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An Exelon Company

July 11, 2018

VIA FEDERAL EXPRESS and
ELECTRONIC MAIL
aida.camacho@bpu.nj.gov
board.secretary@bpu. nj.gov

Aida Camacho-Welch
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 (2018)
BPU Docket No. ______________________

Dear Secretary Camacho-Welch:

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 the Board meeting currently scheduled for August 29, 2018.

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[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 (2018)	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]

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[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 May 15, 2018, to be effective June 1, 2018. 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 27, 2018, formula rate update filings were made by Baltimore Gas and Electric Company (May 4, 2018), PPL Electric Utilities Corporation (April 27, 2018), Trans-Allegheny Interstate Line Company (also referred to as "TrAILCo") (May 15, 2018), PECO Energy (May 11, 2018), Delmarva Power & Light Company (May 15, 2018), and Potomac Electric Power Company (May 15, 2018), to be effective June 1, 2018. 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 Saturday, September 1, 2018. 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. Note that these allocations incorporate changes to the PJM OATT pursuant to FERC Orders issued on December 15, 2017, in Docket Nos. EL17-84-000 and EL17-90-000 (the HTP and Linden VFT Orders). PJM implemented these changes in the

OATT effective January 1, 2018. The allocations also incorporate changes to the OATT pursuant to a FERC Order issued on April 25, 2017, in Docket Nos. ER17-950-000 and ER17-940-001 (the ConEd Wheel Order). **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. For an average residential customer using approximately 679 kWh per month, this filing, once implemented, represents an increase of approximately $0.55 or 0.45 percent on a total monthly bill as shown in **Exhibit F** included herewith.

14. 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.

15. 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, 2018 through May 31, 2019 will be made upon the Board's approval of this request. For the period beginning June 1, 2018, 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.

16. 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

P.O. 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

Alison Regan
Senior Rate Analyst
500 N. Wakefield Drive
Newark, Delaware 19702

and

Daniel A. Tudor
Manager, Energy Acquisition Operations
Pepco Holdings LLC/Atlantic City Electric Company
701 Ninth Street, N.W.
Washington, DC 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, including any TEC updates referenced in the Petition and the Exhibits thereto;

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 11, 2018

Passanante /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 (2018)	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.

JAMIELA LANE
NOTARY PUBLIC
EXP. 5-14-21
DISTRICT OF COLUMBIA

KEVIN M. McGOWAN

SWORN TO AND SUBSCRIBED before me this 9 day of July, 2018.

District of Columbia: SS
Subscribed and sworn to before me, in my presence, this 9 day of July 2018

Jamiela Lane, Notary Public, D.C.
My commission expires May 14, 2021.

Notary Public
My Commission Expires: 5/14/21

Exhibit A

ATTACHMENT H-1A

Atlantic City Electric Company

Formula Rate - Appendix A

Shaded cells are are input cells

Line	Description		Notes	FERC Form 1 Page # or Instruction	2017
	Allocators				
	Wages & Salary Allocation Factor				
1	Transmission Wages Expense			p354.21.b	$ 2,295,571
2	Total Wages Expense			p354.28b	$ 36,223,095
3	Less A&G Wages Expense			p354.27b	$ 1,243,809
4	Total			(Line 2 - 3)	34,979,286
5	Wages & Salary Allocator			(Line 1 / 4)	6.5627%
	Plant Allocation Factors				
6	Electric Plant in Service		(Note B)	p207.104g (see Attachment 5)	$ 3,605,589,602
7	Common Plant In Service - Electric			(Line 24)	0
8	Total Plant In Service			(Sum Lines 6 & 7)	3,605,589,602
9	Accumulated Depreciation (Total Electric Plant)			p219.29c (see Attachment 5)	$ 752,843,799
10	Accumulated Intangible Amortization		(Note A)	p200.21c (see Attachment 5)	$ 15,279,562
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)	768,123,361
14	Net Plant			(Line 8 - 13)	2,837,466,241
15	Transmission Gross Plant			(Line 29 - Line 28)	1,283,293,498
16	Gross Plant Allocator			(Line 15 / 8)	35.5918%
17	Transmission Net Plant			(Line 39 - Line 28)	1,035,003,451
18	Net Plant Allocator			(Line 17 / 14)	36.4763%
	Plant Calculations				
	Plant In Service				
19	Transmission Plant In Service		(Note B)	p207.58.g	$ 1,274,493,121
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	-
22	Total Transmission Plant In Service			(Line 19 - 20 + 21)	1,274,493,121
23	General & Intangible			p205.5.g & p207.99.g (see Attachment 5)	$ 134,097,754
24	Common Plant (Electric Only)		(Notes A & B)	p356	$ -
25	Total General & Common			(Line 23 + 24)	134,097,754
26	Wage & Salary Allocation Factor			(Line 5)	6.56266%
27	General & Common Plant Allocated to Transmission			(Line 25 * 26)	8,800,377
28	Plant Held for Future Use (Including Land)		(Note C)	p214	782,029
29	TOTAL Plant In Service			(Line 22 + 27 + 28)	1,284,075,527
	Accumulated Depreciation				
30	Transmission Accumulated Depreciation		(Note B)	p219.25.c	$ 245,046,572
31	Accumulated General Depreciation			p219.28.c (see Attachment 5)	$ 34,143,635
32	Accumulated Intangible Amortization			(Line 10)	15,279,562
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)	49,423,197
36	Wage & Salary Allocation Factor			(Line 5)	6.56266%
37	General & Common Allocated to Transmission			(Line 35 * 36)	3,243,476
38	TOTAL Accumulated Depreciation			(Line 30 + 37)	248,290,048
39	TOTAL Net Property, Plant & Equipment			(Line 29 - 38)	1,035,785,480
	Adjustment To Rate Base				
	Accumulated Deferred Income Taxes				
40	ADIT net of FASB 106 and 109			Attachment 1	-329,243,425
41	Accumulated Investment Tax Credit Account No. 255	Enter Negative	(Notes A & I)	p266.h	0
42	Net Plant Allocation Factor			(Line 18)	36.48%
43	Accumulated Deferred Income Taxes Allocated To Transmission			(Line 41 * 42) + Line 40	-329,243,425
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	-2,046,990
	Prepayments				
45	Prepayments		(Note A)	Attachment 5	4,876,221
46	Total Prepayments Allocated to Transmission			(Line 45)	4,876,221
	Materials and Supplies				
47	Undistributed Stores Exp		(Note A)	p227.6c & 16.c	0
48	Wage & Salary Allocation Factor			(Line 5)	6.56%
49	Total Transmission Allocated			(Line 47 * 48)	0
50	Transmission Materials & Supplies			p227.8c	$ 1,857,041
51	Total Materials & Supplies Allocated to Transmission			(Line 49 + 50)	1,857,041
	Cash Working Capital				
52	Operation & Maintenance Expense			(Line 85)	27,124,788
53	1/8th Rule			x 1/8	12.5%
54	Total Cash Working Capital Allocated to Transmission			(Line 52 * 53)	3,390,598
	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)	-321,166,555
59	Rate Base			(Line 39 + 58)	714,618,924

O&M

	Transmission O&M				
60	Transmission O&M		p321.112.b (see Attachment 5)	$	21,706,703
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)		21,706,703
	Allocated General & Common Expenses				
67	Common Plant O&M	(Note A)	p356	$	-
68	Total A&G		p323.197.b (see Attachment 5)	$	83,679,206
68a	For informational purposes: PBOB expense in FERC Account 926	(Note S)	Attachment 5	$	773,511
69	Less Property Insurance Account 924		p323.185b	$	469,686
70	Less Regulatory Commission Exp Account 928	(Note E)	p323.189b	$	4,783,058
71	Less General Advertising Exp Account 930.1		p323.191b	$	286,452
72	Less DE Enviro & Low Income and MD Universal Funds		p335.b	$	-
73	Less EPRI Dues	(Note D)	p352-353	$	220,349
74	General & Common Expenses		(Lines 67 + 68) - Sum (69 to 73)		77,919,661
75	Wage & Salary Allocation Factor		(Line 5)		6.5627%
76	General & Common Expenses Allocated to Transmission		(Line 74 * 75)		5,113,601
	Directly Assigned A&G				
77	Regulatory Commission Exp Account 928	(Note G)	p323.189b		133,159
78	General Advertising Exp Account 930.1	(Note F)	p323.191b		0
79	Subtotal - Transmission Related		(Line 77 + 78)		133,159
80	Property Insurance Account 924		p323.185b	$	469,686
81	General Advertising Exp Account 930.1	(Note K)	p323.191b		0
82	Total		(Line 80 + 81)		469,686
83	Net Plant Allocation Factor		(Line 18)		36.48%
84	A&G Directly Assigned to Transmission		(Line 82 * 83)		171,324
85	Total Transmission O&M		(Line 66 + 76 + 79 + 84)		27,124,788

Depreciation & Amortization Expense

	Depreciation Expense				
86	Transmission Depreciation Expense		p336.7b&c		29,624,450
87	General Depreciation		p336.10b&c (see Attachment 5)		6,449,388
88	Intangible Amortization	(Note A)	p336.1d&e (see Attachment 5)		159,633
89	Total		(Line 87 + 88)		6,609,021
90	Wage & Salary Allocation Factor		(Line 5)		6.5627%
91	General Depreciation Allocated to Transmission		(Line 89 * 90)		433,727
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)		6.5627%
96	Common Depreciation - Electric Only Allocated to Transmission		(Line 94 * 95)		0
97	Total Transmission Depreciation & Amortization		(Line 86 + 91 + 96)		30,058,177

Taxes Other than Income

98	Taxes Other than Income		Attachment 2		1,053,584
99	Total Taxes Other than Income		(Line 98)		1,053,584

Return / Capitalization Calculations

	Long Term Interest					
100	Long Term Interest			p117.62c through 67c		62,992,469
101	Less LTD Interest on Securitization Bonds		(Note P)	Attachment 8		5,670,914
102	Long Term Interest			"(Line 100 - line 101)"		57,321,555
103	Preferred Dividends		enter positive	p118.29c	$	-
	Common Stock					
104	Proprietary Capital			p112.16c	$	1,042,601,119
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)		1,042,601,119
	Capitalization					
108	Long Term Debt			p112.17c through 21c	$	1,077,521,230
109	Less Loss on Reacquired Debt		enter negative	p111.81.c	$	(5,278,948)
110	Plus Gain on Reacquired Debt		enter positive	p113.61.c	$	-
111	Less ADIT associated with Gain or Loss		enter negative	Attachment 1		1,483,912
112	Less LTD on Securitization Bonds	(Note P)	enter negative	Attachment 8		-40,506,230
113	Total Long Term Debt			(Sum Lines Lines 108 to 112)		1,033,219,964
114	Preferred Stock			p112.3c	$	-
115	Common Stock			(Line 107)		1,042,601,119
116	Total Capitalization			(Sum Lines 113 to 115)		2,075,821,083
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)		57,340,508

Composite Income Taxes

	Income Tax Rates				
128	FIT=Federal Income Tax Rate				21.00%
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)} =			28.11%
132	T/ (1-T)				39.10%
	ITC Adjustment		(Note I)		
133	Amortized Investment Tax Credit		enter negative	p266.8f	$ (363,377)
134	T/(1-T)			(Line 132)	39.10%
135	Net Plant Allocation Factor			(Line 18)	36.4763%
136	ITC Adjustment Allocated to Transmission			(Line 133 * (1 + 134) * 135)	-184,374
137	Income Tax Component =	CIT=(T/1-T) * Investment Return * (1-(WCLTD/R)) =		[Line 132 * 127 * (1-(123 / 126))]	14,669,867
138	Total Income Taxes			(Line 136 + 137)	14,485,493

REVENUE REQUIREMENT

	Summary			
139	Net Property, Plant & Equipment		(Line 39)	1,035,785,480
140	Adjustment to Rate Base		(Line 58)	-321,166,555
141	Rate Base		(Line 59)	714,618,924
142	O&M		(Line 85)	27,124,788
143	Depreciation & Amortization		(Line 97)	30,058,177
144	Taxes Other than Income		(Line 99)	1,053,584
145	Investment Return		(Line 127)	57,340,508
146	Income Taxes		(Line 138)	14,485,493
147	Gross Revenue Requirement		(Sum Lines 142 to 146)	130,062,550
	Adjustment to Remove Revenue Requirements Associated with Excluded Transmission Facilities			
148	Transmission Plant In Service		(Line 19)	1,274,493,121
149	Excluded Transmission Facilities	(Note M)	Attachment 5	0
150	Included Transmission Facilities		(Line 148 - 149)	1,274,493,121
151	Inclusion Ratio		(Line 150 / 148)	100.00%
152	Gross Revenue Requirement		(Line 147)	130,062,550
153	Adjusted Gross Revenue Requirement		(Line 151 * 152)	130,062,550
	Revenue Credits & Interest on Network Credits			
154	Revenue Credits		Attachment 3	2,245,360
155	Interest on Network Credits	(Note N)	PJM Data	-
156	Net Revenue Requirement		(Line 153 - 154 + 155)	127,817,189
	Net Plant Carrying Charge			
157	Net Revenue Requirement		(Line 156)	127,817,189
158	Net Transmission Plant		(Line 19 - 30)	1,029,446,549
159	Net Plant Carrying Charge		(Line 157 / 158)	12.4161%
160	Net Plant Carrying Charge without Depreciation		(Line 157 - 86) / 158	9.5384%
161	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes		(Line 157 - 86 - 127 - 138) / 158	2.5613%
	Net Plant Carrying Charge Calculation per 100 Basis Point increase in ROE			
162	Net Revenue Requirement Less Return and Taxes		(Line 156 - 145 - 146)	55,991,189
163	Increased Return and Taxes		Attachment 4	76,796,225
164	Net Revenue Requirement per 100 Basis Point increase in ROE		(Line 162 + 163)	132,787,414
165	Net Transmission Plant		(Line 19 - 30)	1,029,446,549
166	Net Plant Carrying Charge per 100 Basis Point increase in ROE		(Line 164 / 165)	12.8989%
167	Net Plant Carrying Charge per 100 Basis Point increase in ROE without Depreciation		(Line 163 - 86) / 165	10.0212%
168	Net Revenue Requirement		(Line 156)	127,817,189
169	True-up amount		Attachment 6	8,525,952
170	Plus any increased ROE calculated on Attachment 7 other than PJM Sch. 12 projects		Attachment 7	289,177
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)	136,632,319
	Network Zonal Service Rate			
173	1 CP Peak	(Note L)	PJM Data	2,541
174	Rate ($/MW-Year)		(Line 172 / 173)	53,775
175	Network Service Rate ($/MW/Year)		(Line 174)	53,775

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	-	(942,450,108)	-	
ADIT-283	(4,331,250)	48,279	(34,109,695)	
ADIT-190	-	34,472,927	7,228,456	
Subtotal	(4,331,250)	(907,928,901)	(26,881,239)	
Wages & Salary Allocator			6.5627%	
Gross Plant Allocator		35.5918%		
ADIT	(4,331,250)	(323,148,052)	(1,764,124)	(329,243,425)

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 (1,483,912)

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	C	D	E	F	G
		Total					
ADIT-190			Gas, Prod or Other Related	Only Transmission Related	Plant	Labor	Justifications
190	1999 AMT	443,467	-	-	443,467	-	Reflects the deferred tax asset related to New Jersey Alternative Minimum Assessment (AMA) credit. Relates to both Transmission and Distribution.
190	Accrual Labor Related	5,077,299	-	-	-	5,077,299	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	70,036	-	-	-	70,036	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.	3,178,991	2,352,122	-	826,869	-	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	3,102,873	2,161,580	-	941,293	-	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	1,039,304	-	-	1,039,304	-	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	4,995,180	4,995,180	-	-	-	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	582,061	582,061	-	-	-	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	176,796	176,796	-	-	-	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	4,162,474	-	-	-	4,162,474	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	SERP	247,791	-	-	-	247,791	Represents deferred taxes for supplemental executive retirement plan ("SERP"). Accrued SERP expense is included on book but is not deductible for tax until economic performance is met.
190	Stranded Costs	1,218,428	1,218,428	-	-	-	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	Use Tax Reserve	784,569	784,569	-	-	-	Represents deferred taxes for FAS 5/ASC 450 Use Tax Reserves which are not fixed and determinable and therefore not deductible for income tax purposes.
190	Federal NOL	13,246,763	-	-	13,246,763	-	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	21,234,578	7,304,705	-	13,929,873	-	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	406,383	-	-	406,383	-	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 unamortized ITC. These amoutns are removed from rate base below.
190	Gross up on TCJA FAS 109 Excess Deferred Taxes	5,770,244	-	459,854	2,712,088	2,598,303	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 2017 Tax Cuts and Jobs Act (2017) Federal Tax Rate reduction. These amounts are removed from rate base below.
190	Gross up on FAS 109 Deferred Taxes	109,423,708	-	-	109,423,708	-	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 from rate base below.
190	Subtotal - p234	175,160,945	19,575,441	459,854	142,969,747	12,155,903	
	Less FASB 109 Above if not separately removed	102,712,541	(7,009,106)	459,854	108,496,820	764,973	
190	Less FASB 106 Above if not separately removed	4,162,474	-	-	-	4,162,474	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	68,285,930	26,584,547	-	34,472,927	7,228,456	

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	(942,450,108)			(942,450,108)		This deferred tax balance relates to our plant and results from life and method differences. Related to both T & D plant.
282	CIAC	50,313,891	50,313,891				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	11,277,468	11,277,468				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	279,845,977	(12,427,784)	-	292,273,761		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	(601,012,772)	49,163,575	-	(650,176,347)	-	
	Less FASB 109 Above if not separately removed	279,845,977	(12,427,784)	-	292,273,761	-	
	Less FASB 106 Above if not separately removed	-					
282	Total	(880,858,749)	61,591,359	-	(942,450,108)	-	

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

	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	(1,458,050)	-	-	-	(1,458,050)	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	(2,615,558)	(2,615,558)	-	-	-	Relates to deferred costs associated with Basic Generation Service. Retail related.
283	Interest on Contingent Taxes	48,279	-	-	48,279	-	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	(1,483,912)	(1,483,912)	-	-	-	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	(484,545)	(484,545)	-	-	-	Represents deferred taxes on miscellaneous deferred debits deducted for tax purposes in advance of book purposes. Retail related.
283	NUG BUYOUT	(6,627,894)	(6,627,894)	-	-	-	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.
	Other- 283	(432,517)	(432,517)				Represents deferred taxes realted to income on books not included for tax.
283	PENSION PAYMENT RESERVE	(22,468,488)	-	-	-	(22,468,488)	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	(2,980,451)	-	(2,980,451)	-	-	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	(7,770,512)	(7,770,512)	-	-	-	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 - General	2,814,050	2,814,050				For book purposes, regulatory assets are established with an increase to book income. For tax purposes the regulatory assets are not recognized and book income is reversed.
283	Regulatory Asset - NJ RGGI	(1)	(1)	-	-	-	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	(178,463)	(178,463)	-	-	-	Represents deferred income tax liability on the Solar Renewable Energy Certificate Program. Retail related.
283	Stranded Costs	(19,844,720)	(19,844,720)	-	-	-	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	Subtotal - p277 (Form 1-F filer: see note 6, below)	(63,482,782)	(36,624,072)	(2,980,451)	48,279	(23,926,538)	
283	Less FASB 109 Above if not separately removed	28,684,225	17,150,270	1,350,799	-	10,183,157	
283	Less FASB 106 Above if not separately removed	-					
283	Total	(92,167,007)	(53,774,342)	(4,331,250)	48,279	(34,109,695)	

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	3,697,280	363,377
5	Total		3,697,280	363,377
6	Form No. 1 balance (p.266) for amortization	Total Form No. 1 (p 266 & 267	3,697,280	363,377
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)	2,444,578		
2	Personal property	-		
3	City License	-		
4	Federal Excise	14,173		
	Total Plant Related	2,458,751	35.5918%	875,113
	Labor Related		***Wages & Salary Allocator***	
5	Federal FICA & Unemployment	2,487,661		
6	Unemployment(State)	214,003		
	Total Labor Related	2,701,664	6.5627%	177,301
	Other Included		***Gross Plant Allocator***	
7	Miscellaneous	3,286		
	Total Other Included	3,286	35.5918%	1,170
	Total Included			1,053,584
	Excluded			
8	State Franchise tax	-		
9	TEFA	-		
10	Use & Sales Tax	1,140,217		
10	Excluded merger costs in line 5	15		
11	Total "Other" Taxes (included on p. 263)	6,303,933		
12	Total "Taxes Other Than Income Taxes" - acct 408.10 (p. 114.14)	6,303,933		
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)		966,076
2	Total Rent Revenues	(Sum Line 1)	966,076
	Account 456 - Other Electric Revenues (Note 1)		
3	Schedule 1A		$ 816,004
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)		462,720
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)	2,864,180
12	Less line 17g		(618,820)
13	Total Revenue Credits		2,245,360

<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.		966,076
17b	Costs associated with revenues in line 17a	Attachment 5 - Cost Support	271,564
17c	Net Revenues (17a - 17b)		694,512
17d	50% Share of Net Revenues (17c / 2)		347,256
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)		347,256
17g	Line 17f less line 17a		(618,820)
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.		9,741,348
19	Amount offset in line 4 above		133,095,697
20	Total Account 454, 456 and 456.1		145,701,225
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)	76,796,225
B	100 Basis Point increase in ROE				1.00%
	Return Calculation				
59	Rate Base			(Line 39 + 58)	714,618,924
	Long Term Interest				
100	Long Term Interest			p117.62c through 67c	62,992,469
101	Less LTD Interest on Securitization E (Note P)			Attachment 8	5,670,914
102	**Long Term Interest**			"(Line 100 - line 101)"	57,321,555
103	**Preferred Dividends**		enter positive	p118.29c	0
	Common Stock				
104	Proprietary Capital			p112.16c	1,042,601,119
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)	1,042,601,119
	Capitalization				
108	Long Term Debt			p112.17c through 21c	1,077,521,230
109	Less Loss on Reacquired Debt		enter negative	p111.81.c	-5,278,948
110	Plus Gain on Reacquired Debt		enter positive	p113.61.c	0
111	Less ADIT associated with Gain or Loss		enter negative	Attachment 1	1,483,912
112	Less LTD on Securitization Bonds		enter negative	Attachment 8	-40,506,230
113	Total Long Term Debt			(Sum Lines Lines 108 to 112)	1,033,219,964
114	Preferred Stock			p112.3c	0
115	Common Stock			(Line 107)	1,042,601,119
116	**Total Capitalization**			(Sum Lines 113 to 115)	2,075,821,083
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)**	**60,913,602**
	Composite Income Taxes			(Note L)	
	Income Tax Rates				
128	FIT=Federal Income Tax Rate				21.00%
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)} =			28.11%
132	T/ (1-T)				39.10%
	ITC Adjustment				
133	Amortized Investment Tax Credit		enter negative	p266.8f	-363,377
134	T/(1-T)			(Line 132)	39.10%
135	Net Plant Allocation Factor			(Line 18)	36.4763%
136	**ITC Adjustment Allocated to Transmission**		(Note I from Appendix A)	(Line 133 * (1 + 134) * 135)	**-184,374**
137	**Income Tax Component =**	CIT=(T/1-T) * Investment Return * (1-(WCLTD/R)) =			16,066,997
138	**Total Income Taxes**				**15,882,623**

Atlantic City Electric Company

Attachment 5 - Cost Support

Electric / Non-electric Cost Support

	Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions			Form 1 Amount	Electric Portion	Non-electric Portion	Details
	Plant Allocation Factors						
10	Accumulated Intangible Amortization	(Note A)	p200.21c (see Attachm	15,293,580	15,293,580	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	3,697,280	3,697,280	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	173,651	173,651	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

	Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions			Form 1 Amount	Transmission Related	Non-transmission Related	Details
28	Plant Held for Future Use (Including Land)	(Note C)	p214	12,883,207	782,029	12,101,178	Transmission Right of Way - Carll's Corner to Landis

CWIP & Expensed Lease Worksheet

	Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions			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	3,607,191,404	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	1,274,493,121	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	245,046,572	0	0	See Form 1

EPRI Dues Cost Support

	Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions			Form 1 Amount	EPRI Dues	Details
	Allocated General & Common Expenses					
73	Less EPRI Dues	(Note D)	p352-353	220,349	220,349	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	4,783,058	133,159	4,649,899	FERC Form 1 page 351 line 6 (h) and 7 (h)
	Directly Assigned A&G						
77	Regulatory Commission Exp Account 928	(Note G)	p323.189b	4,783,058	133,159	4,649,899	FERC Form 1 page 351 line 6 (h) and 7 (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	286,452	-	286,452	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	286,452	-	286,452	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	15,238,358	6.56%	1,000,041	
	Plant Related	2,941,546	35.59%	1,046,949	
	Other		0.00%	-	
	Total Transmission Related Reserves	18,179,904		2,046,990	

Prepayments

Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions						Description of the Prepayments
45	Prepayments					
5	Wages & Salary Allocator			6.563%	To Line 45	
	Pension Liabilities, if any, in Account 242		-	6.563%	-	
	Prepayments	$	371,936	6.563%	24,409	
	Prepaid Pensions if not included in Prepayments	$	73,930,586	6.563%	4,851,812	Prepaid Pension is recorded in FERC account 186 (see FERC Form 1 page 233).
			74,302,522		4,876,221	
						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	2,540.8	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	
6	Electric Plant in Service	p207.104g	3,607,191,404	157,222	3,607,034,182	
9	Accumulated Depreciation (Total Electric Plant)	p219.29c	753,019,802	198	753,019,604	
10	Accumulated Intangible Amortization	p200.21c	15,293,580	14,018	15,279,562	
23	General & Intangible	p205.5.g & p207.99.g	134,744,748	157,222	134,587,526	
60	Transmission O&M	p321.112.b	21,789,347	82,644	21,706,703	
68	Total A&G	p323.197.b	79,823,542	(3,855,664)	83,679,206	Removal of $4,315,518 of 2017 merger related costs, offset by establishment of regulatory asset of $8,171,182 in A&G accounts.
87	General Depreciation	p336.10b&c	6,449,586	198	6,449,388	
88	Intangible Amortization	p336.1d&e	173,651	14,018	159,633	

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	3,607,191,404	1,444,581	3,605,746,823	Distribution ARO-$954,809 and General & Intangible ARO-$489,772
9	Accumulated Depreciation (Total Electric Plant)	p219.29c	753,019,802	175,805	752,843,997	Distribution ARO-$113,267 and General ARO-$62,538

Atlantic City Electric Company

Attachment 5 - Cost Support

23	General & Intangible	p205.5.g & p207.99.g	134,744,748	489,772	134,254,976		General & Intangible ARO-$489,772
31	Accumulated General Depreciation	p219.28.c	34,206,372	62,538	34,143,834		General ARO-$62,538

ARO & Merger Related Exclusion - Cost Support

	Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions		Form 1 Amount	ARO's	Merger Costs	Non-ARO's & Non Merger Related	
6	Electric Plant in Service	p207.104g	3,607,191,404	1,444,581	157,222	3,605,589,602	Distribution ARO-$954,809, General & Intangible ARO-$489,772 and Intangible Merger Cost $157,222
9	Accumulated Depreciation (Total Electric Plant)	p219.29c	753,019,802	175,805	198	752,843,799	Distribution ARO-$113,267 and General ARO-$62,538 and General Merger Cost $198
23	General & Intangible	p205.5.g & p207.99.g	134,744,748	489,772	157,222	134,097,754	General & Intangible ARO-$489,772 and Intangible Merger Cost $157,222
31	Accumulated General Depreciation	p219.28.c	34,206,372	62,538	198	34,143,635	General ARO-$62,538 and General Merger Cost $198

PBOP Expense in FERC 926

	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	79,823,542	14,039,705	773,511	1,000,545	The actuarially determined amount of OPEB expense in FERC 926 decreased $.227 million from the prior year; the decrease primarily represents a ($0.2 million) decrease in service cost primarily due to (i) change in the discount rate from 3.80% in 2016 to 4.0% in 2017 and (ii) updated census data, ($0.3 million) increase in expected return on plan assets due to year over year assets growth, offset by $0.1 million increase in amortization of unregonized gain/loss. This decrease was offset by a $0.183 million decrease in OPEB costs directly charged to capital or other income deduction accounts (i.e. below the line).

Attachment 3 - Revenue Credit Workpaper

17b	Costs associated with revenues in line 17a	$	271,564
	Revenue Subject to 50/50 sharing (Attachment 3 - line 17a)	$	966,076
	Federal Income Tax Rate		21.00%
	Federal Tax on Revenue subject to 50/50 sharing		202,876
	Net Revenue subject to 50/50 sharing		763,200
	Composite State Income Tax Rate		9.000%
	State Tax on Revenue subject to 50/50 sharing		68,688
	Total Tax on Revenue subject to 50/50 sharing	$	271,564

Atlantic City Electric Company

Attachment 5a - Allocations of Costs to Affiliate

	Delmarva Power	Atlantic City	Pepco	Non - Regulated	Total
Executive Management	6,721,922	6,040,279	11,559,004	2,731,918	27,053,123
Procurement & Administrative Services	5,753,548	4,160,116	8,276,756	3,721,474	21,911,894
Financial Services & Corporate Expenses	16,768,656	13,558,856	23,867,875	15,207,024	69,402,411
Insurance Coverage and Services	292,642	563,869	(390,363)	(5,012)	461,136
Human Resources	(1,116,564)	(1,258,037)	(540,100)	5,485,522	2,570,821
Legal Services	2,170,665	1,000,599	4,150,743	6,816,457	14,138,464
Customer Services	52,746,755	47,419,527	45,717,038	2,626	145,885,946
Information Technology	17,257,383	13,248,946	32,727,761	10,871,056	74,105,146
External Affairs	3,411,728	2,935,223	5,190,824	626,833	12,164,608
Environmental Services	2,358,711	2,065,133	2,509,472	346	6,933,662
Safety Services	481,504	493,828	775,837		1,751,169
Regulated Electric & Gas T&D	44,391,825	35,785,749	58,175,755	2,973,981	141,327,310
Internal Consulting Services	241,911	194,452	414,624		850,987
Interns	174,619	133,726	128,150		436,495
Cost of Benefits	13,261,385	8,972,178	22,145,832		44,379,395
Building Services	146,800	96,476	4,309,323	849,170	5,401,769
Total	**$ 165,063,490**	**$ 135,410,920**	**$ 219,018,531**	**$ 49,281,395**	**$ 568,774,336**

Name of Respondent PHI Service Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Resubmission Date (Mo, Da, Yr) / /	Year/Period of Report Dec 31, 2017

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 Company	54,658,874	164,339,096	20,561	219,018,531
2	Delmarva Power & Light Company	43,878,996	121,169,503	14,991	165,063,490
3	Atlantic City Electric Company	29,283,609	106,115,313	11,998	135,410,920
4	Exelon Business Services Company, LLC	47,134,513			47,134,513
5	Pepco Energy Services, Inc	415,765	1,111,189		1,526,954
6	Pepco Holdings LLC	45,859	490,907	268	537,034
7	Atlantic Southern Properties, Inc	2,419	39,576		41,995
8	Conectiv Properties & Investments, Inc	250	29,336		29,586
9	Atlantic City Electric Transition Funding, LLC	2,895	2,847	4	5,746
10	Conectiv Holding Company, Inc.	3,279			3,279
11	Potomac Capital Investments Corporation	1,623	255		1,878
12	Conectiv Thermal Systems, Inc.		410		410
13					
14					
15					
16					
17					
18					
19					
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21					
22					
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40	Total	175,428,082	393,298,432	47,822	568,774,336

Service Company Billing Analysis by Utility FERC Account
YTD Dec 2017
Total PHI

FERC Accounts	FERC Account Name	DPL	ACE	PEPCO	Non-Utility	Total	Inclusion in ATRR
107	Constr Work In Progress	26,393,027	20,238,001	36,545,201	-	83,176,229	Not included
182.3	Other Regulatory Assets	2,372,237	217,458	7,097,229	-	9,686,924	Not included
184	Clearing Accounts - Other	290,866	240,842	743,443	(623,559)	651,592	Not included
408.1	Taxes other than inc taxes, utility operating inc	1,821	705	1,742	-	4,268	Wage & Salary Factor
416-421.2	Other Income -Below the Line	791,529	668,026	953,108	49,904,954	52,317,617	Not included
426.1-426.5	Other Income Deductions - Below the Line	793,436	612,278	1,127,607	-	2,533,321	Not included
430	Interest-Debt to Associated Companies	33,667	27,028	45,561	-	106,256	Not included
431	Interest-Short Term Debt	(16,005)	(12,879)	(21,440)	-	(50,324)	Not included
556	System cont & load dispatch	1,762,459	1,397,736	1,967,404	-	5,127,599	Not included
557	Other expenses	1,289,456	1,123,936	1,209,338	-	3,622,730	Not included
560	Operation Supervision & Engineering	3,383,115	3,135,496	4,630,184	-	11,148,795	100% included
561.1	Load Dispatching - Reliability	14,659	9,981	-	-	24,640	100% included
561.2	Load Dispatch - Monitor & Operate Transmission Sys	67,228	19,453	727,609	-	814,290	100% included
561.3	Load Dispatch - Transmission Service & Scheduling	33,317	44,911	29,401	-	107,629	100% included
561.5	Reliability, Planning and Standards	348,426	219,013	131,562	-	699,001	100% included
563	Overhead line expenses	-	-	225	-	225	100% included
562	Station expenses	-	-	6,587	-	6,587	100% included
564	Underground Line Expenses - Transmission	-	-	525	-	525	100% included
566	Miscellaneous transmission expenses	964,413	829,555	916,409	-	2,710,377	100% included
568	Maintenance Supervision & Engineering	131,952	100,446	465,203	-	697,601	100% included
569	Maint of structures	6,463	6,993	7,169	-	20,625	100% included
569.2	Maintenance of Computer Software	646,321	311,341	457,266	-	1,414,928	100% included
569.4	Maintenance of Transmission Plant	-	-	4	-	4	100% included
570	Maintenance of station equipment	177,361	64,923	367,252	-	609,536	100% included
571	Maintenance of overhead lines	393,340	286,999	590,906	-	1,271,245	100% included
572	Maintenance of underground lines	194	172	1,137	-	1,503	100% included
573	Maintenance of miscellaneous transmission plant	15,358	28,110	145,477	-	188,945	100% included
575.5	Ancillary services market administration	-	-	8,945	-	8,945	Not included
580	Operation Supervision & Engineering	1,205,549	900,876	1,342,800	-	3,449,225	Not included
581	Load dispatching	1,088,271	408,220	1,622,032	-	3,118,523	Not included
582	Station expenses	519,935	-	127,953	-	647,888	Not included
583	Overhead line expenses	79,339	179,386	37,971	-	296,696	Not included
584	Underground line expenses	35,984	-	181,498	-	217,482	Not included
585	Street lighting	1,575	-	27	-	1,602	Not included
586	Meter expenses	709,279	447,257	1,114,080	-	2,270,616	Not included
587	Customer installations expenses	345,833	349,544	1,003,345	-	1,698,722	Not included
588	Miscellaneous distribution expenses	3,807,435	4,244,289	6,809,195	-	14,860,919	Not included
589	Rents	80,562	409	77,296	-	158,267	Not included
590	Maintenance Supervision & Engineering	948,744	573,387	499,410	-	2,021,541	Not included
591	Maintain structures	7,013	6,792	6,974	-	20,779	Not included
592	Maintain equipment	353,360	427,768	916,673	-	1,697,801	Not included
593	Maintain overhead lines	1,754,068	1,231,469	1,850,015	-	4,835,552	Not included
594	Maintain underground line	129,627	69,299	728,487	-	927,413	Not included
595	Maintain line transformers	2,257	-	150,585	-	152,842	Not included
596	Maintain street lighting & signal systems	41,343	36,511	6,306	-	84,160	Not included
597	Maintain meters	164,705	34,459	132,584	-	331,748	Not included
598	Maintain distribution plant	44,155	20,222	574,205	-	638,582	Not included
800-894	Total Gas Accounts	2,355,199	-	-	-	2,355,199	Not included
902	Meter reading expenses	144,273	36,799	129,651	-	310,723	Not included
903	Customer records and collection expenses	50,866,226	47,660,833	48,331,246	-	146,858,305	Not included
907	Supervision - Customer Svc & Information	88	156,520	42,124	-	198,732	Not included
908	Customer assistance expenses	1,897,100	652,072	545,344	-	3,094,516	Not included
909	Informational & instructional advertising	524,046	539,891	834,890	-	1,898,827	Not included
912	Demonstrating and selling expense	161,461	-	-	-	161,461	Not included
913	Advertising expense	40,738	-	-	-	40,738	Not included
920	Administrative & General salaries	339,115	100,744	689,110	-	1,128,969	Wage & Salary Factor
921	Office supplies & expenses	240	712	361	-	1,313	Wage & Salary Factor
923	Outside services employed	46,996,640	42,150,533	75,985,080	-	165,132,253	Wage & Salary Factor
924	Property insurance	113	91	154	-	358	Net Plant Factor
926	Employee pensions & benefits	7,809,871	4,323,683	12,245,344	-	24,378,898	Wage & Salary Factor
928	Regulatory commission expenses	1,470,858	492,412	2,686,522	-	4,649,792	Direct Transmission Only
929	Duplicate charges-Credit	422,348	150,426	1,117,064	-	1,689,838	Wage & Salary Factor
930.1	General ad expenses	208	186	356	-	750	Direct Transmission Only
930.2	Miscellaneous general expenses	518,497	510,021	999,424	-	2,027,942	Wage & Salary Factor
935	Maintenance of general plant	302,795	135,585	75,371	-	513,751	Wage & Salary Factor
	Total	**165,063,490**	**135,410,920**	**219,018,531**	**49,281,395**	**568,774,336**	

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)

134,969,330 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	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	-	-	-	
								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!	

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

$ 14,359,330 Input to Formula Line 21

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

136,237,027 — 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)

$ 136,237,027

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

139,451,889 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 $ 165,916,002 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	511,099				11.5	5,877,635	-	-	-	489,803	-	-	-	
Feb	23,017,869				10.5	241,687,625	-	-	-	20,140,635	-	-	-	
Mar	12,390,468				9.5	117,709,450	-	-	-	9,809,121	-	-	-	
Apr	3,126,413				8.5	26,574,509	-	-	-	2,214,542	-	-	-	
May	43,195,708				7.5	323,967,808	-	-	-	26,997,317	-	-	-	
Jun	19,857,062				6.5	129,070,901	-	-	-	10,755,908	-	-	-	
Jul	1,066,553				5.5	5,866,044	-	-	-	488,837	-	-	-	
Aug	(1,192,298)				4.5	(5,365,340)	-	-	-	(447,112)	-	-	-	
Sep	16,096,775				3.5	56,338,711	-	-	-	4,694,893	-	-	-	
Oct	21,329,923				2.5	53,324,807	-	-	-	4,443,734	-	-	-	
Nov	1,960,383				1.5	2,940,575	-	-	-	245,048	-	-	-	
Dec	24,556,048				0.5	12,278,024	-	-	-	1,023,169	-	-	-	
Total	165,916,002	-	-	-		970,270,749	-	-	-	80,855,896	-	-	-	
New Transmission Plant Additions and CWIP (weighted by months in service)										80,855,896	-	-	-	
								Input to Line 21 of Appendix A		80,855,896	-		-	80,855,896
								Input to Line 43a of Appendix A				-		-
								Month In Service or Month for CWIP		6.15	#DIV/0!	#DIV/0!	#DIV/0!	

131,992,058 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	-				9.5	-	-	-	-	-	-	-	-	
Apr	-				8.5	-	-	-	-	-	-	-	-	
May					7.5	-	-	-	-	-	-	-	-	
Jun	-				6.5	-	-	-	-	-	-	-	-	
Jul					5.5	-	-	-	-	-	-	-	-	
Aug					4.5	-	-	-	-	-	-	-	-	
Sep					3.5	-	-	-	-	-	-	-	-	
Oct					2.5	-	-	-	-	-	-	-	-	
Nov					1.5	-	-	-	-	-	-	-	-	
Dec					0.5	-	-	-	-	-	-	-	-	
Total	-	-	-	-		-	-	-	-	-	-	-	-	
New Transmission Plant Additions and CWIP (weighted by months in service)										-	-	-	-	
128,106,367								Input to Line 21 of Appendix A		-	-		-	-
								Input to Line 43a of Appendix A				-		-
								Month In Service or Month for CWIP		#DIV/0!	#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		
131,992,058	-	123,838,425	=	8,153,633

Interest on Amount of Refunds or Surcharges

Interest rate pursuant to 35.19a for March c 0.3600%

Month	Yr	1/12 of Step 9	Interest rate for March of the Current Yr	Months	Interest	Surcharge (Refund) Owed
Jun	Year 1	679,469	0.3600%	11.5	28,130	707,599
Jul	Year 1	679,469	0.3600%	10.5	25,684	705,153
Aug	Year 1	679,469	0.3600%	9.5	23,238	702,707
Sep	Year 1	679,469	0.3600%	8.5	20,792	700,261
Oct	Year 1	679,469	0.3600%	7.5	18,346	697,815
Nov	Year 1	679,469	0.3600%	6.5	15,900	695,369
Dec	Year 1	679,469	0.3600%	5.5	13,453	692,923
Jan	Year 2	679,469	0.3600%	4.5	11,007	690,477
Feb	Year 2	679,469	0.3600%	3.5	8,561	688,031
Mar	Year 2	679,469	0.3600%	2.5	6,115	685,585
Apr	Year 2	679,469	0.3600%	1.5	3,669	683,139
May	Year 2	679,469	0.3600%	0.5	1,223	680,692
Total		8,153,633				8,329,752

		Balance	Interest rate from above	Amortization over Rate Year	Balance
Jun	Year 2	8,329,752	0.3600%	710,496	7,649,243
Jul	Year 2	7,649,243	0.3600%	710,496	6,966,284
Aug	Year 2	6,966,284	0.3600%	710,496	6,280,867
Sep	Year 2	6,280,867	0.3600%	710,496	5,592,982
Oct	Year 2	5,592,982	0.3600%	710,496	4,902,621
Nov	Year 2	4,902,621	0.3600%	710,496	4,209,774
Dec	Year 2	4,209,774	0.3600%	710,496	3,514,433
Jan	Year 3	3,514,433	0.3600%	710,496	2,816,589
Feb	Year 3	2,816,589	0.3600%	710,496	2,116,233
Mar	Year 3	2,116,233	0.3600%	710,496	1,413,355
Apr	Year 3	1,413,355	0.3600%	710,496	707,947
May	Year 3	707,947	0.3600%	710,496	(0)
Total with interest				8,525,952	

The difference between the Reconciliation in Step 7 and the forecast in Prior Year with interest	8,525,952
Rev Req based on Year 2 data with estimated Cap Adds and CWIP for Year 3 (Step 8)	$ 128,106,367
Revenue Requirement for Year 3	136,632,319

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

$ 136,632,319

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

$ 136,632,319

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	9.5384%
5	B	167	Net Plant Carrying Charge per 100 Basis Point increase in ROE without Depreciation	10.0212%
6	C		Line B less Line A	0.4828%

7 **FCR if a CIAC**

Line		Formula Line		
8	D	161	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes	2.5613%

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 ic**

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		9.5384%		9.5384%	9.5384%
17	Line 6 times line 15 divided by 100 basis points	FCR for This Project		10.2626%		9.5384%	9.5384%
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	B0265 Mickelton Beginning	Depreciation	Ending	Revenue	B0276 Monroe Beginning	Depreciation	Ending	Revenue	B0211 Union-Corson Beginning	Depreciation	Ending	Revenue
41	Base FCR	2018	3,675,671	138,705	3,536,967	476,075	5,964,825	225,088	5,739,737	772,567	10,095,560	392,061	9,703,499	1,317,619
42	W Increased ROE	2018	3,675,671	138,705	3,536,967	501,690	5,964,825	225,088	5,739,737	772,567	10,095,560	392,061	9,703,499	1,317,619
43	Base FCR	2019	3,536,967	138,705	3,398,262	462,844	5,739,737	225,088	5,514,650	751,097	9,703,499	392,061	9,311,439	1,280,223
44	W Increased ROE	2019	3,536,967	138,705	3,398,262	487,455	5,739,737	225,088	5,514,650	751,097	9,703,499	392,061	9,311,439	1,280,223
45	Base FCR	2020	3,398,262	138,705	3,259,557	449,614	5,514,650	225,088	5,289,562	729,627	9,311,439	392,061	8,919,378	1,242,827
46	W Increased ROE	2020	3,398,262	138,705	3,259,557	473,220	5,514,650	225,088	5,289,562	729,627	9,311,439	392,061	8,919,378	1,242,827
47	Base FCR	2021	3,259,557	138,705	3,120,853	436,384	5,289,562	225,088	5,064,474	708,158	8,919,378	392,061	8,527,317	1,205,430
48	W Increased ROE	2021	3,259,557	138,705	3,120,853	458,986	5,289,562	225,088	5,064,474	708,158	8,919,378	392,061	8,527,317	1,205,430
49	Base FCR	2022	3,120,853	138,705	2,982,148	423,154	5,064,474	225,088	4,839,386	686,688	8,527,317	392,061	8,135,257	1,168,034
50	W Increased ROE	2022	3,120,853	138,705	2,982,148	444,751	5,064,474	225,088	4,839,386	686,688	8,527,317	392,061	8,135,257	1,168,034
51	Base FCR	2023	2,982,148	138,705	2,843,444	409,924	4,839,386	225,088	4,614,299	665,218	8,135,257	392,061	7,743,196	1,130,638
52	W Increased ROE	2023	2,982,148	138,705	2,843,444	430,516	4,839,386	225,088	4,614,299	665,218	8,135,257	392,061	7,743,196	1,130,638
53	Base FCR	2024	2,843,444	138,705	2,704,739	396,693	4,614,299	225,088	4,389,211	643,748	7,743,196	392,061	7,351,136	1,093,241
54	W Increased ROE	2024	2,843,444	138,705	2,704,739	416,281	4,614,299	225,088	4,389,211	643,748	7,743,196	392,061	7,351,136	1,093,241
55	Base FCR	2025	2,704,739	138,705	2,566,035	383,463	4,389,211	225,088	4,164,123	622,279	7,351,136	392,061	6,959,075	1,055,845
56	W Increased ROE	2025	2,704,739	138,705	2,566,035	402,047	4,389,211	225,088	4,164,123	622,279	7,351,136	392,061	6,959,075	1,055,845
57	Base FCR	2026	2,566,035	138,705	2,427,330	370,233	4,164,123	225,088	3,939,035	600,809	6,959,075	392,061	6,567,015	1,018,449
58	W Increased ROE	2026	2,566,035	138,705	2,427,330	387,812	4,164,123	225,088	3,939,035	600,809	6,959,075	392,061	6,567,015	1,018,449
59	Base FCR	2027	2,427,330	138,705	2,288,625	357,003	3,939,035	225,088	3,713,948	579,339	6,567,015	392,061	6,174,954	981,052
60	W Increased ROE	2027		138,705	(138,705)	124,470	3,939,035	225,088	3,713,948	579,339	6,567,015	392,061	6,174,954	981,052
61		....		....	.....	....	....	....	.....	....	....	....	.....	....
62		....	....	.....	.....	....	....	.....	.....	....	....	.....	.....	....
63														

dentified 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
Yes	Yes	No	Yes
35	35	35	35
No	No	No	No
150	150	150	0
9.5384%	9.5384%	9.5384%	9.5384%
10.2626%	10.2626%	10.2626%	9.5384%
26,046,638	18,572,212	6,759,777	4,045,398
744,190	530,635	193,136	115,583
7.00	7	2	5

Beginning	Depreciation	Ending	Revenue	Beginning	Depreciation	Ending	Revenue	Beginning	Depreciation	Ending	Revenue	Beginning	Depreciation	Ending	Revenue
19,038,852	744,190	18,294,662	2,489,208	13,575,403	530,635	13,044,768	1,774,897	5,246,875	193,136	5,053,738	675,182	3,827,154	115,583	3,711,571	469,607
19,038,852	744,190	18,294,662	2,621,699	13,575,403	530,635	13,044,768	1,869,368	5,246,875	193,136	5,053,738	711,782	3,827,154	115,583	3,711,571	469,607
18,294,662	744,190	17,550,473	2,418,224	13,044,768	530,635	12,514,133	1,724,283	5,053,738	193,136	4,860,602	656,760	3,711,571	115,583	3,595,988	458,583
18,294,662	744,190	17,550,473	2,545,326	13,044,768	530,635	12,514,133	1,814,911	5,053,738	193,136	4,860,602	691,961	3,711,571	115,583	3,595,988	458,583
17,550,473	744,190	16,806,283	2,347,240	12,514,133	530,635	11,983,499	1,673,669	4,860,602	193,136	4,667,465	638,338	3,595,988	115,583	3,480,405	447,558
17,550,473	744,190	16,806,283	2,468,953	12,514,133	530,635	11,983,499	1,760,454	4,860,602	193,136	4,667,465	672,140	3,595,988	115,583	3,480,405	447,558
16,806,283	744,190	16,062,093	2,276,257	11,983,499	530,635	11,452,864	1,623,055	4,667,465	193,136	4,474,329	619,916	3,480,405	115,583	3,364,823	436,533
16,806,283	744,190	16,062,093	2,392,580	11,983,499	530,635	11,452,864	1,705,997	4,667,465	193,136	4,474,329	652,319	3,480,405	115,583	3,364,823	436,533
16,062,093	744,190	15,317,904	2,205,273	11,452,864	530,635	10,922,229	1,572,441	4,474,329	193,136	4,281,192	601,494	3,364,823	115,583	3,249,240	425,508
16,062,093	744,190	15,317,904	2,316,206	11,452,864	530,635	10,922,229	1,651,540	4,474,329	193,136	4,281,192	632,499	3,364,823	115,583	3,249,240	425,508
15,317,904	744,190	14,573,714	2,134,289	10,922,229	530,635	10,391,595	1,521,827	4,281,192	193,136	4,088,056	583,072	3,249,240	115,583	3,133,657	414,484
15,317,904	744,190	14,573,714	2,239,833	10,922,229	530,635	10,391,595	1,597,083	4,281,192	193,136	4,088,056	612,678	3,249,240	115,583	3,133,657	414,484
14,573,714	744,190	13,829,524	2,063,305	10,391,595	530,635	9,860,960	1,471,213	4,088,056	193,136	3,894,919	564,649	3,133,657	115,583	3,018,074	403,459
14,573,714	744,190	13,829,524	2,163,460	10,391,595	530,635	9,860,960	1,542,626	4,088,056	193,136	3,894,919	592,857	3,133,657	115,583	3,018,074	403,459
13,829,524	744,190	13,085,335	1,992,321	9,860,960	530,635	9,330,326	1,420,598	3,894,919	193,136	3,701,783	546,227	3,018,074	115,583	2,902,491	392,434
13,829,524	744,190	13,085,335	2,087,086	9,860,960	530,635	9,330,326	1,488,169	3,894,919	193,136	3,701,783	573,036	3,018,074	115,583	2,902,491	392,434
13,085,335	744,190	12,341,145	1,921,338	9,330,326	530,635	8,799,691	1,369,984	3,701,783	193,136	3,508,646	527,805	2,902,491	115,583	2,786,909	381,409
13,085,335	744,190	12,341,145	2,010,713	9,330,326	530,635	8,799,691	1,433,713	3,701,783	193,136	3,508,646	553,215	2,902,491	115,583	2,786,909	381,409
12,341,145	744,190	11,596,955	1,850,354	8,799,691	530,635	8,269,056	1,319,370	3,508,646	193,136	3,315,510	509,383	2,786,909	115,583	2,671,326	370,385
12,341,145	744,190	11,596,955	1,934,340	8,799,691	530,635	8,269,056	1,379,256	3,508,646	193,136	3,315,510	533,394	2,786,909	115,583	2,671,326	370,385
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....	.....	.....	....	....	.....	.....	....	....	.....	.....	....	....	.....	.....	....

B1398.3.1 Mickleton Deptford 230kv terminal				B1600 Upgrade Mill T2 138/69 kV Transformer						
Yes				Yes						
35				35						
No				No						
0				0						
9.5384%				9.5384%						
9.5384%				9.5384%						
13,176,210				14,841,978						
376,463				424,057						
5				6						
Beginning	Depreciation	Ending	Revenue	Beginning	Depreciation	Ending	Revenue	Total	Incentive Charged	Revenue Credit
11,828,392	376,463	11,451,929	1,468,794	14,223,334	424,057	13,799,277	1,740,287	$ 11,184,236		$ 11,184,236
11,828,392	376,463	11,451,929	1,468,794	14,223,334	424,057	13,799,277	1,740,287	$ 11,473,413	$ 11,473,413	
11,451,929	376,463	11,075,466	1,432,885	13,799,277	424,057	13,375,221	1,699,839	$ 10,884,738		$ 10,884,738
11,451,929	376,463	11,075,466	1,432,885	13,799,277	424,057	13,375,221	1,699,839	$ 11,162,280	$ 11,162,280	
11,075,466	376,463	10,699,003	1,396,977	13,375,221	424,057	12,951,164	1,659,390	$ 10,585,241		$ 10,585,241
11,075,466	376,463	10,699,003	1,396,977	13,375,221	424,057	12,951,164	1,659,390	$ 10,851,147	$ 10,851,147	
10,699,003	376,463	10,322,539	1,361,068	12,951,164	424,057	12,527,107	1,618,942	$ 10,285,743		$ 10,285,743
10,699,003	376,463	10,322,539	1,361,068	12,951,164	424,057	12,527,107	1,618,942	$ 10,540,013	$ 10,540,013	
10,322,539	376,463	9,946,076	1,325,160	12,527,107	424,057	12,103,051	1,578,494	$ 9,986,245		$ 9,986,245
10,322,539	376,463	9,946,076	1,325,160	12,527,107	424,057	12,103,051	1,578,494	$ 10,228,880	$ 10,228,880	
9,946,076	376,463	9,569,613	1,289,251	12,103,051	424,057	11,678,994	1,538,046	$ 9,686,747		$ 9,686,747
9,946,076	376,463	9,569,613	1,289,251	12,103,051	424,057	11,678,994	1,538,046	$ 9,917,746	$ 9,917,746	
9,569,613	376,463	9,193,150	1,253,343	11,678,994	424,057	11,254,938	1,497,598	$ 9,387,249		$ 9,387,249
9,569,613	376,463	9,193,150	1,253,343	11,678,994	424,057	11,254,938	1,497,598	$ 9,606,613	$ 9,606,613	
9,193,150	376,463	8,816,687	1,217,434	11,254,938	424,057	10,830,881	1,457,149	$ 9,087,752		$ 9,087,752
9,193,150	376,463	8,816,687	1,217,434	11,254,938	424,057	10,830,881	1,457,149	$ 9,295,480	$ 9,295,480	
8,816,687	376,463	8,440,224	1,181,526	10,830,881	424,057	10,406,825	1,416,701	$ 8,788,254		$ 8,788,254
8,816,687	376,463	8,440,224	1,181,526	10,830,881	424,057	10,406,825	1,416,701	$ 8,984,346	$ 8,984,346	
8,440,224	376,463	8,063,761	1,145,617	10,406,825	424,057	9,982,768	1,376,253	$ 8,488,756		$ 8,488,756
8,440,224	376,463	8,063,761	1,145,617	10,406,825	424,057	9,982,768	1,376,253	$ 8,424,106	$ 8,424,106	
....	....	.....	....	....	....	.....	....			$ -
....	.....	.....	....	....	.....	.....	....		$ -	
									$ 207,459,487	$ 201,047,950

Atlantic City Electric Company

Attachment 8 - Company Exhibit - Securitization Workpaper

Line #		
	Long Term Interest	
101	**Less LTD Interest on Securitization Bonds**	5,670,914
	Capitalization	
112	**Less LTD on Securitization Bonds**	40,506,230

Calculation of the above Securitization Adjustments

Inputs from Atlantic City Electric Company 2017 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

ATLANTIC CITY ELECTRIC COMPANY
BPU NJ No. 11 Electric Service - Section IV Revised Sheet Replaces 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)	$4.83	$4.83
Distribution Rates ($/kWH)		
First Block	$0.055619	$0.051319
(Summer <= 750 kWh; Winter<= 500kWh)		
Excess kWh	$0.063942	$0.051319
Non-Utility Generation Charge (NGC) ($/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	$0.020355	$0.020355
Reliability Must Run Transmission Surcharge	$0.003737	$0.003737
Transmission Enhancement Charge ($/kWh)	See Rider BGS	
Basic Generation Service Charge ($/kWh)	See Rider BGS	
Regional Greenhouse Gas Initiative Recovery Charge ($/kWh)	See Rider RGGI	

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: **Effective Date:**

Issued by:

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

RATE SCHEDULE MGS-SECONDARY
(Monthly General Service)

AVAILABILITY

Available at any point within the 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	WINTER
	June Through September	October Through May
Delivery Service Charges:		
Customer Charge		
Single Phase	$8.35	$8.35
Three Phase	$9.72	$9.72
Distribution Demand Charge (per kW)	$2.07	$1.70
Reactive Demand Charge	$0.48	$0.48
(For each kvar over one-third of kW demand**)**		
Distribution Rates ($/kWh)	$0.049365	$0.044591
Non-Utility Generation Charge (NGC) ($/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)	$3.43	$3.05
Reliability Must Run Transmission Surcharge ($/kWh)	$0.003737	$0.003737
Transmission Enhancement Charge ($/kWh)	See Rider BGS	
Basic Generation Service Charge ($/kWh)	See Rider BGS	
Regional Greenhouse Gas Initiative Recovery Charge ($/kWh)	See Rider RGGI	

The minimum monthly bill will be $8.35 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 within the 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	**WINTER**
	June Through September	October Through May
Delivery Service Charges:		
Customer Charge		
Single Phase	$14.80	$14.80
Three Phase	$16.08	$16.08
Distribution Demand Charge (per kW)	$1.58	$1.23
Reactive Demand Charge	$0.44	$0.44
(For each kvar over one-third of kW demand)		
Distribution Rates ($/kWh)	$0.044522	$0.043240
Non-Utility Generation Charge (NGC) ($/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)	$2.42	$2.08
Reliability Must Run Transmission Surcharge ($/kWh)	$0.003650	$0.003650
Transmission Enhancement Charge ($/kWh)	See Rider BGS	
Basic Generation Service Charge ($/kWh)	See Rider BGS	
Regional Greenhouse Gas Initiative Recovery Charge ($/kWh)	See Rider RGGI	

The minimum monthly bill will be $14.80 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 within the 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	$161.98
Distribution Demand Charge ($/kW)	$9.44
Reactive Demand (for each kvar over one-third of kW demand)	$0.73
Non-Utility Generation Charge (NGC) ($/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)	$3.68
Reliability Must Run Transmission Surcharge ($/kWh)	$0.003737
Transmission Enhancement Charge ($/kWh)	See Rider BGS
Basic Generation Service Charge ($/kWh)	See Rider BGS
Regional Greenhouse Gas Initiative Recovery Charge ($/kWh)	See Rider RGGI

ATLANTIC CITY ELECTRIC COMPANY
BPU NJ No. 11 Electric Service - Section IV Revised Sheet Replaces Revised Sheet No. 19

RATE SCHEDULE AGS-PRIMARY
(Annual General Service)

AVAILABILITY

Available at any point within the 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	$585.08
Distribution Demand Charge ($/kW)	$7.56
Reactive Demand (for each kvar over one-third of kW demand)	$0.56
Non-Utility Generation Charge (NGC) ($/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)	$3.80
Reliability Must Run Transmission Surcharge ($/kWh)	$0.003650
Transmission Enhancement Charge ($/kWh)	See Rider BGS
Basic Generation Service Charge ($/kWh)	See Rider BGS
Regional Greenhouse Gas Initiative Recovery Charge ($/kWh)	See Rider RGGI

ATLANTIC CITY ELECTRIC COMPANY
BPU NJ No. 11 Electric Service - Section IV Revised Sheet Replaces 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 within the 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	$132.67
5,000 – 9,000 kW	$4,393.94
Greater than 9,000 kW	$7,976.15
Distribution Demand Charge ($/kW)	
Maximum billed demand within the most recent 12 billing months.	
Less than 5,000 kW	$3.81
5,000 – 9,000 kW	$2.93
Greater than 9,000 kW	$1.46
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)	$2.03
Reliability Must Run Transmission Surcharge ($/kWh)	$0.003570
Transmission Enhancement Charge ($/kWh)	See Rider BGS
Basic Generation Service Charge ($/kWh)	See Rider BGS
Regional Greenhouse Gas Initiative Recovery Charge ($/kWh)	See Rider RGGI

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. 29a

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

AVAILABILITY
Available at any point within the 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	$129.11	
5,000 – 9,000 kW	$4,275.98	
Greater than 9,000 kW	$19,450.62	
Distribution Demand Charge ($/kW)		
Maximum billed demand within the most recent 12 billing months.		
Less than 5,000 kW	$2.96	
5,000 – 9,000 kW	$2.29	
Greater than 9,000 kW	$0.15	
Reactive Demand (for each kvar over one-third of kW demand)	$0.50	
Non-Utility Generation Charge (NGC) ($/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)	$2.13	
Reliability Must Run Transmission Surcharge ($/kWh)	$0.003570	$0.003570
Transmission Enhancement Charge ($/kWh)	See Rider BGS	
Basic Generation Service Charge ($/kWh)	See Rider BGS	
Regional Greenhouse Gas Initiative Recovery Charge ($/kWh)	See Rider RGGI	

ATLANTIC CITY ELECTRIC COMPANY
BPU NJ No. 11 Electric Service – Section IV Revised Sheet Replaces Revised Sheet No. 31

RATE SCHEDULE DDC
(Direct Distribution Connection)

AVAILABILITY
Available at any point within 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)	$0.162252
Energy (per day for each kW of effective load)	$0.781508
Non-Utility Generation Charge (NGC) ($/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)	$0.007659
Reliability Must Run Transmission Surcharge ($/kWh)	$0.003737
Transmission Enhancement Charge ($/kWh)	See Rider BGS
Basic Generation Service Charge ($/kWh)	See Rider BGS
Regional Greenhouse Gas Initiative Recovery Charge ($/kWh)	See Rider RGGI

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.

ATLANTIC CITY ELECTRIC COMPANY
BPU NJ No. 11 Electric Service - Section IV Revised Sheet Replaces Revised Sheet No. 44

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 the Company's 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	$0.35	$0.11
MGS Primary	$0.25	$0.14
AGS Secondary	$0.37	$0.96
AGS Primary	$0.39	$0.77
TGS Sub Transmission	$0.22	$0.00
TGS Transmission	$0.22	$0.00

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. 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	0.000437	0.000361	0.000293	0.000242	0.000194	0.000187	-	0.000147
TrAILCo	0.000448	0.000372	0.000368	0.000257	0.000209	0.000187	-	0.000179
PSE&G	0.000582	0.000482	0.000391	0.000323	0.000259	0.000251	-	0.000197
PATH	(0.000050)	(0.000042)	(0.000034)	(0.000028)	(0.000022)	(0.000021)	-	(0.000017)
PPL	0.000213	0.000177	0.000176	0.000123	0.000100	0.000090	-	0.000085
Pepco	0.000018	0.000015	0.000015	0.000011	0.000009	0.000007	-	0.000007
PECO	0.000223	0.000186	0.000183	0.000128	0.000104	0.000094	-	0.000090
MAIT	0.000031	0.000026	0.000028	0.000017	0.000014	0.000013		0.000011
JCP&L	0.000003	0.000003	0.000002	0.000002	0.000001	0.000001	-	0.000001
Delmarva	0.000001	0.000001	0.000001	0.000001	0.000001	0.000001	-	0.000001
BG&E	0.000039	0.000033	0.000032	0.000022	0.000018	0.000016	-	0.000016
AEP - East	0.000131	0.000108	0.000087	0.000073	0.000058	0.000055	-	0.000044
Total	0.002076	0.001722	0.001542	0.001171	0.000945	0.000881	-	0.000761

Date of Issue: **Effective Date:**
Issued by:

Exhibit B

Redlined Tariff Sheets

ATLANTIC CITY ELECTRIC COMPANY
BPU NJ No. 11 Electric Service - Section IV ~~Forty-First~~ Revised Sheet Replaces Revised ~~Fortieth~~ 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)	$4.83	$4.83
Distribution Rates ($/kWH)		
First Block	$0.055619	$0.051319
(Summer <= 750 kWh; Winter<= 500kWh)		
Excess kWh	$0.063942	$0.051319
Non-Utility Generation Charge (NGC) ($/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.~~019377~~020355	$0.~~019377~~020355
Reliability Must Run Transmission Surcharge	$0.003737	$0.003737
Transmission Enhancement Charge ($/kWh)	See Rider BGS	
Basic Generation Service Charge ($/kWh)	See Rider BGS	
Regional Greenhouse Gas Initiative Recovery Charge ($/kWh)	See Rider RGGI	

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: ~~**March 29, 2018**~~ **Effective Date:** ~~**April 1, 2018**~~

~~**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 Nos. AX18010001 and ER18030241**~~
Issued by:

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

RATE SCHEDULE MGS-SECONDARY
(Monthly General Service)

AVAILABILITY

Available at any point within the 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	$8.35	$8.35
Three Phase	$9.72	$9.72
Distribution Demand Charge (per kW)	$2.07	$1.70
Reactive Demand Charge	$0.48	$0.48
(For each kvar over one-third of kW demand**)**		
Distribution Rates ($/kWh)	$0.049365	$0.044591
Non-Utility Generation Charge (NGC) ($/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.~~26~~43	$~~2.88~~3.05
Reliability Must Run Transmission Surcharge ($/kWh)	$0.003737	$0.003737
Transmission Enhancement Charge ($/kWh)	See Rider BGS	
Basic Generation Service Charge ($/kWh)	See Rider BGS	
Regional Greenhouse Gas Initiative Recovery Charge ($/kWh)	See Rider RGGI	

The minimum monthly bill will be $8.35 per month plus any applicable adjustment.

Date of Issue: ~~**March 29, 2018**~~ **Effective Date:** ~~**April 1, 2018**~~

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

RATE SCHEDULE MGS-PRIMARY
(Monthly General Service)

AVAILABILITY
Available at any point within the 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	WINTER
	June Through September	October Through May
Delivery Service Charges:		
Customer Charge		
Single Phase	$14.80	$14.80
Three Phase	$16.08	$16.08
Distribution Demand Charge (per kW)	$1.58	$1.23
Reactive Demand Charge	$0.44	$0.44
(For each kvar over one-third of kW demand)		
Distribution Rates ($/kWh)	$0.044522	$0.043240
Non-Utility Generation Charge (NGC) ($/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~~2.42	$2.~~81~~08
Reliability Must Run Transmission Surcharge ($/kWh)	$0.003650	$0.003650
Transmission Enhancement Charge ($/kWh)	See Rider BGS	
Basic Generation Service Charge ($/kWh)	See Rider BGS	
Regional Greenhouse Gas Initiative Recovery Charge ($/kWh)	See Rider RGGI	

The minimum monthly bill will be $14.80 per month plus any applicable adjustment.

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

RATE SCHEDULE AGS-SECONDARY
(Annual General Service)

AVAILABILITY
Available at any point within the 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	$161.98
Distribution Demand Charge ($/kW)	$9.44
Reactive Demand (for each kvar over one-third of kW demand)	$0.73
Non-Utility Generation Charge (NGC) ($/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)	$3.~~56~~68
Reliability Must Run Transmission Surcharge ($/kWh)	$0.003737
Transmission Enhancement Charge ($/kWh)	See Rider BGS
Basic Generation Service Charge ($/kWh)	See Rider BGS
Regional Greenhouse Gas Initiative Recovery Charge ($/kWh)	See Rider RGGI

Date of Issue: ~~**March 29, 2018**~~ **Effective Date:** ~~**April 1, 2018**~~

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ATLANTIC CITY ELECTRIC COMPANY
BPU NJ No. 11 Electric Service - Section IV ~~Forty-First~~ Revised Sheet Replaces ~~Fortieth~~ Revised Sheet No. 19

RATE SCHEDULE AGS-PRIMARY
(Annual General Service)

AVAILABILITY
Available at any point within the 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	$585.08
Distribution Demand Charge ($/kW)	$7.56
Reactive Demand (for each kvar over one-third of kW demand)	$0.56
Non-Utility Generation Charge (NGC) ($/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)	$3.~~57~~80
Reliability Must Run Transmission Surcharge ($/kWh)	$0.003650
Transmission Enhancement Charge ($/kWh)	See Rider BGS
Basic Generation Service Charge ($/kWh)	See Rider BGS
Regional Greenhouse Gas Initiative Recovery Charge ($/kWh)	See Rider RGGI

Date of Issue: ~~March 29, 2018~~ **Effective Date: ~~April 1, 2018~~**

~~**Issued by: David M. Velazquez, President and Chief Executive Officer – Atlantic City Electric Company**~~
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ATLANTIC CITY ELECTRIC COMPANY
BPU NJ No. 11 Electric Service - Section IV ~~Fortieth~~ Revised Sheet Replaces ~~Thirty-Ninth~~ 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 within the 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	$132.67
5,000 – 9,000 kW	$4,393.94
Greater than 9,000 kW	$7,976.15

Distribution Demand Charge ($/kW)

Maximum billed demand within the most recent 12 billing months.	
Less than 5,000 kW	$3.81
5,000 – 9,000 kW	$2.93
Greater than 9,000 kW	$1.46

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)	$~~1.67~~2.03
Reliability Must Run Transmission Surcharge ($/kWh)	$0.003570
Transmission Enhancement Charge ($/kWh)	See Rider BGS
Basic Generation Service Charge ($/kWh)	See Rider BGS
Regional Greenhouse Gas Initiative Recovery Charge ($/kWh)	See Rider RGGI

ATLANTIC CITY ELECTRIC COMPANY
BPU NJ No. 11 Electric Service - Section IV ~~Ninth~~ Revised Sheet Replaces ~~Eighth~~ Revised Sheet No. 29a

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

AVAILABILITY
Available at any point within the 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	$129.11	
5,000 – 9,000 kW	$4,275.98	
Greater than 9,000 kW	$19,450.62	
Distribution Demand Charge ($/kW)		
Maximum billed demand within the most recent 12 billing months.		
Less than 5,000 kW	$2.96	
5,000 – 9,000 kW	$2.29	
Greater than 9,000 kW	$0.15	
Reactive Demand (for each kvar over one-third of kW demand)	$0.50	
Non-Utility Generation Charge (NGC) ($/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)	$~~1.84~~2.13	
Reliability Must Run Transmission Surcharge ($/kWh)	$0.003570	$0.003570
Transmission Enhancement Charge ($/kWh)	See Rider BGS	
Basic Generation Service Charge ($/kWh)	See Rider BGS	
Regional Greenhouse Gas Initiative Recovery Charge ($/kWh)	See Rider RGGI	

Date of Issue: ~~**March 29, 2018**~~ **Effective Date:** ~~**April 1, 2018**~~

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

RATE SCHEDULE DDC
(Direct Distribution Connection)

AVAILABILITY
Available at any point within 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)	$0.162252
Energy (per day for each kW of effective load)	$0.781508
Non-Utility Generation Charge (NGC) ($/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)	$0.~~006465~~007659
Reliability Must Run Transmission Surcharge ($/kWh)	$0.003737
Transmission Enhancement Charge ($/kWh)	See Rider BGS
Basic Generation Service Charge ($/kWh)	See Rider BGS
Regional Greenhouse Gas Initiative Recovery Charge ($/kWh)	See Rider RGGI

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.

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ATLANTIC CITY ELECTRIC COMPANY
BPU NJ No. 11 Electric Service - Section IV ~~Twenty-First~~ Revised Sheet Replaces ~~Twentieth~~ Revised Sheet No. 44

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 the Company’s 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~~35	$0.11
MGS Primary	$0.~~32~~25	$0.14
AGS Secondary	$0.~~36~~37	$0.96
AGS Primary	$0.~~36~~39	$0.77
TGS Sub Transmission	$0.~~19~~22	$0.00
TGS Transmission	$0.~~19~~22	$0.00

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BPU NJ No. 11 Electric Service - Section IV ~~Thirty-Sixth~~ Revised Sheet Replaces ~~Thirty-Fifth~~ 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	0.000437	0.000361	0.000293	0.000242	0.000194	0.000187	-	0.000147
TrAILCo	0.~~000587~~ 000448	~~0.000491~~ 0.000372	0.~~000530~~ 000368	~~0.000324~~ 0.000257	0.~~000260~~ 000209	0.~~000249~~ 000187	-	0.~~000206~~ 000179
PSE&G	0.000582	0.000482	0.000391	0.000323	0.000259	0.000251	-	0.000197
PATH	(0.000050)	(0.000042)	(0.000034)	(0.000028)	(0.000022)	(0.000021)	-	(0.000017)
PPL	0.~~000237~~000213	0.~~000199~~000177	0.~~000214~~000176	0.~~000131~~000123	0.~~000105~~000100	0.~~000102~~000090	-	0.~~000083~~000085
Pepco	0.~~000021~~000018	0.~~000018~~000015	0.~~000019~~000015	0.~~000012~~000011	0.~~000010~~000009	0.~~000010~~000007	-	0.000007
PECO	0.~~000194~~000223	~~0.000160~~ 0.000186	0.~~000130~~000183	~~0.000108~~ 0.000128	0.~~000086~~000104	0.~~000083~~000094	-	0.~~000066~~000090
MAIT	0.000031	0.000026	0.000028	0.000017	0.000014	0.000013		0.000011
JCP&L	0.000003	0.000003	0.000002	0.000002	0.000001	0.000001	-	0.000001
Delmarva	0.000001	0.000001	0.000001	0.000001	0.000001	0.000001	-	0.000001
BG&E	0.~~000073~~000039	0.~~000061~~000033	0.~~000066~~000032	0.~~000041~~000022	0.~~000032~~000018	0.~~000031~~000016	-	0.~~000026~~000016
AEP - East	0.000131	0.000108	0.000087	0.000073	0.000058	0.000055	-	0.000044
Total	0.~~002247~~002076	0.~~001867~~001722	0.~~001727~~001542	0.~~001246~~001171	0.~~000998~~000945	0.~~000962~~000881	-	0.~~000772~~000761

Date of Issue: ~~May 29, 2018~~ **Effective Date: ~~June 1, 2018~~**
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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, 2018
To reflect FERC-approved ACE Project Transmission Enhancement Charge (Schedule 12 PJM OATT) effective June 1, 2018

Transmission Enhancement Costs Allocated to ACE Zone (2018)	$	22,082
	$	22,082
2018 ACE Zone Transmission Peak Load (MW)		2,541
Transmission Enhancement Rate ($/MW-Month)	$	8.69

Rate Class	Col. 1 Transmission Obligation (MW)		Col. 2 Allocated Cost Recovery	Col. 3 BGS Eligible Sales June 2018 - May 2019 (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 1.06625 Transmission Enhancement Charge w/ SUT ($/kWh)
RS	1,439	$	150,118	4,059,095,046	$	0.000037	$	0.000037	$	0.000039
MGS Secondary	357	$	37,188	1,208,290,228	$	0.000031	$	0.000031	$	0.000033
MGS Primary	9	$	917	30,079,842	$	0.000030	$	0.000030	$	0.000032
AGS Secondary	382	$	39,797	1,873,810,489	$	0.000021	$	0.000021	$	0.000022
AGS Primary	96	$	9,993	576,381,592	$	0.000017	$	0.000017	$	0.000018
TGS	132	$	13,757	888,340,177	$	0.000015	$	0.000015	$	0.000016
SPL/CSL	0	$	-	69,443,692	$	-	$	-	$	-
DDC	2	$	194	13,058,581	$	0.000015	$	0.000015	$	0.000016
	2,416	$	251,963	8,718,499,648						

Attachment 2B PJM Schedule 12 - Transmission Enhancement Charges for June 2018 - May 2019
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 *per PJM website*	**PJM Upgrade ID** *per PJM spreadsheet*	**June 2018 - May 2019 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**
Install a second Conastone – Graceton 230 kV circuit	b0497	$ 2,934,126	9.03%	9.67%	14.11%	0.52%	$264,952	$283,730	$414,005	$15,257	$977,944
install new 500 kV transmission from Possum Point to Calvert Cliffs	b0512	$ 1,687	1.66%	3.74%	6.26%	0.26%	$28	$63	$106	$4	$201
		$ -					$0	$0	$0	$0	$0
Totals							**$264,980**	**$283,793**	**$414,111**	**$15,262**	**$978,145**
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 18/19**	**2018TX Peak Load** *per PJM website*	**Rate in $/MW-mo.**	**2018 Impact (7 months)**	**2019 Impact (5 months)**	**2018-2019 Impact (12 months)**
PSE&G	$ 34,509.23	9,566.9	$ 3.61	$ 241,565	$ 172,546	$ 414,111
JCP&L	$ 23,649.42	5,721.0	$ 4.13	$ 165,546	$ 118,247	$ 283,793
ACE	$ 22,081.63	2,540.8	$ 8.69	$ 154,571	$ 110,408	$ 264,980
RE	$ 1,271.82	401.7	$ 3.17	$ 8,903	$ 6,359	$ 15,262
Total Impact on NJ Zones	**$ 81,512.11**			**$ 570,585**	**$ 407,561**	**$ 978,145**
Notes on calculations >>>			= (k) * (l)	= (k) * 7	= (k) * 5	= (n) * (o)

Notes:
1) 2018 allocation share percentages are from PJM OATT

Atlantic City Electric Company
Proposed TrAIL CO Projects Transmission Enhancement Charge (TrAIL Co Project-TEC Surcharge) effective June 1, 2018
To reflect FERC-approved ACE Project Transmission Enhancement Charge (Schedule 12 PJM OATT) effective June 1, 2018

Transmission Enhancement Costs Allocated to ACE Zone (2018)	$	250,122
	$	250,122
2018 ACE Zone Transmission Peak Load (MW)		2,541
Transmission Enhancement Rate ($/MW)	$	98.44

Rate Class	Col. 1 Transmission Obligation (MW)		Col. 2 Allocated Cost Recovery	Col. 3 BGS Eligible Sales June 2018 - May 2019 (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 1.06625 Transmission Enhancement Charge w/ SUT ($/kWh)
RS	1,439	$	1,700,404	4,059,095,046	$	0.000419	$	0.000420	$	0.000448
MGS Secondary	357	$	421,232	1,208,290,228	$	0.000349	$	0.000349	$	0.000372
MGS Primary	9	$	10,382	30,079,842	$	0.000345	$	0.000345	$	0.000368
AGS Secondary	382	$	450,789	1,873,810,489	$	0.000241	$	0.000241	$	0.000257
AGS Primary	96	$	113,187	576,381,592	$	0.000196	$	0.000196	$	0.000209
TGS	132	$	155,826	888,340,177	$	0.000175	$	0.000175	$	0.000187
SPL/CSL	0	$	-	69,443,692	$	-	$	-	$	-
DDC	2	$	2,195	13,058,581	$	0.000168	$	0.000168	$	0.000179
	2,416	$	2,854,016	8,718,499,648						

Attachment 2A PJM Schedule 12 - Transmission Enhancement Charges for June 2018 - May 2019
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 *per PJM website*	**PJM Upgrade ID** *per PJM spreadsheet*	**June 2018-May 2019 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**
502 Junction-Mt Storm-Meadowbrook (>=500kV) - CWIP[1]	b0328.1; b0328.2; b0347.1; b0347.2; b0347.3; b0347.4	$ 116,390,367.10	1.66%	3.74%	6.26%	0.26%	$1,932,080	$4,353,000	$7,286,037	$302,615	$13,873,732
Wylie Ridge [2]	b0218	$ 2,327,769.14	11.83%	15.56%	0.00%	0.00%	$275,375	$362,201	$0	$0	$637,576
Black Oak	b0216	$ 4,809,312.08	1.66%	3.74%	6.26%	0.26%	$79,835	$179,868	$301,063	$12,504	$573,270
Meadowbrook 200 MVAR capacitor	b0559	$ 653,969.56	1.66%	3.74%	6.26%	0.26%	$10,856	$24,458	$40,938	$1,700	$77,953
Replace Kammer 765/500 kV TXfmr	b0495	$ 3,959,496.93	1.66%	3.74%	6.26%	0.26%	$65,728	$148,085	$247,865	$10,295	$471,972
Doubs TXfmr 2	b0343	$ 521,436.22	1.85%	0.00%	0.00%	0.00%	$9,647	$0	$0	$0	$9,647
Doubs TXfmr 3	b0344	$ 477,541.75	1.86%	0.00%	0.00%	0.00%	$8,882	$0	$0	$0	$8,882
Doubs TXfmr 4	b0345	$ 591,741.74	1.85%	0.00%	0.00%	0.00%	$10,947	$0	$0	$0	$10,947
New Osage 138KV Ckt	b0674	$ 2,021,189.84	0.00%	0.00%	0.25%	0.01%	$0	$0	$5,053	$202	$5,255
Cap at Grover 230	b0556	$ 93,468.58	8.64%	18.30%	26.32%	0.98%	$8,076	$17,105	$24,601	$916	$50,697
Upgrade transformer 500/230	b1153	$ 3,063,019.33	3.86%	12.95%	21.15%	0.74%	$118,233	$396,661	$647,829	$22,666	$1,185,388
Build a 300 MVAR Switched Shunt at Doubs 500kV	b1803	$ 547,995.64	1.66%	3.74%	6.26%	0.26%	$9,097	$20,495	$34,305	$1,425	$65,321
Install 500 MVAR svc at Hunterstown 500kV Sub	b1800	$ 4,824,064.07	1.66%	3.74%	6.26%	0.26%	$80,079	$180,420	$301,986	$12,543	$575,028
Install a new 600 MVAR SVC at Meadowbrook 500 kV	b1804	$ 6,713,546.77	1.66%	3.74%	6.26%	0.26%	$111,445	$251,087	$420,268	$17,455	$800,255
Build 250 MVAR svc at Altoona 230kV	b1801	$ 3,979,083.16	6.48%	8.15%	8.19%	0.33%	$257,845	$324,295	$325,887	$13,131	$921,158
Convert Moshannon sub to 4 breaker 230 kv ring bus	b1964	$ 856,936.63	0.00%	5.48%	0.00%	0.00%	$0	$46,960	$0	$0	$46,960
Build a 100 MVAR Fast Switched Shunt and 200 MVAR Switched Shunt at Mansfield 345 kV	b1802	$ 155,919.37	6.48%	8.15%	8.19%	0.33%	$10,104	$12,707	$12,770	$515	$36,095
Install 100 MVAR capacitor at Johnstown 230 kV substation	b0555	$ 153,191.13	8.64%	18.30%	26.32%	0.98%	$13,236	$28,034	$40,320	$1,501	$83,091
Install 300 MVAR capacitor at Conemaugh 500 kV substation	b0376	$ -	1.66%	3.74%	6.26%	0.26%	$0	$0	$0	$0	$0
							$3,001,463	**$6,345,377**	**$9,688,921**	**$397,468**	**$19,433,228**
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 18/19**	**2018TX Peak Load** *per PJM website*	**Rate in $/MW-mo.**	**2018 Impact (7 months)**	**2019 Impact (5 months)**	**2018-2019 Impact (12 months)**
PSE&G	$ 807,410.08	9,566.9	$ 84.40	$ 5,651,871	$ 4,037,050	$ 9,688,921
JCP&L	$ 528,781.40	5,721.0	$ 92.43	$ 3,701,470	$ 2,643,907	$ 6,345,377
ACE	$ 250,121.88	2,540.8	$ 98.44	$ 1,750,853	$ 1,250,609	$ 3,001,463
RE	$ 33,122.33	401.7	$ 82.46	$ 231,856	$ 165,612	$ 397,468
Total Impact on NJ Zones	**$ 1,619,435.69**			**$ 11,336,050**	**$ 8,097,178**	**$ 19,433,228**
Notes on calculations >>>			= (k) * (l)	= (k) * 7	= (k) * 5	= (n) * (o)

Notes:
1) 2018 allocation share percentages are from PJM OATT

Atlantic City Electric Company
Proposed PECO Projects Transmission Enhancement Charge (PECO-TEC Surcharge) effective June 1, 2018
To reflect FERC-approved ACE Project Transmission Enhancement Charge (Schedule 12 PJM OATT) effective June 1, 2018

Transmission Enhancement Costs Allocated to ACE Zone (2018)	$	124,958
	$	124,958
2018 ACE Zone Transmission Peak Load (MW)		2,541
Transmission Enhancement Rate ($/MW)	$	49.18

Rate Class	Col. 1 Transmission Obligation (MW)		Col. 2 Allocated Cost Recovery	Col. 3 BGS Eligible Sales Jun 2018 - May 2019 (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 1.06625 Transmission Enhancement Charge w/ SUT ($/kWh)
RS	1,439	$	849,500	4,059,095,046	$	0.000209	$	0.000209	$	0.000223
MGS Secondary	357	$	210,442	1,208,290,228	$	0.000174	$	0.000174	$	0.000186
MGS Primary	9	$	5,187	30,079,842	$	0.000172	$	0.000172	$	0.000183
AGS Secondary	382	$	225,208	1,873,810,489	$	0.000120	$	0.000120	$	0.000128
AGS Primary	96	$	56,547	576,381,592	$	0.000098	$	0.000098	$	0.000104
TGS	132	$	77,849	888,340,177	$	0.000088	$	0.000088	$	0.000094
SPL/CSL	-	$	-	69,443,692	$	-	$	-	$	-
DDC	2	$	1,096	13,058,581	$	0.000084	$	0.000084	$	0.000090
	2,416	$	1,425,829	8,718,499,648						

Attachment 2G - Transmission Enhancement Charges for June 2018 - May 2019
Calculation of costs and monthly PJM charges for PECO Energy Company Transmission Projects

Required Transmission Enhancement *per PJM website*	PJM Upgrade ID *per PJM spreadsheet*	(a) 2018/2019 Annual Revenue Requirement *per PJM website*	(b) ACE Zone Share[1]	(c) JCP&L Zone Share[1]	(d) PSE&G Zone Share[1]	(e) RE Zone Share[1]	(f) ACE Zone Charges	(g) JCP&L Zone Charges	(h) PSE&G Zone Charges	(i) RE Zone Charges	(j) Total NJ Zones Charges
			Responsible Customers - Schedule 12 Appendix *per PJM Open Access Transmission Tariff*				Estimated New Jersey EDC Zone Charges by Project				
Install a new 500 kV Center Point substation in PECO by tapping the Elroy – Whitpain 500 kV circuit.	b0269	$ 3,834,453.99	1.66%	3.74%	6.26%	0.26%	$63,652	$143,409	$240,037	$9,970	$457,067
Add a new 230 kV circuit between Whitpain and Heaton substations	b0269.1	$ 4,852,276.34	8.25%	0.00%	0.00%	0.00%	$400,313	$0	$0	$0	$400,313
Add a new 500kV brkr. at Whitpain bet. #3 transfmr. and 5029 line	b0269.6	$ 539,744.43	1.66%	3.74%	6.26%	0.26%	$8,960	$20,186	$33,788	$1,403	$64,338
Replace 2-500 kV circt brkrs and 2 wave traps at Elroy subs to increase rating of Elroy - Hosensack 500kV	b0171.1	$ 726,651.74	1.66%	3.74%	6.26%	0.26%	$12,062	$27,177	$45,488	$1,889	$86,617
Increase the rating of lines 220-39 and 220-43 (Linwood-Chicester 230kV lines) and install reactors.	b1900	$ 3,515,277.26	0.00%	6.07%	21.01%	0.84%	$0	$213,377	$738,560	$29,528	$981,465
Rebuild Bryn Mawr-Plymouth Meeting 138 kV line (130-35 Line)	b0727	$ 3,379,204.64	1.25%	0.00%	0.00%	0.00%	$42,240	$0	$0	$0	$42,240
Recndr Chichester - Saville 138 kV line and upgrade term equip	b1182	$ 3,137,518.20	0.00%	5.12%	14.31%	0.57%	$0	$160,641	$448,979	$17,884	$627,504
Add a second 230/138 kV trans at Chichester. Add an inductor in series with the parallel tranfmrs	b1178	$ 1,425,743.54	0.00%	4.17%	12.18%	0.48%	$0	$59,454	$173,656	$6,844	$239,953
Increase Bradford - Planebrook 230 kV Ckt.220-31 line rating. Replace terminal equipment	b0790	$ 302,838.57	0.00%	17.46%	34.00%	1.32%	$0	$52,876	$102,965	$3,997	$159,838
Reconductor the North Wales - Hartman 230 kV circuit	b0506	$ 378,009.12	8.58%	0.00%	0.00%	0.00%	$32,433	$0	$0	$0	$32,433
Reconductor the North Wales - Whitpain 230 kV circuit	b0505	$ 422,393.72	8.58%	0.00%	0.00%	0.00%	$36,241	$0	$0	$0	$36,241
Increase Bradford - Planebrook 230 kV Ckt.220-02 line rating. Replace terminal equipment	b0789	$ 414,363.33	0.73%	17.52%	33.83%	1.32%	$3,025	$72,596	$140,179	$5,470	$221,270
Install 161MVAR capacitor at Planebrook 230kV substation	b0206	$ 560,607.56	14.20%	0.00%	3.47%	0.00%	$79,606	$0	$19,453	$0	$99,059
Install 161MVAR capacitor at Newlinville 230kV substation	b0207	$ 756,164.56	14.20%	0.00%	3.47%	0.00%	$107,375	$0	$26,239	$0	$133,614
Install 2% series reactor at Chichester substation on the Chichester - Mickleton 230kV circuit	b0209	$ 428,681.01	65.23%	25.87%	6.35%	0.00%	$279,629	$110,900	$27,221	$0	$417,750
Upgrade Chichester - Delco Tap 230kV and the PECO portion of the Delco Tap - Mickleton 230kV cicuit	b0264	$ 358,865.79	89.87%	9.48%	0.00%	0.00%	$322,513	$34,020	$0	$0	$356,533
Reconductor Buckingham - Pleasant Valley 230kV; same impedance as existing line; ratings of 760MVA normal/882MVA emergency	b0357	$ 366,372.73	0.00%	37.89%	55.19%	2.37%	$0	$138,819	$202,201	$8,683	$349,703
Reconductor Richmond-Waneeta kv and replace terminal equipment at Waneeta Substation	b1398.8	$ 280,237.30	0.00%	13.03%	31.99%	1.27%	$0	$36,515	$89,648	$3,559	$129,722
Install 600 MVAR cap banks at Elroy 500kv Substation	b0287	$ 912,611.66	1.66%	3.74%	6.26%	0.26%	$15,149	$34,132	$57,129	$2,373	$108,783
Install 161 MVAR capcitor at Heaton 230kV Substation	b0208	$ 678,119.35	14.20%	0.00%	3.47%	0.00%	$96,293	$0	$23,531	$0	$119,824
							$1,499,492	**$1,104,101**	**$2,369,074**	**$91,600**	**$5,064,267**
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 18/19	(l) 2018TX Peak Load *per PJM website*	(m) Rate in $/MW-mo.	(n) 2018 Impact (7 months)	(o) 2019 Impact (5 months)	(n) 2018 Impact (12 months)
PSE&G	$ 197,422.84	9,566.9	$ 20.64	$ 1,381,960	$ 987,114	$ 2,369,074
JCP&L	$ 92,008.43	5,721.0	$ 16.08	$ 644,059	$ 460,042	$ 1,104,101
ACE	$ 124,957.64	2,540.8	$ 49.18	$ 874,703	$ 624,788	$ 1,499,492
RE	$ 7,633.32	401.7	$ 19.00	$ 53,433	$ 38,167	$ 91,600
Total Impact on NJ Zones	**$ 422,022.23**			**$ 2,954,156**	**$ 2,110,111**	**$ 5,064,267**
Notes on calculations >>>			= (k) * (l)	= (k) * 7	= (k) * 5	= (k) *12

Notes:
1) 2018 allocation share percentages are from PJM OATT

Atlantic City Electric Company
Proposed PEPCO Projects Transmission Enhancement Charge (PEPCO Project-TEC Surcharge) effective June 1, 2018
To reflect FERC-approved ACE Project Transmission Enhancement Charge (Schedule 12 PJM OATT) effective June 1, 2018

Transmission Enhancement Costs Allocated to ACE Zone (2018)	$	10,337
	$	10,337
2018 ACE Zone Transmission Peak Load (MW)		2,541
Transmission Enhancement Rate ($/MW-Month)	$	4.07

Rate Class	Col. 1 Transmission Obligation (MW)		Col. 2 Allocated Cost Recovery	Col. 3 BGS Eligible Sales June 2018 - May 2019 (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 1.06625 Transmission Enhancement Charge w/ SUT ($/kWh)
RS	1,439	$	70,277	4,059,095,046	$	0.000017	$	0.000017	$	0.000018
MGS Secondary	357	$	17,409	1,208,290,228	$	0.000014	$	0.000014	$	0.000015
MGS Primary	9	$	429	30,079,842	$	0.000014	$	0.000014	$	0.000015
AGS Secondary	382	$	18,631	1,873,810,489	$	0.000010	$	0.000010	$	0.000011
AGS Primary	96	$	4,678	576,381,592	$	0.000008	$	0.000008	$	0.000009
TGS	132	$	6,440	888,340,177	$	0.000007	$	0.000007	$	0.000007
SPL/CSL	0	$	-	69,443,692	$	-	$	-	$	-
DDC	2	$	91	13,058,581	$	0.000007	$	0.000007	$	0.000007
	2,416	$	117,955	8,718,499,648						

Attachment 2F PJM Schedule 12 - Transmission Enhancement Charges for June 2018 to May 2019
Calculation of costs and monthly PJM charges for PEPCO 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 2018-May 2019 Annual Revenue Requirement** *per PJM website*	**ACE Zone Share[1]**	**JCP&L Zone Share[1]**	**PSE&G Zone Share[1]** *per PJM Open Access Transmission Tariff*	**RE Zone Share[1]**	**ACE Zone Charges**	**JCP&L Zone Charges**	**PSE&G Zone Charges**	**RE Zone Charges**	**Total NJ Zones Charges**
Reconductor 23035 for Dickerson-Quince	b0367.1-2	$ 2,686,508	1.78%	2.67%	3.82%	0.00%	$47,820	$71,730	$102,625	$0	$222,174
Replace 230 1A breaker	b0512.7	$ 256,343	1.66%	3.74%	6.26%	0.26%	$4,255	$9,587	$16,047	$666	$30,556
Replace 230 1B breaker	b0512.8	$ 256,343	1.66%	3.74%	6.26%	0.26%	$4,255	$9,587	$16,047	$666	$30,556
Replace 230 2A breaker	b0512.9	$ 256,343	1.66%	3.74%	6.26%	0.26%	$4,255	$9,587	$16,047	$666	$30,556
Replace 230 3A breaker	b0512.12	$ 258,743	1.66%	3.74%	6.26%	0.26%	$4,295	$9,677	$16,197	$673	$30,842
Ritchie-Benning 230 lines	b0526	$ 7,684,181	0.77%	1.39%	2.10%	0.08%	$59,168	$106,810	$161,368	$6,147	$333,493
Totals							**$124,049**	**$216,979**	**$328,331**	**$8,820**	**$678,178**
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 18/19**	**2018TX Peak Load** *per PJM website*	**Rate in $/MW-mo.**	**2018 Impact (7 months)**	**2019 Impact (5 months)**	**2018-2019 Impact (12 months)**
PSE&G	$ 27,360.91	9,566.9	$ 2.86	$ 191,526	$ 136,805	$ 328,331
JCP&L	$ 18,081.55	5,721.0	$ 3.16	$ 126,571	$ 90,408	$ 216,979
ACE	$ 10,337.42	2,540.8	$ 4.07	$ 72,362	$ 51,687	$ 124,049
RE	$ 734.96	401.7	$ 1.83	$ 5,145	$ 3,675	$ 8,820
Total Impact on NJ Zones	**$ 56,514.84**			**$ 395,604**	**$ 282,574**	**$ 678,178**
Notes on calculations >>>			= (k) * (l)	= (k) * 7	= (k) * 5	= (n) * (o)

Notes:
1) 2018 allocation share percentages are from PJM OATT

Atlantic City Electric Company
Proposed DPL Projects Transmission Enhancement Charge (DPL Project-TEC Surcharge) effective June 1, 2018
To reflect FERC-approved ACE Project Transmission Enhancement Charge (Schedule 12 PJM OATT) effective June 1, 2018

Transmission Enhancement Costs Allocated to ACE Zone (2018)	$	814
	$	814
2018 ACE Zone Transmission Peak Load (MW)		2,541
Transmission Enhancement Rate ($/MW-Month)	$	0.32

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 1.06625 Transmission Enhancement Charge w/ SUT ($/kWh)
RS	1,439	$	5,536	4,059,095,046	$	0.000001	$	0.000001	$	0.000001
MGS Secondary	357	$	1,371	1,208,290,228	$	0.000001	$	0.000001	$	0.000001
MGS Primary	9	$	34	30,079,842	$	0.000001	$	0.000001	$	0.000001
AGS Secondary	382	$	1,468	1,873,810,489	$	0.000001	$	0.000001	$	0.000001
AGS Primary	96	$	368	576,381,592	$	0.000001	$	0.000001	$	0.000001
TGS	132	$	507	888,340,177	$	0.000001	$	0.000001	$	0.000001
SPL/CSL	0	$	-	69,443,692	$	-	$	-	$	-
DDC	2	$	7	13,058,581	$	0.000001	$	0.000001	$	0.000001
	2,416	$	9,291	8,718,499,648						

Attachment 2E PJM Schedule 12 - Transmission Enhancement Charges for June 2018 - May 2019
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 2018-May 2019 Annual Revenue Requirement** *per PJM website*	**ACE Zone Share**[1]	**JCP&L Zone Share**[1]	**PSE&G Zone Share**[1] *per PJM Open Access Transmission Tariff*	**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	$ 24,299	1.66%	3.74%	6.26%	0.26%	$403	$909	$1,521	$63	$2,896
Add two breakers- Keeney	b0751	$ 564,319	1.66%	3.74%	6.26%	0.26%	$9,368	$21,106	$35,326	$1,467	$67,267
Totals							**$9,771**	**$22,014**	**$36,847**	**$1,530**	**$70,163**
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 18/19**	**2018TX Peak Load** *per PJM website*	**Rate in $/MW-mo.**	**2018 Impact (7 months)**	**2019 Impact (5 months)**	**2018-2019 Impact (12 months)**
PSE&G	$ 3,070.62	9,566.9	$ 0.32	$ 21,494	$ 15,353	$ 36,847
JCP&L	$ 1,834.53	5,721.0	$ 0.32	$ 12,842	$ 9,173	$ 22,014
ACE	$ 814.25	2,540.8	$ 0.32	$ 5,700	$ 4,071	$ 9,771
RE	$ 127.53	401.7	$ 0.32	$ 893	$ 638	$ 1,530
Total Impact on NJ Zones	**$ 5,846.94**			**$ 40,929**	**$ 29,235**	**$ 70,163**
Notes on calculations >>>			= (k) * (l)	= (k) * 7	= (k) * 5	= (n) * (o)

Notes:
1) 2018 allocation share percentages are from PJM OATT

Atlantic City Electric Company
Proposed PPL Projects Transmission Enhancement Charge (PPL Project-TEC Surcharge) effective June 1, 2018
To reflect FERC-approved ACE Project Transmission Enhancement Charge (Schedule 12 PJM OATT) effective June 1, 2018

Transmission Enhancement Costs Allocated to ACE Zone (2018)	$	119,289
	$	119,289
2018 ACE Zone Transmission Peak Load (MW)		2,541
Transmission Enhancement Rate ($/MW-Month)	$	46.95

Rate Class	Col. 1 Transmission Obligation (MW)		Col. 2 Allocated Cost Recovery	Col. 3 BGS Eligible Sales June 2018 - May 2019 (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 1.06625 Transmission Enhancement Charge w/ SUT ($/kWh)
RS	1,439	$	810,965	4,059,095,046	$	0.000200	$	0.000200	$	0.000213
MGS Secondary	357	$	200,896	1,208,290,228	$	0.000166	$	0.000166	$	0.000177
MGS Primary	9	$	4,952	30,079,842	$	0.000165	$	0.000165	$	0.000176
AGS Secondary	382	$	214,993	1,873,810,489	$	0.000115	$	0.000115	$	0.000123
AGS Primary	96	$	53,982	576,381,592	$	0.000094	$	0.000094	$	0.000100
TGS	132	$	74,317	888,340,177	$	0.000084	$	0.000084	$	0.000090
SPL/CSL	-	$	-	69,443,692	$	-	$	-	$	-
DDC	2	$	1,047	13,058,581	$	0.000080	$	0.000080	$	0.000085
	2,416	$	1,361,152	8,718,499,648						

Attachment 2C PJM Schedule 12 - Transmission Enhancement Charges for June 2018 - May 2019
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 2018- May 2019 Annual Revenue Requirement** *per PJM website*		**ACE Zone Share[1]**	**JCP&L Zone Share[1]**	**PSE&G Zone Share[1]** *per PJM Open Access Transmission Tariff*	**RE Zone Share[1]**	**ACE Zone Charges**	**JCP&L Zone Charges**	**PSE&G Zone Charges**	**RE Zone Charges**	**Total NJ Zones Charges**
New 500 KV Susquehana-Roseland Line	b0487	$	73,470,886.00	1.66%	3.74%	6.26%	0.26%	$1,219,617	$2,747,811	$4,599,277	$191,024	$8,757,730
Replace wave trap at Alburtus 500 kV Sub	b0171.2	$	8,381.00	1.66%	3.74%	6.26%	0.26%	$139	$313	$525	$22	$999
Replace wavetrap at Hosensack 500KV Sub	b0172.1	$	6,010.00	1.66%	3.74%	6.26%	0.26%	$100	$225	$376	$16	$716
Replace wavetraps at Juniata 500KV Sub	b0284.2	$	12,153.00	1.66%	3.74%	6.26%	0.26%	$202	$455	$761	$32	$1,449
New S-R additions < 500kV[2]	b0487.1	$	1,756,533.00	0.00%	0.00%	5.14%	0.19%	$0	$0	$90,286	$3,337	$93,623
New substation and transformers Middletown	b0468	$	2,408,736.00	0.00%	4.56%	5.94%	0.22%	$0	$109,838	$143,079	$5,299	$258,216
Install Lauschtown 500/230 kV Sub below 500kv portion	b2006	$	2,618,100.00	1.11%	9.68%	11.43%	0.45%	$29,061	$253,432	$299,249	$11,781	$593,523
Install Lauschtown 500/230 kV Sub 500kv portion tie line	b2006.1	$	8,698,675.00	1.66%	3.74%	6.26%	0.26%	$144,398	$325,330	$544,537	$22,617	$1,036,882
200 MVAR shunt reactor at Alburtis 500kv	b2237	$	2,286,532.50	1.66%	3.74%	6.26%	0.26%	$37,956	$85,516	$143,137	$5,945	$272,555
Totals								**$1,431,473**	**$3,522,921**	**$5,821,227**	**$240,073**	**$11,015,693**
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 18/19**		**2018 Peak Load** *per PJM website*		**Rate in $/MW-mo.**		**2018 Impact (7 months)**		**2019 Impact (5 months)**		**2018-2019 Impact (12 months)**
PSE&G	$	485,102.22	9,566.9	$	50.71	$	3,395,716	$	2,425,511	$	5,821,227
JCP&L	$	293,576.76	5,721.0	$	51.32	$	2,055,037	$	1,467,884	$	3,522,921
ACE	$	119,289.39	2,540.8	$	46.95	$	835,026	$	596,447	$	1,431,473
RE	$	20,006.08	401.7	$	49.80	$	140,043	$	100,030	$	240,073
Total Impact on NJ Zones	**$**	**917,974.45**				**$**	**6,425,821**	**$**	**4,589,872**	**$**	**11,015,693**
Notes on calculations >>>					= (k) * (l)		= (k) * 7		= (k) * 5		= (n) * (o)

Notes:
1) 2018 allocation share percentages are from PJM OATT

Exhibit D

ATLANTIC CITY ELECTRIC COMPANY
Proposed Transmission Rate Design
Formula Rate Effective June 1, 2018

Line			
1	Transmission Service Annual Revenue Requirement	$	136,632,319
2	Less Total Schedule 12 TEC Included in Line (1)	$	(10,761,631)
3	ACE Customer Share of Schedule 12 TEC included in Line 2	$	4,832,360
4	Total Transmission Costs Borne by ACE Customers	$	130,703,048
5	2018 ACE Newtwork Service Peak		2,541
6	2018 Network Integration Transmission Service Rate (per MW Per Year)	**$**	**51,441.69**

PJM Schedule 12 - Transmission Enhancement Charges for June 2018 - May 2019
Calculation of costs and monthly PJM charges for ACE Projects

	Required Transmission Enhancement *per PJM website*	**PJM Upgrade ID** *per PJM spreadsheet*	**June 2018 - May 2019 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	$ 501,690	89.87%	$ 450,869
8	Replace Monroe 230/69 kV TXfmrs	b0276	$ 772,567	91.46%	$ 706,590
9	Reconductor Union - Corson 138 kV	b0211	$ 1,317,619	65.23%	$ 859,483
10	New 500/230 Kv Sub on Salem-East Windsor (>500 kV portion)	b0210.A	$ 2,621,699	1.66%	$ 43,520
11	New 500/230kV Sub on Salem-East Windsor (< 500kV) portion[2]	b0210.B	$ 1,869,368	65.23%	$ 1,219,389
12	Reconductor the existing Mickleton - Goucestr 230 kV circuit (AE portion)	b1398.5	$ 469,607	0.00%	$ -
13	Build second 230kV parallel from Mickelton to Gloucester	b1398.3.1	$ 1,468,794	0.00%	$ -
14	Upgrade to Mill T2 138/69 kV transformer	b1600	$ 1,740,287	89.21%	$ 1,552,510
	Total		**$10,761,631**		**$4,832,360**

Exhibit E

Atlantic City Electric Company
Proposed Transmission Rate Design
Formula Rate Effective June 1, 2018
Change in FERC Formual Based Rate

	2017 Booked Total Revenue ($)	Annualized Transmission Revenue based on Current Billing Determinants ($)	Transmission Peak Load Share (kW)	Transmission Revenue based on Peak Load Share ($)	Increase/(Decrease) ($)	Increase/(Decrease) (%)
Residential						
Residential	$ 619,204,272	$ 70,664,018	1,439,427	$ 74,228,572	$ 3,564,554	0.58%
Commercial and Industrial						
MGS Secondary	$ 155,662,730	$ 17,411,087	356,582	$ 18,388,260	$ 977,173	0.63%
MGS Primary	$ 5,722,594	$ 604,431	8,789	$ 453,232	$ (151,199)	-2.64%
AGS Secondary	$ 120,841,461	$ 19,062,086	381,603	$ 19,678,531	$ 616,444	0.51%
AGS Primary	$ 28,446,328	$ 4,648,160	95,815	$ 4,941,022	$ 292,862	1.03%
TGS - Subtransmission	$ 31,645,550	$ 1,603,476	83,853	$ 4,324,117	$ 2,720,642	8.60%
TGS - Transmission	$ 14,782,273	$ 2,139,866	48,058	$ 2,478,241	$ 338,375	2.29%
SPL/CSL	$ 19,130,073	$ -	-	$ -	$ -	0.00%
DDC	$ 1,015,862	$ 80,865	1,858	$ 95,803	$ 14,938	1.47%
Subtotal Commercial and Industrial	$ 377,246,871	$ 45,549,972	976,557	$ 50,359,206	$ 4,809,235	1.27%
Total Jurisdiction	$ 996,451,143	$ 116,213,990	2,415,984	$ 124,587,778	$ 8,373,789	0.84%
Wholesale Transmission Rate		$ 51.44				
Rate Including Regulatory Assessment		$ 51.57				

ATLANTIC CITY ELECTRIC COMPANY
Proposed Transmission Rate Design
Formula Rate Effective June 1, 2018

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	3,888,406,860	$ 0.019377	$ 0.018173	$ 70,664,018	$ 0.000917	$ 0.019090	$ 0.020355
Transmission Rate Change				$ 3,564,554			

ATLANTIC CITY ELECTRIC COMPANY
Proposed Transmission Rate Design
Formula Rate Effective June 1, 2018

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	$ 3.26	$ 3.06	$ 9,140,563	$ 0.160000	$ 3.22	$ 3.43
WIN > 3 KW	3,063,157	$ 2.88	$ 2.70	$ 8,270,524	$ 0.160000	$ 2.86	$ 3.05
TOTAL KW	6,050,269			$ 17,411,087			
Transmission Rate Change				$ 977,173			

ATLANTIC CITY ELECTRIC COMPANY
Proposed Transmission Rate Design
Formula Rate Effective June 1, 2018

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	87,682	$ 3.16	$ 2.96	$ 259,539	$ (0.69)	$ 2.27	$ 2.42
WIN > 3 KW	130,641	$ 2.81	$ 2.64	$ 344,892	$ (0.69)	$ 1.95	$ 2.08
TOTAL KW	218,323			$ 604,431			
Transmission Rate Change				$ (151,199)			

ATLANTIC CITY ELECTRIC COMPANY
Proposed Transmission Rate Design
Formula Rate Effective June 1, 2018

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	5,707,212	$ 3.56	$ 3.34	$ 19,062,086	$ 0.11	$ 3.45	$ 3.68
Transmission Rate Change				$ 616,444			

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	1,387,511	$ 3.57	$ 3.35	$ 4,648,160	$ 0.21	$ 3.56	$ 3.80
Transmission Rate Change				$ 292,862			

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	1,021,322	$ 1.67	$ 1.57	$ 1,603,476	$ 0.33	$ 1.90	$ 2.03
Transmission Rate Change				$ 338,375			

ATLANTIC CITY ELECTRIC COMPANY
Proposed Transmission Rate Design
Formula Rate Effective June 1, 2018

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	1,236,917	$ 1.84	$ 1.73	$ 2,139,866	$ 0.27	$ 2.00	$ 2.13
Transmission Rate Change				$ 338,375			

ATLANTIC CITY ELECTRIC COMPANY
Proposed Transmission Rate Design
Formula Rate Effective June 1, 2018

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	72,902,499	$ -	$ -	$ -	$ -	$ -	$ -
Transmission Rate Change				$ -	$ -		

ATLANTIC CITY ELECTRIC COMPANY
Proposed Transmission Rate Design
Formula Rate Effective June 1, 2018

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	13,337,433	$ 0.006465	$ 0.006063	$ 80,865	$ 0.001120	$ 0.007183	$ 0.007659
Transmission Rate Change				$ 14,938			

Atlantic City Electric Company
Standby Rate Development
Formula Rate Effective June 1, 2018

Rate Schedule	Demand Rates ($/kW) Transmission	Standby Rates ($/kW) Transmission	Transmission Standby Factor
MGS Secondary	$ 3.43	$ 0.35	0.101604278
MGS Primary	$ 2.42	$ 0.25	0.101604278
AGS Secondary	$ 3.68	$ 0.37	0.101604278
AGS Primary	$ 3.80	$ 0.39	0.101604278
TGS Transmission	$ 2.13	$ 0.22	0.101604278

Exhibit F

ATLANTIC CITY ELECTRIC COMPANY
RESIDENTIAL SERVICE ("RS")
8 WINTER MONTHS (October Through May)

Present Rates
vs.
Proposed Rates

Monthly Usage (kWh)	Present Delivery ($)	Present Supply+T ($)	Present Total ($)	New Delivery ($)	New Supply+T ($)	New Total ($)	Difference Delivery ($)	Difference Supply+T ($)	Total Difference ($)	(%)
0	$ 4.83	$ -	$ 4.83	$ 4.83	$ -	$ 4.83	$ -	$ -	$ -	0.00%
25	$ 6.75	$ 2.41	$ 9.16	$ 6.75	$ 2.43	$ 9.18	$ -	$ 0.02	$ 0.02	0.22%
50	$ 8.66	$ 4.82	$ 13.48	$ 8.66	$ 4.86	$ 13.52	$ -	$ 0.04	$ 0.04	0.30%
75	$ 10.58	$ 7.23	$ 17.81	$ 10.58	$ 7.29	$ 17.87	$ -	$ 0.06	$ 0.06	0.34%
100	$ 12.49	$ 9.64	$ 22.13	$ 12.49	$ 9.72	$ 22.21	$ -	$ 0.08	$ 0.08	0.36%
150	$ 16.32	$ 14.46	$ 30.78	$ 16.32	$ 14.58	$ 30.90	$ -	$ 0.12	$ 0.12	0.39%
200	$ 20.15	$ 19.28	$ 39.43	$ 20.15	$ 19.45	$ 39.60	$ -	$ 0.17	$ 0.17	0.43%
250	$ 23.98	$ 24.11	$ 48.09	$ 23.98	$ 24.31	$ 48.29	$ -	$ 0.20	$ 0.20	0.42%
300	$ 27.81	$ 28.93	$ 56.74	$ 27.81	$ 29.17	$ 56.98	$ -	$ 0.24	$ 0.24	0.42%
350	$ 31.64	$ 33.75	$ 65.39	$ 31.64	$ 34.03	$ 65.67	$ -	$ 0.28	$ 0.28	0.43%
400	$ 35.47	$ 38.57	$ 74.04	$ 35.47	$ 38.89	$ 74.36	$ -	$ 0.32	$ 0.32	0.43%
450	$ 39.30	$ 43.39	$ 82.69	$ 39.30	$ 43.75	$ 83.05	$ -	$ 0.36	$ 0.36	0.44%
500	$ 43.13	$ 48.21	$ 91.34	$ 43.13	$ 48.61	$ 91.74	$ -	$ 0.40	$ 0.40	0.44%
600	$ 50.79	$ 57.85	$ 108.64	$ 50.79	$ 58.34	$ 109.13	$ -	$ 0.49	$ 0.49	0.45%
679	**$ 56.85**	**$ 65.47**	**$ 122.32**	**$ 56.85**	**$ 66.02**	**$ 122.87**	**$ -**	**$ 0.55**	**$ 0.55**	**0.45%**
700	$ 58.45	$ 67.50	$ 125.95	$ 58.45	$ 68.06	$ 126.51	$ -	$ 0.56	$ 0.56	0.44%
716	$ 59.68	$ 69.04	$ 128.72	$ 59.68	$ 69.62	$ 129.30	$ -	$ 0.58	$ 0.58	0.45%
750	$ 62.28	$ 72.32	$ 134.60	$ 62.28	$ 72.92	$ 135.20	$ -	$ 0.60	$ 0.60	0.45%
800	$ 66.11	$ 77.14	$ 143.25	$ 66.11	$ 77.78	$ 143.89	$ -	$ 0.64	$ 0.64	0.45%
900	$ 73.78	$ 86.78	$ 160.56	$ 73.78	$ 87.51	$ 161.29	$ -	$ 0.73	$ 0.73	0.45%
1000	$ 81.44	$ 96.42	$ 177.86	$ 81.44	$ 97.23	$ 178.67	$ -	$ 0.81	$ 0.81	0.46%
1200	$ 96.76	$ 115.71	$ 212.47	$ 96.76	$ 116.68	$ 213.44	$ -	$ 0.97	$ 0.97	0.46%
1500	$ 119.74	$ 144.63	$ 264.37	$ 119.74	$ 145.84	$ 265.58	$ -	$ 1.21	$ 1.21	0.46%
2000	$ 158.04	$ 192.85	$ 350.89	$ 158.04	$ 194.46	$ 352.50	$ -	$ 1.61	$ 1.61	0.46%
2500	$ 196.35	$ 241.06	$ 437.41	$ 196.35	$ 243.07	$ 439.42	$ -	$ 2.01	$ 2.01	0.46%
3000	$ 234.65	$ 289.27	$ 523.92	$ 234.65	$ 291.69	$ 526.34	$ -	$ 2.42	$ 2.42	0.46%
3500	$ 272.95	$ 337.48	$ 610.43	$ 272.95	$ 340.30	$ 613.25	$ -	$ 2.82	$ 2.82	0.46%
4000	$ 311.25	$ 385.69	$ 696.94	$ 311.25	$ 388.92	$ 700.17	$ -	$ 3.23	$ 3.23	0.46%

ATLANTIC CITY ELECTRIC COMPANY
RESIDENTIAL SERVICE ("RS")
4 SUMMER MONTHS (June Through September)

Present Rates
vs.
Proposed Rates

Monthly Usage (kWh)	Present Delivery ($)	Present Supply+T ($)	Present Total ($)	New Delivery ($)	New Supply+T ($)	New Total ($)	Difference Delivery ($)	Difference Supply+T ($)	Total Difference ($)	Total Difference (%)
0	$ 4.83	$ -	$ 4.83	$ 4.83	$ -	$ 4.83	$ -	$ -	$ -	0.00%
25	$ 6.85	$ 2.21	$ 9.06	$ 6.85	$ 2.23	$ 9.08	$ -	$ 0.02	$ 0.02	0.22%
50	$ 8.88	$ 4.42	$ 13.30	$ 8.88	$ 4.46	$ 13.34	$ -	$ 0.04	$ 0.04	0.30%
75	$ 10.90	$ 6.62	$ 17.52	$ 10.90	$ 6.68	$ 17.58	$ -	$ 0.06	$ 0.06	0.34%
100	$ 12.92	$ 8.83	$ 21.75	$ 12.92	$ 8.91	$ 21.83	$ -	$ 0.08	$ 0.08	0.37%
150	$ 16.97	$ 13.25	$ 30.22	$ 16.97	$ 13.37	$ 30.34	$ -	$ 0.12	$ 0.12	0.40%
200	$ 21.01	$ 17.66	$ 38.67	$ 21.01	$ 17.82	$ 38.83	$ -	$ 0.16	$ 0.16	0.41%
250	$ 25.06	$ 22.08	$ 47.14	$ 25.06	$ 22.28	$ 47.34	$ -	$ 0.20	$ 0.20	0.42%
300	$ 29.10	$ 26.49	$ 55.59	$ 29.10	$ 26.74	$ 55.84	$ -	$ 0.25	$ 0.25	0.45%
350	$ 33.15	$ 30.91	$ 64.06	$ 33.15	$ 31.19	$ 64.34	$ -	$ 0.28	$ 0.28	0.44%
400	$ 37.19	$ 35.32	$ 72.51	$ 37.19	$ 35.65	$ 72.84	$ -	$ 0.33	$ 0.33	0.46%
450	$ 41.24	$ 39.74	$ 80.98	$ 41.24	$ 40.10	$ 81.34	$ -	$ 0.36	$ 0.36	0.44%
500	$ 45.28	$ 44.16	$ 89.44	$ 45.28	$ 44.56	$ 89.84	$ -	$ 0.40	$ 0.40	0.45%
600	$ 53.37	$ 52.99	$ 106.36	$ 53.37	$ 53.47	$ 106.84	$ -	$ 0.48	$ 0.48	0.45%
679	**$ 59.77**	**$ 59.96**	**$ 119.73**	**$ 59.77**	**$ 60.51**	**$ 120.28**	**$ -**	**$ 0.55**	**$ 0.55**	**0.46%**
700	$ 61.46	$ 61.82	$ 123.28	$ 61.46	$ 62.38	$ 123.84	$ -	$ 0.56	$ 0.56	0.45%
716	$ 62.76	$ 63.23	$ 125.99	$ 62.76	$ 63.81	$ 126.57	$ -	$ 0.58	$ 0.58	0.46%
750	$ 65.51	$ 66.23	$ 131.74	$ 65.51	$ 66.84	$ 132.35	$ -	$ 0.61	$ 0.61	0.46%
800	$ 69.97	$ 71.15	$ 141.12	$ 69.97	$ 71.80	$ 141.77	$ -	$ 0.65	$ 0.65	0.46%
900	$ 78.89	$ 80.98	$ 159.87	$ 78.89	$ 81.71	$ 160.60	$ -	$ 0.73	$ 0.73	0.46%
1000	$ 87.82	$ 90.81	$ 178.63	$ 87.82	$ 91.62	$ 179.44	$ -	$ 0.81	$ 0.81	0.45%
1200	$ 105.66	$ 110.48	$ 216.14	$ 105.66	$ 111.45	$ 217.11	$ -	$ 0.97	$ 0.97	0.45%
1500	$ 132.43	$ 139.97	$ 272.40	$ 132.43	$ 141.18	$ 273.61	$ -	$ 1.21	$ 1.21	0.44%
2000	$ 177.05	$ 189.13	$ 366.18	$ 177.05	$ 190.75	$ 367.80	$ -	$ 1.62	$ 1.62	0.44%
2500	$ 221.66	$ 238.29	$ 459.95	$ 221.66	$ 240.31	$ 461.97	$ -	$ 2.02	$ 2.02	0.44%
3000	$ 266.28	$ 287.45	$ 553.73	$ 266.28	$ 289.87	$ 556.15	$ -	$ 2.42	$ 2.42	0.44%
3500	$ 310.89	$ 336.61	$ 647.50	$ 310.89	$ 339.44	$ 650.33	$ -	$ 2.83	$ 2.83	0.44%
4000	$ 355.50	$ 385.77	$ 741.27	$ 355.50	$ 389.00	$ 744.50	$ -	$ 3.23	$ 3.23	0.44%

ATLANTIC CITY ELECTRIC COMPANY
RESIDENTIAL SERVICE ("RS")
Annual Average

Present Rates
vs.
Proposed Rates

Monthly Usage (kWh)	Present Delivery ($)	Present Supply+T ($)	Present Total ($)	New Delivery ($)	New Supply+T ($)	New Total ($)	Difference Delivery ($)	Difference Supply+T ($)	Total Difference ($)	Total Difference (%)
0	$ 4.83	$ -	$ 4.83	$ 4.83	$ -	$ 4.83	$ -	$ -	$ -	0.00%
25	$ 6.78	$ 2.34	$ 9.12	$ 6.78	$ 2.36	$ 9.14	$ -	$ 0.02	$ 0.02	0.22%
50	$ 8.73	$ 4.69	$ 13.42	$ 8.73	$ 4.73	$ 13.46	$ -	$ 0.04	$ 0.04	0.30%
75	$ 10.69	$ 7.03	$ 17.72	$ 10.69	$ 7.09	$ 17.78	$ -	$ 0.06	$ 0.06	0.34%
100	$ 12.63	$ 9.37	$ 22.00	$ 12.63	$ 9.45	$ 22.08	$ -	$ 0.08	$ 0.08	0.36%
150	$ 16.54	$ 14.06	$ 30.60	$ 16.54	$ 14.18	$ 30.72	$ -	$ 0.12	$ 0.12	0.39%
200	$ 20.44	$ 18.74	$ 39.18	$ 20.44	$ 18.91	$ 39.35	$ -	$ 0.17	$ 0.17	0.43%
250	$ 24.34	$ 23.43	$ 47.77	$ 24.34	$ 23.63	$ 47.97	$ -	$ 0.20	$ 0.20	0.42%
300	$ 28.24	$ 28.12	$ 56.36	$ 28.24	$ 28.36	$ 56.60	$ -	$ 0.24	$ 0.24	0.43%
350	$ 32.14	$ 32.80	$ 64.94	$ 32.14	$ 33.08	$ 65.22	$ -	$ 0.28	$ 0.28	0.43%
400	$ 36.04	$ 37.49	$ 73.53	$ 36.04	$ 37.81	$ 73.85	$ -	$ 0.32	$ 0.32	0.44%
450	$ 39.95	$ 42.17	$ 82.12	$ 39.95	$ 42.53	$ 82.48	$ -	$ 0.36	$ 0.36	0.44%
500	$ 43.85	$ 46.86	$ 90.71	$ 43.85	$ 47.26	$ 91.11	$ -	$ 0.40	$ 0.40	0.44%
600	$ 51.65	$ 56.23	$ 107.88	$ 51.65	$ 56.72	$ 108.37	$ -	$ 0.49	$ 0.49	0.45%
679	**$ 57.82**	**$ 63.63**	**$ 121.45**	**$ 57.82**	**$ 64.18**	**$ 122.00**	**$ -**	**$ 0.55**	**$ 0.55**	**0.45%**
700	$ 59.45	$ 65.61	$ 125.06	$ 59.45	$ 66.17	$ 125.62	$ -	$ 0.56	$ 0.56	0.45%
716	$ 60.71	$ 67.10	$ 127.81	$ 60.71	$ 67.68	$ 128.39	$ -	$ 0.58	$ 0.58	0.45%
750	$ 63.36	$ 70.29	$ 133.65	$ 63.36	$ 70.89	$ 134.25	$ -	$ 0.60	$ 0.60	0.45%
800	$ 67.40	$ 75.14	$ 142.54	$ 67.40	$ 75.79	$ 143.19	$ -	$ 0.65	$ 0.65	0.46%
900	$ 75.48	$ 84.85	$ 160.33	$ 75.48	$ 85.58	$ 161.06	$ -	$ 0.73	$ 0.73	0.46%
1000	$ 83.57	$ 94.55	$ 178.12	$ 83.57	$ 95.36	$ 178.93	$ -	$ 0.81	$ 0.81	0.45%
1200	$ 99.73	$ 113.97	$ 213.70	$ 99.73	$ 114.94	$ 214.67	$ -	$ 0.97	$ 0.97	0.45%
1500	$ 123.97	$ 143.08	$ 267.05	$ 123.97	$ 144.29	$ 268.26	$ -	$ 1.21	$ 1.21	0.45%
2000	$ 164.38	$ 191.61	$ 355.99	$ 164.38	$ 193.22	$ 357.60	$ -	$ 1.61	$ 1.61	0.45%
2500	$ 204.79	$ 240.14	$ 444.93	$ 204.79	$ 242.15	$ 446.94	$ -	$ 2.01	$ 2.01	0.45%
3000	$ 245.19	$ 288.66	$ 533.85	$ 245.19	$ 291.08	$ 536.27	$ -	$ 2.42	$ 2.42	0.45%
3500	$ 285.60	$ 337.19	$ 622.79	$ 285.60	$ 340.01	$ 625.61	$ -	$ 2.82	$ 2.82	0.45%
4000	$ 326.00	$ 385.72	$ 711.72	$ 326.00	$ 388.95	$ 714.95	$ -	$ 3.23	$ 3.23	0.45%

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 (2018)	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 11, 2018, 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 Aida Camacho-Welch, 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 11, 2018, 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 11, 2018 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 (2018)
BPU Docket No. _______________

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