rider SBC
Lifeline	See Rider SBC
Uncollectible Accounts	See Rider SBC
Transition Bond Charge (TBC) ($/kWh)	See Rider SEC
Market Transition Charge Tax (MTC-Tax) ($/kWh)	See Rider SEC
CIEP Standby Fee ($/kWh)	See Rider BGS
Transmission Demand Charge ($/kW)	$~~0.96~~3.58
Reliability Must Run Transmission Surcharge ($/kWh)	$0.000000
Transmission Enhancement Charge ($/kWh)	See Rider BGS
Basic Generation Service Charge ($/kWh)	See Rider BGS
Regional Greenhouse Gas Initiative Recovery Charge ($/kWh)	See Rider RGGI
Infrastructure Investment Surcharge	See Rider IIS

Date of Issue: ~~**December 8, 2016**~~ **Effective Date:** ~~**January 1, 2017**~~

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ATLANTIC CITY ELECTRIC COMPANY
BPU NJ No. 11 Electric Service - Section IV ~~Thirty-Seventh~~ Revised Sheet Replaces ~~Thirty-Sixth~~ Revised Sheet No. 29

RATE SCHEDULE TGS
(Transmission General Service)
(Sub Transmission Service Taken at 23kV and 34.5 kV)

AVAILABILITY

Available at any point of Company's system where facilities of adequate character and capacity exist for the entire electric service requirements of any customer contracting for annual service delivered at one point and metered at or compensated to the voltage subtransmission level (23 or 34.5 kV).

MONTHLY RATE

Delivery Service Charges:

Customer Charge

Maximum billed demand within the most recent 12 billing months.	
Less than 5,000 kW	$137.29
5,000 – 9,000 kW	$4,546.92
Greater than 9,000 kW	$8,253.86

Distribution Demand Charge ($/kW)

Maximum billed demand within the most recent 12 billing months.	
Less than 5,000 kW	$3.94
5,000 – 9,000 kW	$3.03
Greater than 9,000 kW	$1.52

Reactive Demand (for each kvar over one-third of kW demand)	$0.54
Non-Utility Generation Charge (NGC) ($/kWH)	See Rider NGC
Societal Benefits Charge ($/kWh)	
Clean Energy Program	See Rider SBC
Universal Service Fund	See Rider SBC
Lifeline	See Rider SBC
Uncollectible Accounts	See Rider SBC
Transition Bond Charge (TBC) ($/kWh)	See Rider SEC
Market Transition Charge Tax (MTC-Tax) ($/kWh)	See Rider SEC
CIEP Standby Fee ($/kWh)	See Rider BGS
Transmission Demand Charge ($/kW)	$~~0.50~~1.68
Reliability Must Run Transmission Surcharge ($/kWh)	$0.000000
Transmission Enhancement Charge ($/kWh)	See Rider BGS
Basic Generation Service Charge ($/kWh)	See Rider BGS
Regional Greenhouse Gas Initiative Recovery Charge ($/kWh)	See Rider RGGI
Infrastructure Investment Surcharge	See Rider IIS

Date of Issue: ~~December 8, 2016~~ **Effective Date:** ~~January 1, 2017~~

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~~Filed pursuant to Board of Public Utilities of the State of New Jersey directives associated with the BPU Docket No. ER16111054~~

Issued by:

RATE SCHEDULE TGS
(Transmission General Service)
(Transmission Service Taken at or above 69kV)

AVAILABILITY
Available at any point of Company's system where facilities of adequate character and capacity exist for the entire electric service requirements of any customer contracting for annual service delivered at one point and metered at or compensated to the voltage at transmission level (69 kV or higher).

MONTHLY RATE

Delivery Service Charges:

Customer Charge		
Maximum billed demand within the most recent 12 billing months.		
Less than 5,000 kW	$133.60	
5,000 – 9,000 kW	$4,424.86	
Greater than 9,000 kW	$20,080.75	
Distribution Demand Charge ($/kW)		
Maximum billed demand within the most recent 12 billing months.		
Less than 5,000 kW	$3.07	
5,000 – 9,000 kW	$2.36	
Greater than 9,000 kW	$0.15	
Reactive Demand (for each kvar over one-third of kW demand)	$0.52	
Non-Utility Generation Charge (NGC) ($/kWH)	See Rider NGC	
Societal Benefits Charge ($/kWh)		
Clean Energy Program	See Rider SBC	
Universal Service Fund	See Rider SBC	
Lifeline	See Rider SBC	
Uncollectible Accounts	See Rider SBC	
Transition Bond Charge (TBC) ($/kWh)	See Rider SEC	
Market Transition Charge Tax (MTC-Tax) ($/kWh)	See Rider SEC	
CIEP Standby Fee ($/kWh)	See Rider BGS	
Transmission Demand Charge ($/kW)	$~~0.94~~1.85	
Reliability Must Run Transmission Surcharge ($/kWh)	$0.000000	$0.000000
Transmission Enhancement Charge ($/kWh)	See Rider BGS	
Basic Generation Service Charge ($/kWh)	See Rider BGS	
Regional Greenhouse Gas Initiative Recovery Charge ($/kWh)	See Rider RGGI	
Infrastructure Investment Surcharge	See Rider IIS	

ATLANTIC CITY ELECTRIC COMPANY
BPU NJ No. 11 Electric Service – Section IV ~~Sixty-Second~~ Revised Sheet Replaces ~~Sixty-First~~ Revised Sheet No. 31

RATE SCHEDULE DDC
(Direct Distribution Connection)

AVAILABILITY

Available at any point of the Company's existing distribution system where facilities of adequate character exist for the connection of fixed, constant and predictable non-residential loads not to exceed one kilowatt

MONTHLY RATES

Distribution:

Service and Demand (per day per connection)	$0.167902
Energy (per day for each kW of effective load)	$0.808718
Non-Utility Generation Charge (NGC) ($/kWH)	See Rider NGC
Societal Benefits Charge ($/kWh)	
Clean Energy Program	See Rider SBC
Universal Service Fund	See Rider SBC
Lifeline See Rider SBC	
Uncollectible Accounts	See Rider SBC
Transition Bond Charge (TBC) ($/kWh)	See Rider SEC
Market Transition Charge Tax (MTC-Tax) ($/kWh)	See Rider SEC
Transmission Rate ($/kWh)	$0.~~004361~~<u>006480</u>
Reliability Must Run Transmission Surcharge ($/kWh)	$0.000000
Transmission Enhancement Charge ($/kWh)	See Rider BGS
Basic Generation Service Charge ($/kWh)	See Rider BGS
Regional Greenhouse Gas Initiative Recovery Charge ($/kWh)	See Rider RGGI
Infrastructure Investment Surcharge	See Rider IIS

CORPORATE BUSINESS TAX (CBT)

Charges under this rate schedule include a component for Corporate Business Taxes as set forth in Rider CBT.

NEW JERSEY SALES AND USE TAX (SUT)

Charges under this rate schedule include a component for New Jersey Sales and Use Tax as set forth in Rider SUT.

LOAD CONSUMPTION

Effective load shall be determined by the Company and be specified in the contract. Effective load is defined as the sum of the products of the connected load in kilowatts times the percent load on at one time. No changes in attached load may be made by the customer without the permission of the Company and customer shall allow the Company access to his premises to assure conformance with this provision.

Date of Issue: ~~**December 8, 2016**~~ **Effective Date:** ~~**January 1, 2017**~~

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<u>**Issued by:**</u>

RIDER STB-STANDBY SERVICE
(Applicable to MGS, AGS, TGS and SPP Rate Schedules)

AVAILABILITY
This rider is available to customers having other sources of electrical energy supply, but who desire to purchase Standby Service from the Company. The terms of this rider shall not be available in any month when the customer's Generation Availability for the current and preceding five (5) months does not exceed 50%.

DEFINITIONS

Standby Service:
Standby Service is defined as the additional electrical capacity available to a customer in the event of a forced outage and during a mutually agreed upon customer's scheduled maintenance shutdown of the customer owned electrical energy source.

Standby Service Capacity:
The Standby Service Capacity shall be the maximum electrical capacity in kW supplied by the customer owned electrical energy source during the current and preceding five (5) months. Such Standby Service Capacity may be revised with Company approval as changes in the customer's load conditions warrant.

Generation Availability:
Generation Availability is defined as the availability of the customer owned electrical energy source during the current and preceding five (5) months and shall be determined by dividing the Kwhrs produced during this period by the product of the Standby Service Capacity times 4380 hours.

MODIFICATION OF DEMAND DETERMINATION
The monthly billing demand shall be as defined under the "Demand Determination" section of the applicable rate schedule.

The Standby Service Demand shall be the "Standby Service Capacity" as defined above.

During the billing months in which a forced outage or mutually agreed upon customer's scheduled maintenance shutdown occurs, the billing demand will be determined by subtracting the Standby Service Capacity from the total demand and waives the minimum charge provision of the applicable rate schedule. Electric service is provided under the terms of the applicable rate schedule. Total demand is defined as the sum of the Company's demand meter plus demand supplied by the other sources of electrical energy, all computed to the nearest whole kilowatt during a fifteen minute period.

STANDBY SERVICE CHARGE
This rider imposes a Standby Service Charge at the following voltage levels:

Tariff	Transmission Stand By Rate ($/kW)	Distribution Stand By Rate ($/kW)
MGS-Secondary	$0.~~25~~33	$0.10
MGS Primary	$0.~~11~~32	$0.13
AGS Secondary	$0.~~20~~36	$0.90
AGS Primary	$0.~~10~~36	$0.74
TGS Sub Transmission	$0.~~10~~19	$0.00
TGS Transmission	$0.~~10~~19	$0.00

ATLANTIC CITY ELECTRIC COMPANY
BPU NJ No. 11 Electric Service - Section IV ~~Thirty-First~~ Revised Sheet Replaces ~~Thirtieth~~ Revised Sheet No. 60b

RIDER (BGS) continued
Basic Generation Service (BGS)

CIEP Standby Fee $0.000160 per kWh
This charge recovers the costs associated with the winning BGS-CIEP bidders maintaining the availability of the hourly priced default electric supply service plus administrative charges pursuant to N.J.S.A. 48:2-60 and New Jersey Sales and Use Tax as set forth in Rider SUT. This charge is assessed on all kWhs delivered to all CIEP- eligible customers on Rate Schedules MGS Secondary, MGS Primary, AGS Secondary, AGS Primary or TGS.

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

Rate Class

	RS	MGS Secondary	MGS Primary	AGS Secondary	AGS Primary	TGS	SPL/ CSL	DDC
VEPCo	0.~~000402~~000588	0.~~000317~~000492	0.~~000333~~000531	0.~~000221~~000325	0.~~000186~~000261	0.~~000142~~000250	~~-~~ -	0.~~000134~~000206
TrAIL Co	0.~~000606~~000632	0.~~000461~~000498	0.~~000238~~000523	0.~~000277~~000349	0.~~000108~~000294	0.~~000208~~000226	-	0.~~000213~~000209
PSE&G	0.000642	0.000506	0.000531	0.000355	0.000298	0.000228	~~-~~ -	0.000214
PATH	0.000051	0.000041	0.000043	0.000029	0.000024	0.000018	~~-~~ -	0.000017
PPL	0.~~000244~~000238	0.~~000186~~000199	0.~~000096~~000215	0.~~000111~~000131	0.~~000044~~000105	0.~~000083~~000102	-	0.~~000086~~000083
Pepco	0.~~000024~~000021	0.~~000017~~000018	0.~~000010~~000019	0.~~000011~~000012	0.~~000004~~000010	0.~~000007~~000010	-	0.~~000009~~000007
JCP&L	0.000003	0.000003	0.000003	0.000002	0.000002	0.000001	~~-~~ -	0.000001
Delmarva	0.000001	0.000001	0.000001	0.000001	~~-~~ 0.000001	0.000001	-	0.000001
BG&E	0.000073	0.000061	0.000066	0.000041	0.000032	0.000031	-	0.000026
AEP - East	0.000106	0.000080	0.000042	0.000048	0.000019	0.000036	-	0.000037
Total	0.~~002079~~002355	0.~~001612~~001899	0.~~001297~~001974	0.~~001055~~001293	0.~~000685~~001046	0.~~000724~~000903	~~-~~ -	0.~~000712~~000801

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Exhibit C

Atlantic City Electric Company
Proposed BG&E Projects Transmission Enhancement Charge (BG&E Project-TEC Surcharge) effective June 1, 2017
To reflect FERC-approved ACE Project Transmission Enhancement Charge (Schedule 12 PJM OATT) effective June 1, 2017

Transmission Enhancement Costs Allocated to ACE Zone (2017)	$	40,996
	$	40,996
2017 ACE Zone Transmission Peak Load (MW)		2,673
Transmission Enhancement Rate ($/MW-Month)	$	15.33

Rate Class	Col. 1 Transmission Obligation (MW)		Col. 2 Allocated Cost Recovery	Col. 3 BGS Eligible Sales June 2017 - May 2018 (kWh)		Col. 4 = Col. 2/Col. 3 Transmission Enhancement Charge ($/kWh)		Col. 5 = Col. 4 x 1/(1-Effective Rate) Transmission Enhancement Charge w/ BPU Assessment ($/kWh)		Col. 6 = Col. 5 x 1.06875 Transmission Enhancement Charge w/ SUT ($/kWh)
RS	1,553	$	285,710	4,171,964,933	$	0.000068	$	0.000068	$	0.000073
MGS Secondary	359	$	65,972	1,152,950,462	$	0.000057	$	0.000057	$	0.000061
MGS Primary	8	$	1,512	24,456,016	$	0.000062	$	0.000062	$	0.000066
AGS Secondary	393	$	72,360	1,917,585,029	$	0.000038	$	0.000038	$	0.000041
AGS Primary	94	$	17,299	571,955,641	$	0.000030	$	0.000030	$	0.000032
TGS	146	$	26,877	920,786,585	$	0.000029	$	0.000029	$	0.000031
SPL/CSL	0	$	-	73,240,385	$	-	$	-	$	-
DDC	2	$	304	12,621,752	$	0.000024	$	0.000024	$	0.000026
	2,554	$	470,032	8,845,560,805						

Attachment 2B PJM Schedule 12 - Transmission Enhancement Charges for June 2017 - May 2018
Calculation of costs and monthly PJM charges for BG&E

		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
			Responsible Customers - Schedule 12 Appendix				Estimated New Jersey EDC Zone Charges by Project				
Required Transmission Enhancement	**PJM Upgrade ID**	**June 2017 - May 2018 Annual Revenue Requirement**	**ACE Zone Share[1]**	**JCP&L Zone Share[1]**	**PSE&G Zone Share[1]**	**RE Zone Share[1]**	**ACE Zone Charges**	**JCP&L Zone Charges**	**PSE&G Zone Charges**	**RE Zone Charges**	**Total NJ Zones Charges**
per PJM website	*per PJM spreadsheet*	*per PJM website*	*per PJM Open Access Transmission Tariff*								
Install a second Conastone – Graceton 230 kV circuit	b0497	$ 5,234,913	9.00%	9.64%	14.07%	0.52%	$471,142	$504,646	$736,552	$27,222	$1,739,562
install new 500 kV transmission from Possum Point to Calvert Cliffs	b0512	$ 1,224,312	1.70%	3.78%	6.22%	0.25%	$20,813	$46,279	$76,152	$3,061	$146,305
		$ -					$0	$0	$0	$0	$0
Totals							**$491,955**	**$550,925**	**$812,704**	**$30,282**	**$1,885,867**

Notes on calculations >>> = (a) * (b) = (a) * (c) = (a) * (d) = (a) * (e) = (f) + (g) + (h) + (i)

	(k)	(l)	(m)	(n)	(o)	(p)
Zonal Cost Allocation for New Jersey Zones	**Average Monthly Impact on Zone Customers in 17/18**	**2017TX Peak Load** *per PJM website*	**Rate in $/MW-mo.**	**2017 Impact (7 months)**	**2018 Impact (5 months)**	**2017-2018 Impact (12 months)**
PSE&G	$ 67,725.37	9,800.3	$ 6.91	$ 474,078	$ 338,627	$ 812,704
JCP&L	$ 45,910.38	5,954.8	$ 7.71	$ 321,373	$ 229,552	$ 550,925
ACE	$ 40,996.29	2,673.4	$ 15.33	$ 286,974	$ 204,981	$ 491,955
RE	$ 2,523.53	402.0	$ 6.28	$ 17,665	$ 12,618	$ 30,282
Total Impact on NJ Zones	**$ 157,155.57**			**$ 1,100,089**	**$ 785,778**	**$ 1,885,867**
Notes on calculations >>>			= (k) * (l)	= (k) * 7	= (k) * 5	= (n) * (o)

Notes:
1) 2017 allocation share percentages are from PJM OATT

	(k)			(n)	(o)	(p)
Total Impact on NJ Zones	**$ 475,704.21**			**$ 3,329,929**	**$ 2,378,521**	**$ 5,708,450**
Notes on calculations >>>			= (k) * (l)	= (k) * 7	= (k) * 5	= (n) * (o)

Notes:
1) 2016 allocation share percentages are from PJM OATT
2) Percentage allocation for regional projects (columns b-e) will change on January 1, 2017, however resultant customer rates will not be changed.

Atlantic City Electric Company
Proposed TrAIL CO Projects Transmission Enhancement Charge (TrAIL Co Project-TEC Surcharge) effective June 1, 2017
To reflect FERC-approved ACE Project Transmission Enhancement Charge (Schedule 12 PJM OATT) effective June 1, 2017

Transmission Enhancement Costs Allocated to ACE Zone (2017)	$	328,828
	$	328,828
2017 ACE Zone Transmission Peak Load (MW)		2,673
Transmission Enhancement Rate ($/MW)	$	123.00

Rate Class	Col. 1 Transmission Obligation (MW)		Col. 2 Allocated Cost Recovery	Col. 3 BGS Eligible Sales June 2017 - May 2018 (kWh)		Col. 4 = Col. 2/Col. 3 Transmission Enhancement Charge ($/kWh)		Col. 5 = Col. 4 x 1/(1-Effective Rate) Transmission Enhancement Charge w/ BPU Assessment ($/kWh)		Col. 6 = Col. 5 x 1.06875 Transmission Enhancement Charge w/ SUT ($/kWh)
RS	1,553	$	2,291,655	4,171,964,933	$	0.000549	$	0.000550	$	0.000588
MGS Secondary	359	$	529,153	1,152,950,462	$	0.000459	$	0.000460	$	0.000492
MGS Primary	8	$	12,125	24,456,016	$	0.000496	$	0.000497	$	0.000531
AGS Secondary	393	$	580,395	1,917,585,029	$	0.000303	$	0.000304	$	0.000325
AGS Primary	94	$	138,751	571,955,641	$	0.000243	$	0.000244	$	0.000261
TGS	146	$	215,577	920,786,585	$	0.000234	$	0.000234	$	0.000250
SPL/CSL	0	$	-	73,240,385	$	-	$	-	$	-
DDC	2	$	2,436	12,621,752	$	0.000193	$	0.000193	$	0.000206
	2,554	$	3,770,092	8,845,560,805						

Attachment 2A PJM Schedule 12 - Transmission Enhancement Charges for June 2017 - May 2018
Calculation of costs and monthly PJM charges for Allegheny TrAILCo Projects

		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
			Responsible Customers - Schedule 12 Appendix				Estimated New Jersey EDC Zone Charges by Project				
Required Transmission Enhancement	**PJM Upgrade ID**	**June 2017-May 2018 Annual Revenue Requirement**	**ACE Zone Share[1]**	**JCP&L Zone Share[1]**	**PSE&G Zone Share[1]**	**RE Zone Share[1]**	**ACE Zone Charges**	**JCP&L Zone Charges**	**PSE&G Zone Charges**	**RE Zone Charges**	**Total NJ Zones Charges**
per PJM website	*per PJM spreadsheet*	*per PJM website*	*per PJM Open Access Transmission Tariff*								
502 Junction-Mt Storm-Meadowbrook (>=500kV) - CWIP[1]	b0328.1; b0328.2; b0347.1; b0347.2; b0347.3; b0347.4	$ 142,698,296.88	1.70%	3.78%	6.22%	0.25%	$2,425,871	$5,393,996	$8,875,834	$356,746	$17,052,446
Wylie Ridge [2]	b0218	$ 2,884,641.73	11.83%	15.56%	0.00%	0.00%	$341,253	$448,850	$0	$0	$790,103
Black Oak	b0216	$ 5,754,277.45	1.70%	3.78%	6.22%	0.25%	$97,823	$217,512	$357,916	$14,386	$687,636
Meadowbrook 200 MVAR capacitor	b0559	$ 794,379.64	1.70%	3.78%	6.22%	0.25%	$13,504	$30,028	$49,410	$1,986	$94,928
Replace Kammer 765/500 kV TXfmr	b0495	$ 4,802,279.44	1.70%	3.78%	6.22%	0.25%	$81,639	$181,526	$298,702	$12,006	$573,872
Doubs TXfmr 2	b0343	$ 635,524.86	1.85%	0.00%	0.00%	0.00%	$11,757	$0	$0	$0	$11,757
Doubs TXfmr 3	b0344	$ 582,767.79	1.86%	0.00%	0.00%	0.00%	$10,839	$0	$0	$0	$10,839
Doubs TXfmr 4	b0345	$ 717,765.46	1.85%	0.00%	0.00%	0.00%	$13,279	$0	$0	$0	$13,279
New Osage 138KV Ckt	b0674-b1023.3	$ 1,621,416.68	0.00%	0.00%	0.25%	0.01%	$0	$0	$4,054	$162	$4,216
Cap at Grover 230	b0556	$ 121,286.39	8.58%	18.16%	26.13%	0.97%	$10,406	$22,026	$31,692	$1,176	$65,301
Upgrade transformer 500/230	b1153	$ 3,743,231.50	3.74%	12.57%	20.52%	0.72%	$139,997	$470,524	$768,111	$26,951	$1,405,583
Build a 300 MVAR Switched Shunt at Doubs 500kV	b1803	$ 662,641.57	1.70%	3.78%	6.22%	0.25%	$11,265	$25,048	$41,216	$1,657	$79,186
Install 500 MVAR svc at Hunterstown 500kV Sub	b1800	$ 5,875,239.81	1.70%	3.78%	6.22%	0.25%	$99,879	$222,084	$365,440	$14,688	$702,091
Install a new 600 MVAR SVC at Meadowbrook 500 kV	b1804	$ 8,162,156.68	1.70%	3.78%	6.22%	0.25%	$138,757	$308,530	$507,686	$20,405	$975,378
Build 250 MVAR svc at Altoona 230kV	b1801	$ 4,701,915.58	6.47%	8.14%	8.18%	0.33%	$304,214	$382,736	$384,617	$15,516	$1,087,083
Convert Moshannon sub to 4 breaker 230 kv ring bus	b1964	$ 1,087,213.05	0.00%	5.48%	0.00%	0.00%	$0	$59,579	$0	$0	$59,579
Build a 100 MVAR Fast Switched Shunt and 200 MVAR Switched Shunt at Mansfield 345 kV	b1802	$ 3,524,047.39	6.47%	8.14%	8.18%	0.33%	$228,006	$286,857	$288,267	$11,629	$814,760
Install 100 MVAR capacitor at Johnstown 230 kV substation	b0555	$ 203,348.58	8.58%	18.16%	26.13%	0.97%	$17,447	$36,928	$53,135	$1,972	$109,483
Install 300 MVAR capacitor at Conemaugh 500 kV substation	b0376	$ -	1.70%	3.78%	6.22%	0.25%	$0	$0	$0	$0	$0
							$3,945,936	**$8,086,223**	**$12,026,080**	**$479,281**	**$24,537,521**
Notes on calculations >>>							= (a) * (b)	= (a) * (c)	= (a) * (d)	= (a) * (e)	= (f) + (g) + (h) + (i)

	(k)	(l)	(m)	(n)	(o)	(p)
Zonal Cost Allocation for New Jersey Zones	**Average Monthly Impact on Zone Customers in 17/18**	**2017TX Peak Load** *per PJM website*	**Rate in \$/MW-mo.**	**2017 Impact (7 months)**	**2018 Impact (5 months)**	**2017-2018 Impact (12 months)**
PSE&G	$ 1,002,173.35	9,800.3	$ 102.26	$ 7,015,213	$ 5,010,867	$ 12,026,080
JCP&L	$ 673,851.94	5,954.8	$ 113.16	$ 4,716,964	$ 3,369,260	$ 8,086,223
ACE	$ 328,828.04	2,673.4	$ 123.00	$ 2,301,796	$ 1,644,140	$ 3,945,936
RE	$ 39,940.10	402.0	$ 99.35	$ 279,581	$ 199,701	$ 479,281
Total Impact on NJ Zones	**$ 2,044,793.43**			**$ 14,313,554**	**$ 10,223,967**	**$ 24,537,521**
Notes on calculations >>>			= (k) * (l)	= (k) * 7	= (k) * 5	= (n) * (o)

Notes:
1) 2017 allocation share percentages are from PJM OATT

Atlantic City Electric Company
Proposed PEPCO Projects Transmission Enhancement Charge (PEPCO Project-TEC Surcharge) effective June 1, 2017
To reflect FERC-approved ACE Project Transmission Enhancement Charge (Schedule 12 PJM OATT) effective June 1, 2017

Transmission Enhancement Costs Allocated to ACE Zone (2017)	$	12,082
	$	12,082
2017 ACE Zone Transmission Peak Load (MW)		2,673
Transmission Enhancement Rate ($/MW-Month)	$	4.52

Rate Class	Col. 1 Transmission Obligation (MW)		Col. 2 Allocated Cost Recovery	Col. 3 BGS Eligible Sales June 2017 - May 2018 (kWh)		Col. 4 = Col. 2/Col. 3 Transmission Enhancement Charge ($/kWh)		Col. 5 = Col. 4 x 1/(1-Effective Rate) Transmission Enhancement Charge w/ BPU Assessment ($/kWh)		Col. 6 = Col. 5 x 1.06875 Transmission Enhancement Charge w/ SUT ($/kWh)
RS	1,553	$	84,202	4,171,964,933	$	0.000020	$	0.000020	$	0.000021
MGS Secondary	359	$	19,443	1,152,950,462	$	0.000017	$	0.000017	$	0.000018
MGS Primary	8	$	446	24,456,016	$	0.000018	$	0.000018	$	0.000019
AGS Secondary	393	$	21,325	1,917,585,029	$	0.000011	$	0.000011	$	0.000012
AGS Primary	94	$	5,098	571,955,641	$	0.000009	$	0.000009	$	0.000010
TGS	146	$	7,921	920,786,585	$	0.000009	$	0.000009	$	0.000010
SPL/CSL	0	$	-	73,240,385	$	-	$	-	$	-
DDC	2	$	89	12,621,752	$	0.000007	$	0.000007	$	0.000007
	2,554	$	138,523	8,845,560,805						

Attachment 2E PJM Schedule 12 - Transmission Enhancement Charges for June 2017 to May 2018
Calculation of costs and monthly PJM charges for PEPCO Projects

Required Transmission Enhancement *per PJM website*	PJM Upgrade ID *per PJM spreadsheet*	(a) June 2017-May 2018 Annual Revenue Requirement *per PJM website*	(b) Responsible Customers - Schedule 12 Appendix: ACE Zone Share[1]	(c) JCP&L Zone Share[1]	(d) PSE&G Zone Share[1]	(e) RE Zone Share[1] *per PJM Open Access Transmission Tariff*	(f) Estimated New Jersey EDC Zone Charges by Project: ACE Zone Charges	(g) JCP&L Zone Charges	(h) PSE&G Zone Charges	(i) RE Zone Charges	(j) Total NJ Zones Charges
Reconductor 23035 for Dickerson-Quince	b0367.1-2	$ 3,134,708	1.78%	2.67%	3.81%	0.00%	$55,798	$83,697	$119,432	$0	$258,927
Replace 230 1A breaker	b0512.7	$ 298,286	1.70%	3.78%	6.22%	0.25%	$5,071	$11,275	$18,553	$746	$35,645
Replace 230 1B breaker	b0512.8	$ 298,286	1.70%	3.78%	6.22%	0.25%	$5,071	$11,275	$18,553	$746	$35,645
Replace 230 2A breaker	b0512.9	$ 298,286	1.70%	3.78%	6.22%	0.25%	$5,071	$11,275	$18,553	$746	$35,645
Replace 230 3A breaker	b0512.12	$ 301,090	1.70%	3.78%	6.22%	0.25%	$5,119	$11,381	$18,728	$753	$35,980
Ritchie-Benning 230 lines	b0526	$ 8,942,285	0.77%	1.39%	2.10%	0.08%	$68,856	$124,298	$187,788	$7,154	$388,095
Totals							**$144,985**	**$253,201**	**$381,608**	**$10,144**	**$789,938**
Notes on calculations >>>							= (a) * (b)	= (a) * (c)	= (a) * (d)	= (a) * (e)	= (f) + (g) + (h) + (i)

Zonal Cost Allocation for New Jersey Zones	(k) Average Monthly Impact on Zone Customers in 17/18	(l) 2017TX Peak Load *per PJM website*	(m) Rate in $/MW-mo.	(n) 2017 Impact (7 months)	(o) 2018 Impact (5 months)	(p) 2017-2018 Impact (12 months)
PSE&G	$ 31,800.69	9,800.3	$ 3.24	$ 222,605	$ 159,003	$ 381,608
JCP&L	$ 21,100.11	5,954.8	$ 3.54	$ 147,701	$ 105,501	$ 253,201
ACE	$ 12,082.04	2,673.4	$ 4.52	$ 84,574	$ 60,410	$ 144,985
RE	$ 845.31	402.0	$ 2.10	$ 5,917	$ 4,227	$ 10,144
Total Impact on NJ Zones	**$ 65,828.15**			**$ 460,797**	**$ 329,141**	**$ 789,938**
Notes on calculations >>>			= (k) * (l)	= (k) * 7	= (k) * 5	= (n) * (o)

Notes:
1) 2017 allocation share percentages are from PJM OATT

Atlantic City Electric Company
Proposed PPL Projects Transmission Enhancement Charge (PPL Project-TEC Surcharge) effective June 1, 2017
To reflect FERC-approved ACE Project Transmission Enhancement Charge (Schedule 12 PJM OATT) effective June 1, 2017

Transmission Enhancement Costs Allocated to ACE Zone (2017)	$	133,226
	$	133,226
2017 ACE Zone Transmission Peak Load (MW)		2,673
Transmission Enhancement Rate ($/MW-Month)	$	49.83

Rate Class	Col. 1 Transmission Obligation (MW)		Col. 2 Allocated Cost Recovery	Col. 3 BGS Eligible Sales June 2017 - May 2018 (kWh)		Col. 4 = Col. 2/Col. 3 Transmission Enhancement Charge ($/kWh)		Col. 5 = Col. 4 x 1/(1-Effective Rate) Transmission Enhancement Charge w/ BPU Assessment ($/kWh)		Col. 6 = Col. 5 x 1.06875 Transmission Enhancement Charge w/ SUT ($/kWh)
RS	1,553	$	928,471	4,171,964,933	$	0.000223	$	0.000223	$	0.000238
MGS Secondary	359	$	214,388	1,152,950,462	$	0.000186	$	0.000186	$	0.000199
MGS Primary	8	$	4,912	24,456,016	$	0.000201	$	0.000201	$	0.000215
AGS Secondary	393	$	235,149	1,917,585,029	$	0.000123	$	0.000123	$	0.000131
AGS Primary	94	$	56,215	571,955,641	$	0.000098	$	0.000098	$	0.000105
TGS	146	$	87,342	920,786,585	$	0.000095	$	0.000095	$	0.000102
SPL/CSL	0	$	-	73,240,385	$	-	$	-	$	-
DDC	2	$	987	12,621,752	$	0.000078	$	0.000078	$	0.000083
	2,554	$	1,527,465	8,845,560,805						

Attachment 2C PJM Schedule 12 - Transmission Enhancement Charges for June 2017 - May 2018
Calculation of costs and monthly PJM charges for PPL Projects

		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
			Responsible Customers - Schedule 12 Appendix				**Estimated New Jersey EDC Zone Charges by Project**				
Required Transmission Enhancement *per PJM website*	**PJM Upgrade ID** *per PJM spreadsheet*	**June 2017- May 2018 Annual Revenue Requirement** *per PJM website*	**ACE Zone Share**[1]	**JCP&L Zone Share**[1]	**PSE&G Zone Share**[1]	**RE Zone Share**[1]	**ACE Zone Charges**	**JCP&L Zone Charges**	**PSE&G Zone Charges**	**RE Zone Charges**	**Total NJ Zones Charges**
			per PJM Open Access Transmission Tariff								
New 500 KV Susquehana-Roseland Line	b0487	$ 94,007,965.00	1.70%	3.78%	6.22%	0.25%	$1,598,135	$3,553,501	$5,847,295	$235,020	$11,233,952
Replace wave trap at Alburtus 500 kV Sub	b0171.2	$ 10,646.00	1.70%	3.78%	6.22%	0.25%	$181	$402	$662	$27	$1,272
Replace wavetrap at Hosensack 500KV Sub	b0172.1	$ 7,634.00	1.70%	3.78%	6.22%	0.25%	$130	$289	$475	$19	$912
Replace wavetraps at Juniata 500KV Sub	b0284.2	$ 15,445.00	1.70%	3.78%	6.22%	0.25%	$263	$584	$961	$39	$1,846
New S-R additions < 500kV[2]	b0487.1	$ 2,146,064.00	0.00%	0.00%	5.13%	0.19%	$0	$0	$110,093	$4,078	$114,171
New substation and transformers Middletown	b0468	$ 3,068,630.00	0.00%	4.55%	5.93%	0.22%	$0	$139,623	$181,970	$6,751	$328,343
Totals							**$1,598,709**	**$3,694,399**	**$6,141,456**	**$245,933**	**$11,680,496**
Notes on calculations >>>							= (a) * (b)	= (a) * (c)	= (a) * (d)	= (a) * (e)	= (f) + (g) + (h) + (i)

	(k)	(l)	(m)	(n)	(o)	(p)
Zonal Cost Allocation for New Jersey Zones	**Average Monthly Impact on Zone Customers in 17/18**	**2017 Peak Load** *per PJM website*	**Rate in $/MW-mo.**	**2017 Impact (7 months)**	**2018 Impact (5 months)**	**2017-2018 Impact (12 months)**
PSE&G	$ 511,788.00	9,800.3	$ 52.22	$ 3,582,516	$ 2,558,940	$ 6,141,456
JCP&L	$ 307,866.55	5,954.8	$ 51.70	$ 2,155,066	$ 1,539,333	$ 3,694,399
ACE	$ 133,225.73	2,673.4	$ 49.83	$ 932,580	$ 666,129	$ 1,598,709
RE	$ 20,494.39	402.0	$ 50.98	$ 143,461	$ 102,472	$ 245,933
Total Impact on NJ Zones	**$ 973,374.66**			**$ 6,813,623**	**$ 4,866,873**	**$ 11,680,496**
Notes on calculations >>>			= (k) * (l)	= (k) * 7	= (k) * 5	= (n) * (o)

Notes:
1) 2017 allocation share percentages are from PJM OATT

Atlantic City Electric Company
Proposed DPL Projects Transmission Enhancement Charge (DPL Project-TEC Surcharge) effective June 1, 2017
To reflect FERC-approved ACE Project Transmission Enhancement Charge (Schedule 12 PJM OATT) effective June 1, 2017

Transmission Enhancement Costs Allocated to ACE Zone (2017)	$	884
	$	884
2017 ACE Zone Transmission Peak Load (MW)		2,673
Transmission Enhancement Rate ($/MW-Month)	$	0.33

Rate Class	Col. 1 Transmission Obligation (MW)	Col. 2 Allocated Cost Recovery	Col. 3 BGS Eligible Sales June 2017 - May 2018 (kWh)	Col. 4 = Col. 2/Col. 3 Transmission Enhancement Charge ($/kWh)	Col. 5 = Col. 4 x 1/(1-Effective Rate) Transmission Enhancement Charge w/ BPU Assessment ($/kWh)	Col. 6 = Col. 5 x 1.06875 Transmission Enhancement Charge w/ SUT ($/kWh)
RS	1,553	$ 6,161	4,171,964,933	$ 0.000001	$ 0.000001	$ 0.000001
MGS Secondary	359	$ 1,423	1,152,950,462	$ 0.000001	$ 0.000001	$ 0.000001
MGS Primary	8	$ 33	24,456,016	$ 0.000001	$ 0.000001	$ 0.000001
AGS Secondary	393	$ 1,560	1,917,585,029	$ 0.000001	$ 0.000001	$ 0.000001
AGS Primary	94	$ 373	571,955,641	$ 0.000001	$ 0.000001	$ 0.000001
TGS	146	$ 580	920,786,585	$ 0.000001	$ 0.000001	$ 0.000001
SPL/CSL	0	$ -	73,240,385	$ -	$ -	$ -
DDC	2	$ 7	12,621,752	$ 0.000001	$ 0.000001	$ 0.000001
	2,554	$ 10,136	$ 8,845,560,805			

Attachment 2D1 PJM Schedule 12 - Transmission Enhancement Charges for June 2017 - May 2018
Calculation of costs and monthly PJM charges for Delmarva Projects

		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
			Responsible Customers - Schedule 12 Appendix				**Estimated New Jersey EDC Zone Charges by Project**				
Required Transmission Enhancement *per PJM website*	**PJM Upgrade ID** *per PJM spreadsheet*	**June 2017-May 2018 Annual Revenue Requirement** *per PJM website*	**ACE Zone Share[1]** *per PJM Open Access Transmission Tariff*	**JCP&L Zone Share[1]**	**PSE&G Zone Share[1]**	**RE Zone Share[1]**	**ACE Zone Charges**	**JCP&L Zone Charges**	**PSE&G Zone Charges**	**RE Zone Charges**	**Total NJ Zones Charges**
Replace line trap-Keeney	b0272.1	$ 25,760	1.70%	3.78%	6.22%	0.25%	$438	$974	$1,602	$64	$3,078
Add two breakers-Keeney	b0751	$ 598,259	1.70%	3.78%	6.22%	0.25%	$10,170	$22,614	$37,212	$1,496	$71,492
Totals							**$10,608**	**$23,588**	**$38,814**	**$1,560**	**$74,570**
Notes on calculations >>>							= (a) * (b)	= (a) * (c)	= (a) * (d)	= (a) * (e)	= (f) + (g) + (h) + (i)

	(k)	(l)	(m)	(n)	(o)	(p)
Zonal Cost Allocation for New Jersey Zones	**Average Monthly Impact on Zone Customers in 17/18**	**2017TX Peak Load** *per PJM website*	**Rate in $/MW-mo.**	**2017 Impact (7 months)**	**2018 Impact (5 months)**	**2017-2018 Impact (12 months)**
PSE&G	$ 3,234.50	9,800.3	$ 0.33	$ 22,641	$ 16,172	$ 38,814
JCP&L	$ 1,965.66	5,954.8	$ 0.33	$ 13,760	$ 9,828	$ 23,588
ACE	$ 884.03	2,673.4	$ 0.33	$ 6,188	$ 4,420	$ 10,608
RE	$ 130.00	402.0	$ 0.32	$ 910	$ 650	$ 1,560
Total Impact on NJ Zones	**$ 6,214.19**			**$ 43,499**	**$ 31,071**	**$ 74,570**
Notes on calculations >>>			= (k) * (l)	= (k) * 7	= (k) * 5	= (n) * (o)

Notes:
1) 2017 allocation share percentages are from PJM OATT

Exhibit D

ATLANTIC CITY ELECTRIC COMPANY
Proposed Transmission Rate Design
Formula Rate Effective June 1, 2017

Line			
1	Transmission Service Annual Revenue Requirement	$	136,237,027
2	Less Total Schedule 12 TEC Included in Line (1)	$	(12,271,184)
3	ACE Customer Share of Schedule 12 TEC included in Line 2	$	5,498,524
4	Total Transmission Costs Borne by ACE Customers	$	129,464,367
5	2017 ACE Newtwork Service Peak		2,673
6	2017 Network Integration Transmission Service Rate (per MW Per Year)	**$**	**48,426.86**

PJM Schedule 12 - Transmission Enhancement Charges for June 2017 - May 2018
Calculation of costs and monthly PJM charges for ACE Projects

	Required Transmission Enhancement *per PJM website*	**PJM Upgrade ID** *per PJM spreadsheet*		**June 2017 - May 2018 Annual Revenue Requirement** *per PJM website*	**ACE Zone Share** *per PJM Open Access Transmission Tariff*		**ACE Zone Charges**
7	Upgrade AE portion of Delco Tap	b0265	$	573,925	89.87%	$	515,786
8	Replace Monroe 230/69 kV TXfmrs	b0276	$	877,862	91.28%	$	801,313
9	Reconductor Union - Corson 138 kV	b0211	$	1,496,892	65.23%	$	976,422
10	New 500/230 Kv Sub on Salem-East Windsor (>500 kV portion)	b0210.A	$	2,998,498	1.70%	$	50,974
11	New 500/230kV Sub on Salem-East Windsor (< 500kV) portion[2]	b0210.B	$	2,138,040	65.23%	$	1,394,643
12	Reconductor the existing Mickleton - Goucestr 230 kV circuit (AE portion)	b1398.5	$	534,416	0.00%	$	-
		b1398.5.3.1	$	1,670,931	0.00%	$	-
13	Upgrade to Mill T2 138/69 kV transformer	b1600	$	1,980,620	88.83%	$	1,759,385
	Total			**$12,271,184**			**$5,498,524**

Exhibit E

Atlantic City Electric Company
Proposed Transmission Rate Design
Formula Rate Effective June 1, 2017
Change in FERC Formual Based Rate

	2016 Booked Total Revenue ($)	Annualized Transmission Revenue based on Current Billing Determinants ($)	Transmission Peak Load Share (kW)	Transmission Revenue based on Peak Load Share ($)	Increase/(Decrease) ($)	(%)
Residential						
Residential	$ 676,547,384	$ 47,725,085	1,552,613	$ 75,403,823	$ 27,678,738	4.09%
Commercial and Industrial						
MGS Secondary	$ 164,188,149	$ 12,873,385	358,505	$ 17,411,055	$ 4,537,670	2.76%
MGS Primary	$ 3,603,182	$ 114,771	8,215	$ 398,953	$ 284,182	7.89%
AGS Secondary	$ 134,558,157	$ 10,750,325	393,222	$ 19,097,127	$ 8,346,802	6.20%
AGS Primary	$ 31,345,840	$ 1,227,884	94,005	$ 4,565,405	$ 3,337,521	10.65%
TGS - Subtransmission	$ 33,527,903	$ 559,042	91,110	$ 4,424,832		
TGS - Transmission	$ 16,573,268	$ 1,356,151	54,945	$ 2,668,436	$ 1,312,285	7.92%
SPL/CSL	$ 20,125,932	$ -	-	$ -	$ -	0.00%
DDC	$ 1,069,882	$ 53,939	1,650	$ 80,148	$ 26,210	2.45%
Subtotal Commercial and Industrial	$ 404,992,313	$ 26,935,497	1,001,651	$ 48,645,957	$ 17,844,670	4.41%
Total Jurisdiction	$ 1,081,539,697	$ 74,660,582	2,554,264	$ 124,049,780	$ 45,523,409	4.21%
Wholesale Transmission Rate		$ 48.43				
Rate Including Regulatory Assessment		$ 48.57				

ATLANTIC CITY ELECTRIC COMPANY
Proposed Transmission Rate Design
Formula Rate Effective June 1, 2017

Residential ("RS")

	Billing Determinants	Rate	Rate w/o SUT	Annualized Present Revenue w/o SUT	Rate Adjustment	Proposed Rate w/o SUT	Proposed Rate w/SUT
kWh	4,149,285,788	$ 0.012293	$ 0.011502	$ 47,725,085	$ 0.006671	$ 0.018173	$ 0.019422
Transmission Rate Change				$ 27,678,738			

ATLANTIC CITY ELECTRIC COMPANY
Proposed Transmission Rate Design
Formula Rate Effective June 1, 2017

Monthly General Service - Secondary (MGS Secondary)

	Billing Determinants	Rate	Rate w/o SUT	Annualized Present Revenue w/o SUT	Rate Adjustment	Proposed Rate w/o SUT	Proposed Rate w/SUT
Demand							
SUM > 3 KW	2,987,112	$ 2.47	$ 2.31	$ 6,900,229	$ 0.750000	$ 3.06	$ 3.27
WIN > 3 KW	3,063,157	$ 2.08	$ 1.95	$ 5,973,156	$ 0.750000	$ 2.70	$ 2.89
TOTAL KW	6,050,269			$ 12,873,385			
Transmission Rate Change				$ 4,537,670			

ATLANTIC CITY ELECTRIC COMPANY
Proposed Transmission Rate Design
Formula Rate Effective June 1, 2017

Monthly General Service - Primary (MGS Primary)

	Billing Determinants	Rate	Rate w/o SUT	Annualized Present Revenue w/o SUT	Rate Adjustment	Proposed Rate w/o SUT	Proposed Rate w/SUT
Demand							
SUM > 3 KW	43,795	$ 1.08	$ 1.01	$ 44,232	$ 1.95	$ 2.96	$ 3.16
WIN > 3 KW	102,231	$ 0.74	$ 0.69	$ 70,539	$ 1.95	$ 2.64	$ 2.82
TOTAL KW	146,025			$ 114,771			
Transmission Rate Change				$ 284,182			

ATLANTIC CITY ELECTRIC COMPANY
Proposed Transmission Rate Design
Formula Rate Effective June 1, 2017

Annual General Service Secondary (AGS Secondary)

	Billing Determinants	Rate	Rate w/o SUT	Annualized Present Revenue w/o SUT	Rate Adjustment	Proposed Rate w/o SUT	Proposed Rate w/SUT
Demand KW	5,718,258	$ 2.01	$ 1.88	$ 10,750,325	$ 1.46	$ 3.34	$ 3.57
Transmission Rate Change				$ 8,346,802			

ATLANTIC CITY ELECTRIC COMPANY
Proposed Transmission Rate Design
Formula Rate Effective June 1, 2017

Annual General Service Primary (AGS Primary)

	Billing Determinants	Rate	Rate w/o SUT	Annualized Present Revenue w/o SUT	Rate Adjustment	Proposed Rate w/o SUT	Proposed Rate w/SUT
Demand KW	1,364,315	$ 0.96	$ 0.90	$ 1,227,884	$ 2.45	$ 3.35	$ 3.58
Transmission Rate Change				$ 3,337,521			

Sub Transmission General Service (TGS)

	Billing Determinants	Rate	Rate w/o SUT	Annualized Present Revenue w/o SUT	Rate Adjustment	Proposed Rate w/o SUT	Proposed Rate w/SUT
Demand KW	1,189,452	$ 0.50	$ 0.47	$ 559,042	$ 1.10	$ 1.57	$ 1.68
Transmission Rate Change				$ 1,312,285			

Transmission General Service (TGS)

	Billing Determinants	Rate	Rate w/o SUT	Annualized Present Revenue w/o SUT	Rate Adjustment	Proposed Rate w/o SUT	Proposed Rate w/SUT
Demand KW	1,541,081	$ 0.94	$ 0.88	$ 1,356,151	$ 0.85	$ 1.73	$ 1.85
Transmission Rate Change				$ 1,312,285			

Street and Private Lighting (SPL)
Contributed Street Lighting (CSL)

	Billing Determinants	Rate	Rate w/o SUT	Annualized Present Revenue w/o SUT	Rate Adjustment	Proposed Rate w/o SUT	Proposed Rate w/SUT
Kilowatthour charge							
Annual	73,343,971	$ -	$ -	$ -	$ -	$ -	$ -
Transmission Rate Change				$ -	$ -		

Direct Distribution Connection (DDC)

	Billing Determinants	Rate	Rate w/o SUT	Annualized Present Revenue w/o SUT	Rate Adjustment	Proposed Rate w/o SUT	Proposed Rate w/SUT
Kilowatthour charge							
Annual	13,220,236	0.004361	$ 0.004080	$ 53,939	$ 0.001983	$ 0.006063	$ 0.006480
Transmission Rate Change				$ 26,210			

Atlantic City Electric Company
Standby Rate Development
Formula Rate Effective June 1, 2017

Rate Schedule	Demand Rates ($/kW) Transmission	Standby Rates ($/kW) Transmission	Transmission Standby Factor
MGS Secondary	$ 3.27	$ 0.33	0.101604278
MGS Primary	$ 3.16	$ 0.32	0.101604278
AGS Secondary	$ 3.57	$ 0.36	0.101604278
AGS Primary	$ 3.58	$ 0.36	0.101604278
TGS Transmission	$ 1.85	$ 0.19	0.101604278

IN THE MATTER OF THE PETITION OF ATLANTIC CITY ELECTRIC COMPANY FOR APPROVAL TO IMPLEMENT FERC-APPROVED CHANGES TO ACE'S RETAIL TRANSMISSION (FORMULA) RATE PURSUANT TO PARAGRAPHS 15.9 OF THE BGS-RSCP AND BGS-CIEP SUPPLIER MASTER AGREEMENTS (2017)	**STATE OF NEW JERSEY** **BOARD OF PUBLIC UTILITIES**

CERTIFICATION OF SERVICE

PHILIP J. PASSANANTE, of full age, certifies as follows:

1. I am an attorney at law of the State of New Jersey and serve as Assistant General Counsel to Atlantic City Electric Company, the Petitioner in the within matter, with which I am familiar.

2. I hereby certify that, on July 14, 2017, I caused three conformed copies of the within Verified Petition of Atlantic City Electric Company for Approval to Implement FERC-Approved Changes to Its Retail Transmission (Formula) Rate Pursuant to Paragraphs 15.9 of the BGS-RSCP and BGS-CIEP Supplier Master Agreements (the "Petition") to be sent by electronic mail and overnight courier to Irene Kim Asbury, Esquire, Secretary of the Board, State of New Jersey, Board of Public Utilities, 44 South Clinton Avenue, 3rd Floor, Suite 314, Trenton, New Jersey 08625.

3. I further certify that, on July 14, 2017, I caused a complete copy of the Petition to be sent by electronic mail to each of the parties listed on the attached Service List, except for copies that were directed to the Division of Rate Counsel, which were sent by electronic mail and overnight courier.

4. I further and finally certify that the foregoing statements made by me are true. I am aware that, if any of the foregoing statements made by me are willfully false, I am subject to punishment.

Dated: July 14, 2017 By: /jpr

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I/M/O the Petition of Atlantic City Electric Company for Approval to Implement FERC-Approved Changes to ACE's Retail Transmission (Formula) Rate Pursuant to Paragraphs 15.9 of the BGS-RSCP and BGS-CIEP Supplier Master Agreements (2017)
BPU Docket No. ____________________

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