Docket No. 20170260-EI
Comprehensive Exhibit List for Entry into Hearing Record
May 8, 2018

EXH #	Witness	I.D. # As Filed	Exhibit Description	Issue Nos.	Entered
STAFF					
1		Exhibit List	Comprehensive Exhibit List		
TAMPA ELECTRIC COMPANY- (DIRECT)					
2	Mark D. Ward	MDW-1	Payne Creek Solar Project Specifications; Payne Creek Solar Project General Arrangement Drawing; Payne Creek Solar Project Projected Installed Cost by Category; Balm Solar Project Specifications; Balm Solar Project General Arrangement Drawing; Balm Solar Project Projected Installed Cost by Category	1, 2, 3, 4, 5, 7	
3	R. James Rocha	RJR-1[1]	Demand and Energy Forecasts; Fuel Price Forecast; Revenue Requirements for First SoBRA; Cost-effectiveness Test for First SoBRA[2]	1, 2, 5, 7	

[1] Exhibit RJR-1 page 25, Second Revision on March 6, 2018. RJR-1 page 26 Revised on February 14, 2018.
[2] Testimony of R. James Rocha revised on February 14, 2018

4	William R. Ashburn	WRA-1[3]	Development of First SoBRA Base Revenue Increase by Rate Class; Base Revenue by Rate Schedule; Rollup Base Revenue by Rate Class; Typical Bills Reflecting first SoBRA Base Revenue Increase; Redlined Tariffs Reflecting First SoBRA Base Revenue Increase; Clean Tariffs Reflecting First SoBRA Base Revenue Increase[4]	1, 6, 7	
STAFF HEARING EXHIBITS					
5	Rocha		Staff's First Data Request 1[5], 2-5, 6[6], 9, 10, 13, 14, and 15 **(See additional files contained on Staff Hearing Exhibit CD/USB for No. 13)** **Confidential DN# 00931-2018 (10)** *[Bates Nos. 00001-00022]*	2, 5	
6	Rocha		Staff's Second Data Request 1 and 3 **Confidential DN# 01872-2018 (1)** *[Bates Nos. 00023-00028]*	2, 5	
7	Ward (1,4,5) Rocha (2,3)		Staff's First set of Interrogatories (1 - 5) *[Bates Nos. 00029-00038]*	3, 4, 5	
8	Ashburn		Staff's 2nd set of Interrogatories (6 - 7) *[Bates Nos. 00039-00044]*	7	

[3] Exhibit WRA-1 Revised on February 14, 2018.
[4] Testimony of William R. Ashburn revised on February 14, 2018.
[5] Data Request 1, Revised on March 6, 2018
[6] Data Request 6, Revised on March 6, 2018

9	Rocha (8, 9, 11, 12, 13, 15, 16,17,18) Ward (9)		Staff's 3rd set of Interrogatories 8, 9, 11, 12, 13, 15 - 18 **(See additional files contained on Staff Hearing Exhibit CD/USB for Nos. 13, 16, 17, and 18)** *[Bates Nos. 00045-00067]*	1, 2, 3, 4, 5, 6	
10	Rocha		Staff's 4th set of Interrogatories 19 **(See additional file contained on Staff Hearing Exhibit CD/USB for No. 19)** *[Bates Nos. 00068-00071]*	2, 5	
11	Rocha		Staff's 5th set of Interrogatories 20 *[Bates Nos. 00072-00074]*	2, 5	
12	Rocha		Staff's 6th set of Interrogatories 21-29 *[Bates Nos. 00075-00086]*	2, 5	

OTHER HEARING EXHIBITS

LIVE Exhibit Number	Witness	Party	Description	Moved In/Due Date of Late Filed
13	Ward	OPC	FPL's response to staff's 3rd set of Interrrogatories, No. 24	
14	Ward	OPC	NREL Q 1 2016 Benchmark Report	
15	Ward	OPC	2017 Agreement	

TAMPA ELECTRIC COMPANY
DOCKET NO. 2017_______-EI
EXHIBIT NO. _____(MDW-1)

EXHIBIT

OF

MARK D. WARD

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20170260-EI   EXHIBIT: 2
PARTY: TAMPA ELECTRIC COMPANY-(DIRECT)
DESCRIPTION: Mark D. Ward MDW-1

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Payne Creek Solar Project Specifications

Specifications of Proposed Solar PV Generating Facilities

(1)	Plant Name and Unit Number	Payne Creek Solar
(2)	Net Capability	70.3 MW_{ac}
(3)	Technology Type	Single Axis Tracking Solar PV
(4)	Anticipated Construction Timing	
	A. Field Construction Start Date	July 2017
	B. Commercial In-Service Date	September 2018
(5)	Fuel	
	A. Primary Fuel	Solar
	B. Alternate Fuel	N/A
(6)	Air Pollution Control Strategy	N/A
(7)	Cooling Method	N/A
(8)	Total Site Area	+500 Acres
(9)	Construction Status	Planned
(10)	Certification Status	N/A
(11)	Status with Federal Agencies	N/A
(12)	Projected Unit Performance Data	
	Planned Outage Factor (POF)	0.0
	Forced Outage Factor (FOF)	0.0
	Equivalent Availability Factor (EAF)	N/A
	Resulting Capacity Factor (2018)	26.3
	Average Net Operating Heat Rate (ANOHR) [1]	N/A
(13)	Projected Unit Financial Data	
	Book Life (Years)	30
	Total Installed Cost (In-Service Year $/kW) [1]	1,324
	Direct Construction Cost ($/kW)	1,293
	AFUDC Amount ($/kW) [2]	31
	Escalation ($/kW)	N/A
	Fixed O&M ($/kW – yr)	7.16
	Variable O&M ($/MWh)	0.0
	K-Factor [3]	1.13

1 Includes interconnect, AFUDC, land, w/o incentive
2 Based on the current AFUDC rate of 6.46%
3 W/o land

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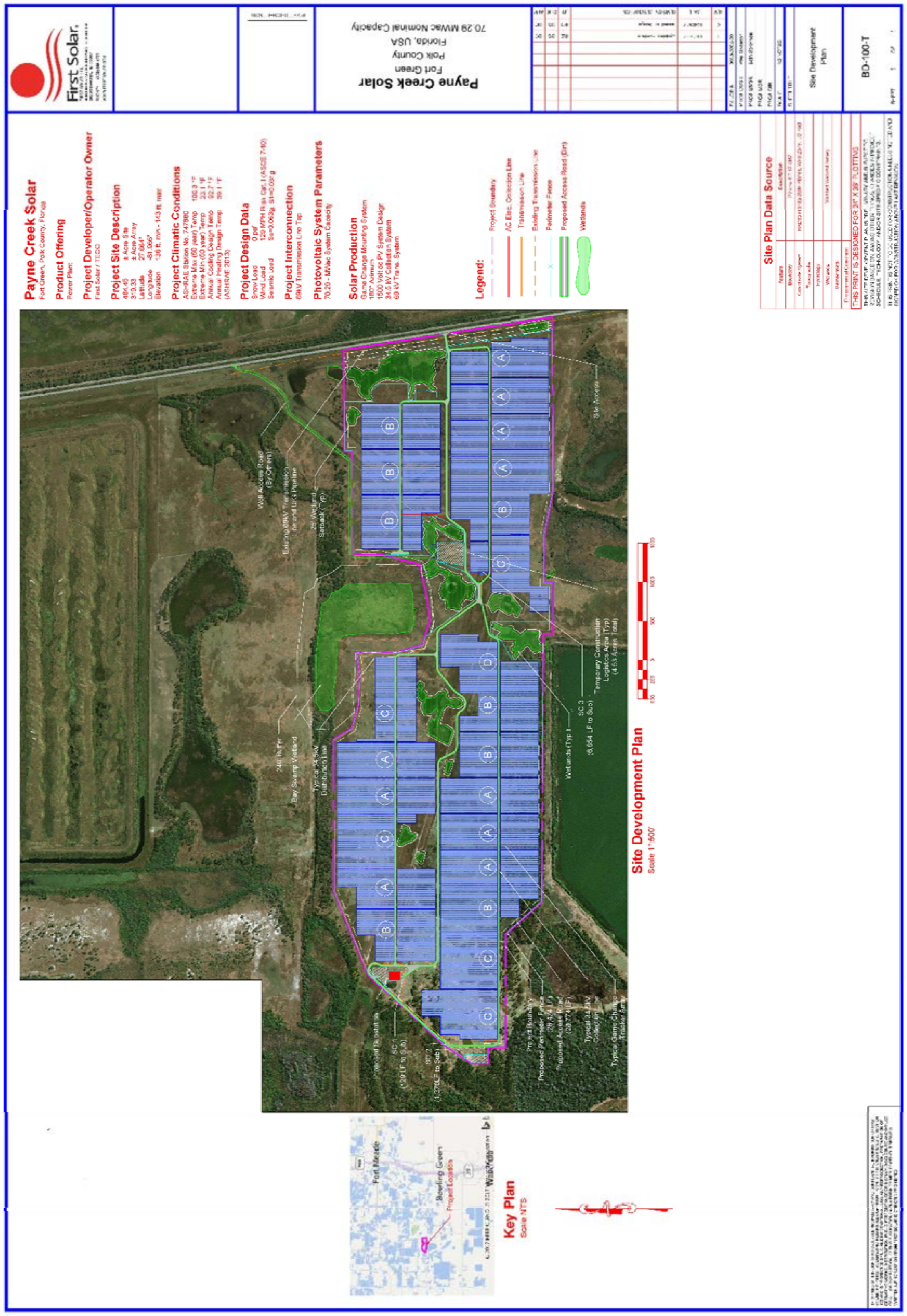
Payne Creek Solar Project General Arrangement Drawing



Payne Creek Solar Project Projected Installed Cost by Category

Payne Creek Solar Estimated Costs ($)	
Project Output (MW-ac)	70.3
Modules	30,827,672
Major Equipment	23,811,685
Balance of System	28,417,389
Development	1,593,623
Transmission Interconnect	4,400,000
Land	1,408,400
Owners Costs	419,383
Total Installed Cost ($)	90,878,151
AFUDC ($)	2,195,318
Total All-in-Cost ($)	93,073,469
Total ($/kW-ac)	1,324

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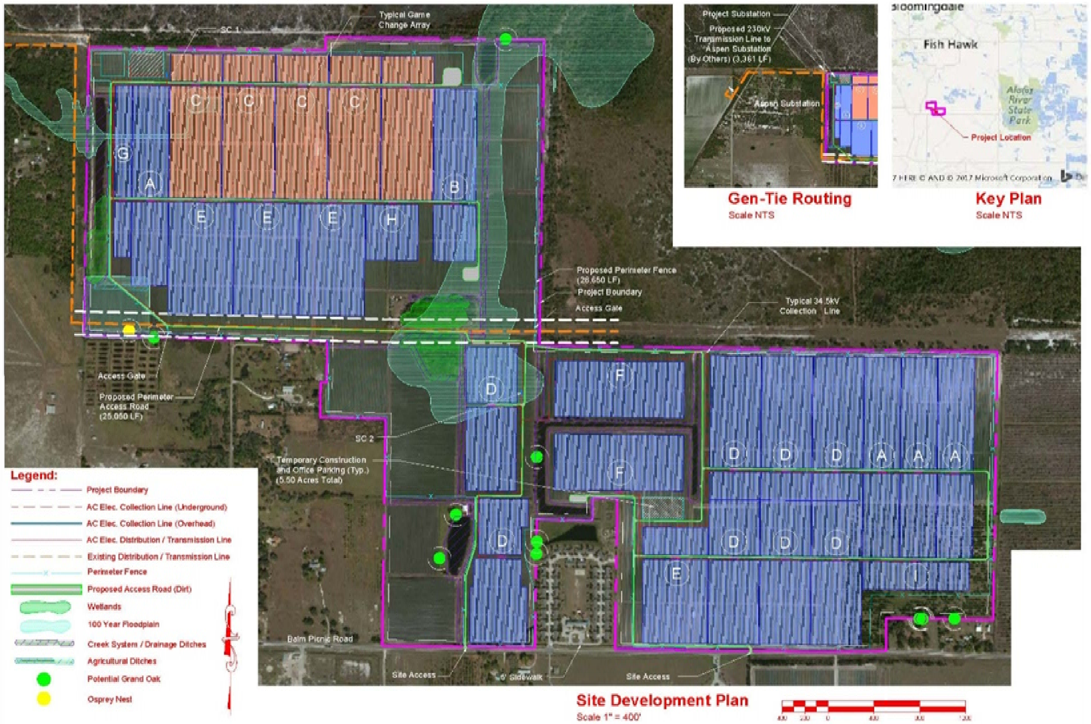
Balm Solar Project Specifications

Specifications of Proposed Solar PV Generating Facilities

(1)	Plant Name and Unit Number	Balm Solar
(2)	Net Capability	74.4 MW_{ac}
(3)	Technology Type	Single Axis Tracking Solar PV
(4)	Anticipated Construction Timing	
	A. Field Construction Start Date	July 2017
	B. Commercial In-Service Date	September 2018
(5)	Fuel	
	A. Primary Fuel	N/A
	B. Alternate Fuel	N/A
(6)	Air Pollution Control Strategy	N/A
(7)	Cooling Method	N/A
(8)	Total Site Area	+544 Acres
(9)	Construction Status	N/A
(10)	Certification Status	N/A
(11)	Status with Federal Agencies	N/A
(12)	Projected Unit Performance Data	
	Planned Outage Factor (POF)	0.0
	Forced Outage Factor (FOF)	0.0
	Equivalent Availability Factor (EAF)	N/A
	Resulting Capacity Factor (2018)	26.3
	Average Net Operating Heat Rate (ANOHR)	N/A
(13)	Projected Unit Financial Data	
	Book Life (Years)	30
	Total Installed Cost (In-Service Year $/kW) [1]	1,480
	Direct Construction Cost ($/kW)	1,450
	AFUDC Amount ($/kW) [2]	29
	Escalation ($/kW)	N/A
	Fixed O&M ($/kW – yr)	7.16
	Variable O&M ($/MWh)	0.0
	K-Factor [3]	1.14

1 Includes interconnect, AFUDC, land w/o incentive
2 Based on the current AFUDC rate of 6.46%
3 W/o land

Balm Solar Project General Arrangement Drawing



Site Development Plan
Scale 1" = 400'

Gen-Tie Routing
Scale NTS

Key Plan
Scale NTS

Balm Solar
Balm , Hillsborough, Florida

Product Offering
Power Plant

Project Developer/Operator Owner
First Solar / TECO

Project Site Description
541.48 ± Acre Site
329.70 ± Acre Array
Latitude 27.767°
Longitude -82.234°
Elevation 120 ft. min - 135 ft. max

Project Climatic Conditions
ASHRAE Station No. 747880
Extreme Max (50 year) Temp 100.3 °F
Extreme Min (50 year) Temp 23.1 °F
Annual Cooling Design Temp 92.0 °F
Annual Heating Design Temp 39.1 °F
(ASHRAE 2013)

Project Design Data
Snow Load 0 PSF
Wind Load 132 MPH (ASCE 7-10)
Seismic Load Ss = 0.06g, S1 = 0.031g

Project Interconnection
230kV Transmission Line to Aspen Substation

Photovoltaic System Parameters
74.41 - MWac System Capacity (Nominal Output)

Solar Production
Game Change Mounting System
181° Azimuth
1500 Volt dc PV System Design
34.5 kV Collection System
230 kV Trans. System

Site Plan Data Source

First Solar

Balm Solar
Balm
Hillsborough
Florida, USA
74.41MWac Nominal Capacity

Site Development Plan

BD-100-T

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Balm Solar Project Projected Installed Cost by Category

Balm Solar Estimated Costs ($)	
Project Output (MW-ac)	74.4
Modules	29,263,256
Major Equipment	25,206,219
Balance of System	30,081,657
Development	1,686,953
Transmission Interconnect	2,500,000
Land	18,720,128
Owners Costs	443,970
Total Installed Cost ($)	107,902,183
AFUDC ($)	2,188,259
Total All-in-Cost ($)	110,090,442
Total ($/kW-ac)	1,480

EXHIBIT

OF

R. JAMES ROCHA

REVISED 2/14/2018

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20170260-EI EXHIBIT: 3
PARTY: TAMPA ELECTRIC COMPANY-
(DIRECT)
DESCRIPTION: R. James Rocha RJR-1

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Demand & Energy Forecast

	Winter (MW)	Summer (MW)	Energy (GWh)
2017	3,138	4,080	20,274
2018	4,285	4,126	20,501
2019	4,347	4,175	20,677
2020	4,408	4,227	20,886
2021	4,468	4,281	21,105
2022	4,519	4,328	21,267
2023	4,583	4,384	21,522
2024	4,647	4,441	21,785
2025	4,708	4,497	22,045
2026	4,754	4,536	22,165
2027	4,817	4,594	22,452
2028	4,880	4,652	22,750
2029	4,943	4,710	23,050
2030	5,005	4,762	23,318
2031	5,060	4,812	23,576
2032	5,114	4,862	23,838
2033	5,169	4,913	24,103
2034	5,224	4,965	24,375
2035	5,282	5,018	24,654
2036	5,337	5,069	24,937
2037	5,337	5,069	24,937
2038	5,337	5,069	24,937
2039	5,337	5,069	24,937
2040	5,337	5,069	24,937
2041	5,337	5,069	24,937
2042	5,337	5,069	24,937
2043	5,337	5,069	24,937
2044	5,337	5,069	24,937
2045	5,337	5,069	24,937
2046	5,337	5,069	24,937
2047	5,337	5,069	24,937

Fuel Forecast ($/MMBtu)

	Coal	Natural Gas
2017	2.24	3.51
2018	2.35	3.24
2019	2.72	3.28
2020	3.00	3.58
2021	3.19	3.82
2022	3.23	3.95
2023	3.28	4.22
2024	3.33	4.48
2025	3.37	4.73
2026	3.44	4.98
2027	3.54	5.25
2028	3.76	5.84
2029	3.97	6.11
2030	4.26	6.68
2031	4.34	6.93
2032	4.53	7.50
2033	4.54	7.59
2034	4.70	8.10
2035	4.79	8.42
2036	4.94	8.59
2037	5.12	8.78
2038	5.28	8.96
2039	5.48	9.21
2040	5.67	9.40
2041	5.88	9.65
2042	6.17	10.06
2043	6.50	10.55
2044	6.78	10.90
2045	7.09	11.30
2046	7.42	11.70
2047	7.84	12.28

Revenue Requirements for First SoBRA

145 MW of Solar (Tranche 1)

($000)	2018
Balm Solar	10,257
Payne Creek	10,291
Capital RR	20,548
Balm Solar	533
Payne Creek	503
FOM	1,036
Land RR	2,271
TOTAL RR	23,856

Revenue Requirements for First SOBRA

With Sharing Mechanism

**145 MW of Solar (Tranche 1)
with 75%/25% Incentive**

($000)	2018
Balm Solar	10,300
Payne Creek	10,637
Capital RR	20,938
Balm Solar	533
Payne Creek	503
FOM	1,036
Land RR	2,271
TOTAL RR	24,245

Cost-Effectiveness Test for First SoBRA

Delta CPVRR (2017 $000)	**Cost/(Savings) ($ millions)**
Capital RR - Other New Units	($129.5)
Capital RR - Solar New Arrays (w/Interconnect)	$164.3
RR of Land for Solar	$26.5
System VOM	($9.7)
FOM - Other Future Units	($5.0)
FOM - Solar Future Arrays	$15.3
System Fuel	($198.5)
Sub Total w/o NO_X or CO_2 Cost	**($136.6)**
Plus Emissions (NO_x and CO_2) Cost/(Savings)	($11.4)
Total w/ NO_X & CO_2 Cost	**($148.0)**

EXHIBIT

OF

WILLIAM R. ASHBURN

REVISED 2/14/2018

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20170260-EI EXHIBIT: 4
PARTY: TAMPA ELECTRIC COMPANY-(DIRECT)
DESCRIPTION: William R. Ashburn WRA-1

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Development of First

SoBRA Base Revenue Increase

by Rate Class

REVISED: 2/14/2018

TAMPA ELECTRIC COMPANY
DEVELOPMENT OF SoBRA BASE REVENUE INCREASE BY RATE CLASS
USING JANUARY 1, 2018 RATES ADJUSTED FOR SoBRA AND 2018 TAX REFORM
($000)

150 MW SoBRA Tranche #1

		12CP &1/13 - All Demand	(A)	(B)	(C)	(D)	(E)	(F)	(G)
			Adjusted Revenue	Present Base	Base Revenue Deficiency		Proposed Base Rev. Increase		2017 Targeted Base
Line		Rate Class	Requirement(1)	Revenue(2)	$	%	$	%	Revenue
					(A) - (B)	(C) / (B)		(E) / (B)	(B) + (E)
1	I.	Residential (RS,RSVP)	$ 660,977	$ 647,455	$ 13,522	2.09%			
2									
3	II.	General Service							
4		Non-Demand (GS,CS)	70,283	69,017	1,265	1.83%			
5									
6									
7		Sub-Total: I. + II.	$ 731,260	$ 716,472	$ 14,788	2.06%	$ 14,788	2.06%	$ 731,260
8									
9									
10	III.	General Service							
11		Demand (GSD, SBF)	361,651	352,952	8,699	2.46%	$ 8,699	2.46%	361,651
12									
13	IV.	Interruptible Service (IS/SBI)	35,006	34,275	731	2.13%	$ 731	2.13%	35,006
15									
16									
19	V.	Lighting (LS-1)							
20		A. - Energy	$ 5,235	5,208	27	0.52%	$ 27	0.52%	$ 5,235
21		B. - Facilities	43,545	43,545	-	0.00%	$ -	0.00%	$ 43,545
22									
23									
24		Total	$ 1,176,697	$ 1,152,452	$ 24,245	2.10%	$ 24,245	2.10%	$ 1,176,697
25									
26				$ 24,245					
27									

28 (1) The Adjusted Revenue Requirement column reflects an increase of $24.245 million annual SoBRA revenues based on each class' percentage of 12 CP & 1/13th allocator
29 plus an 40% allocation to lighting service of SoBRA increase.
30 (2) Present base revenue is calculated using base rates in effect on January 16, 2017.
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Lighting allocation spread over other classes

	68		0.286%
		60.00%	
12 CP &1/13 Allocation	41		
		40.00%	
24245	27		

		Lighting Share Reallocation FINAL RR			Lighting Share Reallocation FINAL RR		
$000	%	$000	%	$000	$000	%	$000
13,500	55.6800%	38	55.84%	13,538	23	55.84%	13,522
1,263	5.2100%	4	5.22%	1,267	2	5.22%	1,265
8,685	35.8200%	24	35.92%	8,709	15	35.92%	8,699
730	3.0100%	2	3.02%	732	1	3.02%	731
68	0.2800%						27
24,245	100.0000%	68	100%	24,245	41	100%	24,245

Base Revenue by Rate Schedule

REVISED: 2/14/2018

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: TAMPA ELECTRIC COMPANY

EXPLANATION: By rate schedule, calculate revenues under present and proposed rates for the test year. If any customers are to be transferred from one schedule to another, show revenues separately for the transfer group. Correction factors are used for historic test years only. The total base revenue by class must equal that shown in Schedule E-13a. The billing units must equal those shown in Schedule E-15.
PROVIDE TOTAL NUMBER OF BILLS, MWH's, AND BILLING kW FOR EACH RATE SCHEDULE (INCLUDING STANDARD AND TIME OF USE CUSTOMERS) AND TRANSFER GROUP.

Type of data shown:
XX Projected Test year Ended 12/31/2018

Supporting Schedules:

Recap Schedules: E-13a

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FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: TAMPA ELECTRIC COMPANY

EXPLANATION: By rate schedule, calculate revenues under present and proposed rates for the test year. If any customers are to be transferred from one schedule to another, show revenues separately for the transfer group. Correction factors are used for historic test years only. The total base revenue by class must equal that shown in Schedule E-13a. The billing units must equal those shown in Schedule E-15.
PROVIDE TOTAL NUMBER OF BILLS, MWH's, AND BILLING kW FOR EACH RATE SCHEDULE (INCLUDING STANDARD AND TIME OF USE CUSTOMERS) AND TRANSFER GROUP.

Type of data shown:
XX Projected Test year Ended 12/31/2018

Rate Schedule RS, RSVP-1

Line No.	Type of Charges	Present Revenue Calculation				Proposed Revenue Calculation				Percent Increase
		Units		Charge/Unit	$ Revenue	Units		Charge/Unit	$ Revenue	
1										
2	Basic Service Charge:									
3	Standard	8,034,426	Bills	$ 16.62	133,532,160	8,034,426	Bills	$ 16.62	133,532,160	
4	RSVP-1	54,194	Bills	$ 16.62	900,704	54,194	Bills	$ 16.62	900,704	
5	Total	8,088,620	Bills		134,432,864	8,088,620	Bills		134,432,864	0.0%
6										
7										
8										
9	Energy Charge:									
10	Standard									
11	First 1,000 kWh	6,288,472	MWH	$ 52.00	327,000,544	6,288,472	MWH	$ 53.81	338,351,236	
12	All additional kWh	2,878,950	MWH	$ 63.08	181,604,166	2,878,950	MWH	$ 63.81	183,691,405	
13	RSVP-1	79,602	MWH	$ 55.49	4,417,115	79,602	MWH	$ 56.95	4,532,936	
14	Total	9,247,024	MWH		513,021,825	9,247,024	MWH		526,575,577	2.6%
15										
16										
17										
18	Total Base Revenue:				647,454,689				661,008,441	2.1%
19										
20										
21										
22										
23										
24										
25										
26										
27										
28										
29										
30										
31										
32										
33										
34										
35										

Supporting Schedules: Recap Schedules: E-13a

TAMPA ELECTRIC COMPANY
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FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: TAMPA ELECTRIC COMPANY

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PROVIDE TOTAL NUMBER OF BILLS, MWH's, AND BILLING kW FOR EACH RATE SCHEDULE (INCLUDING STANDARD AND TIME OF USE CUSTOMERS) AND TRANSFER GROUP.

Type of data shown:
XX Projected Test year Ended 12/31/2018

Rate Schedule GS, GST

Line No.	Type of Charges	Present Revenue Calculation Units		Charge/Unit	$ Revenue	Proposed Revenue Calculation Units		Charge/Unit	$ Revenue	Percent Increase
1										
2	Basic Service Charge:									
3	Standard Metered	770,609	Bills	$ 19.94	15,365,943	770,609	Bills	$ 19.94	15,365,943	
4	Standard Unmetered	1,164	Bills	$ 16.62	19,346	1,164	Bills	$ 16.62	19,346	
5	T-O-D	28,750	Bills	$ 22.16	637,100	28,750	Bills	$ 22.16	637,100	
6	T-O-D (Meter CIAC paid)	24	Bills	$ 19.94	479	24	Bills	$ 19.94	479	
7	Total	800,547	Bills		16,022,868	800,547	Bills		16,022,868	0.0%
8										
9	Energy Charge:									
10	Standard	900,400	MWH	$ 55.49	49,963,196	900,400	MWH	$ 56.76	51,108,955	
11	Standard Unmetered	1,416	MWH	$ 55.49	78,574	1,416	MWH	$ 56.76	80,376	
12	T-O-D On-Peak	9,546	MWH	$ 151.88	1,449,846	9,546	MWH	$ 144.88	1,383,024	
13	T-O-D Off-Peak	27,642	MWH	$ 10.30	284,713	27,642	MWH	$ 15.45	427,069	
14	Total	939,004	MWH		51,776,329	939,004	MWH		52,999,424	2.4%
15										
16	Emergency Relay Charge:									
17	Standard	2,010	MWH	$ 1.67	3,357	2,010	MWH	$ 1.71	3,445	
18	T-O-D	-	MWH	$ 1.67	-	-	MWH	$ 1.71	-	
19	Total	2,010	MWH		3,357	2,010	MWH		3,445	2.6%
20										
21										
22										
23	Total Base Revenue:				67,802,553				69,025,736	1.8%
24										
25										
26										
27										
28										
29										
30										
31										
32										
33										
34										
35										

Supporting Schedules: Recap Schedules: E-13a

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FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: TAMPA ELECTRIC COMPANY

EXPLANATION: By rate schedule, calculate revenues under present and proposed rates for the test year. If any customers are to be transferred from one schedule to another, show revenues separately for the transfer group. Correction factors are used for historic test years only. The total base revenue by class must equal that shown in Schedule E-13a. The billing units must equal those shown in Schedule E-15.
PROVIDE TOTAL NUMBER OF BILLS, MWH's, AND BILLING kW FOR EACH RATE SCHEDULE (INCLUDING STANDARD AND TIME OF USE CUSTOMERS) AND TRANSFER GROUP.

Type of data shown:
XX Projected Test year Ended 12/31/2018

Rate Schedule CS

Line No.	Type of Charges	Present Revenue Calculation Units	Present Charge/Unit	Present $ Revenue	Proposed Revenue Calculation Units	Proposed Charge/Unit	Proposed $ Revenue	Percent Increase
1								
2	Basic Service Charge:							
3		36,706 Bills	$ 19.94	731,918	36,706 Bills	$ 19.94	731,918	
4	Total	36,706 Bills		731,918	36,706 Bills		731,918	0.0%
5								
6	Energy Charge:							
7		8,703 MWH	$ 55.49	482,929	8,703 MWH	$ 56.76	494,004	
8	Total	8,703 MWH		482,929	8,703 MWH		494,004	2.3%
9								
10								
11								
12	Total Base Revenue:			1,214,847			1,225,922	0.9%
13								
14								
15								
16								
17								
18								
19								
20								
21								
22								
23								
24								
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26								
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30								
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32								
33								
34								
35								

Supporting Schedules: Recap Schedules: E-13a

TAMPA ELECTRIC COMPANY
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FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: TAMPA ELECTRIC COMPANY

EXPLANATION: By rate schedule, calculate revenues under present and proposed rates for the test year. If any customers are to be transferred from one schedule to another, show revenues separately for the transfer group. Correction factors are used for historic test years only. The total base revenue by class must equal that shown in Schedule E-13a. The billing units must equal those shown in Schedule E-15.
PROVIDE TOTAL NUMBER OF BILLS, MWH's, AND BILLING kW FOR EACH RATE SCHEDULE (INCLUDING STANDARD AND TIME OF USE CUSTOMERS) AND TRANSFER GROUP.

Type of data shown:
XX Projected Test year Ended 12/31/2018

Rate Schedule GSD, GSDT

Line No.	Type of Charges	Present Revenue Calculation Units		Charge/Unit	$ Revenue	Proposed Revenue Calculation Units		Charge/Unit	$ Revenue	Percent Increase
1	Basic Service Charge:									
2	Standard - Secondary	156,983	Bills	$ 33.24	5,218,115	156,983	Bills	$ 33.24	5,218,115	
3	Standard - Primary	765	Bills	$ 144.03	110,127	765	Bills	$ 144.03	110,127	
4	Standard - Subtransmission	-	Bills	$ 1,096.82	-	0	Bills	$ 1,096.82	-	
5	T-O-D - Secondary	13,710	Bills	$ 33.24	455,720	13,710	Bills	$ 33.24	455,720	
6	T-O-D - Primary	771	Bills	$ 144.03	111,047	771	Bills	$ 144.03	111,047	
7	T-O-D - Subtransmission	30	Bills	$ 1,096.82	32,905	30	Bills	$ 1,096.82	32,905	
8	Total	172,259	Bills		5,927,914	172,259			5,927,914	0.0%
9										
10	Energy Charge:									
11	Standard - Secondary	4,355,024	MWH	$ 17.54	76,387,121	4,355,024	MWH	$ 17.54	76,387,121	
12	Standard - Primary	304,831	MWH	$ 17.54	5,346,736	304,831	MWH	$ 17.54	5,346,736	
13	Standard - Subtransmission	-	MWH	$ 17.54	-	-	MWH	$ 17.54	-	
14	T-O-D On-Peak - Secondary	547,588	MWH	$ 32.11	17,583,051	547,588	MWH	$ 32.11	17,583,051	
15	T-O-D On-Peak - Primary	277,061	MWH	$ 32.11	8,896,429	277,061	MWH	$ 32.11	8,896,429	
16	T-O-D On-Peak - Subtrans.	645	MWH	$ 32.11	20,711	645	MWH	$ 32.11	20,711	
17	T-O-D Off-Peak - Secondary	1,509,852	MWH	$ 11.59	17,499,185	1,509,852	MWH	$ 11.59	17,499,185	
18	T-O-D Off-Peak - Primary	751,688	MWH	$ 11.59	8,712,064	751,688	MWH	$ 11.59	8,712,064	
19	T-O-D Off-Peak - Subtrans.	1,821	MWH	$ 11.59	21,105	1,821	MWH	$ 11.59	21,105	
20	Total	7,748,510	MWH		134,466,401	7,748,510	MWH		134,466,401	0.0%
21										
22	Demand Charge:									
23	Standard - Secondary	11,401,551	kW	$ 10.25	116,865,898	11,401,551	kW	$ 10.70	121,996,596	
24	Standard - Primary	754,324	kW	$ 10.25	7,731,821	754,324	kW	$ 10.70	8,071,267	
25	Standard - Subtransmission	-	kW	$ 10.25	-	-	kW	$ 10.70	-	
26	T-O-D Billing - Secondary	3,875,489	kW	$ 3.46	13,409,192	3,875,489	kW	$ 3.61	13,990,515	
27	T-O-D Billing - Primary	1,963,244	kW	$ 3.46	6,792,824	1,963,244	kW	$ 3.61	7,087,311	
28	T-O-D Billing - Subtrans.	6,078	kW	$ 3.46	21,030	6,078	kW	$ 3.61	21,942	
29	T-O-D Peak - Secondary	3,745,684	kW (1)	$ 6.79	25,433,194	3,745,684	kW (1)	$ 7.09	26,556,900	
30	T-O-D Peak - Primary	1,881,812	kW (1)	$ 6.79	12,777,503	1,881,812	kW (1)	$ 7.09	13,342,047	
31	T-O-D Peak - Subtrans.	5,934	kW (1)	$ 6.79	40,292	5,934	kW (1)	$ 7.09	42,072	
32	Total	18,000,686	kW		183,071,755	18,000,686	kW		191,108,649	4.4%
33										
34	(1) Not included in Total.									
35										

Continued on Page 6

Supporting Schedules: Recap Schedules: E-13a

TAMPA ELECTRIC COMPANY
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FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: TAMPA ELECTRIC COMPANY

EXPLANATION: By rate schedule, calculate revenues under present and proposed rates for the test year. If any customers are to be transferred from one schedule to another, show revenues separately for the transfer group. Correction factors are used for historic test years only. The total base revenue by class must equal that shown in Schedule E-13a. The billing units must equal those shown in Schedule E-15.
PROVIDE TOTAL NUMBER OF BILLS, MWH's, AND BILLING kW FOR EACH RATE SCHEDULE (INCLUDING STANDARD AND TIME OF USE CUSTOMERS) AND TRANSFER GROUP.

Type of data shown:
XX Projected Test year Ended 12/31/2018

Rate Schedule GSD, GSDT

Line No.	Type of Charges	Present Revenue Calculation Units		Charge/Unit	$ Revenue	Proposed Revenue Calculation Units		Charge/Unit	$ Revenue	Percent Increase
1	Continued from Page 8									
2										
3	Delivery Voltage Credit:									
4	Standard Primary	635,630	kW	$ (0.83)	(527,573)	635,630	kW	$ (0.87)	(552,998)	
5	Standard - Subtransmission	-	kW	$ (2.58)	-	-	kW	$ (2.69)	-	
6	T-O-D Primary	1,546,627	kW	$ (0.83)	(1,283,700)	1,546,627	kW	$ (0.87)	(1,345,565)	
7	T-O-D Subtransmission	11,316	kW	$ (2.58)	(29,195)	11,316	kW	$ (2.69)	(30,440)	
8	Total	2,193,573	kW		(1,840,469)	2,193,573	kW		(1,929,004)	4.8%
9										
10	Emergency Relay Charge:									
11	Standard Secondary	436,205	kW	$ 0.66	287,895	436,205	kW	$ 0.69	300,981	
12	Standard Primary	179,652	kW	$ 0.66	118,570	179,652	kW	$ 0.69	123,960	
13	Standard - Subtransmission	-	kW	$ 0.66	-	-	kW	$ 0.69	-	
14	T-O-D Secondary	746,274	kW	$ 0.66	492,541	746,274	kW	$ 0.69	514,929	
15	T-O-D Primary	786,269	kW	$ 0.66	518,938	786,269	kW	$ 0.69	542,526	
16	T-O-D Subtransmission	-	kW	$ 0.66	-	-	kW	$ 0.69	-	
17	Total	2,148,400	kW		1,417,944	2,148,400	kW		1,482,396	4.5%
18										
19	Power Factor Charge:									
20	Standard Secondary	14,339	MVARh	$ 2.22	31,833	14,339	MVARh	$ 2.22	31,833	
21	Standard Primary	24,464	MVARh	$ 2.22	54,310	24,464	MVARh	$ 2.22	54,310	
22	Standard - Subtransmission	0	MVARh	$ 2.22	-	0	MVARh	$ 2.22	-	
23	T-O-D Secondary	15,294	MVARh	$ 2.22	33,953	15,294	MVARh	$ 2.22	33,953	
24	T-O-D Primary	21,137	MVARh	$ 2.22	46,924	21,137	MVARh	$ 2.22	46,924	
25	T-O-D Subtransmission	48	MVARh	$ 2.22	107	48	MVARh	$ 2.22	107	
26		75,282	MVARh		167,126	75,282	MVARh		167,126	0.0%
27										
28										
29										
30										
31										
32										
33										
34										
35										

Supporting Schedules:

Recap Schedules: E-13a

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TAMPA ELECTRIC COMPANY
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FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: TAMPA ELECTRIC COMPANY

EXPLANATION: By rate schedule, calculate revenues under present and proposed rates for the test year. If any customers are to be transferred from one schedule to another, show revenues separately for the transfer group. Correction factors are used for historic test years only. The total base revenue by class must equal that shown in Schedule E-13a. The billing units must equal those shown in Schedule E-15.
PROVIDE TOTAL NUMBER OF BILLS, MWH's, AND BILLING kW FOR EACH RATE SCHEDULE (INCLUDING STANDARD AND TIME OF USE CUSTOMERS) AND TRANSFER GROUP.

Type of data shown:
XX Projected Test year Ended 12/31/2018

Rate Schedule GSD, GSDT

Line No.	Type of Charges	Present Revenue Calculation Units	Charge/Unit	$ Revenue	Proposed Revenue Calculation Units	Charge/Unit	$ Revenue	Percent Increase
1	Continued from Page 9							
2								
3	Power Factor Credit:							
4	Standard Secondary	29097 MVARh	$ (1.11)	(32,298)	29097 MVARh	$ (1.11)	(32,298)	
5	Standard Primary	15610 MVARh	$ (1.11)	(17,327)	15610 MVARh	$ (1.11)	(17,327)	
6	Standard - Subtransmission	0 MVARh	$ (1.11)	-	0 MVARh	$ (1.11)	-	
7	T-O-D Secondary	122119 MVARh	$ (1.11)	(135,552)	122119 MVARh	$ (1.11)	(135,552)	
8	T-O-D Primary	70768 MVARh	$ (1.11)	(78,552)	70768 MVARh	$ (1.11)	(78,552)	
9	T-O-D Subtransmission	2 MVARh	$ (1.11)	(2)	2 MVARh	$ (1.11)	(2)	
10		237,596 MVARh		(263,732)	237,596 MVARh		(263,732)	0.0%
11								
12								
13	Metering Voltage Adjustment:							
14	Standard Primary	12,706,537 $	-1%	(127,065)	13,025,947 $	-1%	(130,259)	
15	Standard - Subtransmission	- $	-2%	-	- $	-2%	-	
16	T-O-D Primary	36,382,429 $	-1%	(363,824)	37,203,182 $	-1%	(372,032)	
17	T-O-D Subtransmission	74,047 $	-2%	(1,481)	75,494 $	-2%	(1,510)	
18	Total	49,163,013 $		(492,371)	50,304,624 $		(503,801)	2.3%
19								
20								
21								
22								
23	Total Base Revenue:			322,454,569			330,455,949	2.5%
24								
25								
26								
27								
28								
29								
30								
31								
32								
33								
34								
35								

Supporting Schedules: Recap Schedules: E-13a

TAMPA ELECTRIC COMPANY
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FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: TAMPA ELECTRIC COMPANY

EXPLANATION: By rate schedule, calculate revenues under present and proposed rates for the test year. If any customers are to be transferred from one schedule to another, show revenues separately for the transfer group. Correction factors are used for historic test years only. The total base revenue by class must equal that shown in Schedule E-13a. The billing units must equal those shown in Schedule E-15.
PROVIDE TOTAL NUMBER OF BILLS, MWH's, AND BILLING kW FOR EACH RATE SCHEDULE (INCLUDING STANDARD AND TIME OF USE CUSTOMERS) AND TRANSFER GROUP.

Type of data shown:
XX Projected Test year Ended 12/31/2018

Rate Schedule GSD Optional

Line No.	Type of Charges	Present Revenue Calculation Units		Charge/Unit	$ Revenue	Proposed Revenue Calculation Units		Charge/Unit	$ Revenue	Percent Increase
1	Basic Service Charge:									
2	Optional - Secondary	19,003	Bills	$ 33.24	631,660	19,003	Bills	$ 33.24	631,660	
3	Optional - Primary	288	Bills	$ 144.03	41,481	288	Bills	$ 144.03	41,481	
4	Optional - Subtransmission	-		$ 1,096.82	-	-		$ 1,096.82	-	
5	Total	19,291	Bills		673,140	19,291	Bills		673,140	0.0%
6										
7	Energy Charge:									
8	Optional - Secondary	363,509	MWH	$ 66.60	24,209,699	363,509	MWH	$ 68.12	24,762,233	
9	Optional - Primary	10,390	MWH	$ 66.60	691,974	10,390	MWH	$ 68.12	707,767	
10	Total	373,899	MWH		24,901,673	373,899	MWH		25,470,000	2.3%
11										
12	Demand Charge:									
13	Optional - Secondary	3,657,763	kW	$ -	-	3,657,763	kW	$ -	-	
14	Optional - Primary	157,490	kW	$ -	-	157,490	kW	$ -	-	
15	Total	3,815,253	kW		-	3,815,253			-	0.0%
16										
17	Delivery Voltage Credit:									
18	Optional - Primary	5,381	MWH	$ (2.20)	(11,838)	5,381	MWH	$ (2.30)	(12,376)	
19	Optional - Subtransmission	-	MWH	$ (6.72)	-	-	MWH	$ (7.02)	-	
20	Total	5,381	MWH		(11,838)	5,381	MWH		(12,376)	4.5%
21										
22	Emergency Relay									
23	Optional - Secondary	10,763	MWH	$ 1.67	17,974	10,763	MWH	$ 1.74	18,728	
24	Optional - Primary	-	MWH	$ 1.67	-	-	MWH	$ 1.74	-	
25	Total	10,763	MWH		17,974	10,763	MWH		18,728	4.2%
26										
27	Metering Voltage Adjustment:									
28	Optional - Primary	680,136	$	-1%	(6,801)	695,391	$	-1%	(6,954)	
29	Optional - Subtransmission	-	$	-2%	-	-	$	-2%	-	
30	Total	680,136	$		(6,801)	695,391	$		(6,954)	2.2%
31										
32										
33										
34	Total Base Revenue:				25,574,148				26,142,538	2.2%
35										

Supporting Schedules: Recap Schedules: E-13a

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TAMPA ELECTRIC COMPANY
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COMPANY: TAMPA ELECTRIC COMPANY

EXPLANATION: By rate schedule, calculate revenues under present and proposed rates for the test year. If any customers are to be transferred from one schedule to another, show revenues separately for the transfer group. Correction factors are used for historic test years only. The total base revenue by class must equal that shown in Schedule E-13a. The billing units must equal those shown in Schedule E-15.
PROVIDE TOTAL NUMBER OF BILLS, MWH's, AND BILLING kW FOR EACH RATE SCHEDULE (INCLUDING STANDARD AND TIME OF USE CUSTOMERS) AND TRANSFER GROUP.

Type of data shown:
XX Projected Test year Ended 12/31/2018

Rate Schedule SBF, SBFT

Line No.	Type of Charges	Present Revenue Calculation Units		Present Charge/Unit	Present $ Revenue	Proposed Revenue Calculation Units		Proposed Charge/Unit	Proposed $ Revenue	Percent Increase
1										
2	Basic Service Charge:									
3	Standard Secondary	0	Bills	$ 60.93	-	0	Bills	$ 60.93	-	
4	Standard Primary	0	Bills	$ 171.72	-	0	Bills	$ 171.72	-	
5	Standard Subtransmission	0	Bills	$ 1,124.52	-	0	Bills	$ 1,124.52	-	
6	T-O-D Secondary	0	Bills	$ 60.93	-	0	Bills	$ 60.93	-	
7	T-O-D Primary	38	Bills	$ 171.72	6,525	38	Bills	$ 171.72	6,525	
8	T-O-D Subtransmission	50	Bills	$ 1,124.52	56,226	50	Bills	$ 1,124.52	56,226	
9	Total	88	Bills		62,751	88	Bills		62,751	0.0%
10										
11	Energy Charge - Supplemental:									
12	Standard Secondary	0	MWH	$ 17.54	-	-	MWH	$ 17.54	-	
13	Standard Primary	0	MWH	$ 17.54	-	-	MWH	$ 17.54	-	
14	Standard Subtransmission	0	MWH	$ 17.54	-	-	MWH	$ 17.54	-	
15	T-O-D On-Peak - Secondary	0	MWH	$ 32.11	-	-	MWH	$ 32.11	-	
16	T-O-D On-Peak - Primary	28,060	MWH	$ 32.11	901,007	28,060	MWH	$ 32.11	901,007	
17	T-O-D On-Peak - Subtrans.	-	MWH	$ 32.11	-	-	MWH	$ 32.11	-	
18	T-O-D Off-Peak - Secondary	0	MWH	$ 11.59	-	-	MWH	$ 11.59	-	
19	T-O-D Off-Peak - Primary	84,167	MWH	$ 11.59	975,496	84,167	MWH	$ 11.59	975,496	
20	T-O-D Off-Peak - Subtrans.	-	MWH	$ 11.59	-	-	MWH	$ 11.59	-	
21	Energy Charge - Standby:									
22	T-O-D On-Peak -Secondary	-	MWH	$ 10.12	-	-	MWH	$ 10.12	-	
23	T-O-D On-Peak - Primary	1,552	MWH	$ 10.12	15,706	1,552	MWH	$ 10.12	15,706	
24	T-O-D On-Peak - Subtrans.	1,391	MWH	$ 10.12	14,077	1,391	MWH	$ 10.12	14,077	
25	T-O-D Off-Peak -Secondary	-	MWH	$ 10.12	-	-	MWH	$ 10.12	-	
26	T-O-D Off-Peak - Primary	5,354	MWH	$ 10.12	54,182	5,354	MWH	$ 10.12	54,182	
27	T-O-D Off-Peak - Subtrans.	4,799	MWH	$ 10.12	48,566	4,799	MWH	$ 10.12	48,566	
28	Total	125,323	MWH		2,009,034	125,323	MWH		2,009,034	0.0%
29										
30										
31										
32										
33										
34										
35										

Supporting Schedules: Recap Schedules: E-13a

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TAMPA ELECTRIC COMPANY
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EXPLANATION: By rate schedule, calculate revenues under present and proposed rates for the test year. If any customers are to be transferred from one schedule to another, show revenues separately for the transfer group. Correction factors are used for historic test years only. The total base revenue by class must equal that shown in Schedule E-13a. The billing units must equal those shown in Schedule E-15.
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Type of data shown:
XX Projected Test year Ended 12/31/2018

COMPANY: TAMPA ELECTRIC COMPANY

Rate Schedule SBF, SBFT

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Line No.	Type of Charges	Present Revenue Calculation Units	Present Charge/Unit	Present $ Revenue	Proposed Revenue Calculation Units	Proposed Charge/Unit	Proposed $ Revenue	Percent Increase
1	Continued from Page 13							
2								
3	Demand Charge - Supplemental:							
4	Standard Secondary	- kW	$ 10.25	-	- kW	$ 10.70	-	
5	Standard Primary	- kW	$ 10.25	-	- kW	$ 10.70	-	
6	Standard Subtransmission	- kW	$ 10.25	-	- kW	$ 10.70	-	
7	T-O-D Billing - Secondary	- kW	$ 3.46	-	- kW	$ 3.61	-	
8	T-O-D Billing - Primary	189,757 kW	$ 3.46	656,559	189,757 kW	$ 3.61	685,023	
9	T-O-D billing - Subtransmission	- kW	$ 3.46	-	- kW	$ 3.61	-	
10	T-O-D Peak - Secondary	- kW (1)	$ 6.79	-	- kW (1)	$ 7.09	-	
11	T-O-D Peak - Primary	182,747 kW (1)	$ 6.79	1,240,852	182,747 kW (1)	$ 7.09	1,295,676	
12	T-O-D Peak - Subtransmission	- kW (1)	$ 6.79	-	- kW (1)	$ 7.09	-	
13	Demand Charge - Standby:							
14	T-O-D Facilities Reservation - Sec.	- kW	$ 2.15	-	- kW	$ 2.15	-	
15	T-O-D Facilities Reservation - Pri.	124,472 kW	$ 2.15	267,615	124,472 kW	$ 2.15	267,615	
16	T-O-D Facilities Reservation - Sub.	239,385 kW	$ 2.15	514,678	239,385 kW	$ 2.15	514,678	
17	T-O-D Power Supply Res. - Sec.	- kW (1)	$ 1.71 / kW-mo.	-	- kW (1)	$ 1.71 kW-mo.	-	
18	T-O-D Power Supply Res. - Pri.	58,727 kW (1)	$ 1.71 / kW-mo.	100,423	58,727 kW (1)	$ 1.71 kW-mo.	100,423	
19	T-O-D Power Supply Res. - Sub.	186,159 kW (1)	$ 1.71 / kW-mo.	318,332	186,159 kW (1)	$ 1.71 kW-mo.	318,332	
20	T-O-D Power Supply Dmd. - Sec.	- kW (1)	$ 0.68 / kW-day	-	- kW (1)	$ 0.68 kW-day	-	
21	T-O-D Power Supply Dmd. - Pri.	336,057 kW (1)	$ 0.68 / kW-day	228,519	336,057 kW (1)	$ 0.68 kW-day	228,519	
22	T-O-D Power Supply Dmd. - Sub.	306,977 kW (1)	$ 0.68 / kW-day	208,744	306,977 kW (1)	$ 0.68 kW-day	208,744	
23	Total	553,614 kW		3,535,722	553,614 kW		3,619,010	2.4%
24								
25								
26	Power Factor Charge Supplemental & Standby:							
27	Standard Secondary	- MVARh	$ 2.22	-	- MVARh	$ 2.22	-	
28	Standard Primary	- MVARh	$ 2.22	-	- MVARh	$ 2.22	-	
29	Standard Subtransmission	- MVARh	$ 2.22	-	- MVARh	$ 2.22	-	
30	T-O-D Secondary	94 MVARh	$ 2.22	209	94 MVARh	$ 2.22	209	
31	T-O-D Primary	5,019 MVARh	$ 2.22	11,142	5,019 MVARh	$ 2.22	11,142	
32	T-O-D Subtransmission	1,038 MVARh	$ 2.22	2,304	1,038 MVARh	$ 2.22	2,304	
33		6,151		13,655	6,151		13,655	0.0%
34	(1) Not included in Total.							
35								

Continued on Page 11

Supporting Schedules:

Recap Schedules: E-13a

TAMPA ELECTRIC COMPANY
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FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: TAMPA ELECTRIC COMPANY

EXPLANATION: By rate schedule, calculate revenues under present and proposed rates for the test year. If any customers are to be transferred from one schedule to another, show revenues separately for the transfer group. Correction factors are used for historic test years only. The total base revenue by class must equal that shown in Schedule E-13a. The billing units must equal those shown in Schedule E-15.
PROVIDE TOTAL NUMBER OF BILLS, MWH's, AND BILLING kW FOR EACH RATE SCHEDULE (INCLUDING STANDARD AND TIME OF USE CUSTOMERS) AND TRANSFER GROUP.

Type of data shown:
XX Projected Test year Ended 12/31/2018

Rate Schedule SBF, SBFT

Line No.	Type of Charges	Present Revenue Calculation: Units		Charge/Unit	$ Revenue	Proposed Revenue Calculation: Units		Charge/Unit	$ Revenue	Percent Increase
1	Continued from Page 14									
2										
3	Power Factor Credit Supplemental & Standby:									
4	Standard Secondary	-	MVARh	$ (1.11)	-	-	MVARh	$ (1.11)	-	
5	Standard Primary	-	MVARh	$ (1.11)	-	-	MVARh	$ (1.11)	-	
6	Standard Subtransmission	-	MVARh	$ (1.11)	-	-	MVARh	$ (1.11)	-	
7	T-O-D Secondary	-	MVARh	$ (1.11)	-	-	MVARh	$ (1.11)	-	
8	T-O-D Primary	2,108	MVARh	$ (1.11)	(2,340)	2,108	MVARh	$ (1.11)	(2,340)	
9	T-O-D Subtransmission	680	MVARh	$ (1.11)	(755)	680	MVARh	$ (1.11)	(755)	
14	Total	2,788	MVARh		(3,095)	2,788	MVARh		(3,095)	0.0%
15										
16	Delivery Voltage Credit - Supplemental.:									
17	Standard Primary	-	kW	$ (0.83)	-	-	kW	$ (0.87)	-	
18	Standard Subtransmission	-	kW	$ (2.58)	-	-	kW	$ (2.69)	-	
19	T-O-D Primary	189,757	kW	$ (0.83)	(157,498)	189,757	kW	$ (0.87)	(165,089)	
20	T-O-D Subtransmission	-	kW	$ (2.58)	-	-	kW	$ (2.69)	-	
21	Delivery Voltage Credit. - Standby.:									
22	T-O-D Primary	124,376	kW	$ (0.69)	(85,819)	124,376	kW	$ (0.69)	(85,819)	
23	T-O-D Subtransmission	239,481	kW	$ (2.16)	(517,279)	239,481	kW	$ (2.16)	(517,279)	
24	Total	553,614	kW		(760,597)	553,614	kW		(768,187)	1.0%
25										
26	Emergency Relay Charge - Supplemental and Standby.									
27	Standard Secondary	-	kW	$ 0.66	-	-	kW	$ 0.69	-	
28	Standard Primary	-	kW	$ 0.66	-	-	kW	$ 0.69	-	
29	Standard Subtransmission	-	kW	$ 0.66	-	-	kW	$ 0.69	-	
30	T-O-D Secondary	-	kW	$ 0.66	-	-	kW	$ 0.69	-	
31	T-O-D Primary	183,003	kW	$ 0.66	120,782	183,003	kW	$ 0.69	126,272	
32	T-O-D Subtransmission	-	kW	$ 0.66	-	-	kW	$ 0.69	-	
33		183,003			120,782	183,003			126,272	4.5%
34										
35										
36										
37										
34										
35										

Supporting Schedules: Recap Schedules: E-13a

TAMPA ELECTRIC COMPANY
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FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: TAMPA ELECTRIC COMPANY

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PROVIDE TOTAL NUMBER OF BILLS, MWH's, AND BILLING kW FOR EACH RATE SCHEDULE (INCLUDING STANDARD AND TIME OF USE CUSTOMERS) AND TRANSFER GROUP.

Type of data shown:
XX Projected Test year Ended 12/31/2018

Rate Schedule SBF, SBFT

Line No.	Type of Charges	Present Revenue Calculation: Units		Present Revenue Calculation: Charge/Unit	Present Revenue Calculation: $ Revenue	Proposed Revenue Calculation: Units		Proposed Revenue Calculation: Charge/Unit	Proposed Revenue Calculation: $ Revenue	Percent Increase
1	Continued from Page 15									
2										
3	Metering Voltage Adjustment - Supplemental and Stanby.:									
4	Standard Primary	-	$	-1.0%	-	-	$	-1.0%	-	
5	Standard Subtransmission	-	$	-2.0%	-	-	$	-2.0%	-	
6	T-O-D Primary	4,326,625	$	-1.0%	(43,266)	4,407,813	$	-1.0%	(44,078)	
7	T-O-D Subtransmission	588,667	$	-2.0%	(11,773)	588,667	$	-2.0%	(11,773)	
8	Total	4,915,293	$		(55,040)	4,996,480	$		(55,851)	1.5%
9										
10										
11										
12	Total Base Revenue:				4,923,213				5,003,589	1.6%
13										
14										
15										
16										
17										
18										
19										
20										
21										
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26										
27										
28										
29										
30										
31										
32										
33										
34										
35										

Supporting Schedules: Recap Schedules: E-13a

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: TAMPA ELECTRIC COMPANY

EXPLANATION: By rate schedule, calculate revenues under present and proposed rates for the test year. If any customers are to be transferred from one schedule to another, show revenues separately for the transfer group. Correction factors are used for historic test years only. The total base revenue by class must equal that shown in Schedule E-13a. The billing units must equal those shown in Schedule E-15.
PROVIDE TOTAL NUMBER OF BILLS, MWH's, AND BILLING kW FOR EACH RATE SCHEDULE (INCLUDING STANDARD AND TIME OF USE CUSTOMERS) AND TRANSFER GROUP.

Type of data shown:
XX Projected Test year Ended 12/31/2018

Rate Schedule IS, IST

Line No.	Type of Charges	Present Units		Present Charge/Unit	Present $ Revenue	Proposed Units		Proposed Charge/Unit	Proposed $ Revenue	Percent Increase
1										
2	Basic Service Charge:									
3	Standard Pri.	98	Bills	$ 689.11	67,533	98	Bills	$ 689.11	67,533	
4	Standard Subtrans.	-	Bills	$ 2,627.94	-	-	Bills	$ 2,627.94	-	
5	T-O-D Primary	127	Bills	$ 689.11	87,531	127	Bills	$ 689.11	87,531	
6	T-O-D Subtransmission	113	Bills	$ 2,627.94	296,721	113	Bills	$ 2,627.94	296,721	
7	Total	338	Bills		451,784	338	Bills		451,784	0.0%
8										
9	Energy Charge:									
10	Standard Primary	43,405	MWH	$ 27.74	1,204,055	43,405	MWH	$ 27.74	1,204,055	
11	Standard Subtransmission	-	MWH	$ 27.74	-	-	MWH	$ 27.74	-	
12	T-O-D On-Peak - Pri.	37,618	MWH	$ 27.74	1,043,523	37,618	MWH	$ 27.74	1,043,523	
13	T-O-D On-Peak - Subtrans.	105,438	MWH	$ 27.74	2,924,850	105,438	MWH	$ 27.74	2,924,850	
14	T-O-D Off-Peak - Pri.	103,161	MWH	$ 27.74	2,861,686	103,161	MWH	$ 27.74	2,861,686	
15	T-O-D Off-Peak - Subtrans.	327,030	MWH	$ 27.74	9,071,812	327,030	MWH	$ 27.74	9,071,812	
16	Total	616,652	MWH		17,105,926	616,652	MWH		17,105,926	0.0%
17										
18	Demand Charge:									
19	Standard Primary	109,262	kW	$ 1.61	175,912	109,262	kW	$ 2.19	239,284	
20	Standard Subtrans.	-	kW	$ 1.61	-	-	kW	$ 2.19	-	
21	T-O-D Billing - Primary	266,444	kW	$ 1.61	428,975	266,444	kW	$ 2.19	583,512	
22	T-O-D Billing - Subtrans.	1,165,839	kW	$ 1.61	1,877,001	1,165,839	kW	$ 2.19	2,553,187	
23	T-O-D Peak - Primary	264,818	kW (1)	$ -	-	264,818	kW (1)	$ -	-	
24	T-O-D Peak - Subtrans.	1,146,121	kW (1)	$ -	-	1,146,121	kW (1)	$ -	-	
25	Total	1,541,545	kW		2,481,887	1,541,545	kW		3,375,984	36.0%
26										
27	Power Factor Charge:									
28	Standard Primary	7,673	MVARh	$ 2.22	17,034	7,673	MVARh	$ 2.22	17,034	
29	Standard Subtrans.	-	MVARh	$ 2.22	-	-	MVARh	$ 2.22	-	
30	T-O-D Primary	12,211	MVARh	$ 2.22	27,108	12,211	MVARh	$ 2.22	27,108	
31	T-O-D Subtransmission	21,904	MVARh	$ 2.22	48,627	21,904	MVARh	$ 2.22	48,627	
32	Total	41,788	MVARh		92,769	41,788	MVARh		92,769	0.0%
33										
34	(1) Not included in Total.									
35										

Continued on Page 14

Supporting Schedules:

Recap Schedules: E-13a

TAMPA ELECTRIC COMPANY
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FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: TAMPA ELECTRIC COMPANY

EXPLANATION: By rate schedule, calculate revenues under present and proposed rates for the test year. If any customers are to be transferred from one schedule to another, show revenues separately for the transfer group. Correction factors are used for historic test years only. The total base revenue by class must equal that shown in Schedule E-13a. The billing units must equal those shown in Schedule E-15.
PROVIDE TOTAL NUMBER OF BILLS, MWH's, AND BILLING kW FOR EACH RATE SCHEDULE (INCLUDING STANDARD AND TIME OF USE CUSTOMERS) AND TRANSFER GROUP.

Type of data shown:
XX Projected Test year Ended 12/31/2018

Rate Schedule IS, IST

Line No.	Type of Charges	Present Revenue Calculation: Units		Charge/Unit	$ Revenue	Proposed Revenue Calculation: Units		Charge/Unit	$ Revenue	Percent Increase
1	Continued from Page 17									
2										
3	Power Factor Credit:									
4	Standard Primary	3,486	MVARh	$ (1.11)	(3,869)	3,486	MVARh	$ (1.11)	(3,869)	
5	Standard Subtrans.	-	MVARh	$ (1.11)	-	-	MVARh	$ (1.11)	-	
6	T-O-D Primary	2,398	MVARh	$ (1.11)	(2,662)	2,398	MVARh	$ (1.11)	(2,662)	
7	T-O-D Subtransmission	12,324	MVARh	$ (1.11)	(13,680)	12,324	MVARh	$ (1.11)	(13,680)	
8	Total	18,208	MVARh		(20,211)	18,208	MVARh		(20,211)	0.0%
9										
10	Emergency Relay Service									
11	Standard Primary	-	kW	$ 0.63	-	-	kW	$ 0.86	-	
12	Standard Subtrans.	-	kW	$ 0.63	-	-	kW	$ 0.86	-	
13	T-O-D Primary	-	kW	$ 0.63	-	-	kW	$ 0.86	-	
14	T-O-D Subtransmission	-	kW	$ 0.63	-	-	kW	$ 0.86	-	
15	Total	-	kW		-	-	kW		-	0.0%
16										
17	Delivery Voltage Credit:									
18	Standard Primary	109,262	kW	$ -	-	109,262	kW	$ -	-	
19	Standard Subtrans.	-	kW	$ (0.44)	-	-	kW	$ (0.60)	-	
20	T-O-D Primary	293,919	kW	$ -	-	293,919	kW	$ -	-	
21	T-O-D Subtransmission	1,138,363	kW	$ (0.44)	(500,880)	1,138,363	kW	$ (0.60)	(683,018)	
22	Total	1,541,544	kW		(500,880)	1,541,544	kW		(683,018)	36.4%
23										
24	Metering Voltage Adjustment:									
25	Standard Primary	1,393,131	$	0%	-	1,456,503	$	0%	-	
26	Standard Subtrans.	-	$	-1%	-	-	$	-1%	-	
27	T-O-D Primary	4,358,631	$	0%	-	4,513,168	$	0%	-	
28	T-O-D Subtransmission	13,407,731	$	-1%	(134,077)	13,901,779	$	-1%	(139,018)	
29	Total	19,159,493	$		(134,077)	19,871,451	$		(139,018)	3.7%
30										
31										
32										
33	Total Base Revenue:				19,477,200				20,184,217	3.6%
34										
35										

Supporting Schedules: Recap Schedules: E-13a

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TAMPA ELECTRIC COMPANY
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FLORIDA PUBLIC SERVICE COMMISSION

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PROVIDE TOTAL NUMBER OF BILLS, MWH's, AND BILLING kW FOR EACH RATE SCHEDULE (INCLUDING STANDARD AND TIME OF USE CUSTOMERS) AND TRANSFER GROUP.

Type of data shown:
XX Projected Test year Ended 12/31/2018

Rate Schedule SBI

Line No.	Type of Charges	Present Revenue Calculation: Units	Present: Charge/Unit	Present: $ Revenue	Proposed Revenue Calculation: Units	Proposed: Charge/Unit	Proposed: $ Revenue	Percent Increase
1								
2	Basic Service Charge:							
3	T-O-D Primary	0 Bills	$ 717	-	0 Bills	$ 716.81	-	
4	T-O-D Subtransmission	80 Bills	$ 2,656	212,451	80 Bills	$ 2,655.64	212,451	
5	Total	80 Bills		212,451	80 Bills		212,451	0.0%
6								
7	Energy Charge - Supplemental:							
8	T-O-D On-Peak - Pri.	- MWH	$ 27.74	-	- MWH	$ 27.74	-	
9	T-O-D On-Peak - Subtrans.	6,127 MWH	$ 27.74	169,963	6,127 MWH	$ 27.74	169,963	
10	T-O-D Off-Peak - Pri.	- MWH	$ 27.74	-	- MWH	$ 27.74	-	
11	T-O-D Off-Peak - Subtrans.	21,491 MWH	$ 27.74	596,160	21,491 MWH	$ 27.74	596,160	
12	Energy Charge - Standby:							
13	T-O-D On-Peak - Pri.	- MWH	$ 11.15	-	- MWH	$ 11.15	-	
14	T-O-D On-Peak - Subtrans.	69,213 MWH	$ 11.15	771,725	69,213 MWH	$ 11.15	771,725	
15	T-O-D Off-Peak - Pri.	- MWH	$ 11.15	-	- MWH	$ 11.15	-	
16	T-O-D Off-Peak - Subtrans.	198,395 MWH	$ 11.15	2,212,104	198,395 MWH	$ 11.15	2,212,104	
17	Total	295,226 MWH		3,749,953	295,226 MWH		3,749,953	0.0%
18								
19	Demand Charge - Supplemental:							
20	T-O-D Billing - Primary	- kW	$ 1.61 kW	-	- kW	$ 2.19 kW	-	
21	T-O-D Billing - Subtrans.	75,667 kW	$ 1.61 kW	121,824	75,667 kW	$ 2.19 kW	165,711	
22	T-O-D Peak - Primary	- kW (1)	$ - kW	-	- kW (1)	$ - kW	-	
23	T-O-D Peak - Subtrans.	42,115 kW (1)	$ - kW	-	42,115 kW (1)	$ - kW	-	
24	Demand Charge - Standby:							
25	T-O-D Facilities Reservation - Pri.	- kW	$ 1.61 kW	-	- kW	$ 1.61 kW	-	
26	T-O-D Facilities Res. - Subtrans.	2,391,609 kW	$ 1.61 kW	3,850,490	2,391,609 kW	$ 1.61 kW	3,850,490	
27	T-O-D Bulk Trans. Res. - Pri.	- kW (1)	$ 1.33 kW-mo.	-	- kW (1)	$ 1.33 kW-mo.	-	
28	T-O-D Bulk Trans. Res. - Subtrans.	289,032 kW (1)	$ 1.33 kW-mo.	384,413	289,032 kW (1)	$ 1.33 kW-mo.	384,413	
29	T-O-D Bulk Trans. Dmd. - Pri.	- kW (1)	$ 0.53 kW-day	-	- kW (1)	$ 0.53 kW-day	-	
30	T-O-D Bulk Trans Dmd. - Subtrans.	14,058,825 kW (1)	$ 0.53 kW-day	7,451,177	14,058,825 kW (1)	$ 0.53 kW-day	7,451,177	
31	Total	2,467,276 kW		11,807,904	2,467,276 kW		11,851,791	0.4%
32								
33								
34	(1) Not included in Total.							
35								

Continued on Page 16

Supporting Schedules: Recap Schedules: E-13a

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TAMPA ELECTRIC COMPANY
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FLORIDA PUBLIC SERVICE COMMISSION

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Type of data shown:
XX Projected Test year Ended 12/31/2018

Rate Schedule SBI

Line No.	Type of Charges	Present Revenue Calculation Units		Charge/Unit	$ Revenue	Proposed Revenue Calculation Units		Charge/Unit	$ Revenue	Percent Increase
1	Continued from Page 19									
2										
3	Power Factor Charge Supplemental & Standby:									
4	T-O-D Primary	-	MVARh	$ 2.22	-	-	MVARh	$ 2.22	-	
5	T-O-D Subtransmission	52,182	MVARh	$ 2.22	115,844	52,182	MVARh	$ 2.22	115,844	
6	Total	52,182	MVARh		115,844	52,182	MVARh		115,844	0.0%
7										
8	Power Factor Credit Supplemental & Standby:									
9	T-O-D Primary	-	MVARh	$ (1.11)	-	-	MVARh	$ (1.11)	-	
10	T-O-D Subtransmission	20,629	MVARh	$ (1.11)	(22,898)	20,629	MVARh	$ (1.11)	(22,898)	
11	Total	20,629	MVARh		(22,898)	20,629	MVARh		(22,898)	0.0%
12										
13	Emergency Relay Charge - Supp.									
14	T-O-D Primary	-	kW	$ 0.63	-	-	kW	$ 0.86	-	
15	T-O-D Subtransmission	-	kW	$ 0.63	-	-	kW	$ 0.86	-	
16	Total	-	kW		-	-	kW		-	0.0%
17										
18	Delivery Voltage Credit - Supplemental.:									
19	T-O-D Primary	-	kW	$ -	-	-	kW	$ -	-	
20	T-O-D Subtransmission	75,667	kW	$ (0.44)	(33,293)	75,667	kW	$ (0.60)	(45,400)	
21	Delivery Voltage Credit. - Standby.:									
22	T-O-D Primary	-	kW	$ -	-	-	kW	$ -	-	
23	T-O-D Subtransmission	2,391,609	kW	$ (0.37)	(884,895)	2,391,609	kW	$ (0.37)	(884,895)	
24	Total	2,467,276	kW		(918,189)	2,467,276	kW		(930,296)	1.3%
25										
26	Metering Voltage Adjustment - Supplemental and Stanby.:									
27	T-O-D Primary	-	$	0.0%	-	-	$	0.0%	-	
28	T-O-D Subtransmission	14,732,614	$	-1.0%	(147,326)	14,764,394	$	-1.0%	(147,644)	
29	Total	14,732,614	$		(147,326)	14,764,394	$		(147,644)	0.2%
30										
31										
32										
33	Total Base Revenue:				14,797,739				14,829,201	0.2%
34										
35										

Supporting Schedules: Recap Schedules: E-13a

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TAMPA ELECTRIC COMPANY
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Type of data shown:
XX Projected Test year Ended 12/31/2018

Rate Schedule LS-1 (Energy Service)

Line No.	Type of Charges	Present Revenue Calculation Units		Charge/Unit		$ Revenue	Proposed Revenue Calculation Units		Charge/Unit		$ Revenue	Percent Increase
1												
2	Basic Service Charge:	2,810	Bills	$	11.62	32,652	2,810	Bills	$	11.62	32,652	0.0%
3												
4	Energy Charge	189,780	MWH	$	27.27	5,175,301	189,780	MWH	$	27.41	5,201,870	0.5%
5												
6												
7	Total Base Revenue:					5,207,953					5,234,522	0.5%
8												
9												
10												
11												
12												
13												
14												
15												
16												
17												
18												
19												
20												
21												
22												
23												
24												
25												
26												
27												
28												
29												
30												
31												
32												
33												
34												
35												

Supporting Schedules: E-13d

Recap Schedules: E-13a

34

TAMPA ELECTRIC COMPANY
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Rollup Base Revenue by Rate Class

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: TAMPA ELECTRIC COMPANY

EXPLANATION: Compare jurisdictional revenue excluding service charges by rate schedule under present and proposed rates for the test year. If any customers are to be transferred from one schedule to another, the revenue and billing determinant information shall be shown separately for the transfer group and not be included under either the new or old classification.

Type of data shown:
XX Projected Year Ended 12/31/2018

($000)

12CP & 1/13 - all demand

Line No.	Rate	(1) Base Revenue at Present Rates	(2) Base Revenue Under Proposed Rates	Increase (3) Dollars (2) - (1)	Increase (4) Percent (3) / (1)
1	RS, RSVP-1	647,455	661,008	13,554	2.1%
2	GS, GST	67,803	69,026	1,223	1.8%
3	CS	1,215	1,226	11	0.9%
4	GSD, GSDT	322,455	330,456	8,001	2.5%
5	GSD Optional	25,574	26,143	568	2.2%
6	SBF, SBFT	4,923	5,004	80	1.6%
7	IS, IST	19,477	20,184	707	3.6%
8	SBI	14,798	14,829	31	0.2%
9	LS-1 (Energy Service)	5,208	5,235	27	0.5%
10	LS-1 (Facilities)	43,545	43,545	-	0.0%
11					
12					
13	TOTAL	$ 1,152,452	$ 1,176,655	$ 24,203	2.1%
14					
15					
16		`			
17					
18					
19					
20					
21					
22	Summary by Rate Class				
23	RS	647,455	661,008	13,554	2.1%
24					
25	GS	69,017	70,252	1,234	1.8%
26					
27	GSD	352,952	361,602	8,650	2.5%
28					
29	IS	34,275	35,013	738	2.2%
30					
31	Lighting	48,753	48,780	27	0.1%
32					
33	TOTAL	1,152,452	1,176,655	24,203	2.1%
34					
35					
36					

Supporting Schedules: E-13c, E-13d

Recap Schedules:

TAMPA ELECTRIC COMPANY
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REVISED: 02/14/2018

Typical Bills Reflecting

First SoBRA Base Revenue Increase

SOBRA
12CP and 1/13 With 40% Allocation to Lighting
All Demand

SCHEDULE A-2 | FULL REVENUE REQUIREMENTS BILL COMPARISON - TYPICAL MONTHLY BILLS | Page 1 of 4

FLORIDA PUBLIC SERVICE COMMISSION | EXPLANATION: For each rate, calculate typical monthly bills for present rates and proposed rates. | Type of data shown:
XX Projected Test year Ended 12/31/2018

COMPANY: TAMPA ELECTRIC COMPANY

RS - RESIDENTIAL SERVICE

	RATE SCHEDULE RS		BILL UNDER PRESENT RATES							BILL UNDER PROPOSED RATES							INCREASE		COSTS IN CENTS/KWH	
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)	(20)
Line No.	TYPICAL KW	KWH	BASE RATE	FUEL CHARGE	ECCR CHARGE	CAPACITY CHARGE	ECRC CHARGE	GRT CHARGE	TOTAL	BASE RATE	FUEL CHARGE	ECCR CHARGE	CAPACITY CHARGE	ECRC CHARGE	GRT CHARGE	TOTAL	DOLLARS (16)-(9)	PERCENT (17)/(9)	PRESENT (9)/(2)*100	PROPOSED (16)/(2)*100
1	0	-	$ 16.62	$ -	$ -	$ -	$ -	$ 0.43	$ 17.05	$ 16.62	$ -	$ -	$ -	$ -	$ 0.43	$ 17.05	$ -	0.0%	-	-
2																				
3	0	100	$ 21.82	$ 2.82	$ 0.25	$ 0.07	$ 0.34	$ 0.65	$ 25.94	$ 22.00	$ 2.82	$ 0.25	$ 0.07	$ 0.34	$ 0.65	$ 26.13	$ 0.19	0.7%	25.94	26.13
4																				
5	0	250	$ 29.62	$ 7.05	$ 0.62	$ 0.17	$ 0.86	$ 0.98	$ 39.28	$ 30.07	$ 7.05	$ 0.62	$ 0.17	$ 0.86	$ 0.99	$ 39.75	$ 0.46	1.2%	15.71	15.90
6																				
7	0	500	$ 42.62	$ 14.09	$ 1.23	$ 0.33	$ 1.72	$ 1.54	$ 61.52	$ 43.52	$ 14.09	$ 1.23	$ 0.33	$ 1.72	$ 1.56	$ 62.45	$ 0.93	1.5%	12.30	12.49
8																				
9	0	750	$ 55.62	$ 21.14	$ 1.85	$ 0.50	$ 2.57	$ 2.09	$ 83.76	$ 56.97	$ 21.14	$ 1.85	$ 0.50	$ 2.57	$ 2.13	$ 85.15	$ 1.39	1.7%	11.17	11.35
10																				
11	0	1,000	$ 68.62	$ 28.18	$ 2.46	$ 0.66	$ 3.43	$ 2.65	$ 106.00	$ 70.43	$ 28.18	$ 2.46	$ 0.66	$ 3.43	$ 2.70	$ 107.85	$ 1.85	1.7%	10.60	10.79
12																				
13	0	1,250	$ 84.39	$ 37.73	$ 3.08	$ 0.83	$ 4.29	$ 3.34	$ 133.64	$ 86.38	$ 37.73	$ 3.08	$ 0.83	$ 4.29	$ 3.39	$ 135.68	$ 2.04	1.5%	10.69	10.85
14																				
15	0	1,500	$ 100.16	$ 47.27	$ 3.69	$ 0.99	$ 5.15	$ 4.03	$ 161.29	$ 102.33	$ 47.27	$ 3.69	$ 0.99	$ 5.15	$ 4.09	$ 163.51	$ 2.22	1.4%	10.75	10.90
16																				
17	0	2,000	$ 131.70	$ 66.36	$ 4.92	$ 1.32	$ 6.86	$ 5.41	$ 216.57	$ 134.23	$ 66.36	$ 4.92	$ 1.32	$ 6.86	$ 5.48	$ 219.17	$ 2.59	1.2%	10.83	10.96
18																				
19	0	3,000	$ 194.78	$ 104.54	$ 7.38	$ 1.98	$ 10.29	$ 8.18	$ 327.15	$ 198.04	$ 104.54	$ 7.38	$ 1.98	$ 10.29	$ 8.26	$ 330.49	$ 3.34	1.0%	10.90	11.02
20																				
21	0	5,000	$ 320.94	$ 180.90	$ 12.30	$ 3.30	$ 17.15	$ 13.71	$ 548.30	$ 325.65	$ 180.90	$ 12.30	$ 3.30	$ 17.15	$ 13.83	$ 553.12	$ 4.83	0.9%	10.97	11.06

Line No.		PRESENT	PROPOSED
22			
23			
24		PRESENT	PROPOSED
25	CUSTOMER CHARGE	16.62 $/Bill	16.62 $/Bill
26	DEMAND CHARGE	- $/KW	- $/KW
27	ENERGY CHARGE		
28	0 - 1,000 KWH	5.200 ¢/kWH	5.381 ¢/kWH
29	Over 1,000 KWH	6.308 ¢/kWH	6.381 ¢/kWH
30	FUEL CHARGE		
31	0 - 1,000 KWH	2.818 ¢/kWH	2.818 ¢/kWH
32	Over 1,000 KWH	3.818 ¢/kWH	3.818 ¢/kWH
33	CONSERVATION CHARGE	0.246 ¢/kWH	0.246 ¢/kWH
34	CAPACITY CHARGE	0.066 ¢/kWH	0.066 ¢/kWH
35	ENVIRONMENTAL CHARGE	0.343 ¢/kWH	0.343 ¢/kWH
36			
37			
38	Note: Cost recovery clause factors are the current 2018 factors. 2018 fuel clause factors used for both PRESENT and PROPOSED bills above includes the fuel benefit of Tranche #1 of SoBRA.		
39			

Supporting Schedules: E-13c, E-14 Supplement | Recap Schedules:

TAMPA ELECTRIC COMPANY
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SOBRA
12CP and 1/13 With 40% Allocation to Lighting
All Demand

FLORIDA PUBLIC SERVICE COMMISSION | EXPLANATION: For each rate, calculate typical monthly bills for present rates and proposed rates. | Type of data shown:
XX Projected Test year Ended 12/31/2018

COMPANY: TAMPA ELECTRIC COMPANY

GS - GENERAL SERVICE NON-DEMAND

Line No.	RATE SCHEDULE GS (1) TYPICAL KW	(2) TYPICAL KWH	BILL UNDER PRESENT RATES (3) BASE RATE	(4) FUEL CHARGE	(5) ECCR CHARGE	(6) CAPACITY CHARGE	(7) ECRC CHARGE	(8) GRT CHARGE	(9) TOTAL	BILL UNDER PROPOSED RATES (10) BASE RATE	(11) FUEL CHARGE	(12) ECCR CHARGE	(13) CAPACITY CHARGE	(14) ECRC CHARGE	(15) GRT CHARGE	(16) TOTAL	INCREASE (17) DOLLARS (16)-(9)	(18) PERCENT (17)/(9)	COSTS IN CENTS/KWH (19) PRESENT (9)/(2)*100	(20) PROPOSED (16)/(2)*100
1	0	-	$ 19.94	$ -	$ -	$ -	$ -	$ 0.51	$ 20.45	$ 19.94	$ -	$ -	$ -	$ -	$ 0.51	$ 20.45	$ -	0.0%	-	-
2																				
3	0	100	$ 25.49	$ 3.13	$ 0.23	$ 0.06	$ 0.34	$ 0.75	$ 30.01	$ 25.62	$ 3.13	$ 0.23	$ 0.06	$ 0.34	$ 0.75	$ 30.14	$ 0.13	0.4%	30.01	30.14
4																				
5	0	250	$ 33.81	$ 7.83	$ 0.58	$ 0.15	$ 0.86	$ 1.11	$ 44.34	$ 34.13	$ 7.83	$ 0.58	$ 0.15	$ 0.86	$ 1.12	$ 44.66	$ 0.33	0.7%	17.74	17.87
6																				
7	0	500	$ 47.69	$ 15.66	$ 1.16	$ 0.30	$ 1.72	$ 1.71	$ 68.23	$ 48.32	$ 15.66	$ 1.16	$ 0.30	$ 1.72	$ 1.72	$ 68.88	$ 0.65	1.0%	13.65	13.78
8																				
9	0	750	$ 61.56	$ 23.49	$ 1.74	$ 0.45	$ 2.57	$ 2.30	$ 92.11	$ 62.51	$ 23.49	$ 1.74	$ 0.45	$ 2.57	$ 2.33	$ 93.09	$ 0.98	1.1%	12.28	12.41
10																				
11	0	1,000	$ 75.43	$ 31.32	$ 2.32	$ 0.60	$ 3.43	$ 2.90	$ 116.00	$ 76.70	$ 31.32	$ 2.32	$ 0.60	$ 3.43	$ 2.93	$ 117.31	$ 1.31	1.1%	11.60	11.73
12																				
13	0	1,250	$ 89.30	$ 39.15	$ 2.90	$ 0.75	$ 4.29	$ 3.50	$ 139.89	$ 90.89	$ 39.15	$ 2.90	$ 0.75	$ 4.29	$ 3.54	$ 141.52	$ 1.63	1.2%	11.19	11.32
14																				
15	0	1,500	$ 103.18	$ 46.98	$ 3.48	$ 0.90	$ 5.15	$ 4.09	$ 163.77	$ 105.08	$ 46.98	$ 3.48	$ 0.90	$ 5.15	$ 4.14	$ 165.73	$ 1.96	1.2%	10.92	11.05
16																				
17	0	2,000	$ 130.92	$ 62.64	$ 4.64	$ 1.20	$ 6.86	$ 5.29	$ 211.55	$ 133.47	$ 62.64	$ 4.64	$ 1.20	$ 6.86	$ 5.35	$ 214.16	$ 2.61	1.2%	10.58	10.71
18																				
19	0	3,000	$ 186.41	$ 93.96	$ 6.96	$ 1.80	$ 10.29	$ 7.68	$ 307.10	$ 190.23	$ 93.96	$ 6.96	$ 1.80	$ 10.29	$ 7.78	$ 311.01	$ 3.92	1.3%	10.24	10.37
20																				
21	0	5,000	$ 297.39	$ 156.60	$ 11.60	$ 3.00	$ 17.15	$ 12.45	$ 498.19	$ 303.75	$ 156.60	$ 11.60	$ 3.00	$ 17.15	$ 12.62	$ 504.72	$ 6.53	1.3%	9.96	10.09
22																				
23	0	8,500	$ 491.61	$ 266.22	$ 19.72	$ 5.10	$ 29.16	$ 20.82	$ 832.62	$ 502.42	$ 266.22	$ 19.72	$ 5.10	$ 29.16	$ 21.09	$ 843.71	$ 11.09	1.3%	9.80	9.93
24																				
25																				

Line No.		PRESENT	PROPOSED
26		PRESENT	PROPOSED
27	CUSTOMER CHARGE	19.94 $/Bill	19.94 $/Bill
28	ENERGY CHARGE	5.549 ¢/kWH	5.676 ¢/kWH
29	FUEL CHARGE	3.132 ¢/kWH	3.132 ¢/kWH
30	CONSERVATION CHARGE	0.232 ¢/kWH	0.232 ¢/kWH
31	CAPACITY CHARGE	0.060 ¢/kWH	0.060 ¢/kWH
32	ENVIRONMENTAL CHARGE	0.343 ¢/kWH	0.343 ¢/kWH
33			
34			
35			
36			
37	Note: Cost recovery clause factors are the current 2018 factors. 2018 fuel clause factors used for both PRESENT and PROPOSED bills above includes the fuel benefit of Tranche #1 of SoBRA.		
38			
39			

Supporting Schedules: E-13c, E-14 Supplement | Recap Schedules:

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SOBRA
12CP and 1/13 With 40% Allocation to Lighting
All Demand

aw | FULL REVENUE REQUIREMENTS BILL COMPARISON - TYPICAL MONTHLY BILLS |

FLORIDA PUBLIC SERVICE COMMISSION | EXPLANATION: For each rate, calculate typical monthly bills for present rates and proposed rates. | Type of data shown: XX Projected Test year Ended 12/31/2018

COMPANY: TAMPA ELECTRIC COMPANY

GSD - GENERAL SERVICE DEMAND

Line No.	RATE SCHEDULE GSD (1) TYPICAL KW	(2) KWH	BILL UNDER PRESENT RATES (3) BASE RATE	(4) FUEL CHARGE	(5) ECCR CHARGE	(6) CAPACITY CHARGE	(7) ECRC CHARGE	(8) GRT CHARGE	(9) TOTAL
1	75	10,950	$ 762.51	$ 342.95	$ 22.01	$ 5.15	$ 37.45	$ 30.00	$ 1,200.07
2	75	19,163	$ 1,138.10	$ 600.17	$ 65.25	$ 15.00	$ 65.54	$ 48.31	$ 1,932.36
3	75	32,850	$ 1,378.18	$ 1,028.86	$ 65.25	$ 15.00	$ 112.35	$ 66.66	$ 2,666.30
4	75	49,275	$ 1,620.78	$ 1,536.27	$ 65.25	$ 15.00	$ 168.52	$ 87.33	$ 3,493.15
5									
6	500	73,000	$ 4,895.04	$ 2,286.36	$ 146.73	$ 34.31	$ 249.66	$ 195.18	$ 7,807.28
7	500	127,750	$ 7,398.98	$ 4,001.13	$ 435.00	$ 100.00	$ 436.91	$ 317.23	$ 12,689.24
8	500	219,000	$ 8,999.50	$ 6,859.08	$ 435.00	$ 100.00	$ 748.98	$ 439.55	$ 17,582.11
9	500	328,500	$ 10,616.81	$ 10,241.81	$ 435.00	$ 100.00	$ 1,123.47	$ 577.36	$ 23,094.45
10									
11	2000	292,000	$ 19,480.44	$ 9,145.44	$ 586.92	$ 137.24	$ 998.64	$ 778.17	$ 31,126.85
12	2000	511,000	$ 29,496.18	$ 16,004.52	$ 1,740.00	$ 400.00	$ 1,747.62	$ 1,266.37	$ 50,654.69
13	2000	876,000	$ 35,898.28	$ 27,436.32	$ 1,740.00	$ 400.00	$ 2,995.92	$ 1,755.65	$ 70,226.17
14	2000	1,314,000	$ 42,367.52	$ 40,967.24	$ 1,740.00	$ 400.00	$ 4,493.88	$ 2,306.89	$ 92,275.52

Line No.	BILL UNDER PROPOSED RATES (10) BASE RATE	(11) FUEL CHARGE	(12) ECCR CHARGE	(13) CAPACITY CHARGE	(14) ECRC CHARGE	(15) GRT CHARGE	(16) TOTAL	INCREASE (17) DOLLARS (16)-(9)	(18) PERCENT (17)/(9)	COSTS IN CENTS/KWH (19) PRESENT (9)/(2)*100	(20) PROPOSED (16)/(2)*100
1	$ 779.15	$ 342.95	$ 22.01	$ 5.15	$ 37.45	$ 30.43	$ 1,217.14	$ 17.07	1.4%	10.96	11.12
2	$ 1,171.85	$ 600.17	$ 65.25	$ 15.00	$ 65.54	$ 49.17	$ 1,966.98	$ 34.62	1.8%	10.08	10.26
3	$ 1,411.93	$ 1,028.86	$ 65.25	$ 15.00	$ 112.35	$ 67.52	$ 2,700.91	$ 34.62	1.3%	8.12	8.22
4	$ 1,654.30	$ 1,536.27	$ 65.25	$ 15.00	$ 168.52	$ 88.19	$ 3,527.53	$ 34.38	1.0%	7.09	7.16
5											
6	$ 5,006.00	$ 2,286.36	$ 146.73	$ 34.31	$ 249.66	$ 198.03	$ 7,921.09	$ 113.81	1.5%	10.69	10.85
7	$ 7,623.98	$ 4,001.13	$ 435.00	$ 100.00	$ 436.91	$ 323.00	$ 12,920.01	$ 230.77	1.8%	9.93	10.11
8	$ 9,224.50	$ 6,859.08	$ 435.00	$ 100.00	$ 748.98	$ 445.32	$ 17,812.88	$ 230.77	1.3%	8.03	8.13
9	$ 10,840.31	$ 10,241.81	$ 435.00	$ 100.00	$ 1,123.47	$ 583.09	$ 23,323.68	$ 229.23	1.0%	7.03	7.10
10											
11	$ 19,924.28	$ 9,145.44	$ 586.92	$ 137.24	$ 998.64	$ 789.55	$ 31,582.07	$ 455.22	1.5%	10.66	10.82
12	$ 30,396.18	$ 16,004.52	$ 1,740.00	$ 400.00	$ 1,747.62	$ 1,289.44	$ 51,577.76	$ 923.08	1.8%	9.91	10.09
13	$ 36,798.28	$ 27,436.32	$ 1,740.00	$ 400.00	$ 2,995.92	$ 1,778.73	$ 71,149.25	$ 923.08	1.3%	8.02	8.12
14	$ 43,261.52	$ 40,967.24	$ 1,740.00	$ 400.00	$ 4,493.88	$ 2,329.81	$ 93,192.44	$ 916.92	1.0%	7.02	7.09

Line No.		PRESENT GSD	PRESENT GSDT		PRESENT GSD OPT.		PROPOSED GSD	PROPOSED GSDT		PROPOSED GSD OPT.	
15											
16											
17											
18											
19	CUSTOMER CHARGE	33.24	33.24	$/Bill	33.24	$/Bill	33.24	33.24		33.24	$/Bill
20	DEMAND CHARGE	10.25	-	$/KW	-	$/KW	10.70	-	$/KW	-	$/KW
21	BILLING	-	3.46	$/KW	-	$/KW	-	3.61	$/KW	-	$/KW
22	PEAK	-	6.79	$/KW	-	$/KW	-	7.09	$/KW	-	$/KW
23	ENERGY CHARGE	1.754	-	¢/KWH	6.660	¢/KWH	1.754	-	¢/KWH	6.812	¢/KWH
24	ON-PEAK	-	3.211	¢/KWH	-	¢/KWH	-	3.211	¢/KWH	-	¢/KWH
25	OFF-PEAK	-	1.159	¢/KWH	-	¢/KWH	-	1.159	¢/KWH	-	¢/KWH
26	FUEL CHARGE	3.132	-	¢/KWH	3.132	¢/KWH	3.132	-	¢/KWH	3.132	¢/KWH
27	ON-PEAK		3.330	¢/KWH	-	¢/KWH		3.330	¢/KWH	-	¢/KWH
28	OFF-PEAK		3.047	¢/KWH	-	¢/KWH		3.047	¢/KWH	-	¢/KWH
29	CONSERVATION CHARGE	0.87	0.87	$/KW	0.201	¢/KWH	0.87	0.87	$/KW	0.201	¢/KWH
30	CAPACITY CHARGE	0.20	0.20	$/KW	0.047	¢/KWH	0.20	0.20	$/KW	0.047	¢/KWH
31	ENVIRONMENTAL CHARGE	0.342	0.342	¢/KWH	0.342	¢/KWH	0.342	0.342	¢/KWH	0.342	¢/KWH
32											

33 Notes:
34 A. The kWh for each kW group is based on 20, 35, 60, and 90% load factors (LF).
35 B. Charges at 20% LF are based on the GSD Option rate; 35% and 60% LF charges are based on the standard rate; and 90% LF charges are based on the TOD rate.
36 C. All calculations assume meter and service at secondary voltage.
37 D. TOD energy charges assume 25/75 on/off-peak % for 90% LF. Peak demand to billing demand ratios are assumed to be 99% at 90% LF.
38 E. Cost recovery clause factors are the current 2018 factors. 2018 fuel clause factors used for both PRESENT and PROPOSED bills above includes the fuel benefit of Tranche #1 of SoBRA.
39

Supporting Schedules: E-13c, E-14 Supplement | Recap Schedules:

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SOBRA
12CP and 1/13 with 40% Allocation to Lighting
All Demand

SCHEDULE A-2 — FULL REVENUE REQUIREMENTS BILL COMPARISON - TYPICAL MONTHLY BILLS — Page 4 of 4

FLORIDA PUBLIC SERVICE COMMISSION — EXPLANATION: For each rate, calculate typical monthly bills for present rates and proposed rates.

Type of data shown:
XX Projected Test year Ended 12/31/2018

COMPANY: TAMPA ELECTRIC COMPANY

IS - INTERRUPTIBLE SERVICE

RATE SCHEDULE IS-1

Line No.	(1) TYPICAL KW	(2) TYPICAL KWH	BILL UNDER PRESENT RATES (3) BASE RATE	(4) CCV CREDIT	(5) FUEL CHARGE	(6) ECCR CHARGE	(7) CAPACITY CHARGE	(8) ECRC CHARGE	(9) GRT CHARGE	(10) TOTAL	BILL UNDER PROPOSED RATES (11) BASE RATE	(12) CCV CREDIT	(13) FUEL CHARGE	(14) ECCR CHARGE	(15) CAPACITY CHARGE	(16) ECRC CHARGE	(17) GRT CHARGE	(18) TOTAL	INCREASE (19) DOLLARS (16)-(9)	(20) PERCENT (17)/(9)	COSTS IN CENTS/KWH (21) PRESENT (9)/(2)*100	(22) FINAL (16)/(2)*100
1	500	127,750	$ 5,038	$ (1,772.75)	$ 3,961.53	$ 335.00	$ 70.00	$ 425.79	$ 207	$ 8,264	$ 5,328	$ (1,772.75)	$ 3,961.53	$ 335.00	$ 70.00	$ 425.41	$ 214.03	$ 8,561.11	$ 297	3.6%	6.47	6.70
2	500	219,000	$ 7,569	$ (3,039.00)	$ 6,791.19	$ 335.00	$ 70.00	$ 729.93	$ 319	$ 12,776	$ 7,859	$ (3,039.00)	$ 6,791.19	$ 335.00	$ 70.00	$ 729.27	$ 326.81	$ 13,072.44	$ 297	2.3%	5.83	5.97
3	500	328,500	$ 10,607	$ (4,558.50)	$ 10,140.80	$ 335.00	$ 70.00	$ 1,093.91	$ 454	$ 18,141	$ 10,897	$ (4,558.50)	$ 10,140.80	$ 335.00	$ 70.00	$ 1,093.91	$ 460.97	$ 18,438.87	$ 297	1.6%	5.52	5.61
4																						
5	1,000	255,500	$ 9,387	$ (3,545.50)	$ 7,923.06	$ 670.00	$ 140.00	$ 851.58	$ 396	$ 15,821	$ 9,967	$ (3,545.50)	$ 7,923.06	$ 670.00	$ 140.00	$ 850.82	$ 410.39	$ 16,415.44	$ 594	3.8%	6.19	6.42
6	1,000	438,000	$ 14,449	$ (6,078.00)	$ 13,582.38	$ 670.00	$ 140.00	$ 1,459.85	$ 621	$ 24,845	$ 15,029	$ (6,078.00)	$ 13,582.38	$ 670.00	$ 140.00	$ 1,458.54	$ 635.95	$ 25,438.10	$ 594	2.4%	5.67	5.81
7	1,000	657,000	$ 20,524	$ (9,117.00)	$ 20,281.59	$ 670.00	$ 140.00	$ 2,187.81	$ 889	$ 35,576	$ 21,104	$ (9,117.00)	$ 20,281.59	$ 670.00	$ 140.00	$ 2,187.81	$ 904.27	$ 36,170.96	$ 595	1.7%	5.41	5.51
8																						
9	5,000	1,277,500	$ 44,177	$ (17,727.50)	$ 39,615.28	$ 3,350.00	$ 700.00	$ 4,257.91	$ 1,907	$ 76,280	$ 47,077	$ (17,727.50)	$ 39,615.28	$ 3,350.00	$ 700.00	$ 4,254.08	$ 1,981.25	$ 79,250.06	$ 2,970	3.9%	5.97	6.20
10	5,000	2,190,000	$ 69,490	$ (30,390.00)	$ 67,911.90	$ 3,350.00	$ 700.00	$ 7,299.27	$ 3,035	$ 121,396	$ 72,390	$ (30,390.00)	$ 67,911.90	$ 3,350.00	$ 700.00	$ 7,292.70	$ 3,109.08	$ 124,363.39	$ 2,968	2.4%	5.54	5.68
11	5,000	3,285,000	$ 99,865	$ (45,585.00)	$ 101,407.95	$ 3,350.00	$ 700.00	$ 10,939.05	$ 4,376	$ 175,053	$ 102,765	$ (45,585.00)	$ 101,407.95	$ 3,350.00	$ 700.00	$ 10,939.05	$ 4,450.69	$ 178,027.70	$ 2,974	1.7%	5.33	5.42
12																						

Line		PRESENT IS	PRESENT IST		PROPOSED IS	PROPOSED IST	
13							
14							
15	CUSTOMER CHARGE	689.11	689.11	$/Bill	689.11	689.11	$/Bill
16	DEMAND CHARGE	1.61	1.61	$/KW	2.19	2.19	$/KW
17	PEAK DEMAND CHARGE	-	-	$/KW	-	-	$/KW
	ENERGY CHARGE	2.774	-	¢/kWH	2.774	-	¢/kWH
18	ON-PEAK ENERGY CHARGE	-	2.774	¢/kWH	-	2.774	¢/kWH
19	OFF-PEAK ENERGY CHARGE	-	2.774	¢/kWH	-	2.774	¢/kWH
20	DELIVERY VOLTAGE CREDIT	-	-	$/KW	-	-	$/KW
21	FUEL CHARGE	3.101	-	¢/kWH	3.101	-	¢/kWH
22	ON-PEAK	-	3.297	¢/kWH	-	3.297	¢/kWH
23	OFF-PEAK	-	3.017	¢/kWH	-	3.017	¢/kWH
24	CONSERVATION CHARGE	0.67	0.67	$/KW	0.67	0.67	$/KW
25	CAPACITY CHARGE	0.14	0.14	$/KW	0.14	0.14	$/KW
26	ENVIRONMENTAL CHARGE	0.333	0.333	¢/kWH	0.333	0.333	¢/kWH
27							
28	GSLM-2 CONTRACT CREDIT VALUE	(10.13)	(10.13)	$/kW	(10.13)	(10.13)	$/kW
29							

30 Notes:
31 A. The kWh for each kW group is based on 35, 60, and 90% load factors (LF).
32 B. Charges at 35% and 60% LF are based on standard rates and charges at 90% LF are based on TOD rates. Peak demand to billing demand ratios are assumed to be 99% at 90% LF.
33 C. Calculations assume meter and service at primary voltage and a power factor of 85%.
34 D. TOD energy charges assume 25/75 on/off-peak % for 90% LF.
35 E. CCV credits in columns 5 and 12 are load-factor adjusted and reflect service at primary voltage.
36 F. Cost recovery clause factors are the current 2018 factors. 2018 fuel clause factors used for both PRESENT and PROPOSED bills above includes the fuel benefit of Tranche #1 of SoBRA.
37 G. The present GSLM-2 Contract Credit Value represents the 2018 factor. The proposed GSLM-2 Contract Credit Value for 2018 is the same.
38
39

Supporting Schedules: E-13c, E-14 Supplement — Recap Schedules:

TAMPA ELECTRIC COMPANY
DOCKET NO. 20170260-EI
REVISED EXHIBIT NO. ___ (WRA-1)
WITNESS: ASHBURN
DOCUMENT NO. 4
PAGE 4 OF 4
FILED: 12/12/2017
REVISED: 02/14/2018

TAMPA ELECTRIC COMPANY
DOCKET NO. 20170260-EI
EXHIBIT NO. ___ (WRA-1)
DOCUMENT NO. 5

Redlined Tariffs

Reflecting First SoBRA Base Revenue Increase

REVISED: 2/14/2018

TWENTY-~~SECOND~~ THIRD REVISED SHEET NO. 6.030
CANCELS TWENTY-~~FIRST~~ SECOND REVISED SHEET NO. 6.030

RESIDENTIAL SERVICE

SCHEDULE: RS

AVAILABLE: Entire service area.

APPLICABLE: To residential consumers in individually metered private residences, apartment units, and duplex units. All energy must be for domestic purposes and should not be shared with or sold to others. In addition, energy used in commonly-owned facilities in condominium and cooperative apartment buildings will qualify for this rate schedule, subject to the following criteria:

1. 100% of the energy is used exclusively for the co-owners' benefit.
2. None of the energy is used in any endeavor which sells or rents a commodity or provides service for a fee.
3. Each point of delivery will be separately metered and billed.
4. A responsible legal entity is established as the customer to whom the Company can render its bills for said service.

Resale not permitted.

Billing charges shall be prorated for billing periods that are less than 25 days or greater than 35 days. If the billing period exceeds 35 days and the billing extension causes energy consumption, based on average daily usage, to exceed 1,000 kWh, the excess consumption will be charged at the lower monthly Energy and Demand Charge.

LIMITATION OF SERVICE: This schedule includes service to single phase motors rated up to 7.5 HP. Three phase service may be provided where available for motors rated 7.5 HP and over.

MONTHLY RATE:

Basic Service Charge:
$16.62

Energy and Demand Charge:

First 1,000 kWh	5.~~200~~381¢ per kWh
All additional kWh	6.~~308~~381¢ per kWh

MINIMUM CHARGE: The Basic Service Charge.

FUEL CHARGE: See Sheet Nos. 6.020 and 6.021.

Continued to Sheet No. 6.031

ISSUED BY: ~~G. L. Gillette~~N. G. Tower, President

DATE EFFECTIVE: ~~June 5, 2017~~

TWENTY-~~THIRD~~ FOURTH REVISED SHEET NO. 6.050
CANCELS TWENTY-~~SECOND~~ THIRD REVISED SHEET NO. 6.050

GENERAL SERVICE - NON DEMAND

SCHEDULE: GS

AVAILABLE: Entire service area.

APPLICABLE: For lighting and power in establishments not classified as residential whose energy consumption has not exceeded 9,000 kWh in any one of the prior twelve (12) consecutive billing periods ending with the current billing period. For any billing period that exceeds 35 days, the energy consumption shall be prorated to that of a 30-day amount for purposes of administering this requirement. Resale not permitted.

CHARACTER OF SERVICE: Single or 3 phase, 60 cycles and approximately 120 volts or higher, at Company's option.

LIMITATION OF SERVICE: All service under this rate shall be furnished through one meter. Standby service permitted on Schedule GST only.

MONTHLY RATE:

Basic Service Charge:

Metered accounts	$19.94
Un-metered accounts	$16.62

Energy and Demand Charge:

5.~~549~~676¢ per kWh

MINIMUM CHARGE: The Basic Service Charge.

EMERGENCY RELAY POWER SUPPLY CHARGE: The monthly charge for emergency relay power supply service shall be 0.1~~67~~71¢ per kWh of billing energy. This charge is in addition to the compensation the customer must make to the Company as a contribution-in-aid of construction.

Continued to Sheet No. 6.051

ISSUED BY: ~~G. L. Gillette~~N. G. Tower, President

DATE EFFECTIVE: ~~January 16, 2017~~

TWENTY-~~SECOND~~ THIRD REVISED SHEET NO. 6.080
CANCELS TWENTY-~~FIRST~~ SECOND REVISED SHEET NO. 6.080

GENERAL SERVICE - DEMAND

SCHEDULE: GSD

AVAILABLE: Entire service area.

APPLICABLE: To any customer whose energy consumption has exceeded 9,000 kWh in any one of the prior twelve (12) consecutive billing periods ending with the current billing period. Also available to customers with energy consumption at any level below 9,000 kWh per billing period who agree to remain on this rate for at least twelve (12) months. For any billing period that exceeds 35 days, the energy consumption shall be prorated to that of a 30-day amount for purposes of administering this requirement. Resale not permitted.

CHARACTER OF SERVICE: A-C; 60 cycles; 3 phase; at any standard Company voltage.

LIMITATION OF SERVICE: Standby service is permitted only for customers who generate less than 20% of their on-site load requirements or whose generating equipment is used for emergency purposes.

MONTHLY RATE:

STANDARD		OPTIONAL	
Basic Service Charge:		Basic Service Charge:	
Secondary Metering Voltage	$ 33.24	Secondary Metering Voltage	$ 33.24
Primary Metering Voltage	$ 144.03	Primary Metering Voltage	$ 144.03
Subtrans. Metering Voltage	$1,096.82	Subtrans. Metering Voltage	$1,096.82
Demand Charge:		Demand Charge:	
$10.~~25~~ 70 per kW of billing demand		$0.00 per kW of billing demand	
Energy Charge:		Energy Charge:	
1.754¢ per kWh		6.~~660~~812¢ per kWh	

The customer may select either standard or optional. Once an option is selected, the customer must remain on that option for twelve (12) consecutive months.

Continued to Sheet No. 6.081

ISSUED BY: ~~G. L. Gillette~~N. G. Tower, President

DATE EFFECTIVE: ~~January 16, 2017~~

~~TWENTIETH~~ TWENTY-FIRST
REVISED SHEET NO. 6.081
CANCELS ~~NINETEENTH~~
TWENTIETH REVISED SHEET NO.
6.081

Continued from Sheet No. 6.080

BILLING DEMAND: The highest measured 30-minute interval kW demand during the billing period.

MINIMUM CHARGE: The Basic Service Charge and any Minimum Charge associated with optional riders.

TEMPORARY DISCONTINUANCE OF SERVICE: Where the use of energy is seasonal or intermittent, no adjustments will be made for a temporary discontinuance of service. Any customer prior to resuming service within 12 months after such service was discontinued will be required to pay all charges which would have been billed if service had not been discontinued.

POWER FACTOR: Power factor will be calculated for customers with measured demands of 1,000 kW or more in any one billing period out of twelve (12) consecutive billing periods ending with the current billing period. When the average power factor during the month is less than 85%, the monthly bill will be increased 0.222¢ for each kVARh by which the reactive energy numerically exceeds 0.619744 times the billing energy. When the average power factor during the month is greater than 90%, the monthly bill will be decreased 0.111¢ for each kVARh by which the reactive energy is numerically less than 0.484322 times the billing energy.

METERING VOLTAGE ADJUSTMENT: When the customer takes energy metered at primary voltage, a discount of 1% will apply to the Demand Charge, Energy Charge, Delivery Voltage Credit, Power Factor billing, and Emergency Relay Power Supply Charge.

When the customer takes energy metered at subtransmission or higher voltage, a discount of 2% will apply to the Demand Charge, Energy Charge, Delivery Voltage Credit, Power Factor billing, and Emergency Relay Power Supply Charge.

DELIVERY VOLTAGE CREDIT: When a customer under the standard rate takes service at primary voltage, a discount of ~~83~~87¢ per kW of billing demand will apply. A discount of $2.~~58~~ 69 per kW of billing demand will apply when a customer under the standard rate takes service at subtransmission or higher voltage.

Continued to Sheet No. 6.082

ISSUED BY: ~~G. L. Gillette~~N. G. Tower, President

DATE EFFECTIVE: ~~February 2, 2017~~

~~SEVENTH~~ EIGHTH REVISED SHEET NO. 6.082
CANCELS ~~SIXTH~~ SEVENTH REVISED SHEET NO. 6.082

Continued from Sheet No. 6.081

When a customer under the optional rate takes service at primary voltage, a discount of 0.~~220~~230¢ per kWh will apply. A discount of 0.~~672~~702¢ per kWh will apply when a customer under the optional rate takes service at subtransmission or higher voltage.

EMERGENCY RELAY POWER SUPPLY CHARGE: The monthly charge for emergency relay power supply service shall be ~~66~~69¢ per kW of billing demand for customers taking service under the standard rate and 0.~~167~~174¢/kWh for customer taking service under the optional rate. This charge is in addition to the compensation the customer must make to the Company as a contribution-in-aid of construction.

FUEL CHARGE: See Sheet Nos. 6.020 and 6.021.

ENERGY CONSERVATION CHARGE: See Sheet Nos. 6.020 and 6.021.

CAPACITY CHARGE: See Sheet Nos. 6.020 and 6.021.

ENVIRONMENTAL COST RECOVERY CHARGE: See Sheet Nos. 6.020 and 6.021.

FLORIDA GROSS RECEIPTS TAX: See Sheet No. 6.021.

FRANCHISE FEE CHARGE: See Sheet No. 6.021.

PAYMENT OF BILLS: See Sheet No. 6.022.

ISSUED BY: ~~G. L. Gillette~~N. G. Tower, President

DATE EFFECTIVE: ~~January 16, 2017~~

TECO TAMPA ELECTRIC AN EMERA COMPANY

~~TWENTIETH~~ TWENTY-FIRST
REVISED SHEET NO. 6.085
CANCELS ~~NINETEENTH~~ TWENTIETH
REVISED SHEET NO. 6.085

INTERRUPTIBLE SERVICE
(CLOSED TO NEW BUSINESS AS OF MAY 7, 2009)

SCHEDULE: IS

AVAILABLE: Entire Service Area.

APPLICABLE: To be eligible for service under Rate Schedule IS, a customer must have been taking interruptible service under rate schedules IS-1, IST-1, IS-3, IST-3, SBI-1, or SBI-3 on May 6, 2009 and have signed the Agreement for the Purchase of Industrial Load Management Service under Rate Schedule GSLM-2. When electric service is desired at more than one location, each such location or point of delivery shall be considered as a separate customer. Resale not permitted.

CHARACTER OF SERVICE: The electric energy supplied under this schedule is three phase primary voltage or higher.

LIMITATION OF SERVICE: Standby service is permitted only for customers who generate less than 20% of their on-site load requirements or whose generating equipment is used for emergency purposes.

MONTHLY RATE:

Basic Service Charge:

Primary Metering Voltage	$ 689.11
Subtransmission Metering Voltage	$2,627.94

Demand Charge:
$~~1.61~~2.19 per KW of billing demand

Energy Charge:
2.774¢ per KWH

Continued to Sheet No. 6.086

ISSUED BY: ~~G. L. Gillette~~N. G. Tower, President

DATE EFFECTIVE: ~~January 16, 2017~~

**~~NINETEENTH~~ TWENTIETH REVISED SHEET NO. 6.086
CANCELS ~~EIGHTEENTH~~ NINETEENTH REVISED SHEET NO. 6.086**

Continued from Sheet No. 6.085

BILLING DEMAND: The highest measured 30-minute interval KW demand during the month.

MINIMUM CHARGE: The Basic Service Charge and any Minimum Charge associated with optional riders.

POWER FACTOR: When the average power factor during the month is less than 85%, the monthly bill will be increased 0.222¢ for each kVARh by which the reactive energy numerically exceeds 0.619744 times the billing energy. When the average power factor during the month is greater than 90%, the monthly bill will be decreased 0.111¢ for each kVARh by which the reactive energy is numerically less than 0.484322 times the billing energy.

METERING VOLTAGE ADJUSTMENT: When the customer takes energy metered at subtransmission or higher voltage, a discount of 1% of the energy and demand charge will apply to the Demand Charge, Energy Charge, Delivery Voltage Credit, Power Factor billing, and Emergency Relay Power Supply Charge.

DELIVERY VOLTAGE CREDIT: When the customer furnishes and installs all subtransmission or higher voltage to utilization voltage substation transformation, a discount of ~~44~~60¢ per KW of billing demand will apply.

EMERGENCY RELAY POWER SUPPLY CHARGE: The monthly charge for emergency relay power supply service shall be ~~63~~86¢ per KW of billing demand. This charge is in addition to the compensation the customer must make to the Company as a contribution-in-aid of construction.

Continued to Sheet No. 6.087

ISSUED BY: ~~G. L. Gillette~~N. G. Tower, President

DATE EFFECTIVE: ~~February 2, 2017~~

CONSTRUCTION SERVICE

SCHEDULE: CS

AVAILABLE: Entire service area.

APPLICABLE: Single phase temporary service used primarily for construction purposes.

LIMITATION OF SERVICE: Service is limited to construction poles and services installed under the TUG program. Construction poles are limited to a maximum of 70 amperes at 240 volts for construction poles. Larger (non-TUG) services and three phase service entrances must be served under the appropriate rate schedule, plus the cost of installing and removing the temporary facilities is required.

MONTHLY RATE:
Basic Service Charge: $19.94

Energy and Demand Charge: 5.~~549~~676¢ per kWh

MINIMUM CHARGE: The Basic Service Charge.

FUEL CHARGE: See Sheet Nos. 6.020 and 6.021.

ENERGY CONSERVATION CHARGE: See Sheet Nos. 6.020 and 6.021.

CAPACITY CHARGE: See Sheet Nos. 6.020 and 6.021.

ENVIRONMENTAL COST RECOVERY CHARGE: See Sheet Nos. 6.020 and 6.021.

FLORIDA GROSS RECEIPTS TAX: Sheet No. 6.021.

FRANCHISE FEE CHARGE: See Sheet No. 6.021.

MISCELLANEOUS: A Temporary Service Charge of $260.00 shall be paid upon application for the recovery of costs associated with providing, installing, and removing the company's temporary service facilities for construction poles. Where the Company is required to provide additional facilities other than a service drop or connection point to the Company's existing distribution system, the customer shall also pay, in advance, for the estimated cost of providing, installing and removing such additional facilities, excluding the cost of any portion of these facilities which will remain as a part of the permanent service.

PAYMENT OF BILLS: See Sheet No. 6.022.

TWENTY-~~SECOND~~ THIRD REVISED SHEET NO. 6.320
CANCELS TWENTY-~~FIRST~~ SECOND REVISED SHEET NO. 6.320

TIME-OF-DAY
GENERAL SERVICE - NON DEMAND
(OPTIONAL)

SCHEDULE: GST

AVAILABLE: Entire service area.

APPLICABLE: For lighting and power in establishments not classified as residential whose energy consumption has not exceeded 9,000 kWh in any one of the prior twelve (12) consecutive billing periods ending with the current billing period. All of the electric load requirements on the customer's premises must be metered at one (1) point of delivery. For any billing period that exceeds 35 days, the energy consumption shall be prorated to that of a 30-day amount for purposes of administering this requirement. Resale not permitted.

CHARACTER OF SERVICE: Single or 3 phase, 60 cycles and approximately 120 volts or higher, at Company's option.

LIMITATION OF SERVICE: All service under this rate shall be furnished through one meter. Standby service permitted.

MONTHLY RATE:

Basic Service Charge:
$22.16

Energy and Demand Charge:
~~15.188~~14.488¢ per kWh during peak hours
~~1.030~~1.545¢ per kWh during off-peak hours

Continued to Sheet No. 6.321

ISSUED BY: ~~G. L. Gillette~~N. G. Tower, President

DATE EFFECTIVE: ~~January 16, 2017~~

TECO TAMPA ELECTRIC AN EMERA COMPANY

~~EIGHTEENTH~~ NINETEENTH REVISED SHEET NO. 6.321
CANCELS ~~SEVENTEENTH~~ EIGHTEENTH REVISED SHEET NO. 6.321

Continued from Sheet No. 6.320

DEFINITIONS OF THE USE PERIODS: All time periods stated in clock time. (Meters are programmed to automatically adjust for changes from standard to daylight saving time and vice-versa.)

	April 1 - October 31	November 1 - March 31
Peak Hours: (Monday-Friday)	12:00 Noon - 9:00 PM	6:00 AM - 10:00 AM and 6:00 PM - 10:00 PM

Off-Peak Hours: All other weekday hours, and all hours on Saturdays, Sundays, New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas Day shall be off-peak.

MINIMUM CHARGE: The Basic Service Charge.

BASIC SERVICE CHARGE CREDIT: Any customer who makes a one time contribution in aid of construction of $94.00 (lump-sum meter payment), shall receive a credit of $2.22 per month. This contribution in aid of construction will be subject to a partial refund if the customer terminates service on this optional time-of-day rate.

TERMS OF SERVICE: A customer electing this optional rate shall have the right to transfer to the standard applicable rate at any time without additional charge for such transaction, except that any customer who requests this optional rate for the second time on the same premises will be required to sign a contract to remain on this rate for at least one (1) year.

EMERGENCY RELAY POWER SUPPLY CHARGE: The monthly charge for emergency relay power supply service shall be 0.~~167~~171¢ per kWh of billing energy. This charge is in addition to the compensation the customer must make to the Company as a contribution-in-aid of construction.

FUEL CHARGE: See Sheet Nos. 6.020 and 6.021.

ENERGY CONSERVATION CHARGE: See Sheet Nos. 6.020 and 6.021.

Continued to Sheet No. 6.322

ISSUED BY: ~~G. L. Gillette~~N. G. Tower, President

DATE EFFECTIVE: ~~January 16, 2017~~

TIME-OF-DAY
GENERAL SERVICE - DEMAND
(OPTIONAL)

SCHEDULE: GSDT

AVAILABLE: Entire service area.

APPLICABLE: To any customer whose energy consumption has exceeded 9,000 kWh in any one of the prior twelve (12) consecutive billing periods ending with the current billing period. Also available to customers with energy consumption at any level below 9,000 kWh per billing period who agree to remain on this rate for at least twelve (12) months. For any billing period that exceeds 35 days, the consumption shall be prorated to that of a 30-day amount for purposes of administering this requirement. Resale not permitted.

CHARACTER OF SERVICE: A-C; 60 cycles; 3 phase; at any standard Company voltage.

LIMITATION OF SERVICE: Standby service is permitted only for customers who generate less than 20% of their on-site load requirements or whose generating equipment is used for emergency purposes.

MONTHLY RATE:

Basic Service Charge:

Secondary Metering Voltage	$ 33.24
Primary Metering Voltage	$ 144.03
Subtransmission Metering Voltage	$1,096.82

Demand Charge:
$3.~~46~~ 61 per kW of billing demand, plus
$~~6.79~~7.09per kW of peak billing demand

Energy Charge:
3.211¢ per kWh during peak hours
1.159¢ per kWh during off-peak hours

Continued to Sheet No. 6.331

ISSUED BY: ~~G. L. Gillette~~N. G. Tower, President **DATE EFFECTIVE:** ~~January 16, 2017~~

~~NINETEENTH~~ TWENTIETH
REVISED SHEET NO. 6.332
CANCELS ~~EIGHTEENTH~~
NINETEENTH REVISED SHEET
NO. 6.332

Continued from Sheet No. 6.331

POWER FACTOR: Power factor will be calculated for customers with measured demands of 1,000 kW in any billing period out of twelve (12) consecutive billing periods ending with the current billing period. When the average power factor during the month is less than 85%, the monthly bill will be increased 0.222¢ for each kVARh by which the reactive energy numerically exceeds 0.619744 times the billing energy. When the average power factor during the month is greater than 90%, the monthly bill will be decreased 0.111¢ for each kVARh by which the reactive energy is numerically less than 0.484322 times the billing energy.

METERING VOLTAGE ADJUSTMENT: When the customer takes energy metered at primary voltage, a discount of 1% will apply to the Demand Charge, Energy Charge, Delivery Voltage Credit, Power Factor billing, and Emergency Relay Power Supply Charge.

When the customer takes energy metered at subtransmission or higher voltage, a discount of 2% will apply to the Demand Charge, Energy Charge, Delivery Voltage Credit, Power Factor billing, and Emergency Relay Power Supply Charge.

DELIVERY VOLTAGE CREDIT: When the customer takes service at primary voltage a discount of ~~83~~87¢ per kW of billing demand will apply. When the customer takes service at subtransmission or higher voltage, a discount of $2.~~58~~ 69 per kW of billing demand will apply.

EMERGENCY RELAY POWER SUPPLY CHARGE: The monthly charge for emergency relay power supply service shall be ~~66~~69¢ per kW of billing demand. This charge is in addition to the compensation the customer must make to the Company as a contribution-in-aid of construction.

FUEL CHARGE: See Sheet Nos. 6.020 and 6.021.

ENERGY CONSERVATION CHARGE: See Sheet Nos. 6.020 and 6.021.

CAPACITY CHARGE: See Sheet Nos. 6.020 and 6.021.

ENVIRONMENTAL COST RECOVERY CHARGE: See Sheet Nos. 6.020 and 6.021.

FLORIDA GROSS RECEIPTS TAX: See Sheet No. 6.021.

FRANCHISE FEE CHARGE: See Sheet No. 6.021.

PAYMENT OF BILLS: See Sheet No. 6.022.

ISSUED BY: ~~G. L. Gillette~~N. G. Tower, President

DATE EFFECTIVE: ~~February 2, 2017~~

~~TWENTIETH~~ TWENTY-FIRST
REVISED SHEET NO. 6.340
CANCELS ~~NINETEENTH~~
TWENTIETH REVISED SHEET NO.
6.340

TIME OF DAY
INTERRUPTIBLE SERVICE
(CLOSED TO NEW BUSINESS AS OF MAY 7, 2009)

SCHEDULE: IST

AVAILABLE: Entire Service Area.

APPLICABLE: To be eligible for service under Rate Schedule IST, a customer must have been taking interruptible service under rate schedules IS-1, IST-1, IS-3, IST-3, SBI-1, or SBI-3 on May 6, 2009 and have signed the Agreement for the Purchase of Industrial Load Management Service under Rate Schedule GSLM-2. When electric service is desired at more than one location, each such location or point of delivery shall be considered as a separate customer. Resale not permitted.

CHARACTER OF SERVICE: The electric energy supplied under this schedule is three phase primary voltage or higher.

LIMITATION OF SERVICE: Standby service is permitted only for customers who generate less than 20% of their on-site load requirements or whose generating equipment is used for emergency purposes.

Basic Service Charge:

Primary Metering Voltage	$ 689.11
Subtransmission Metering Voltage	$2,627.94

Demand Charge:
$~~1.61~~2.19 per KW of billing demand

Energy Charge:
2.774¢ per KWH

Continued to Sheet No. 6.345

ISSUED BY: ~~G. L. Gillette~~N. G. Tower, President

DATE EFFECTIVE: ~~January 16, 2017~~

Continued from Sheet No. 6.345

METERING VOLTAGE ADJUSTMENT: When the customer takes energy metered at subtransmission or higher voltage, a discount of 1% of the energy and demand charge will apply to the Demand Charge, Energy Charge, Delivery Voltage Credit, Power Factor billing, and Emergency Relay Power Supply Charge.

DELIVERY VOLTAGE CREDIT: When the customer furnishes and installs all subtransmission or higher voltage to utilization voltage substation transformation, a discount of ~~44~~60¢ per KW of billing demand will apply.

EMERGENCY RELAY POWER SUPPLY CHARGE: The monthly charge for emergency relay power supply service shall be ~~63~~86¢ per KW of billing demand. This charge is in addition to the compensation the customer must make to the Company as a contribution-in-aid of construction.

FUEL CHARGE: See Sheet Nos. 6.020 and 6.021.

ENERGY CONSERVATION CHARGE: See Sheet Nos. 6.020 and 6.021.

CAPACITY CHARGE: See Sheet Nos. 6.020 and 6.021.

ENVIRONMENTAL COST RECOVERY CHARGE: See Sheet Nos. 6.020 and 6.021.

FLORIDA GROSS RECEIPTS TAX: See Sheet No. 6.021.

FRANCHISE FEE CHARGE: See Sheet No. 6.021.

PAYMENT OF BILLS: See Sheet No. 6.025.

TECO TAMPA ELECTRIC AN EMERA COMPANY

~~EIGHTH~~ NINTH REVISED SHEET NO. 6.565
CANCELS ~~SEVENTH~~ EIGHTH REVISED SHEET NO. 6.565

Continued from Sheet No. 6.560

MONTHLY RATES:
Basic Service Charge: $16.62

Energy and Demand Charges: 5.~~549~~695¢ per kWh (for all pricing periods)

MINIMUM CHARGE: The Basic Service Charge.

FUEL CHARGE: See Sheet Nos. 6.020 and 6.021.

ENERGY CONSERVATION CHARGE: See Sheet Nos. 6.020 and 6.021.

CAPACITY CHARGE: See Sheet Nos. 6.020 and 6.021.

ENVIRONMENTAL COST RECOVERY CHARGE: See Sheet Nos. 6.020 and 6.021.

FLORIDA GROSS RECEIPTS TAX: See Sheet No. 6.021.

FRANCHISE FEE CHARGE: See Sheet No. 6.021.

PAYMENT OF BILLS: See Sheet No. 6.022.

DETERMINATION OF PRICING PERIODS: Pricing periods are established by season for weekdays and weekends. The pricing periods for price levels P_1 (Low Cost Hours), P_2 (Moderate Cost Hours) and P_3 (High Cost Hours) are as follows:

May through October	P_1	P_2	P_3
Weekdays	11 P.M. to 6 A.M.	6 A.M. to 1 P.M. 6 P.M. to 11 P.M.	1 P.M. to 6 P.M.
Weekends	11 P.M. to 6 A.M.	6 A.M. to 11 P.M.	-----------

November through April	P_1	P_2	P_3
Weekdays	11 P.M. to 5 A.M.	5 A.M. to 6 A.M. 10 A.M. to 11 P.M.	6 A.M. to 10 A.M.
Weekends	11 P.M. to 6 A.M.	6 A.M. to 11 P.M.	-----------

The pricing periods for price level P_4 (Critical Cost Hours) shall be determined at the sole discretion of the Company. Level P_4 hours shall not exceed 134 hours per year.

Continued to Sheet No. 6.570

ISSUED BY: ~~G. L. Gillette~~N. G. Tower, President

DATE EFFECTIVE: ~~January 16, 2017~~

~~THIRTEENTH~~ FOURTEENTH
REVISED SHEET NO. 6.601
CANCELS ~~TWELFTH~~
THIRTEENTH REVISED SHEET
NO. 6.601

Continued from Sheet No. 6.600

CHARGES FOR SUPPLEMENTAL SERVICE:

Demand Charge:
$10.~~25~~70 per kW-Month of Supplemental Billing Demand (Supplemental Billing Demand Charge)

Energy Charge:
1.754¢ per Supplemental kWh

DEFINITIONS OF THE USE PERIODS: All time periods stated in clock time. (Meters are programmed to automatically adjust for changes from standard to daylight saving time and vice-versa.)

	April 1 - October 31	November 1 - March 31
Peak Hours: (Monday-Friday)	12:00 Noon - 9:00 PM	6:00 AM - 10:00 AM and 6:00 PM - 10:00 PM

Off-Peak Hours: All other weekday hours, and all hours on Saturdays, Sundays, New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas Day shall be off-peak.

BILLING UNITS:
Demand Units: Metered Demand - The highest measured 30-minute interval kW demand served by the company during the month.

Site Load - The highest kW total of Customer generation plus deliveries by the company less deliveries to the Company, occurring in the same 30-minute interval, during the month.

Normal Generation - The generation level equaled or exceeded by the Customer's generation 10% of the metered intervals during the previous twelve months.

Supplemental Billing Demand - The amount, if any, by which the highest Site Load during any 30-minute interval in the month exceeds Normal Generation, but no greater than Metered Demand.

Continued to Sheet No. 6.602

ISSUED BY: ~~G. L. Gillette~~N. G. Tower, President

DATE EFFECTIVE: ~~January 16, 2017~~

TECO TAMPA ELECTRIC AN EMERA COMPANY

~~FIFTEENTH~~ SIXTEENTH REVISED SHEET NO. 6.603
CANCELS ~~FOURTEENTH~~ FIFTEENTH REVISED SHEET NO. 6.603

Continued from Sheet No. 6.602

METERING VOLTAGE ADJUSTMENT: When the customer takes energy metered at primary voltage, a discount of 1% will apply to the Demand Charge, Energy Charge, Delivery Voltage Credit, Power Factor billing, and Emergency Relay Power Supply Charge.

When the customer takes energy metered at subtransmission or higher voltage, a discount of 2% will apply to the Demand Charge, Energy Charge, Delivery Voltage Credit, Power Factor billing, and Emergency Relay Power Supply Charge.

DELIVERY VOLTAGE CREDIT: When the customer takes service at primary voltage, a discount of ~~83~~87¢ per kW of Supplemental Demand and 69¢ per kW of Standby Demand will apply.

When the customer takes service at subtransmission or higher voltage, a discount of $2.~~58~~ 69 per kW of Supplemental Demand and $2.16 per kW of Standby Demand will apply.

EMERGENCY RELAY POWER SUPPLY CHARGE: The monthly charge for emergency relay power supply service shall be ~~66~~69¢ per kW of Supplemental Demand and Standby Demand. This charge is in addition to the compensation the customer must make to the Company as a contribution-in-aid of construction.

FUEL CHARGE: See Sheet Nos. 6.020 and 6.021. Note: Standby fuel charges shall be based on the time of use (i.e., peak and off-peak) fuel rates for Rate Schedule SBF. Supplemental fuel charges shall be based on the standard fuel rate for Rate Schedule SBF.

ENERGY CONSERVATION CHARGE: See Sheet Nos. 6.020 and 6.021.

CAPACITY CHARGE: See Sheet Nos. 6.020 and 6.021.

ENVIRONMENTAL COST RECOVERY CHARGE: See Sheet Nos. 6.020 and 6.021.

FLORIDA GROSS RECEIPTS TAX: See Sheet No. 6.021.

FRANCHISE FEE CHARGE: See Sheet No. 6.021.

PAYMENT OF BILLS: See Sheet No. 6.022.

ISSUED BY: ~~G. L. Gillette~~N. G. Tower, President **DATE EFFECTIVE:** ~~February 2, 2017~~

~~TENTH~~ ELEVENTH REVISED SHEET NO. 6.606
CANCELS ~~NINTH~~ TENTH REVISED SHEET NO. 6.606

Continued from Sheet No. 6.605

CHARGES FOR SUPPLEMENTAL SERVICE

Demand Charge:

$3.~~46~~61	per kW-Month of Supplemental Demand (Supplemental Billing Demand Charge), plus
$~~6.79~~7.09	per kW-Month of Supplemental Peak Demand (Supplemental Peak Billing Demand Charge)

Energy Charge:

3.211¢	per Supplemental kWh during peak hours
1.159¢	per Supplemental kWh during off-peak hours

DEFINITIONS OF THE USE PERIODS: All time periods stated in clock time. (Meters are programmed to automatically adjust for changes from standard to daylight saving time and vice-versa.)

	April 1 - October 31	November 1 - March 31
Peak Hours: (Monday-Friday)	12:00 Noon - 9:00 PM	6:00 AM - 10:00 AM and 6:00 PM - 10:00 PM

Off-Peak Hours: All other weekday hours, and all hours on Saturdays, Sundays, New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas Day shall be off-peak.

BILLING UNITS:

Demand Units: Metered Demand - The highest measured 30-minute interval kW demand served by the Company during the month.

Metered Peak Demand - The highest measured 30-minute interval kW demand served by the Company during the peak hours.

Site Load - The highest kW total of Customer generation plus deliveries by the company less deliveries to the company, occurring in the same 30-minute interval, during the month.

Continued to Sheet No. 6.607

ISSUED BY: ~~G. L. Gillette~~N. G. Tower, President

DATE EFFECTIVE: ~~January 16, 2017~~

Continued from Sheet No. 6.607

TERM OF SERVICE: Any customer receiving service under this schedule will be required to give the Company written notice at least 60 months prior to transferring to a firm non-standby schedule. Such notice shall be irrevocable unless the Company and the customer should mutually agree to void the notice.

TEMPORARY DISCONTINUANCE OF SERVICE: Where the use of energy is seasonal or intermittent, no adjustments will be made for a temporary discontinuance of service. Any customer prior to resuming service within 12 months after such service was discontinued will be required to pay all charges which would have been billed if service had not been discontinued.

POWER FACTOR: When the average power factor during the month is less than 85%, the monthly bill will be increased 0.222¢ for each kVARh by which the reactive energy numerically exceeds 0.619744 times the billing energy. When the average power factor during the month is greater than 90%, the monthly bill will be decreased 0.111¢ for each kVARh by which the reactive energy is numerically less than 0.484322 times the billing energy.

METERING VOLTAGE ADJUSTMENT: When the customer takes energy metered at primary voltage, a discount of 1% will apply to the Demand Charges, Energy Charges, Delivery Voltage Credit, Power Factor billing,and Emergency Relay Power Supply Charge.

When the customer takes energy metered at subtransmission or higher voltage, a discount of 2% will apply to the Demand Charges, Energy Charges, Delivery Voltage Credit, Power Factor billing,and Emergency Relay Power Supply Charge.

DELIVERY VOLTAGE CREDIT: When the customer takes service at primary voltage, a discount of ~~83~~87¢ per kW of Supplemental Demand and 69¢ per kW of Standby Demand will apply.

When the customer takes service at subtransmission or higher voltage, a discount of $2.~~58~~ 69 per kW of Supplemental Demand and $2.15 per kW of Standby Demand will apply.

EMERGENCY RELAY POWER SUPPLY CHARGE: The monthly charge for emergency relay power supply service shall be ~~66~~69¢ per kW of Supplemental Demand and Standby Demand. This charge is in addition to the compensation the customer must make to the Company as a contribution-in-aid of construction.

Continued to Sheet No. 6.609

ISSUED BY: ~~G. L. Gillette~~N. G. Tower, President

DATE EFFECTIVE: ~~February 2, 2017~~

TECO TAMPA ELECTRIC AN EMERA COMPANY

~~EIGHTH~~ NINTH REVISED SHEET NO. 6.700
CANCELS ~~SEVENTH~~ EIGHTH REVISED SHEET NO. 6.700

INTERRUPTIBLE STANDBY AND SUPPLEMENTAL SERVICE
(CLOSED TO NEW BUSINESS AS OF MAY 7, 2009)

SCHEDULE: SBI

AVAILABLE: Entire service area.

APPLICABLE: Required for all self-generating customers eligible for service under rate schedules IS or IST whose generating capacity in kilowatts (exclusive of emergency generation equipment) exceeds 20% of their site load in kilowatts. Also available to self-generating customers eligible for service under rate schedules IS or IST whose generating capacity in kilowatts does not exceed 20% of their site load in kilowatts, but who agree to all the terms and conditions of this rate schedule. To be eligible for service under this rate schedule, a customer must have been taking interruptible service under rate schedules IS-1, IST-1, IS-3, IST-3, SBI-1, or SBI-3 on May 6, 2009 and have signed the Supplemental Tariff Agreement for the Purchase of Industrial Standby and Supplemental Load Management Rider Service. Resale not permitted.

CHARACTER OF SERVICE: The electric energy supplied under this schedule is three phase primary voltage or higher

LIMITATION OF SERVICE: A customer taking service under this tariff must sign the Tariff Agreement for the Purchase of Standby and Supplemental Service

MONTHLY RATE:

Basic Service Charge:

Primary Metering Voltage	$716.81
Subtransmission Metering Voltage	$2,655.64

Demand Charge:

$~~1.61~~2.19 per KW-Month of Supplemental Demand (Supplemental Demand Charge)
$1.61 per KW-Month of Standby Demand (Local Facilities Reservation Charge)

plus the greater of:
$1.33 per KW-Month of Standby Demand (Power Supply Reservation Charge); or
$0.53 per KW-Day of Actual Standby Billing Demand (Power Supply Demand Charge)

Continued to Sheet No. 6.705

ISSUED BY: ~~G. L. Gillette~~N. G. Tower, President

DATE EFFECTIVE: ~~January 16, 2017~~

TECO TAMPA ELECTRIC AN EMERA COMPANY

~~SIXTH~~ SEVENTH REVISED SHEET NO. 6.715
CANCELS ~~FIFTH~~ SIXTH REVISED SHEET NO. 6.715

Continued from Sheet No. 6.710

POWER FACTOR: When the average power factor during the month is less than 85%, the monthly bill will be increased 0.222¢ for each kVARh by which the reactive energy numerically exceeds 0.619744 times the billing energy. When the average power factor during the month is greater than 90%, the monthly bill will be decreased 0.111¢ for each kVARh by which the reactive energy is numerically less than 0.484322 times the billing energy.

METERING VOLTAGE ADJUSTMENT: When the customer takes energy metered at subtransmission or higher voltage, a discount of 1% will apply to the standby and supplemental demand charges, energy charges, Delivery Voltage Credit, Power Factor billing, and Emergency Relay Power Supply Charges.

DELIVERY VOLTAGE CREDIT: When the customer furnishes and installs all subtransmission or higher voltage to utilization voltage substation transformation, a discount of ~~44~~60¢ per KW of Supplemental Demand and 37¢ per KW of Standby Demand will apply.

EMERGENCY RELAY POWER SUPPLY CHARGE: The monthly charge for emergency relay power supply service shall be ~~63~~86¢ per KW of Supplemental Demand and Standby Demand. This charge is in addition to the compensation the customer must make to the Company as a contribution-in-aid of construction.

FUEL CHARGE: Supplemental energy may be billed at either standard or time-of-day fuel rates at the option of the customer. See Sheet Nos. 6.020 and 6.021.

ENERGY CONSERVATION CHARGE: See Sheet Nos. 6.020 and 6.021.

CAPACITY CHARGE: See Sheet Nos. 6.020 and 6.021.

ENVIRONMENTAL COST RECOVERY CHARGE: See Sheet Nos. 6.020 and 6.021.

FLORIDA GROSS RECEIPTS TAX: See Sheet No. 6.021.

FRANCHISE FEE CHARGE: See Sheet No. 6.021.

PAYMENT OF BILLS: See Sheet No. 6.022.

ISSUED BY: ~~G. L. Gillette~~N. G. Tower, President

DATE EFFECTIVE: ~~February 2, 2017~~

TECO TAMPA ELECTRIC AN EMERA COMPANY

TECO TAMPA ELECTRIC

~~SIXTH~~ SEVENTH REVISED SHEET NO. 6.805
CANCELS ~~FIFTH~~ SIXTH REVISED SHEET NO. 6.805

Continued from Sheet No. 6.800

MONTHLY RATE:

High Pressure Sodium Fixture, Maintenance, and Base Energy Charges:

Rate Code			Lamp Size				Charges per Unit ($)			
					kWh				Base Energy[4]	
Dusk to Dawn	Timed Svc.	Description	Initial Lumens[2]	Lamp Wattage[3]	Dusk to Dawn	Timed Svc.	Fixture	Maint.	Dusk to Dawn	Timed Svc.
800	860	Cobra[1]	4,000	50	20	10	3.16	2.48	0.55	0.27
802	862	Cobra/Nema[1]	6,300	70	29	14	3.20	2.11	0.79	0.38
803	863	Cobra/Nema[1]	9,500	100	44	22	3.63	2.33	1.20	0.60
804	864	Cobra[1]	16,000	150	66	33	4.18	2.02	1.80	0.90
805	865	Cobra[1]	28,500	250	105	52	4.87	2.60	2.86	1.42
806	866	Cobra[1]	50,000	400	163	81	5.09	2.99	4.45	2.21
468	454	Flood[1]	28,500	250	105	52	5.37	2.60	2.86	1.42
478	484	Flood[1]	50,000	400	163	81	5.71	3.00	4.45	2.21
809	869	Mongoose[1]	50,000	400	163	81	6.50	3.02	4.45	2.21
509	508	Post Top (PT)[1]	4,000	50	20	10	3.98	2.48	0.55	0.27
570	530	Classic PT[1]	9,500	100	44	22	11.85	1.89	1.20	0.60
810	870	Coach PT[1]	6,300	70	29	14	4.71	2.11	0.79	0.38
572	532	Colonial PT[1]	9,500	100	44	22	11.75	1.89	1.20	0.60
573	533	Salem PT[1]	9,500	100	44	22	9.03	1.89	1.20	0.60
550	534	Shoebox[1]	9,500	100	44	22	8.01	1.89	1.20	0.60
566	536	Shoebox[1]	28,500	250	105	52	8.69	3.18	2.86	1.42
552	538	Shoebox[1]	50,000	400	163	81	9.52	2.44	4.45	2.21

[1] Closed to new business
[2] Lumen output may vary by lamp configuration and age.
[3] Wattage ratings do not include ballast losses.
[4] The Base Energy charges are calculated by multiplying the kWh times the lighting base energy rate of 2.~~727~~741¢ per kWh for each fixture.

Continued to Sheet No. 6.806

ISSUED BY: ~~G. L. Gillette~~N. G. Tower, President **DATE EFFECTIVE:** ~~January 16, 2017~~

TECO TAMPA ELECTRIC AN EMERA COMPANY

~~FOURTH~~ FIFTH REVISED SHEET NO. 6.806
CANCELS ~~THIRD~~ FOURTH REVISED SHEET NO. 6.806

Continued from Sheet No. 6.805

MONTHLY RATE:

Metal Halide Fixture, Maintenance, and Base Energy Charges:

Rate Code			Lamp Size				Charges per Unit ($)			
					kWh				Base Energy[4]	
Dusk to Dawn	Timed Svc.	Description	Initial Lumens[2]	Lamp Wattage[3]	Dusk to Dawn	Timed Svc.	Fixture	Maint.	Dusk to Dawn	Timed Svc.
704	724	Cobra[1]	29,700	350	138	69	7.53	4.99	3.76	1.88
520	522	Cobra[1]	32,000	400	159	79	6.03	4.01	4.34	2.15
705	725	Flood[1]	29,700	350	138	69	8.55	5.04	3.76	1.88
556	541	Flood[1]	32,000	400	159	79	8.36	4.02	4.34	2.15
558	578	Flood[1]	107,800	1,000	383	191	10.50	8.17	10.44	5.21
701	721	General PT[1]	12,000	150	67	34	10.60	3.92	1.83	0.93
574	548	General PT[1]	14,400	175	74	37	10.89	3.73	2.02	1.01
700	720	Salem PT[1]	12,000	150	67	34	9.33	3.92	1.83	0.93
575	568	Salem PT[1]	14,400	175	74	37	9.38	3.74	2.02	1.01
702	722	Shoebox[1]	12,000	150	67	34	7.22	3.92	1.83	0.93
564	549	Shoebox[1]	12,800	175	74	37	7.95	3.70	2.02	1.01
703	723	Shoebox[1]	29,700	350	138	69	9.55	4.93	3.76	1.88
554	540	Shoebox[1]	32,000	400	159	79	10.02	3.97	4.34	2.15
576	577	Shoebox[1]	107,800	1,000	383	191	16.50	8.17	10.44	5.21

[1] Closed to new business
[2] Lumen output may vary by lamp configuration and age.
[3] Wattage ratings do not include ballast losses.
[4] The Base Energy charges are calculated by multiplying the kWh times the lighting base energy rate of 2.~~727~~741¢ per kWh for each fixture.

Continued to Sheet No. 6.808

ISSUED BY: ~~G. L. Gillette~~N. G. Tower, President **DATE EFFECTIVE:** ~~January 16, 2017~~

TECO TAMPA ELECTRIC AN EMERA COMPANY

~~FIFTH~~ SIXTH REVISED SHEET NO. 6.808
CANCELS ~~FOURTH~~ FIFTH REVISED SHEET NO. 6.808

Continued from Sheet No. 6.806

MONTHLY RATE:

LED Fixture, Maintenance, and Base Energy Charges:

Rate Code			Size				Charges per Unit ($)			
					kWh[1]				Base Energy[4]	
Dusk to Dawn	Timed Svc.	Description	Initial Lumens[2]	Lamp Wattage[3]	Dusk to Dawn	Timed Svc.	Fixture	Maintenance	Dusk to Dawn	Timed Svc.
828	848	Roadway[1]	5,155	56	20	10	7.27	1.74	0.55	0.27
820	840	Roadway [1]	7,577	103	36	18	11.15	1.19	0.98	0.49
821	841	Roadway[1]	8,300	106	37	19	11.15	1.20	1.01	0.52
829	849	Roadway[1]	15,285	157	55	27	11.10	2.26	1.50	0.74
822	842	Roadway[1]	15,300	196	69	34	14.58	1.26	1.88	0.93
823	843	Roadway[1]	14,831	206	72	36	16.80	1.38	1.96	0.98
835	855	Post Top[1]	5,176	60	21	11	16.53	2.28	0.57	0.30
824	844	Post Top[1]	3,974	67	24	12	19.67	1.54	0.65	0.33
825	845	Post Top[1]	6,030	99	35	17	20.51	1.56	0.95	0.46
836	856	Post Top[1]	7,360	100	35	18	16.70	2.28	0.95	0.49
830	850	Area-Lighter[1]	14,100	152	53	27	14.85	2.51	1.45	0.74
826	846	Area-Lighter[1]	13,620	202	71	35	19.10	1.41	1.94	0.95
827	847	Area-Lighter[1]	21,197	309	108	54	20.60	1.55	2.95	1.47
831	851	Flood[1]	22,122	238	83	42	15.90	3.45	2.26	1.15
832	852	Flood[1]	32,087	359	126	63	19.16	4.10	3.44	1.72
833	853	Mongoose[1]	24,140	245	86	43	14.71	3.04	2.35	1.17
834	854	Mongoose[1]	32,093	328	115	57	16.31	3.60	3.14	1.55

(1) Closed to new business
(2) Average
(3) Average wattage. Actual wattage may vary by up to +/- 5 watts.
(4) The Base Energy charges are calculated by multiplying the kWh times the lighting base energy rate of 2.~~727~~741¢ per kWh for each fixture.

Continued to Sheet No. 6.810

ISSUED BY: ~~G. L. Gillette~~N. G. Tower, President **DATE EFFECTIVE:** ~~February 6, 2018~~

~~ORIGINAL~~ FIRST REVISED SHEET NO. 6.809
CANCELS ORIGINAL SHEET NO. 6.809

Continued from Sheet No. 6.808

MONTHLY RATE:

LED Fixture, Maintenance, and Base Energy Charges:

Rate Code			Size				Charges per Unit ($)			
					kWh[1]				Base Energy[3]	
Dusk to Dawn	Timed Svc.	Description	Initial Lumens[1]	Lamp Wattage[2]	Dusk to Dawn	Timed Svc.	Fixture	Maint.	Dusk to Dawn	Timed Svc.
912	981	Roadway	2,600	27	9	5	4.83	1.74	0.25	0.14
914		Roadway	5,392	47	16		5.97	1.74	0.44	
921		Roadway/Area	8,500	88	31		8.97	1.74	0.85	
926	982	Roadway	12,414	105	37	18	6.83	1.19	1.01	0.49
932		Roadway/Area	15,742	133	47		14.15	1.38	1.28	
935		Area-Lighter	16,113	143	50		11.74	1.41	1.36	
937		Roadway	16,251	145	51		8.61	2.26	1.39	
941	983	Roadway	22,233	182	64	32	11.81	2.51	1.75	0.87
945		Area-Lighter	29,533	247	86		16.07	2.51	2.35	
947	984	Area-Lighter	33,600	330	116	58	20.13	1.55	3.16	1.58
951	985	Flood	23,067	199	70	35	11.12	3.45	1.91	0.95
953	986	Flood	33,113	255	89	45	21.48	4.10	2.43	1.23
956	987	Mongoose	23,563	225	79	39	11.78	3.04	2.15	1.06
958		Mongoose	34,937	333	117		17.84	3.60	3.19	
965		Granville Post Top (PT)	3,024	26	9		5.80	2.28	0.25	
967	988	Granville PT	4,990	39	14	7	13.35	2.28	0.38	0.19
968	989	Granville PT Enh[4]	4,476	39	14	7	15.35	2.28	0.38	0.19
971		Salem PT	5,240	55	19		10.95	1.54	0.52	
972		Granville PT	7,076	60	21		14.62	2.28	0.57	
973		Granville PT Enh[4]	6,347	60	21		16.62	2.28	0.57	
975	990	Salem PT	7,188	76	27	13	13.17	1.54	0.74	.35

(1) Average
(2) Average wattage. Actual wattage may vary by up to +/- 10 %.
(3) The Base Energy charges are calculated by multiplying the kWh times the lighting base energy rate of 2.~~727~~741¢ per kWh for each fixture.
(4) Enhanced Post Top. Customizable decorative options

Continued to Sheet No. 6.810

ISSUED BY: ~~G. L. Gillette~~N. G. Tower, President **DATE EFFECTIVE:** ~~February 6, 2018~~

TECO TAMPA ELECTRIC AN EMERA COMPANY

~~FOURTH~~ FIFTH REVISED SHEET NO. 6.815
CANCELS ~~THIRD~~ FOURTH REVISED SHEET NO. 6.815

Continued from Sheet No. 6.810

Miscellaneous Facilities Charges:

Rate Code	Description	Monthly Facility Charge	Monthly Maintenance Charge
563	Timer	$7.54	$1.43
569	PT Bracket (accommodates two post top fixtures)	$4.27	$0.06

NON-STANDARD FACILITIES AND SERVICES:

The customer shall pay all costs associated with additional company facilities and services that are not considered standard for providing lighting service, including but not limited to, the following:

1. relays;
2. distribution transformers installed solely for lighting service;
3. protective shields;
4. bird deterrent devices;
5. light trespass shields;
6. light rotations;
7. light pole relocations;
8. devices required by local regulations to control the levels or duration of illumination including associated planning and engineering costs;
9. removal and replacement of pavement required to install underground lighting cable; and
10. directional boring.

MINIMUM CHARGE: The monthly charge.

FUEL CHARGE: See Sheet Nos. 6.020 and 6.021.

ENERGY CONSERVATION CHARGE: See Sheet Nos. 6.020 and 6.021.

CAPACITY CHARGE: See Sheet Nos. 6.020 and 6.021

ENVIRONMENTAL COST RECOVERY CHARGE: See Sheet Nos. 6.020 and 6.021

FLORIDA GROSS RECEIPTS TAX: See Sheet No. 6.021

FRANCHISE FEE: See Sheet No. 6.021

PAYMENT OF BILLS: See Sheet No. 6.022

SPECIAL CONDITIONS:
On customer-owned public street and highway lighting systems not subject to other rate schedules, the monthly rate for energy served at primary or secondary voltage, at the company's option, shall be 2.~~727~~741¢ per kWh of metered usage, plus a Basic Service Charge of $11.62 per month and the applicable additional charges as specified on Sheet Nos. 6.020 and 6.021.

Continued to Sheet No. 6.820

ISSUED BY: ~~G. L. Gillette~~N. G. Tower, President

DATE EFFECTIVE: ~~January 16, 2017~~

Clean Tariffs

Reflecting First SoBRA Base Revenue Increase

REVISED: 2/14/2018

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

TWENTY-THIRD REVISED SHEET NO. 6.030
CANCELS TWENTY-SECOND REVISED SHEET NO. 6.030

RESIDENTIAL SERVICE

SCHEDULE: RS

AVAILABLE: Entire service area.

APPLICABLE: To residential consumers in individually metered private residences, apartment units, and duplex units. All energy must be for domestic purposes and should not be shared with or sold to others. In addition, energy used in commonly-owned facilities in condominium and cooperative apartment buildings will qualify for this rate schedule, subject to the following criteria:

1. 100% of the energy is used exclusively for the co-owners' benefit.
2. None of the energy is used in any endeavor which sells or rents a commodity or provides service for a fee.
3. Each point of delivery will be separately metered and billed.
4. A responsible legal entity is established as the customer to whom the Company can render its bills for said service.

Resale not permitted.

Billing charges shall be prorated for billing periods that are less than 25 days or greater than 35 days. If the billing period exceeds 35 days and the billing extension causes energy consumption, based on average daily usage, to exceed 1,000 kWh, the excess consumption will be charged at the lower monthly Energy and Demand Charge.

LIMITATION OF SERVICE: This schedule includes service to single phase motors rated up to 7.5 HP. Three phase service may be provided where available for motors rated 7.5 HP and over.

MONTHLY RATE:

Basic Service Charge:
$16.62

Energy and Demand Charge:

First 1,000 kWh	5.381¢ per kWh
All additional kWh	6.381¢ per kWh

MINIMUM CHARGE: The Basic Service Charge.

FUEL CHARGE: See Sheet Nos. 6.020 and 6.021.

Continued to Sheet No. 6.031

ISSUED BY: N. G. Tower, President **DATE EFFECTIVE:**

GENERAL SERVICE - NON DEMAND

SCHEDULE: GS

AVAILABLE: Entire service area.

APPLICABLE: For lighting and power in establishments not classified as residential whose energy consumption has not exceeded 9,000 kWh in any one of the prior twelve (12) consecutive billing periods ending with the current billing period. For any billing period that exceeds 35 days, the energy consumption shall be prorated to that of a 30-day amount for purposes of administering this requirement. Resale not permitted.

CHARACTER OF SERVICE: Single or 3 phase, 60 cycles and approximately 120 volts or higher, at Company's option.

LIMITATION OF SERVICE: All service under this rate shall be furnished through one meter. Standby service permitted on Schedule GST only.

MONTHLY RATE:

Basic Service Charge:

Metered accounts	$19.94
Un-metered accounts	$16.62

Energy and Demand Charge:

5.676¢ per kWh

MINIMUM CHARGE: The Basic Service Charge.

EMERGENCY RELAY POWER SUPPLY CHARGE: The monthly charge for emergency relay power supply service shall be 0.171¢ per kWh of billing energy. This charge is in addition to the compensation the customer must make to the Company as a contribution-in-aid of construction.

Continued to Sheet No. 6.051

ISSUED BY: N. G. Tower, President

DATE EFFECTIVE:

GENERAL SERVICE - DEMAND

SCHEDULE: GSD

AVAILABLE: Entire service area.

APPLICABLE: To any customer whose energy consumption has exceeded 9,000 kWh in any one of the prior twelve (12) consecutive billing periods ending with the current billing period. Also available to customers with energy consumption at any level below 9,000 kWh per billing period who agree to remain on this rate for at least twelve (12) months. For any billing period that exceeds 35 days, the energy consumption shall be prorated to that of a 30-day amount for purposes of administering this requirement. Resale not permitted.

CHARACTER OF SERVICE: A-C; 60 cycles; 3 phase; at any standard Company voltage.

LIMITATION OF SERVICE: Standby service is permitted only for customers who generate less than 20% of their on-site load requirements or whose generating equipment is used for emergency purposes.

MONTHLY RATE:

	STANDARD		OPTIONAL
Basic Service Charge:		Basic Service Charge:	
Secondary Metering Voltage	$ 33.24	Secondary Metering Voltage	$ 33.24
Primary Metering Voltage	$ 144.03	Primary Metering Voltage	$ 144.03
Subtrans. Metering Voltage	$1,096.82	Subtrans. Metering Voltage	$1,096.82
Demand Charge:		Demand Charge:	
$10.70 per kW of billing demand		$0.00 per kW of billing demand	
Energy Charge:		Energy Charge:	
1.754¢ per kWh		6.812¢ per kWh	

The customer may select either standard or optional. Once an option is selected, the customer must remain on that option for twelve (12) consecutive months.

Continued to Sheet No. 6.081

TECO TAMPA ELECTRIC AN EMERA COMPANY

TWENTY-FIRST REVISED SHEET NO. 6.081
CANCELS TWENTIETH REVISED SHEET NO. 6.081

Continued from Sheet No. 6.080

BILLING DEMAND: The highest measured 30-minute interval kW demand during the billing period.

MINIMUM CHARGE: The Basic Service Charge and any Minimum Charge associated with optional riders.

TEMPORARY DISCONTINUANCE OF SERVICE: Where the use of energy is seasonal or intermittent, no adjustments will be made for a temporary discontinuance of service. Any customer prior to resuming service within 12 months after such service was discontinued will be required to pay all charges which would have been billed if service had not been discontinued.

POWER FACTOR: Power factor will be calculated for customers with measured demands of 1,000 kW or more in any one billing period out of twelve (12) consecutive billing periods ending with the current billing period. When the average power factor during the month is less than 85%, the monthly bill will be increased 0.222¢ for each kVARh by which the reactive energy numerically exceeds 0.619744 times the billing energy. When the average power factor during the month is greater than 90%, the monthly bill will be decreased 0.111¢ for each kVARh by which the reactive energy is numerically less than 0.484322 times the billing energy.

METERING VOLTAGE ADJUSTMENT: When the customer takes energy metered at primary voltage, a discount of 1% will apply to the Demand Charge, Energy Charge, Delivery Voltage Credit, Power Factor billing, and Emergency Relay Power Supply Charge.

When the customer takes energy metered at subtransmission or higher voltage, a discount of 2% will apply to the Demand Charge, Energy Charge, Delivery Voltage Credit, Power Factor billing, and Emergency Relay Power Supply Charge.

DELIVERY VOLTAGE CREDIT: When a customer under the standard rate takes service at primary voltage, a discount of 87¢ per kW of billing demand will apply. A discount of $2.69 per kW of billing demand will apply when a customer under the standard rate takes service at subtransmission or higher voltage.

Continued to Sheet No. 6.082

ISSUED BY: N. G. Tower, President **DATE EFFECTIVE:**

Continued from Sheet No. 6.081

When a customer under the optional rate takes service at primary voltage, a discount of 0.230¢ per kWh will apply. A discount of 0.702¢ per kWh will apply when a customer under the optional rate takes service at subtransmission or higher voltage.

EMERGENCY RELAY POWER SUPPLY CHARGE: The monthly charge for emergency relay power supply service shall be 69¢ per kW of billing demand for customers taking service under the standard rate and 0.174¢/kWh for customer taking service under the optional rate. This charge is in addition to the compensation the customer must make to the Company as a contribution-in-aid of construction.

FUEL CHARGE: See Sheet Nos. 6.020 and 6.021.

ENERGY CONSERVATION CHARGE: See Sheet Nos. 6.020 and 6.021.

CAPACITY CHARGE: See Sheet Nos. 6.020 and 6.021.

ENVIRONMENTAL COST RECOVERY CHARGE: See Sheet Nos. 6.020 and 6.021.

FLORIDA GROSS RECEIPTS TAX: See Sheet No. 6.021.

FRANCHISE FEE CHARGE: See Sheet No. 6.021.

PAYMENT OF BILLS: See Sheet No. 6.022.

ISSUED BY: N. G. Tower, President

DATE EFFECTIVE:

TECO TAMPA ELECTRIC AN EMERA COMPANY

TWENTY-FIRST REVISED SHEET NO. 6.085
CANCELS TWENTIETH REVISED SHEET NO. 6.085

INTERRUPTIBLE SERVICE
(CLOSED TO NEW BUSINESS AS OF MAY 7, 2009)

SCHEDULE: IS

AVAILABLE: Entire Service Area.

APPLICABLE: To be eligible for service under Rate Schedule IS, a customer must have been taking interruptible service under rate schedules IS-1, IST-1, IS-3, IST-3, SBI-1, or SBI-3 on May 6, 2009 and have signed the Agreement for the Purchase of Industrial Load Management Service under Rate Schedule GSLM-2. When electric service is desired at more than one location, each such location or point of delivery shall be considered as a separate customer. Resale not permitted.

CHARACTER OF SERVICE: The electric energy supplied under this schedule is three phase primary voltage or higher.

LIMITATION OF SERVICE: Standby service is permitted only for customers who generate less than 20% of their on-site load requirements or whose generating equipment is used for emergency purposes.

MONTHLY RATE:

Basic Service Charge:

Primary Metering Voltage	$ 689.11
Subtransmission Metering Voltage	$2,627.94

Demand Charge:
$2.19 per KW of billing demand

Energy Charge:
2.774¢ per KWH

Continued to Sheet No. 6.086

ISSUED BY: N. G. Tower, President **DATE EFFECTIVE:**

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

TWENTIETH REVISED SHEET NO. 6.086
CANCELS NINETEENTH REVISED SHEET NO. 6.086

Continued from Sheet No. 6.085

BILLING DEMAND: The highest measured 30-minute interval KW demand during the month.

MINIMUM CHARGE: The Basic Service Charge and any Minimum Charge associated with optional riders.

POWER FACTOR: When the average power factor during the month is less than 85%, the monthly bill will be increased 0.222¢ for each kVARh by which the reactive energy numerically exceeds 0.619744 times the billing energy. When the average power factor during the month is greater than 90%, the monthly bill will be decreased 0.111¢ for each kVARh by which the reactive energy is numerically less than 0.484322 times the billing energy.

METERING VOLTAGE ADJUSTMENT: When the customer takes energy metered at subtransmission or higher voltage, a discount of 1% of the energy and demand charge will apply to the Demand Charge, Energy Charge, Delivery Voltage Credit, Power Factor billing, and Emergency Relay Power Supply Charge.

DELIVERY VOLTAGE CREDIT: When the customer furnishes and installs all subtransmission or higher voltage to utilization voltage substation transformation, a discount of 60¢ per KW of billing demand will apply.

EMERGENCY RELAY POWER SUPPLY CHARGE: The monthly charge for emergency relay power supply service shall be 86¢ per KW of billing demand. This charge is in addition to the compensation the customer must make to the Company as a contribution-in-aid of construction.

Continued to Sheet No. 6.087

ISSUED BY: N. G. Tower, President **DATE EFFECTIVE:**

CONSTRUCTION SERVICE

SCHEDULE: CS

AVAILABLE: Entire service area.

APPLICABLE: Single phase temporary service used primarily for construction purposes.

LIMITATION OF SERVICE: Service is limited to construction poles and services installed under the TUG program. Construction poles are limited to a maximum of 70 amperes at 240 volts for construction poles. Larger (non-TUG) services and three phase service entrances must be served under the appropriate rate schedule, plus the cost of installing and removing the temporary facilities is required.

MONTHLY RATE:
Basic Service Charge: $19.94

Energy and Demand Charge: 5.676¢ per kWh
.
MINIMUM CHARGE: The Basic Service Charge.

FUEL CHARGE: See Sheet Nos. 6.020 and 6.021.

ENERGY CONSERVATION CHARGE: See Sheet Nos. 6.020 and 6.021.

CAPACITY CHARGE: See Sheet Nos. 6.020 and 6.021.

ENVIRONMENTAL COST RECOVERY CHARGE: See Sheet Nos. 6.020 and 6.021.

FLORIDA GROSS RECEIPTS TAX: Sheet No. 6.021.

FRANCHISE FEE CHARGE: See Sheet No. 6.021.

MISCELLANEOUS: A Temporary Service Charge of $260.00 shall be paid upon application for the recovery of costs associated with providing, installing, and removing the company's temporary service facilities for construction poles. Where the Company is required to provide additional facilities other than a service drop or connection point to the Company's existing distribution system, the customer shall also pay, in advance, for the estimated cost of providing, installing and removing such additional facilities, excluding the cost of any portion of these facilities which will remain as a part of the permanent service.

PAYMENT OF BILLS: See Sheet No. 6.022.

TECO TAMPA ELECTRIC AN EMERA COMPANY

TIME-OF-DAY
GENERAL SERVICE - NON DEMAND
(OPTIONAL)

SCHEDULE: GST

AVAILABLE: Entire service area.

APPLICABLE: For lighting and power in establishments not classified as residential whose energy consumption has not exceeded 9,000 kWh in any one of the prior twelve (12) consecutive billing periods ending with the current billing period. All of the electric load requirements on the customer's premises must be metered at one (1) point of delivery. For any billing period that exceeds 35 days, the energy consumption shall be prorated to that of a 30-day amount for purposes of administering this requirement. Resale not permitted.

CHARACTER OF SERVICE: Single or 3 phase, 60 cycles and approximately 120 volts or higher, at Company's option.

LIMITATION OF SERVICE: All service under this rate shall be furnished through one meter. Standby service permitted.

MONTHLY RATE:

Basic Service Charge:
$22.16

Energy and Demand Charge:
14.488¢ per kWh during peak hours
1.545¢ per kWh during off-peak hours

Continued to Sheet No. 6.321

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

NINETEENTH REVISED SHEET NO. 6.321
CANCELS EIGHTEENTH REVISED SHEET NO. 6.321

Continued from Sheet No. 6.320

DEFINITIONS OF THE USE PERIODS: All time periods stated in clock time. (Meters are programmed to automatically adjust for changes from standard to daylight saving time and vice-versa.)

	April 1 - October 31	November 1 - March 31
Peak Hours: (Monday-Friday)	12:00 Noon - 9:00 PM	6:00 AM - 10:00 AM and 6:00 PM - 10:00 PM

Off-Peak Hours: All other weekday hours, and all hours on Saturdays, Sundays, New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas Day shall be off-peak.

MINIMUM CHARGE: The Basic Service Charge.

BASIC SERVICE CHARGE CREDIT: Any customer who makes a one time contribution in aid of construction of $94.00 (lump-sum meter payment), shall receive a credit of $2.22 per month. This contribution in aid of construction will be subject to a partial refund if the customer terminates service on this optional time-of-day rate.

TERMS OF SERVICE: A customer electing this optional rate shall have the right to transfer to the standard applicable rate at any time without additional charge for such transaction, except that any customer who requests this optional rate for the second time on the same premises will be required to sign a contract to remain on this rate for at least one (1) year.

EMERGENCY RELAY POWER SUPPLY CHARGE: The monthly charge for emergency relay power supply service shall be 0.171¢ per kWh of billing energy. This charge is in addition to the compensation the customer must make to the Company as a contribution-in-aid of construction.

FUEL CHARGE: See Sheet Nos. 6.020 and 6.021.

ENERGY CONSERVATION CHARGE: See Sheet Nos. 6.020 and 6.021.

Continued to Sheet No. 6.322

ISSUED BY: N. G. Tower, President **DATE EFFECTIVE:**

TIME-OF-DAY
GENERAL SERVICE - DEMAND
(OPTIONAL)

SCHEDULE: GSDT

AVAILABLE: Entire service area.

APPLICABLE: To any customer whose energy consumption has exceeded 9,000 kWh in any one of the prior twelve (12) consecutive billing periods ending with the current billing period. Also available to customers with energy consumption at any level below 9,000 kWh per billing period who agree to remain on this rate for at least twelve (12) months. For any billing period that exceeds 35 days, the consumption shall be prorated to that of a 30-day amount for purposes of administering this requirement. Resale not permitted.

CHARACTER OF SERVICE: A-C; 60 cycles; 3 phase; at any standard Company voltage.

LIMITATION OF SERVICE: Standby service is permitted only for customers who generate less than 20% of their on-site load requirements or whose generating equipment is used for emergency purposes.

MONTHLY RATE:

Basic Service Charge:

Secondary Metering Voltage	$ 33.24
Primary Metering Voltage	$ 144.03
Subtransmission Metering Voltage	$1,096.82

Demand Charge:

$3.61 per kW of billing demand, plus
$7.09per kW of peak billing demand

Energy Charge:

3.211¢ per kWh during peak hours
1.159¢ per kWh during off-peak hours

Continued to Sheet No. 6.331

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

TWENTIETH REVISED SHEET NO. 6.332
CANCELS NINETEENTH REVISED SHEET NO. 6.332

Continued from Sheet No. 6.331

POWER FACTOR: Power factor will be calculated for customers with measured demands of 1,000 kW in any billing period out of twelve (12) consecutive billing periods ending with the current billing period. When the average power factor during the month is less than 85%, the monthly bill will be increased 0.222¢ for each kVARh by which the reactive energy numerically exceeds 0.619744 times the billing energy. When the average power factor during the month is greater than 90%, the monthly bill will be decreased 0.111¢ for each kVARh by which the reactive energy is numerically less than 0.484322 times the billing energy.

METERING VOLTAGE ADJUSTMENT: When the customer takes energy metered at primary voltage, a discount of 1% will apply to the Demand Charge, Energy Charge, Delivery Voltage Credit, Power Factor billing, and Emergency Relay Power Supply Charge.

When the customer takes energy metered at subtransmission or higher voltage, a discount of 2% will apply to the Demand Charge, Energy Charge, Delivery Voltage Credit, Power Factor billing, and Emergency Relay Power Supply Charge.

DELIVERY VOLTAGE CREDIT: When the customer takes service at primary voltage a discount of 87¢ per kW of billing demand will apply. When the customer takes service at subtransmission or higher voltage, a discount of $2.69 per kW of billing demand will apply.

EMERGENCY RELAY POWER SUPPLY CHARGE: The monthly charge for emergency relay power supply service shall be 69¢ per kW of billing demand. This charge is in addition to the compensation the customer must make to the Company as a contribution-in-aid of construction.

FUEL CHARGE: See Sheet Nos. 6.020 and 6.021.

ENERGY CONSERVATION CHARGE: See Sheet Nos. 6.020 and 6.021.

CAPACITY CHARGE: See Sheet Nos. 6.020 and 6.021.

ENVIRONMENTAL COST RECOVERY CHARGE: See Sheet Nos. 6.020 and 6.021.

FLORIDA GROSS RECEIPTS TAX: See Sheet No. 6.021.

FRANCHISE FEE CHARGE: See Sheet No. 6.021.

PAYMENT OF BILLS: See Sheet No. 6.022.

ISSUED BY: N. G. Tower, President **DATE EFFECTIVE:**

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

TWENTY-FIRST REVISED SHEET NO. 6.340
CANCELS TWENTIETH REVISED SHEET NO. 6.340

TIME OF DAY
INTERRUPTIBLE SERVICE
(CLOSED TO NEW BUSINESS AS OF MAY 7, 2009)

SCHEDULE: IST

AVAILABLE: Entire Service Area.

APPLICABLE: To be eligible for service under Rate Schedule IST, a customer must have been taking interruptible service under rate schedules IS-1, IST-1, IS-3, IST-3, SBI-1, or SBI-3 on May 6, 2009 and have signed the Agreement for the Purchase of Industrial Load Management Service under Rate Schedule GSLM-2. When electric service is desired at more than one location, each such location or point of delivery shall be considered as a separate customer. Resale not permitted.

CHARACTER OF SERVICE: The electric energy supplied under this schedule is three phase primary voltage or higher.

LIMITATION OF SERVICE: Standby service is permitted only for customers who generate less than 20% of their on-site load requirements or whose generating equipment is used for emergency purposes.

Basic Service Charge:

Primary Metering Voltage	$ 689.11
Subtransmission Metering Voltage	$2,627.94

Demand Charge:
$2.19per KW of billing demand

Energy Charge:
2.774¢ per KWH

Continued to Sheet No. 6.345

ISSUED BY: N. G. Tower, President **DATE EFFECTIVE:**

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

TWENTY-SIXTH REVISED SHEET NO. 6.350
CANCELS TWENTY-FIFTH REVISED SHEET NO. 6.350

Continued from Sheet No. 6.345

METERING VOLTAGE ADJUSTMENT: When the customer takes energy metered at subtransmission or higher voltage, a discount of 1% of the energy and demand charge will apply to the Demand Charge, Energy Charge, Delivery Voltage Credit, Power Factor billing, and Emergency Relay Power Supply Charge.

DELIVERY VOLTAGE CREDIT: When the customer furnishes and installs all subtransmission or higher voltage to utilization voltage substation transformation, a discount of 60¢ per KW of billing demand will apply.

EMERGENCY RELAY POWER SUPPLY CHARGE: The monthly charge for emergency relay power supply service shall be 86¢ per KW of billing demand. This charge is in addition to the compensation the customer must make to the Company as a contribution-in-aid of construction.

FUEL CHARGE: See Sheet Nos. 6.020 and 6.021.

ENERGY CONSERVATION CHARGE: See Sheet Nos. 6.020 and 6.021.

CAPACITY CHARGE: See Sheet Nos. 6.020 and 6.021.

ENVIRONMENTAL COST RECOVERY CHARGE: See Sheet Nos. 6.020 and 6.021.

FLORIDA GROSS RECEIPTS TAX: See Sheet No. 6.021.

FRANCHISE FEE CHARGE: See Sheet No. 6.021.

PAYMENT OF BILLS: See Sheet No. 6.025.

ISSUED BY: N. G. Tower, President **DATE EFFECTIVE:**

TECO TAMPA ELECTRIC AN EMERA COMPANY

NINTH REVISED SHEET NO. 6.565
CANCELS EIGHTH REVISED SHEET NO. 6.565

Continued from Sheet No. 6.560

MONTHLY RATES:
Basic Service Charge: $16.62

Energy and Demand Charges: 5.695¢ per kWh (for all pricing periods)

MINIMUM CHARGE: The Basic Service Charge.

FUEL CHARGE: See Sheet Nos. 6.020 and 6.021.

ENERGY CONSERVATION CHARGE: See Sheet Nos. 6.020 and 6.021.

CAPACITY CHARGE: See Sheet Nos. 6.020 and 6.021.

ENVIRONMENTAL COST RECOVERY CHARGE: See Sheet Nos. 6.020 and 6.021.

FLORIDA GROSS RECEIPTS TAX: See Sheet No. 6.021.

FRANCHISE FEE CHARGE: See Sheet No. 6.021.

PAYMENT OF BILLS: See Sheet No. 6.022.

DETERMINATION OF PRICING PERIODS: Pricing periods are established by season for weekdays and weekends. The pricing periods for price levels P_1 (Low Cost Hours), P_2 (Moderate Cost Hours) and P_3 (High Cost Hours) are as follows:

May through October	P_1	P_2	P_3
Weekdays	11 P.M. to 6 A.M.	6 A.M. to 1 P.M. 6 P.M. to 11 P.M.	1 P.M. to 6 P.M.
Weekends	11 P.M. to 6 A.M.	6 A.M. to 11 P.M.	-----------

November through April	P_1	P_2	P_3
Weekdays	11 P.M. to 5 A.M.	5 A.M. to 6 A.M. 10 A.M. to 11 P.M.	6 A.M. to 10 A.M.
Weekends	11 P.M. to 6 A.M.	6 A.M. to 11 P.M.	-----------

The pricing periods for price level P_4 (Critical Cost Hours) shall be determined at the sole discretion of the Company. Level P_4 hours shall not exceed 134 hours per year.

Continued to Sheet No. 6.570

ISSUED BY: N. G. Tower, President **DATE EFFECTIVE:**

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

FOURTEENTH REVISED SHEET NO. 6.601
CANCELS THIRTEENTH REVISED SHEET NO. 6.601

Continued from Sheet No. 6.600

CHARGES FOR SUPPLEMENTAL SERVICE:

Demand Charge:
$10.70 per kW-Month of Supplemental Billing Demand (Supplemental Billing Demand Charge)

Energy Charge:
1.754¢ per Supplemental kWh

DEFINITIONS OF THE USE PERIODS: All time periods stated in clock time. (Meters are programmed to automatically adjust for changes from standard to daylight saving time and vice-versa.)

	April 1 - October 31	November 1 - March 31
Peak Hours: (Monday-Friday)	12:00 Noon - 9:00 PM	6:00 AM - 10:00 AM and 6:00 PM - 10:00 PM

Off-Peak Hours: All other weekday hours, and all hours on Saturdays, Sundays, New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas Day shall be off-peak.

BILLING UNITS:

Demand Units: Metered Demand - The highest measured 30-minute interval kW demand served by the company during the month.

Site Load - The highest kW total of Customer generation plus deliveries by the company less deliveries to the Company, occurring in the same 30-minute interval, during the month.

Normal Generation - The generation level equaled or exceeded by the Customer's generation 10% of the metered intervals during the previous twelve months.

Supplemental Billing Demand - The amount, if any, by which the highest Site Load during any 30-minute interval in the month exceeds Normal Generation, but no greater than Metered Demand.

Continued to Sheet No. 6.602

ISSUED BY: N. G. Tower, President **DATE EFFECTIVE:**

Continued from Sheet No. 6.602

METERING VOLTAGE ADJUSTMENT: When the customer takes energy metered at primary voltage, a discount of 1% will apply to the Demand Charge, Energy Charge, Delivery Voltage Credit, Power Factor billing, and Emergency Relay Power Supply Charge.

When the customer takes energy metered at subtransmission or higher voltage, a discount of 2% will apply to the Demand Charge, Energy Charge, Delivery Voltage Credit, Power Factor billing, and Emergency Relay Power Supply Charge.

DELIVERY VOLTAGE CREDIT: When the customer takes service at primary voltage, a discount of 87¢ per kW of Supplemental Demand and 69¢ per kW of Standby Demand will apply.

When the customer takes service at subtransmission or higher voltage, a discount of $2.69 per kW of Supplemental Demand and $2.16 per kW of Standby Demand will apply.

EMERGENCY RELAY POWER SUPPLY CHARGE: The monthly charge for emergency relay power supply service shall be 69¢ per kW of Supplemental Demand and Standby Demand. This charge is in addition to the compensation the customer must make to the Company as a contribution-in-aid of construction.

FUEL CHARGE: See Sheet Nos. 6.020 and 6.021. Note: Standby fuel charges shall be based on the time of use (i.e., peak and off-peak) fuel rates for Rate Schedule SBF. Supplemental fuel charges shall be based on the standard fuel rate for Rate Schedule SBF.

ENERGY CONSERVATION CHARGE: See Sheet Nos. 6.020 and 6.021.

CAPACITY CHARGE: See Sheet Nos. 6.020 and 6.021.

ENVIRONMENTAL COST RECOVERY CHARGE: See Sheet Nos. 6.020 and 6.021.

FLORIDA GROSS RECEIPTS TAX: See Sheet No. 6.021.

FRANCHISE FEE CHARGE: See Sheet No. 6.021.

PAYMENT OF BILLS: See Sheet No. 6.022.

Continued from Sheet No. 6.605

CHARGES FOR SUPPLEMENTAL SERVICE

Demand Charge:

$3.61	per kW-Month of Supplemental Demand (Supplemental Billing Demand Charge), plus
$7.09	per kW-Month of Supplemental Peak Demand (Supplemental Peak Billing Demand Charge)

Energy Charge:

3.211¢	per Supplemental kWh during peak hours
1.159¢	per Supplemental kWh during off-peak hours

DEFINITIONS OF THE USE PERIODS: All time periods stated in clock time. (Meters are programmed to automatically adjust for changes from standard to daylight saving time and vice-versa.)

	April 1 - October 31	November 1 - March 31
Peak Hours: (Monday-Friday)	12:00 Noon - 9:00 PM	6:00 AM - 10:00 AM and 6:00 PM - 10:00 PM

Off-Peak Hours: All other weekday hours, and all hours on Saturdays, Sundays, New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas Day shall be off-peak.

BILLING UNITS:

Demand Units: Metered Demand - The highest measured 30-minute interval kW demand served by the Company during the month.

Metered Peak Demand - The highest measured 30-minute interval kW demand served by the Company during the peak hours.

Site Load - The highest kW total of Customer generation plus deliveries by the company less deliveries to the company, occurring in the same 30-minute interval, during the month.

Continued to Sheet No. 6.607

TECO TAMPA ELECTRIC AN EMERA COMPANY

Continued from Sheet No. 6.607

TERM OF SERVICE: Any customer receiving service under this schedule will be required to give the Company written notice at least 60 months prior to transferring to a firm non-standby schedule. Such notice shall be irrevocable unless the Company and the customer should mutually agree to void the notice.

TEMPORARY DISCONTINUANCE OF SERVICE: Where the use of energy is seasonal or intermittent, no adjustments will be made for a temporary discontinuance of service. Any customer prior to resuming service within 12 months after such service was discontinued will be required to pay all charges which would have been billed if service had not been discontinued.

POWER FACTOR: When the average power factor during the month is less than 85%, the monthly bill will be increased 0.222¢ for each kVARh by which the reactive energy numerically exceeds 0.619744 times the billing energy. When the average power factor during the month is greater than 90%, the monthly bill will be decreased 0.111¢ for each kVARh by which the reactive energy is numerically less than 0.484322 times the billing energy.

METERING VOLTAGE ADJUSTMENT: When the customer takes energy metered at primary voltage, a discount of 1% will apply to the Demand Charges, Energy Charges, Delivery Voltage Credit, Power Factor billing,and Emergency Relay Power Supply Charge.

When the customer takes energy metered at subtransmission or higher voltage, a discount of 2% will apply to the Demand Charges, Energy Charges, Delivery Voltage Credit, Power Factor billing,and Emergency Relay Power Supply Charge.

DELIVERY VOLTAGE CREDIT: When the customer takes service at primary voltage, a discount of 87¢ per kW of Supplemental Demand and 69¢ per kW of Standby Demand will apply.

When the customer takes service at subtransmission or higher voltage, a discount of $2.69 per kW of Supplemental Demand and $2.15 per kW of Standby Demand will apply.

EMERGENCY RELAY POWER SUPPLY CHARGE: The monthly charge for emergency relay power supply service shall be 69¢ per kW of Supplemental Demand and Standby Demand. This charge is in addition to the compensation the customer must make to the Company as a contribution-in-aid of construction.

Continued to Sheet No. 6.609

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

NINTH REVISED SHEET NO. 6.700
CANCELS EIGHTH REVISED SHEET NO. 6.700

INTERRUPTIBLE STANDBY AND SUPPLEMENTAL SERVICE
(CLOSED TO NEW BUSINESS AS OF MAY 7, 2009)

SCHEDULE: SBI

AVAILABLE: Entire service area.

APPLICABLE: Required for all self-generating customers eligible for service under rate schedules IS or IST whose generating capacity in kilowatts (exclusive of emergency generation equipment) exceeds 20% of their site load in kilowatts. Also available to self-generating customers eligible for service under rate schedules IS or IST whose generating capacity in kilowatts does not exceed 20% of their site load in kilowatts, but who agree to all the terms and conditions of this rate schedule. To be eligible for service under this rate schedule, a customer must have been taking interruptible service under rate schedules IS-1, IST-1, IS-3, IST-3, SBI-1, or SBI-3 on May 6, 2009 and have signed the Supplemental Tariff Agreement for the Purchase of Industrial Standby and Supplemental Load Management Rider Service. Resale not permitted.

CHARACTER OF SERVICE: The electric energy supplied under this schedule is three phase primary voltage or higher

LIMITATION OF SERVICE: A customer taking service under this tariff must sign the Tariff Agreement for the Purchase of Standby and Supplemental Service

MONTHLY RATE:

Basic Service Charge:

Primary Metering Voltage	$716.81
Subtransmission Metering Voltage	$2,655.64

Demand Charge:

$2.19 per KW-Month of Supplemental Demand (Supplemental Demand Charge)
$1.61 per KW-Month of Standby Demand (Local Facilities Reservation Charge)

plus the greater of:
$1.33 per KW-Month of Standby Demand (Power Supply Reservation Charge); or
$0.53 per KW-Day of Actual Standby Billing Demand (Power Supply Demand Charge)

Continued to Sheet No. 6.705

ISSUED BY: N. G. Tower, President

DATE EFFECTIVE:

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

SEVENTH REVISED SHEET NO. 6.715
CANCELS SIXTH REVISED SHEET NO. 6.715

Continued from Sheet No. 6.710

POWER FACTOR: When the average power factor during the month is less than 85%, the monthly bill will be increased 0.222¢ for each kVARh by which the reactive energy numerically exceeds 0.619744 times the billing energy. When the average power factor during the month is greater than 90%, the monthly bill will be decreased 0.111¢ for each kVARh by which the reactive energy is numerically less than 0.484322 times the billing energy.

METERING VOLTAGE ADJUSTMENT: When the customer takes energy metered at subtransmission or higher voltage, a discount of 1% will apply to the standby and supplemental demand charges, energy charges, Delivery Voltage Credit, Power Factor billing, and Emergency Relay Power Supply Charges.

DELIVERY VOLTAGE CREDIT: When the customer furnishes and installs all subtransmission or higher voltage to utilization voltage substation transformation, a discount of 60¢ per KW of Supplemental Demand and 37¢ per KW of Standby Demand will apply.

EMERGENCY RELAY POWER SUPPLY CHARGE: The monthly charge for emergency relay power supply service shall be 86¢ per KW of Supplemental Demand and Standby Demand. This charge is in addition to the compensation the customer must make to the Company as a contribution-in-aid of construction.

FUEL CHARGE: Supplemental energy may be billed at either standard or time-of-day fuel rates at the option of the customer. See Sheet Nos. 6.020 and 6.021.

ENERGY CONSERVATION CHARGE: See Sheet Nos. 6.020 and 6.021.

CAPACITY CHARGE: See Sheet Nos. 6.020 and 6.021.

ENVIRONMENTAL COST RECOVERY CHARGE: See Sheet Nos. 6.020 and 6.021.

FLORIDA GROSS RECEIPTS TAX: See Sheet No. 6.021.

FRANCHISE FEE CHARGE: See Sheet No. 6.021.

PAYMENT OF BILLS: See Sheet No. 6.022.

ISSUED BY: N. G. Tower, President **DATE EFFECTIVE:**

TECO TAMPA ELECTRIC AN EMERA COMPANY

SEVENTH REVISED SHEET NO. 6.805
CANCELS SIXTH REVISED SHEET NO. 6.805

Continued from Sheet No. 6.800

MONTHLY RATE:

High Pressure Sodium Fixture, Maintenance, and Base Energy Charges:

Rate Code			Lamp Size				Charges per Unit ($)			
					kWh				Base Energy[4]	
Dusk to Dawn	Timed Svc.	Description	Initial Lumens[2]	Lamp Wattage[3]	Dusk to Dawn	Timed Svc.	Fixture	Maint.	Dusk to Dawn	Timed Svc.
800	860	Cobra[1]	4,000	50	20	10	3.16	2.48	0.55	0.27
802	862	Cobra/Nema[1]	6,300	70	29	14	3.20	2.11	0.79	0.38
803	863	Cobra/Nema[1]	9,500	100	44	22	3.63	2.33	1.20	0.60
804	864	Cobra[1]	16,000	150	66	33	4.18	2.02	1.80	0.90
805	865	Cobra[1]	28,500	250	105	52	4.87	2.60	2.86	1.42
806	866	Cobra[1]	50,000	400	163	81	5.09	2.99	4.45	2.21
468	454	Flood[1]	28,500	250	105	52	5.37	2.60	2.86	1.42
478	484	Flood[1]	50,000	400	163	81	5.71	3.00	4.45	2.21
809	869	Mongoose[1]	50,000	400	163	81	6.50	3.02	4.45	2.21
509	508	Post Top (PT)[1]	4,000	50	20	10	3.98	2.48	0.55	0.27
570	530	Classic PT[1]	9,500	100	44	22	11.85	1.89	1.20	0.60
810	870	Coach PT[1]	6,300	70	29	14	4.71	2.11	0.79	0.38
572	532	Colonial PT[1]	9,500	100	44	22	11.75	1.89	1.20	0.60
573	533	Salem PT[1]	9,500	100	44	22	9.03	1.89	1.20	0.60
550	534	Shoebox[1]	9,500	100	44	22	8.01	1.89	1.20	0.60
566	536	Shoebox[1]	28,500	250	105	52	8.69	3.18	2.86	1.42
552	538	Shoebox[1]	50,000	400	163	81	9.52	2.44	4.45	2.21

[1] Closed to new business
[2] Lumen output may vary by lamp configuration and age.
[3] Wattage ratings do not include ballast losses.
[4] The Base Energy charges are calculated by multiplying the kWh times the lighting base energy rate of 2.741¢ per kWh for each fixture.

Continued to Sheet No. 6.806

ISSUED BY: N. G. Tower, President **DATE EFFECTIVE:**

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

FIFTH REVISED SHEET NO. 6.806
CANCELS FOURTH REVISED SHEET NO. 6.806

Continued from Sheet No. 6.805

MONTHLY RATE:

Metal Halide Fixture, Maintenance, and Base Energy Charges:

Rate Code			Lamp Size				Charges per Unit ($)			
					kWh				Base Energy[4]	
Dusk to Dawn	Timed Svc.	Description	Initial Lumens[2]	Lamp Wattage[3]	Dusk to Dawn	Timed Svc.	Fixture	Maint.	Dusk to Dawn	Timed Svc.
704	724	Cobra[1]	29,700	350	138	69	7.53	4.99	3.76	1.88
520	522	Cobra[1]	32,000	400	159	79	6.03	4.01	4.34	2.15
705	725	Flood[1]	29,700	350	138	69	8.55	5.04	3.76	1.88
556	541	Flood[1]	32,000	400	159	79	8.36	4.02	4.34	2.15
558	578	Flood[1]	107,800	1,000	383	191	10.50	8.17	10.44	5.21
701	721	General PT[1]	12,000	150	67	34	10.60	3.92	1.83	0.93
574	548	General PT[1]	14,400	175	74	37	10.89	3.73	2.02	1.01
700	720	Salem PT[1]	12,000	150	67	34	9.33	3.92	1.83	0.93
575	568	Salem PT[1]	14,400	175	74	37	9.38	3.74	2.02	1.01
702	722	Shoebox[1]	12,000	150	67	34	7.22	3.92	1.83	0.93
564	549	Shoebox[1]	12,800	175	74	37	7.95	3.70	2.02	1.01
703	723	Shoebox[1]	29,700	350	138	69	9.55	4.93	3.76	1.88
554	540	Shoebox[1]	32,000	400	159	79	10.02	3.97	4.34	2.15
576	577	Shoebox[1]	107,800	1,000	383	191	16.50	8.17	10.44	5.21

(1) Closed to new business
(2) Lumen output may vary by lamp configuration and age.
(3) Wattage ratings do not include ballast losses.
(4) The Base Energy charges are calculated by multiplying the kWh times the lighting base energy rate of 2.741¢ per kWh for each fixture.

Continued to Sheet No. 6.808

ISSUED BY: N. G. Tower, President **DATE EFFECTIVE:**

TECO TAMPA ELECTRIC AN EMERA COMPANY

SIXTH REVISED SHEET NO. 6.808
CANCELS FIFTH REVISED SHEET NO. 6.808

Continued from Sheet No. 6.806

MONTHLY RATE:

LED Fixture, Maintenance, and Base Energy Charges:

Rate Code			Size				Charges per Unit ($)			
					kWh[1]				Base Energy[4]	
Dusk to Dawn	Timed Svc.	Description	Initial Lumens[2]	Lamp Wattage[3]	Dusk to Dawn	Timed Svc.	Fixture	Maintenance	Dusk to Dawn	Timed Svc.
828	848	Roadway[1]	5,155	56	20	10	7.27	1.74	0.55	0.27
820	840	Roadway [1]	7,577	103	36	18	11.15	1.19	0.98	0.49
821	841	Roadway[1]	8,300	106	37	19	11.15	1.20	1.01	0.52
829	849	Roadway[1]	15,285	157	55	27	11.10	2.26	1.50	0.74
822	842	Roadway[1]	15,300	196	69	34	14.58	1.26	1.88	0.93
823	843	Roadway[1]	14,831	206	72	36	16.80	1.38	1.96	0.98
835	855	Post Top[1]	5,176	60	21	11	16.53	2.28	0.57	0.30
824	844	Post Top[1]	3,974	67	24	12	19.67	1.54	0.65	0.33
825	845	Post Top[1]	6,030	99	35	17	20.51	1.56	0.95	0.46
836	856	Post Top[1]	7,360	100	35	18	16.70	2.28	0.95	0.49
830	850	Area-Lighter[1]	14,100	152	53	27	14.85	2.51	1.45	0.74
826	846	Area-Lighter[1]	13,620	202	71	35	19.10	1.41	1.94	0.95
827	847	Area-Lighter[1]	21,197	309	108	54	20.60	1.55	2.95	1.47
831	851	Flood[1]	22,122	238	83	42	15.90	3.45	2.26	1.15
832	852	Flood[1]	32,087	359	126	63	19.16	4.10	3.44	1.72
833	853	Mongoose[1]	24,140	245	86	43	14.71	3.04	2.35	1.17
834	854	Mongoose[1]	32,093	328	115	57	16.31	3.60	3.14	1.55

[1] Closed to new business
[2] Average
[3] Average wattage. Actual wattage may vary by up to +/- 5 watts.
[4] The Base Energy charges are calculated by multiplying the kWh times the lighting base energy rate of 2.741¢ per kWh for each fixture.

Continued to Sheet No. 6.810

ISSUED BY: N. G. Tower, President **DATE EFFECTIVE:**

TECO TAMPA ELECTRIC AN EMERA COMPANY

FIRST REVISED SHEET NO. 6.809
CANCELS ORIGINAL SHEET NO. 6.809

Continued from Sheet No. 6.808

MONTHLY RATE:

LED Fixture, Maintenance, and Base Energy Charges:

Rate Code			Size				Charges per Unit ($)			
					kWh[1]				Base Energy[3]	
Dusk to Dawn	Timed Svc.	Description	Initial Lumens[1]	Lamp Wattage[2]	Dusk to Dawn	Timed Svc.	Fixture	Maint.	Dusk to Dawn	Timed Svc.
912	981	Roadway	2,600	27	9	5	4.83	1.74	0.25	0.14
914		Roadway	5,392	47	16		5.97	1.74	0.44	
921		Roadway/Area	8,500	88	31		8.97	1.74	0.85	
926	982	Roadway	12,414	105	37	18	6.83	1.19	1.01	0.49
932		Roadway/Area	15,742	133	47		14.15	1.38	1.28	
935		Area-Lighter	16,113	143	50		11.74	1.41	1.36	
937		Roadway	16,251	145	51		8.61	2.26	1.39	
941	983	Roadway	22,233	182	64	32	11.81	2.51	1.75	0.87
945		Area-Lighter	29,533	247	86		16.07	2.51	2.35	
947	984	Area-Lighter	33,600	330	116	58	20.13	1.55	3.16	1.58
951	985	Flood	23,067	199	70	35	11.12	3.45	1.91	0.95
953	986	Flood	33,113	255	89	45	21.48	4.10	2.43	1.23
956	987	Mongoose	23,563	225	79	39	11.78	3.04	2.15	1.06
958		Mongoose	34,937	333	117		17.84	3.60	3.19	
965		Granville Post Top (PT)	3,024	26	9		5.80	2.28	0.25	
967	988	Granville PT	4,990	39	14	7	13.35	2.28	0.38	0.19
968	989	Granville PT Enh[4]	4,476	39	14	7	15.35	2.28	0.38	0.19
971		Salem PT	5,240	55	19		10.95	1.54	0.52	
972		Granville PT	7,076	60	21		14.62	2.28	0.57	
973		Granville PT Enh[4]	6,347	60	21		16.62	2.28	0.57	
975	990	Salem PT	7,188	76	27	13	13.17	1.54	0.74	.35

(1) Average
(2) Average wattage. Actual wattage may vary by up to +/- 10 %.
(3) The Base Energy charges are calculated by multiplying the kWh times the lighting base energy rate of 2.741¢ per kWh for each fixture.
(4) Enhanced Post Top. Customizable decorative options

Continued to Sheet No. 6.810

ISSUED BY: N. G. Tower, President **DATE EFFECTIVE:**

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

Continued from Sheet No. 6.810

Miscellaneous Facilities Charges:

Rate Code	Description	Monthly Facility Charge	Monthly Maintenance Charge
563	Timer	$7.54	$1.43
569	PT Bracket (accommodates two post top fixtures)	$4.27	$0.06

NON-STANDARD FACILITIES AND SERVICES:

The customer shall pay all costs associated with additional company facilities and services that are not considered standard for providing lighting service, including but not limited to, the following:

1. relays;
2. distribution transformers installed solely for lighting service;
3. protective shields;
4. bird deterrent devices;
5. light trespass shields;
6. light rotations;
7. light pole relocations;
8. devices required by local regulations to control the levels or duration of illumination including associated planning and engineering costs;
9. removal and replacement of pavement required to install underground lighting cable; and
10. directional boring.

MINIMUM CHARGE: The monthly charge.

FUEL CHARGE: See Sheet Nos. 6.020 and 6.021.

ENERGY CONSERVATION CHARGE: See Sheet Nos. 6.020 and 6.021.

CAPACITY CHARGE: See Sheet Nos. 6.020 and 6.021

ENVIRONMENTAL COST RECOVERY CHARGE: See Sheet Nos. 6.020 and 6.021

FLORIDA GROSS RECEIPTS TAX: See Sheet No. 6.021

FRANCHISE FEE: See Sheet No. 6.021

PAYMENT OF BILLS: See Sheet No. 6.022

SPECIAL CONDITIONS:
On customer-owned public street and highway lighting systems not subject to other rate schedules, the monthly rate for energy served at primary or secondary voltage, at the company's option, shall be 2.741¢ per kWh of metered usage, plus a Basic Service Charge of $11.62 per month and the applicable additional charges as specified on Sheet Nos. 6.020 and 6.021.

Continued to Sheet No. 6.820

5

Staff's First Data Request 1, 2, 3, 4, 5, 6, 9, 10, 13, 14, and 15.

(See additional files contained on Staff Hearing Exhibit CD/USB for No. 13)

Confidential DN# 00931-2018 (10)

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20170260-EI EXHIBIT: 5
PARTY: STAFF HEARING EXHIBITS
DESCRIPTION: Rocha

1. Please refer to the Direct Testimony of TECO witness R. James Rocha, page 16, lines 11-25.

- **a.** Please fully explain how the Company developed the $205.3 million projected value of fuel savings presented in this section of testimony.
- **b.** Please identify the source and date of TECO's fuel price forecast used in developing the Current Present Value of Revenue Requirements (CPVRR) analysis of the proposed First Solar Base Rate Adjustment (SoBRA) Transaction.
- **c.** Please identify the date, if known, of TECO's next/updated fuel price forecast that will be used for Company/business planning purposes.
- **d.** Please discuss TECO's fuel forecast methodology. Please also remark on approximate the length of a time TECO has employed this same or very similar fuel forecasting methodology for company planning purposes.
- **e.** Please fully explain how TECO developed the $12 million projected value of (reduced) emissions presented in this section of testimony. Please also specify what particular "emissions" are being referred to and associate a dollar figure to the specific emission type.
- **f.** Please identify the sources and dates of all environmental compliance cost related forecasts TECO used in developing its CPVRR analysis of the proposed First SoBRA Transaction.
- **g.** Please discuss TECO's environmental compliance cost related forecast methodology. Please also remark on approximate the length of a time TECO has employed this same or very similar methodology.
- **h.** Please provide a detailed explanation of the sensitivity analyses TECO performed with regard to forecasted fuel prices and forecasted market prices for carbon dioxide (CO_2) in testing the robustness of the projected cost savings.

A. The requested information is provided below.

- **a.** Using the company's Integrated Resource Planning process, a long term base case model was prepared without the first tranche of solar generation. Next, starting from this base case, a change case model was prepared with the first tranche, 145 MW of solar generation in-service September 2018. Both the base case and change case were run with the production cost modeling software to determine fuel costs for both cases. The change case system fuel cost was then subtracted from the base case system fuel cost equating to $198.5 million in savings to customers.

b. The fuel forecast used in the CPVRR analysis for the first tranche of solar is the same fuel forecast used in preparing the 2018 projected costs and cost recovery factors approved in Docket No. 20170001-EI.

c. The fuel price forecast will be updated in Summer 2018 to prepare the 2019 projected fuel cost recovery factors.

d. Tampa Electric has used the same methodology to forecast fuel commodity prices for approximately the last ten years. The methodology is consistent across commodities. It uses market indicators (e.g., NYMEX futures contracts) to estimate the near-term price (one to three years). The methodology then uses a commercially available, published fuel commodity price forecast from an independent energy consulting firm (e.g., PIRA, Wood MacKenzie) for the mid-term (two to twenty years). The final long-term portion of the fuel price forecast is then escalated using an independent source for the annual price changes (e.g., EIA Long Term Energy Outlook). Blending of sources is used to transition between time periods. The forecast is produced early each summer to support the late-summer fuel clause actual-estimate and projection filings and is used for one year until the next official forecast is produced. The specific sources, time periods and blending approach has changed occasionally over the past ten years, but the fundamental approach of using independent sources for the forecast period that they are most appropriate has not changed.

e. A long-term base case model was prepared without the first tranche of solar. Next, starting from this base case, a change case model was prepared with the first tranche, 145 MW of solar in-service September 2018. Both the base case and change case were run with the production cost modeling software to determine CO_2 and NO_x volumes for both cases using the company's emission factors. Tampa Electric then calculated the avoided emissions between these two cases and multiplied them by a CO_2 price forecast from a global consulting services company, ICF International, Inc., and an estimated NO_X cost estimated using a previous sale of Tampa Electric's NO_X Ozone Season allowances. These calculations resulted in $11.4 million of projected value of reduced emissions from NO_X and CO_2, approximately $10.7 million of CO_2 and $0.7 million of NO_X forecasted. Several policies and regulations relating to emissions valuation are in various stages of development and/or litigation and the anticipated value of emission reductions is captured in the forecast.

f. The CO_2 price forecast used in the cost effectiveness analysis for the first tranche of solar was purchased from a global consulting services company, ICF International, Inc., and developed in the third quarter of 2017. The NO_X price forecast is estimated using an actual sale of Tampa Electric's NO_X Ozone Season allowances in 2016 and escalated by one percent a year after 2017.

g. Tampa Electric has been tracking CO_2 impacts since the initial Clean Power Plan talks began around June 2014. Since that time, the company has assessed carbon emissions as a below-the-line consideration for each project.

h. The fuel forecast sensitivities used in the CPVRR analysis for the first tranche of solar are from the same fuel forecast used in preparing the 2018 projected cost recovery factors approved in Docket No. 20170001-EI. The high and low fuel forecasts were prepared contemporaneously with the base fuel forecast and are shown in the company's response to Data Request No. 9. The results of the high and low fuel forecast sensitivities are shown in the following tables.

Delta CPWRR Revenue Requirements - **Base Fuel Sensitivity** (2017 $000)	Cost/(Savings) ($ millions)
Capital RR - Other New Units	($129.5)
Capital RR - Solar New Arrays (w/Interconnect)	$164.3
RR of Land for Solar	$26.5
System VOM	($9.7)
FOM - Other Future Units	($5.0)
FOM - Solar Future Arrays	$15.3
System Fuel	($198.5)
Sub Total w/o NO_X or CO_2 Cost	($136.6)
Plus Emissions Costs	
CO_2 - Base	($10.7)
CO_2 - High	($39.7)
CO_2 - Low	$0.0
NO_X - Base	($0.7)
Total w/ CO_2 (Base) & NO_X Cost	($148.0)
Total w/ CO_2 (High) & NO_X Cost	($177.0)
Total w/ CO_2 (Low) & NO_X Cost	($137.3)

Delta CPWRR Revenue Requirements - **High Fuel Sensitivity** (2017 $000)	Cost/(Savings) ($ millions)
Capital RR - Other New Units	($129.5)
Capital RR - Solar New Arrays (w/Interconnect)	$164.3
RR of Land for Solar	$26.5
System VOM	($9.3)
FOM - Other Future Units	($5.0)
FOM - Solar Future Arrays	$15.3
System Fuel	($260.8)
Sub Total w/o NOX or CO2 Cost	($198.4)
Plus Emissions Costs	
CO2 - Base	($10.6)
CO2 - High	($39.0)
CO2 - Low	$0.0
NOX - Base	($0.4)
Total w/ CO2 (Base) & NOX Cost	($209.4)
Total w/ CO2 (High) & NOX Cost	($237.8)
Total w/ CO2 (Low) & NOX Cost	($198.8)

Delta CPWRR Revenue Requirements - **Low Fuel Sensitivity** (2017 $000)	Cost/(Savings) ($ millions)
Capital RR - Other New Units	($129.5)
Capital RR - Solar New Arrays (w/Interconnect)	$164.3
RR of Land for Solar	$26.5
System VOM	($10.3)
FOM - Other Future Units	($5.0)
FOM - Solar Future Arrays	$15.3
System Fuel	($145.7)
Sub Total w/o NOX or CO2 Cost	($84.4)
Plus Emissions Costs	
CO2 - Base	($11.9)
CO2 - High	($43.9)
CO2 - Low	$0.0
NOX - Base	($1.0)
Total w/ CO2 (Base) & NOX Cost	($97.3)
Total w/ CO2 (High) & NOX Cost	($129.2)
Total w/ CO2 (Low) & NOX Cost	($85.4)

The sensitivity analyses of CO_2 emissions costs were performed by using the dollars per ton of ICF's 2017 Q3 forecast for the high, low and base sensitivities. These dollars per ton were then multiplied by the actual tons of CO_2 emitted in each run. The delta of the emissions costs from the change case to the base case equates to the estimated reduction in CO_2 emissions costs. The CO_2 emissions cost sensitivities were applied separately from the fuel sensitivities.

2. Please provide a summary of all the existing federal, state, and local government policies and rules regarding the regulation of CO2 emissions. Please also discuss the economic impacts of any such policies or rules.

A. The following is a summary of the potentially relevant existing federal policies and rules regarding the regulation of CO_2 emissions and economic impacts if applicable. There are currently no state or local policies or rules relevant to the subject testimony.

Greenhouse Gas Mandatory Reporting Rule – 40 CFR 98: In 2009, the Environmental Protection Agency ("EPA") promulgated a regulation to require reporting of greenhouse gas emissions from multiple sectors of the economy. The final rule applies to fossil fuel suppliers and industrial gas suppliers, direct greenhouse gas emitters and manufacturers of heavy-duty and off-road vehicles and engines. The rule does not require control of greenhouse gases, rather it requires only that sources above certain threshold levels monitor and report emissions. Tampa Electric's Greenhouse Gas ("GHG") Reporting program was approved by the Commission in Docket No. 090508-EI, Order No. PSC-10-0157-PAA-EI, issued March 22, 2010, and is a result of the EPA's Mandatory reporting rule requiring annual reporting of greenhouse gas emissions. Tampa Electric was required to report greenhouse gas emissions for the first time in 2011. Reporting for the EPA's Greenhouse Gas Mandatory Reporting rule will continue in 2018. For 2018, this activity is projected to result in approximately $93,149 of O&M expenditures.

Prevention of Significant Deterioration - 40 CFR 52: This EPA rule became effective January 2, 2011. It addresses the GHG emission threshold triggers that would require permitting review of new and/or major modifications to existing stationary sources of GHG emissions. A subsequent U. S. Supreme Court ruling narrowed the EPA's authority to implement this rule, but the key provisions remain applicable to Tampa Electric. While this rule does not have an immediate impact on Tampa Electric's operations, GHG permitting was completed for Tampa Electric's most recent base load unit, the Polk Unit 2 – 5 conversion to combined cycle. These standards do not directly pertain to the scope of the subject testimony; however, the standards are not expected to have any significant economic impact to Tampa Electric's current plans to meet load demand.

New Source Performance Standards (NSPS) – 40 CFR 60 Subpart TTTT: The New Source Performance Standards (NSPS) for CO_2 emissions from new electric generating units were promulgated on October 23, 2015. The rule is applicable to any steam generating unit, integrated gasification combined cycle, or stationary CTG that commenced construction after January 8, 2014, or commenced modification or reconstruction after June 18, 2014. This rule is being challenged in the D.C. Circuit, and the case is currently in temporary abeyance. These standards do not directly pertain to the scope of the subject testimony; however, the standards are not expected to have any significant economic impact to Tampa Electric's current plans to meet load demand.

Standards for Modified/Reconstructed Sources - 40 CFR 60 Subpart TTTT: On October 23, 2015, EPA published final standards for existing units that are modified or reconstructed. This rule is being challenged in the D.C. Circuit. These standards do not directly pertain to the scope of the subject testimony; however, the standards are not expected to have any significant economic impact to Tampa Electric's current plans to meet load demand.

Emission Guidelines and State Standards for Existing Sources (Clean Power Plan) - 40 CFR 60 Subpart UUUU: On October 23, 2015, EPA published final Emission Guidelines for existing utility units, setting individual statewide emission rate goals, and directing states to submit initial plans to achieve the goal by September 6, 2016. On Feb. 9, 2016 the Supreme Court stayed implementation of the rule. Florida Department of Environmental Protection ("FDEP") is not actively working on any state plan due to the Supreme Court's stay. These standards were designed to incentivize renewable energy development that is in the scope of the proposed projects. However, on October 16, 2017, EPA published a notice of its intent to repeal the Clean Power Plan rules for existing units. On December 28, 2017, EPA published an Advance Notice of Proposed Rulemaking to solicit comments on EPA's consideration of a new rule to limit GHGs from existing electric generating units. Since the Clean Power Plan replacement rule is in the early stages of development, Tampa Electric utilized the ICF International, Inc. study developed in the third quarter of 2017 to provide a forecasted cost of CO_2 emissions.

3. To date, has TECO incurred any costs related to emissions of CO2? If so, please discuss the economic details as well as the method of cost recovery.

A. As described in the response to Data Request No. 2, Tampa Electric's GHG Reporting program is the only program for which Tampa Electric has incurred costs subject to cost recovery. The project was approved by the Commission in Docket No. 090508-EI, Order No. PSC-10-0157-PAA-EI, issued March 22, 2010, and is a result of the EPA's Mandatory Reporting Rule requiring annual reporting of greenhouse gas emissions. Tampa Electric was required to report greenhouse gas emissions for the first time in 2011. Reporting for the EPA's Greenhouse Gas Mandatory Reporting Rule will continue in 2018. For 2018, this activity is projected to result in approximately $93,149 of O&M expenditures.

4. If the response is negative, when does TECO believe it will be affected by CO2 emissions regulation/costs of emitting?

A. The Clean Power Plan proposed repeal and replacement rule development is in progress, and it is possible that final rules could be promulgated by the end of 2018. However, as with prior rules, litigation is extremely likely and uncertainty relating to final regulations and cost of emitting GHG's is expected to continue for several years.

5. Please refer to the Direct Testimony of TECO witness Rocha, page 17, lines 1-14. Please discuss how the CO2, nitrogen oxide (NOx), and sulfur dioxide (SO2) reduction amounts presented in this section of testimony were formulated and concluded.

A. The emissions reductions stated in the direct testimony of witness Rocha at page 17, lines 1-14, are a direct result of the two cases described in the company's response to Data Request No. 1(a). The tons of CO_2, NO_x, and SO_2 are calculated based on the dispatch of Tampa Electric's generation fleet, then applying an emission rate for each fuel type consumed. The emission rates are calculated based on actual average emission rates derived from Continuous Emissions Monitoring Systems associated with specific emission units operating on specific fuels as projected by Tampa Electric's Resource Planning model runs of the two cases described above. Although SO_2 reductions will also be realized, the current market value of SO_2 in the Acid Rain Program is too low to be material to this evaluation. However, rules such as the Cross State Air Pollution Rule are in various stages of development and litigation. If Tampa Electric becomes subject to future updates of these rules, the value of SO_2 reduction could become relevant to this analysis.

6. Please refer to the Direct Testimony of TECO witness Rocha, page 16, lines 14-18. If the $155.9 million customer savings figure presented in this section of testimony includes costs related to CO2 emission, please provide an alternative CPVRR assuming zero CO2 costs throughout the analysis term.

A. On February 14, 2018, Tampa Electric filed the revised direct testimony of Rocha, Exhibit No. RJR-1, Revised Document No. 4, which includes updates for tax reform legislation passed at the end of 2017. The $155.9 million customer savings figure shown on Document No. 4 was accordingly revised to $148.0 million. Based on these updated figures, Revised Document No. 4 shows the differential CPVRR is favorable for customers by $136.6 million before any value for reduced emissions is included. The estimated emissions reductions in Tampa Electric's analysis are $10.7 million of CO_2 and $0.7 million of NO_X forecasted ($11.4 million after rounding). The differential CPVRR is favorable for customers by $137.3 million without CO_2 emission reductions and including the value of reduced NO_X emissions.

9. Please refer to the Direct Testimony of TECO witness Rocha, page 16, lines 11-25. Please provide a copy of the Company's fuel forecast relied upon in developing its CPVRR analysis referenced in this section of testimony.

A. Please refer to the Direct Testimony of witness Rocha, Exhibit No. RJR-1, Document No. 2, Bates page 22, for the base fuel forecast. The high and low fuel forecasts are provided in the following table.

July 2017 High Fuel Forecast ($/mmBtu)

	Coal	Natural Gas
2017	2.49	4.98
2018	2.61	4.59
2019	3.02	4.65
2020	3.33	5.08
2021	3.54	5.42
2022	3.59	5.60
2023	3.65	5.99
2024	3.70	6.35
2025	3.74	6.71
2026	3.83	7.07
2027	3.93	7.45
2028	4.18	8.29
2029	4.41	8.67
2030	4.73	9.48
2031	4.82	9.83
2032	5.04	10.65
2033	5.05	10.76
2034	5.22	11.50
2035	5.32	11.96
2036	5.49	12.18
2037	5.68	12.47
2038	5.87	12.71
2039	6.09	13.07
2040	6.30	13.34
2041	6.54	13.70
2042	6.85	14.28
2043	7.21	14.97
2044	7.53	15.47
2045	7.87	16.04
2046	8.24	16.61
2047	8.71	17.43

July 2017 Low Fuel Forecast ($/mmBtu)

	Coal	Natural Gas
2017	1.87	2.43
2018	1.95	2.24
2019	2.27	2.27
2020	2.49	2.48
2021	2.65	2.64
2022	2.69	2.73
2023	2.73	2.92
2024	2.77	3.09
2025	2.80	3.27
2026	2.87	3.44
2027	2.95	3.63
2028	3.13	4.04
2029	3.31	4.22
2030	3.55	4.61
2031	3.61	4.79
2032	3.77	5.18
2033	3.78	5.24
2034	3.91	5.59
2035	3.98	5.82
2036	4.11	5.93
2037	4.26	6.07
2038	4.40	6.18
2039	4.56	6.36
2040	4.72	6.49
2041	4.90	6.67
2042	5.13	6.95
2043	5.41	7.28
2044	5.64	7.53
2045	5.90	7.80
2046	6.17	8.08
2047	6.53	8.48

10. Please refer to the Direct Testimony of TECO witness Rocha, page 16, lines 11-25. Please provide copies of any environmental compliance cost related documents the Company relied upon in developing the CPVRR analysis of its proposed First SoBRA Transaction.

A. Please see ICF 2017 Q3 CO_2 study attached.

BATES STAMPED PAGES

22 THROUGH 36

ARE REDACTED

Please refer to the Direct Testimony of TECO witness J. Rocha and Exhibit RJR-1 for the following questions.

13. Please refer to page 7, line 23, for the following questions.

a. Please provide a detailed explanation of the "bonus depreciation."

b. Please specify how the "bonus depreciation" was used in the annual revenue requirement calculation for TECO's First SoBRA.

c. Please provide working papers in Microsoft Excel, with formulas intact, to support your response to (b), above.

A. **a.** Bonus depreciation was authorized by federal legislation in order to stimulate the economy by providing one-time bonus tax depreciation for qualifying investments in the year of in-service. Code Section 168(k) provides a phased down bonus depreciation deduction for qualifying property placed in service by 12/31/2020 at the respective rates of 50%, 40%, and 30% for spending in 2017, 2018, and 2019, respectively. For the case of Tranche 1 as of the date of filing the company's petition in this docket, it allowed for a 50% and 40% bonus deduction for 2017 and 2018 spending, respectively, on the investment of eligible business property.

However, the recent Tax Cuts and Jobs Act ("Act") enacted on December 22, 2017 modified the deduction. The Act raises the bonus depreciation rate to 100%; however, regulated public utilities are specifically excluded from the definition of qualifying property and therefore exempt from the 100% bonus depreciation rate. The Act however provides for a transition rule which maintains the phased down bonus depreciation rates allowed for property acquired before September 28, 2017 and placed in service after September 27, 2017. Because of this transition period, for the case of Tranche 1, the company still assumed a 50% bonus depreciation for capital expenditures through December 31, 2017 and a 40% bonus depreciation for capital expenditures after December 31, 2017 with a corresponding no later than in-service date of December 31, 2018. It is important to note that the Department of the Treasury and/or the Internal Revenue Service are expected to issue clarification on the transition rules which could reduce the amount of qualifying property subject to bonus depreciation for Tranche 1.

b. As defined by the federal legislation, Bonus Depreciation is applied in the first year of tax depreciation for each Tranche 1 solar project. Bonus depreciation only affects tax depreciation, which affects cumulative deferred taxes, which is then used to adjust rate base when calculating the return on capital.

c. Please see Excel file labeled "Q13 – Tranche 1 Full First Year Bonus Depreciation.xlsx."

14. Please refer to pages 9 (lines 10 - 11) and 11 (lines 11 - 12) for the following questions.

a. Referring to page 11, please specify the amount of depreciation expense included in the Revenue Requirement for First SoBRA presented in Document No. 3 of Exhibit RJR-1.

b. Referring to page 11, please explain in detail how the amount of depreciation expense discussed in Question (a) was derived.

c. Please provide working papers in Microsoft Excel, with formulas intact, to support your response to (b) above.

d. Is the "depreciation expense" referred on page 9, line 11, the same as what specified in Question (a)?

e. Referring to page 9, please explain why the depreciation expense discussed in Questions (a) and (c) deem as "reasonable estimates."

f. For each affected depreciation accounts, please identify the following that were used in deriving the depreciation expense discussed in Question (a): (i) plant-in-service amount each month; (ii) the depreciation rate used.

A. **a.** Book depreciation is $6.1 million for a full year. Bonus depreciation only affects tax depreciation, which affects cumulative deferred taxes, which is then used to adjust rate base when calculating the return on capital.

b. The detailed costs of the Tranche 1 projects are described in Mr. Ward's testimony. The cost is subject to a cap and a subsequent true-up. Tampa Electric determined that the appropriate economic life of a photovoltaic solar facility is thirty years.

c. Annual book depreciation is 1/30th of original cost. See the company's response to Data Request No. 13(c), Excel file "Q13 – Tranche 1 Full First Year Bonus Depreciation.xlsx."

d. Yes.

e. See the company's response to Data Request No. 14(b). In addition, Tampa Electric is aware that other solar projects regulated by the FPSC have used a thirty-year book life. Future SoBRA true-up filings will capture any differences from estimated costs.

f. The company uses a thirty-year book life, with straight line depreciation for tracking photovoltaic solar facilities.

15. Referring to page 12, line 18, please explain in detail how the referenced "book depreciation" was calculated.

a. Please provide working papers in Microsoft Excel, with formulas intact, to support your response to Interrogatory No. 3.

A. Annual book depreciation is 1/30th of original cost.

a. The company has been told by Staff that "to support your response to Interrogatory No. 3" should have said "for this calculation" and responds accordingly. See the company's response to Data Request No. 13(c), Excel file "Q13 – Tranche 1 Full First Year Bonus Depreciation.xlsx."

6

Staff's Second Data Request

1 and 3.

Confidential DN# 01872-2018 (1)

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20170260-EI EXHIBIT: 6
PARTY: STAFF HEARING EXHIBITS
DESCRIPTION: Rocha

1. Please refer to TECO's response to Staff's First Data Request, No. 1. In this response, the Company explains its methodologies for developing and forecasting both future fuel and emissions prices. Does TECO test the veracity, and/or compare its fuel and emissions price forecasts to other publically available data resources, such as the Energy Information Administration (EIA)? If so, what were the results?

A. Yes, Tampa Electric compares its fuel price forecasts for natural gas and coal against other sources. The first graph below shows Tampa Electric's forecasted price of natural gas at Henry Hub compared to other sources, both publicly available and as a subscribed service. The second graph shows Tampa Electric's price forecast for "standard" coal at the mine mouth in the Illinois Basin (source of most coal for Tampa Electric) compared to both public and subscriber service sources. The comparison is not as direct as for natural gas due to the quality and locational differences for different types of coal. Nonetheless, the relative price compared to near-term spot prices, *e.g.*, in *Coal Daily*) and longer term modeled prices (EIA average mine-mouth) show that Tampa Electric's coal price forecast is consistent with both near term market prices and longer-term comparative sources. Tampa Electric's fuel price forecasts for natural gas and coal are reasonable for planning purposes and consistent with other sources.

REDACTED

[redacted]

[redacted]

Regarding emissions, Tampa Electric has been monitoring forecasted carbon prices since the draft Clean Power Plan was issued. The company reviewed any forecasts that other IOUs included with their Commission filings, as well as public forecasts found on the internet, such as those of Synapse Energy. At the time of conducting analysis for this petition, Tampa Electric then contracted with a global consulting services company, ICF International, Inc., to obtain a CO_2 forecast that utilized the most current assumptions and market conditions. The consultant compared projections for various regions of the country and included low, medium, and high forecasts. Tampa Electric estimated the NO_X cost using a recent, very small sale of Tampa Electric's NO_X Ozone Season allowances.

3. Please refer to TECO's response to Staff's First Data Request, No. 14, for the following questions.

a. Referring to TECO's response to sub-question (a), please explain how the full year book depreciation of $6.1 million was derived, and provide related work papers in Microsoft Excel, with formulas intact, to support your response.

b. Referring to TECO's response to sub-question (b), please define the term "original cost." Please specify the amount of the "original cost" for each Tranche 1 solar project, and provide a detailed breakdown of the components that comprise it.

A. Tampa Electric provided an Excel file labeled "Q13 – Tranche 1 Full First Year Bonus Depreciation" on February 2, 2018, as part of the response to Staff's First Data Request, No. 13(c).

a. In the Excel file, the total project costs including AFUDC are shown in cells E2 through E7. The useful life of the solar asset is listed as the book life shown on row 14 as thirty years. Annual book depreciation is 1/30th of the total capital cost of the depreciable assets. By adding the Book Depreciation for Balm Solar to Payne Creek Solar, the $6.1 million figure was derived.

b. Original cost is the project's total capital cost including AFUDC at the in-service date. The original cost of the Payne Creek project is $91.7 million, and the original cost of the Balm Solar project is $91.4 million. Please see the detailed breakdown of the cost components in the following tables. These costs were provided in Mark Ward's Direct Testimony, Exhibit No. MDW-1, Document No. 3 for Payne Creek Solar and Document No. 6 for Balm Solar. The original cost is the Total All-in-Cost less the cost for land because land is not depreciable.

Payne Creek Solar Estimated Costs ($)	
Project Output (MW-ac)	70.3
Modules	30,827,672
Major Equipment	23,811,685
Balance of System	28,417,389
Development	1,593,623
Transmission Interconnect	4,400,000
Land	1,408,400
Owners Costs	419,383
Total Installed Cost ($)	90,878,151
AFUDC ($)	2,195,318
Total All-in-Cost ($)	93,073,469
Total ($/kW-ac)	1,324

Balm Solar Estimated Costs ($)	
Project Output (MW-ac)	74.4
Modules	29,263,256
Major Equipment	25,206,219
Balance of System	30,081,657
Development	1,686,953
Transmission Interconnect	2,500,000
Land	18,720,128
Owners Costs	443,970
Total Installed Cost ($)	107,902,183
AFUDC ($)	2,188,259
Total All-in-Cost ($)	110,090,442
Total ($/kW-ac)	1,480

7

Staff's First set of Interrogatories

1, 2, 3, 4, and 5.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20170260-EI EXHIBIT: 7
PARTY: STAFF HEARING EXHIBITS
DESCRIPTION: Ward (1,4,5) Rocha (2,3)

1. On January 22, 2018, trade publications reported that a 30 percent tariff would be levied on solar-related products that are imported from countries outside of the United States. Please answer the following:

a. Identify what impact, if any, this tariff will have on this docket for the first solar tranche.

b. If possible, please identify what impact, if any, this tariff will have on the second, third, or fourth solar tranches.

A. a. The 30 percent tariff levied on solar-related products will have no impact on this docket for the first solar tranche. First Solar modules will be used on all four solar tranches. First Solar modules implement a thin film technology that was not included in the enacted tariff.

b. The 30 percent tariff levied on solar-related products will have no impact on the dockets for the second, third and fourth solar tranches. First Solar modules will be used on all four solar tranches. First Solar modules implement a thin film technology that was not included in the enacted tariff.

2. Page 11, Line 14 and Document Number 3 of Revised Exhibit RJR-1 reflect $24,245,000 as the amount of revenue requirements for the First SoBRA with Sharing Mechanism. Please provide worksheets and/or schedules with formulas intact to demonstrate how:

a. The Capital RR for Balm ($10,458,000) was calculated.
b. The Capital RR for Payne Creek ($10,480,000) was calculated.
c. The FOM for Balm ($533,000) was calculated.
d. The FOM for Payne Creek ($503,000) was calculated.
e. The Land RR ($2,271,000) was calculated.

A. Please refer to Exhibit No. RJR-1, Second Revised Document No. 3, to the revised Direct Testimony of R. James Rocha on behalf of Tampa Electric, as filed on March 6, 2018. The document shows the corrected capital including incentive, calculated using the dollar per kW cost for each project instead of an average. See the Excel file "Q2 – Tranche 1 Full First Year RR.xlsx" for responses to subsections (a) through (e).

a. See cell D37. The corrected capital RR for Balm is ($10,300,000).

b. See cell D63. The corrected capital RR for Payne Creek is ($10,637,000).

c. See cell D39.

d. See cell D65.

e. See cell D44 plus cell D70.

3. Page 11, Lines 18-19. Please identify the specific paragraph citations in the 2017 Agreement that provide the revenue requirement cost recovery provisions.

A. There are several key provisions in the 2017 Agreement that provide the revenue requirement cost recovery provisions. Subparagraph 6(b) of the 2017 Agreement authorizes Tampa Electric to seek recovery of up to 150 MW of new solar generation to be in-service on or before September 1, 2018 through a SoBRA. Per the 2017 Agreement, the effective date of the First SoBRA can be no earlier than September 1, 2018 and its maximum incremental annual revenue requirement may not exceed $30,600,000, with four months of cost recovery in 2018 capped at $10,200,000.

Subparagraph 6(g) of the 2017 Agreement specifies that this annual revenue requirement amount will be trued up for the actual installed cost and in-service dates of the projects covered by the First SoBRA when it petitions for approval of its Second SoBRA. A true-up is not included in the calculation of the First SoBRA, because this is the first solar tranche. After the in-service date of a tranche, when the actual costs are known, and contemporaneous with a fuel docket filing, Tampa Electric will include a true-up for each revenue requirement calculation.

Subparagraph 6(d) of the 2017 Agreement specifies that the installed cost of each individual project to be recovered through a SoBRA may not exceed $1,500 per kWac.

Subparagraph 6(g) of the 2017 Agreement states that the cost-effectiveness for the projects in a SoBRA tranche shall be evaluated in total by considering whether the projects in the tranche will lower the company's projected system Cumulative Present Value Revenue Requirement ("CPVRR") as compared to such CPVRR without the solar projects.

Subparagraphs 6(a) through 6(c) of the 2017 Agreement specify that, subject to the revenue requirement limits in subparagraph 6(b) of the 2017 Agreement, the SoBRA will be calculated using the company's projected installed cost per kWac for each project in the tranche (subject to the Installed Cost Cap); reasonable estimates for depreciation expense, property taxes and fixed O&M expenses; an incremental capital structure reflecting the then current midpoint Return On Equity and a 54 percent equity ratio, adjusted to reflect the inclusion of investment tax credits on a normalized basis.

Subparagraph 6(d) of the 2017 Agreement specifies that the types of costs of solar projects that traditionally have been allowed in rate base are eligible for cost recovery via a SoBRA, and lists the following types of costs as examples: Engineering, Procurement and Construction ("EPC") costs; development costs including third party development fees, if any; permitting fees and costs; actual land costs and land acquisition costs; taxes; utility costs to support or complete development; transmission interconnection costs; installation labor and equipment costs; costs associated with electrical balance of system, structural balance of system, inverters, and modules; Allowance for Funds Used During Construction ("AFUDC") at the weighted average cost of capital from Exhibit B of the 2017 Agreement; and other traditionally allowed rate base costs.

Subparagraph 6(m) of the 2017 Agreement specifies that if the actual installed cost is less than the Installed Cost Cap, the company and customers will share in any beneficial difference with 75 percent going to customers and 25 percent serving as an incentive to the company. If applicable, this incentive will be added to the revenue requirement calculation.

Subparagraph 6(j) of the 2017 agreement allows the company to seek recovery of unused capacity in a future petition for approval if the amount of capacity recovered in the SoBRA is below the maximum amount specified in Subparagraphs 6(b) and 6(c). For instance, if the First SoBRA is less than the allowed 150 MW, that difference could be added to the Second SoBRA.

For the purpose of questions 4-5 and sub-parts, please refer to Exhibit MDW-1, attached to the Prepared Direct Testimony of Mark D. Ward, on behalf of Tampa Electric Company, as filed on December 14, 2017.

4. Please answer the following questions regarding the Payne Creek property:

a. How many total acres are in the Payne Creek property?
b. How many acres in the Payne Creek property are planned for this solar installation?
c. How many acres in the Payne Creek property would be suitable for future development as a solar installation, or for other utility purposes?
d. How many acres in the Payne Creek property are not suitable for a solar installation, or for any other utility purpose?
e. How long has Tampa Electric Company owned the Payne Creek property?
f. Document 3 of Exhibit MDW-1, attached to the Prepared Direct Testimony of Mark D. Ward, reflects that nearly $1.6 million is planned for development of the Payne Creek property. Please describe the work activities that are needed to develop the Payne Creek property.
g. Document 3 of Exhibit MDW-1, attached to the Prepared Direct Testimony of Mark D. Ward, reflects that nearly $4.4 million is planned for developing the transmission interconnection for the Payne Creek property. Please describe the work needed to develop the transmission interconnection for the Payne Creek property.
h. Document 3 of Exhibit MDW-1, attached to the Prepared Direct Testimony of Mark D. Ward, reflects that nearly $400,000 is planned for owner costs. Please describe the costs, citing examples.

A. a. The Payne Creek Solar project property encompasses 484 acres.

b. The Payne Creek solar array will be on 319 acres.

c. Approximately 80 acres may be available for a future cost-effective battery storage project to be integrated with the solar project.

d. Approximately 85 acres are not compatible for PV solar or other utility purposes. This land has been identified as wetlands and will not be mitigated for any other use.

e. Tampa Electric purchased the Payne Creek Solar site in May 2017.

f. The work activities necessary to develop the Payne Creek Solar site include due diligence to ensure the site can support a solar project and engineering required to complete county and state permit applications. Due diligence activities include geotechnical studies, environmental studies, and wetlands delineation. Engineering and design activities include development and analysis of the civil plans, storm water analyses, and design of the project's solar array.

g. The transmission interconnection required for Payne Creek Solar includes constructing three miles of 69kV transmission radial line from the Payne Creek Solar substation to interconnect at the existing Tampa Electric Ft. Green Substation. An additional 3.5 miles of existing 69kV transmission line must be upgraded, including installation of two 69kV 2000A line switches with supervisory control, upgrading one existing 69kV line switch, removing one additional 69kV line switch, installing a 69kV 2000A breaker with 2000A disconnects with line relays in the Ft. Green Substation, and providing telemetry for the Ft. Green Metering Substation. Finally, the transmission cost includes trip testing and checkout and synchronization operations with the solar plant.

h. Owner's costs include costs of work performed by Tampa Electric employees that are assigned to the solar projects and were not employed prior to Tampa Electric's last rate case as well as consultants that have been retained by the company to assist in development and project management activities. An example is the Director of Renewables, an employee hired by Tampa Electric at the end of 2016 who spends the majority of time working on Tampa Electric's utility scale solar projects.

5. Please answer the following questions regarding the Balm property:

a. How many total acres are in the Balm property?
b. How many acres in the Balm property are planned for this solar installation?
c. How many acres in the Balm property would be suitable for future development as a solar installation, or for other utility purposes?
d. How many acres in the Balm property are not suitable for a solar installation, or for any utility purpose?
e. How long has Tampa Electric Company owned the Balm property?
f. Document 6 of Exhibit MDW-1, attached to the Prepared Direct Testimony of Mark D. Ward, reflects that nearly $1.7 million is planned for development of the Balm property. Please describe the work activities that are needed to develop the Balm property.
g. Document 6 of Exhibit MDW-1, attached to the Prepared Direct Testimony of Mark D. Ward, reflects that nearly $2.5 million is planned for developing the transmission interconnection for the Balm property. Please describe the work needed to develop the transmission interconnection for the Balm property.
h. Document 6 of Exhibit MDW-1, attached to the Prepared Direct Testimony of Mark D. Ward, reflects that nearly $18.7 million is planned for purchasing the Balm property. Please describe any unique aspects of this property that justify this expense.
i. Document 6 of Exhibit MDW-1, attached to the Prepared Direct Testimony of Mark D. Ward, reflects that nearly $400,000 is planned for owner costs. Please describe the costs, citing examples.

A. a. The Balm Solar project property encompasses 541 acres.

b. The Balm Solar array will be placed on 330 acres.

c. Approximately 111 acres may be available for future cost-effective battery storage to be integrated with the solar project. There are no plans to expand the project beyond 74.4 MWac.

d. Approximately 100 acres are not compatible for PV solar or other utility purposes. Much of this land has been identified as wetlands or retention ponds and will not be mitigated for any other use.

e. Tampa Electric purchased the Balm Solar site in June of 2017.

f. The work activities necessary to develop the Balm Solar site include due diligence to ensure the site can support a solar project and engineering required to complete county and state permit applications. Due diligence activities include geotechnical studies, ground penetrating radar to locate subsurface structures, removal of structures, environmental studies, and wetlands delineation. Engineering and design activities include development and analysis of the civil plans, storm water analyses, and design of the project's solar array.

g. The transmission interconnection work required for Balm Solar includes the construction of 0.6 miles of 230kV transmission line radial from the proposed Balm Solar substation to interconnect at the company's existing Aspen 203kV Switchyard. It also requires the installation of a 3000A, 63kA circuit breaker and protection relays at the Aspen 203kV Switchyard. Finally, the interconnection cost includes telemetry, system trip testing, and checkout and synchronization operations with the proposed solar plant.

h. There are several reasons that justify the expense for purchasing the Balm Solar site for a project. The site is 541 acres that allows for a cost effective large solar project to be constructed. The site is well suited for a solar project because its previous use was agriculture, meaning it is flat, with minimal wetlands and a subsurface conducive for constructing and supporting a solar project. The land is also located very near areas of strong residential and commercial growth. While this location increases the cost of the land, it also locates the solar generation near the demand for it. The Balm Solar site is also near the Aspen substation which makes it an ideal location for a solar project to interconnect to the company's system.

i. Owner's costs include costs of work performed by Tampa Electric employees that are assigned to the solar projects that were not employed prior to Tampa Electric's last rate case and consultants that have been retained by the company to assist in development and project management activities. An example is the Director of Renewables, an employee hired by Tampa Electric at the end of 2016 who spends the majority of time working on Tampa Electric's utility scale solar projects.

AFFIDAVIT

STATE OF FLORIDA)
)
COUNTY OF HILLSBOROUGH)

Before me the undersigned authority personally appeared Penelope Rusk who deposed and said that she is a Manager, Rates, Tampa Electric Company, and that the individuals listed in Tampa Electric Company's response to Staff's First Set of Interrogatories, (Nos. 1-5) prepared or assisted with the responses to these interrogatories to the best of her information and belief.

Dated at Tampa, Florida this 15th day of March, 2018.

Penelope A Rusk

Sworn to and subscribed before me this 15th day of March, 2018.

Sana Boric

NOTARY PUBLIC STATE OF FLORIDA
Notary Public State of Florida
Sana Boric
My Commission GG 020235
Expires 08/10/2020

My Commission expires ____________________

8

Staff's 2nd set of Interrogatories

6 and 7.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20170260-EI EXHIBIT: 8
PARTY: STAFF HEARING EXHIBITS
DESCRIPTION: Ashburn

6. Appendix B (Typical Bill Analysis) to the petition indicates a bill increase of $1.99 per month for residential customers who use 1,000 kWh per month. Considering the proposed bill impacts stated above, please discuss how and when TECO will inform its customers about the proposed changes. Also, please provide examples of a customer letter, website information, door hanger, press release etc. that are considered TECO's communication methods to inform customers of bill impacts.

A. Tampa Electric plans to provide rate information one month prior to the effective date of the change. A notice of the bill increase is included in the company's communication schedule for August 2018. The notice is included as the last page of the bill, similar to the attached examples that were included in the December 2017 bill for the January 2018 annual clause adjustments. Paperless customers will receive a message in their August bill notification email with a link to the notice online.

Important Rate Information for Residential and Non-Demand Customers

Please note this important information about your 2018 electric bill, including changes to fuel charges.

Effective January 2018, your bill will reflect slightly higher fuel prices and other factors approved by the Florida Public Service Commission as part of an annual adjustment. Fuel costs are passed through from fuel suppliers to our customers with no markup or profit to Tampa Electric.

Effective January 2018		
Standard Residential Rate (RS)		
Basic Service Charge:	\$16.62 per month	
Energy Charge:		
Usage up to 1,000 kWh	5.855 ¢ per kWh	
Usage over 1,000 kWh	6.963 ¢ per kWh	
Fuel Charge:		
Usage up to 1,000 kWh	2.818 ¢ per kWh	
Usage over 1,000 kWh	3.818 ¢ per kWh	
Residential Service Variable Pricing (RSVP-1)		
Basic Service Charge:	\$16.62 per month	
Energy Charge:	4.900 ¢ per kWh	
Fuel Charge:	3.132 ¢ per kWh	
Standard General Service, Non-Demand (GS)		
Basic Service Charge:	\$19.94 per month	
Energy Charge:	6.184 ¢ per kWh	
Fuel Charge:	3.132 ¢ per kWh	
Time-of-Day General Service, Non-Demand (GST)		
Basic Service Charge:	\$22.16 per month	
	On-Peak (¢ per kWh)	Off-Peak (¢ per kWh)
Energy Charge:	15.823	1.665
Fuel Charge:	3.330	3.047

The rate schedules above are subject to gross receipts taxes, city and state taxes, and franchise fees, where applicable. A late payment charge may be applied to any unpaid balance on your electric bill that is not paid by the past-due date.

The energy charge includes 0.655 cents per kWh for rate schedule RS, (0.649) cents per kWh for rate schedule RSVP-1 (based on P2 pricing – rate can vary based on rate tier), 0.635 cents per kWh for rate schedules GS and GST for the conservation, environmental and capacity cost recovery charges.

About your bill

Basic Service Charge

The monthly basic service charge covers the cost of maintaining your electric meter and the wires that bring electrical service to your home or business. The basic service charge also covers the cost of reading the meter and maintaining customer records and accounting for bill payments, credit and other transactions affecting your account. Basic service charges are incurred even if no electricity is used during the month.

Energy Charge

The energy charge includes all other costs of producing the electricity you purchase, except fuel. This also includes conservation, environmental and capacity cost recovery charges. Effective January 2018, residential customers will be billed 5.855 cents per kilowatt-hour (kWh) for the first 1,000 kWh of energy usage and 6.963 cents per kWh for any usage over 1,000 kWh under Tampa Electric's tiered rate structure.

Fuel Charge

This is the cost of fuel used to produce your electricity. Fuel costs are passed through from fuel suppliers to our customers with no markup or profit to Tampa Electric. Effective January 2018, residential customers will be billed 2.818 cents per kWh for fuel usage up to 1,000 kWh, and 3.818 cents per kWh for any usage over 1,000 kWh.

To learn more about our rates and how you can make managing energy costs easier, visit **tampaelectric.com** for energy-savings tips that can help you lower your monthly electric bill. If you prefer to speak with a representative, please call:

Hillsborough County
(813) 223-0800

Polk County
(863) 299-0800

All other counties and out-of-state
1-888-223-0800

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

Important rate information for commercial and industrial customers

Please note this important information about your 2018 electric bill, including changes to fuel charges.

Effective January 2018, your bill will reflect slightly higher fuel prices and other factors approved by the Florida Public Service Commission as part of an annual adjustment. Fuel costs are passed through from fuel suppliers to our customers with no markup or profit to Tampa Electric.

We have several rate schedules for our commercial and industrial customers. Depending on the actual maximum electricity load your facility requires, we will select the appropriate rate schedule. (Your rate schedule appears in the center portion of your bill under "New Charges").

Tampa Electric's Business and Industry department can discuss any questions you have regarding your account and the charges involved. Please contact us at one of the following numbers:

Hillsborough County
(813) 228-1010

Polk County
(863) 299-0800

All other counties and out-of-state
(888) 223-0800

To learn more about our rates and how you can make managing energy costs easier, visit **tampaelectric.com** for energy-savings tips that can help you lower your monthly electric bill.

Effective January 2018

Standard General Service, Demand (GSD)

Basic Service Charge:	$33.24 per month
Demand Charge:	$ 10.25 per kW
Energy Charge:	1.754 ¢ per kWh
Fuel Charge:	3.132 ¢ per kWh
Capacity Charge:	$ 0.20 per kW
Energy Conservation Charge:	$ 0.87 per kW
Environmental Charge:	0.342 ¢ per kWh

Optional General Service, Demand (GSD-option)

Basic Service Charge:	$33.24 per month
Energy Charge:	6.660 ¢ per kWh
Fuel Charge:	3.132 ¢ per kWh
Capacity Charge:	0.047 ¢ per kWh
Energy Conservation Charge:	0.201 ¢ per kWh
Environmental Charge:	0.342 ¢ per kWh

Time-of-Day General Service, Demand (GSDT)

Basic Service Charge:	$33.24 per month	
Demand Charge:	$ 3.46 per kW of billing demand	
	$ 6.79 per kW of peak billing demand	
	On-Peak	Off-Peak
Energy Charge:	3.211 (¢ per kWh)	1.159 (¢ per kWh)
Fuel Charge:	3.330 (¢ per kWh)	3.047 (¢ per kWh)
Capacity Charge	$ 0.20 per kW	
Energy Conservation Charge:	$ 0.87 per kW	
Environmental Charge	0.342 ¢ per kWh	

Interruptible Service (IS) - Closed to new customers

Basic Service Charge:	$689.11 per month
Demand Charge:	$ 1.61 per kW
Energy Charge:	2.774 ¢ per kWh
Fuel Charge:	3.101 ¢ per kWh
Capacity Charge:	$ 0.14 per kW
Energy Conservation Charge:	$ 0.67 per kW
Environmental Charge:	0.333 ¢ per kWh

Interruptible Service Time-of-Day (IST) - Closed to new customers

Basic Service Charge:	$689.11 per month	
Demand Charge:	$ 1.61 per kW of billing demand	
	On-Peak	Off-Peak
Energy Charge:	2.774 (¢ per kWh)	2.774 (¢ per kWh)
Fuel Charge:	3.297 (¢ per kWh)	3.017 (¢ per kWh)
Capacity Charge:	$ 0.14 per kW	
Energy Conservation Charge:	$ 0.67 per kW	
Environmental Charge:	0.333¢ per kWh	

The fuel charge is used to pay the fuel suppliers and does not profit Tampa Electric.

Rate schedules are subject to gross receipts taxes, city and state taxes, and franchise fees, where applicable. A late payment charge may be applied to any unpaid balance on your electric bill that is not paid by the past-due date.

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

TEC 102417

7. TECO requests that the proposed tariff changes if approved be effective with the first billing cycle of September 2018. Please indicate when the first billing cycle of September will begin.

A. September 4, 2018.

A F F I D A V I T

STATE OF FLORIDA)
)
COUNTY OF HILLSBOROUGH)

Before me the undersigned authority personally appeared Penelope Rusk who deposed and said that she is a Manager, Rates, Tampa Electric Company, and that the individuals listed in Tampa Electric Company's response to Staff's Second Set of Interrogatories, (Nos. 6-7) prepared or assisted with the responses to these interrogatories to the best of her information and belief.

Dated at Tampa, Florida this 22nd day of March, 2018.

Penelope Rusk
____

Sworn to and subscribed before me this 22nd day of March, 2018.

Sana Boric
____

Notary Public State of Florida
Sana Boric
My Commission GG 020235
Expires 08/10/2020

NOTARY PUBLIC STATE OF FLORIDA

My Commission expires ____________________

9

Staff's 3rd set of Interrogatories 8, 9, 11, 12, 13, 15, 16, 17, and 18.

(See additional files contained on Staff Hearing Exhibit CD/USB for Nos. 13, 16, 17, and 18)

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20170260-EI EXHIBIT: 9
PARTY: STAFF HEARING EXHIBITS
DESCRIPTION: Rocha (8, 9, 11, 12, 13, 15, 16,17,18)Ward (9)

8. Refer to Witness Rocha's revised testimony page 7 lines 12-21. Please provide TECO history and forecast of fuel requirements using the base forecast from 2017-2048.

A. The production cost modeling performed for this analysis included 30 years, 2017 through 2046, of fuel and purchased power. The requested information is provided in the following tables.

Without Solar Using Base Fuel Forecast (Reference No Solar)

Fuel x1000	Coal (Ton)	Distillate (BBL)	Natural Gas (MCF)	Petcoke (Ton)
2017 Actuals	2,279	-	100,445	380
2018	1,932	-	106,934	366
2019	2,388	-	97,385	432
2020	2,677	-	95,005	433
2021	2,477	-	102,130	396
2022	2,614	-	99,914	432
2023	3,015	-	95,760	423
2024	3,461	-	91,714	396
2025	3,809	-	88,464	432
2026	3,616	-	91,264	432
2027	3,661	-	95,141	395
2028	3,893	-	92,669	396
2029	3,786	-	96,398	426
2030	3,674	-	100,515	426
2031	3,705	-	102,598	404
2032	3,988	-	100,051	427
2033	3,990	-	103,193	426
2034	3,844	-	108,095	404
2035	3,596	-	113,779	426
2036	3,026	-	124,491	282
2037	2,919	-	129,345	-
2038	2,034	-	143,677	-
2039	1,772	-	148,793	-
2040	1,982	-	144,150	-
2041	1,292	-	152,871	-
2042	992	-	156,935	-
2043	779	-	154,679	-
2044	1,016	-	147,627	-
2045	991	-	147,933	-
2046	1,003	-	148,068	-

With 145 MW of Solar in 2018 Using Base Fuel Forecast (Reference w/ 145 MW of Solar)

Fuel x1000	Coal (Ton)	Distillate (BBL)	Natural Gas (MCF)	Petcoke (Ton)
2017 Actuals	2,279	-	100,445	380
2018	1,933	-	106,604	366
2019	2,327	-	96,445	432
2020	2,567	-	94,936	433
2021	2,368	-	99,969	396
2022	2,629	-	97,750	432
2023	2,940	-	94,656	423
2024	3,418	-	89,339	396
2025	3,796	-	86,046	432
2026	3,587	-	89,412	432
2027	3,649	-	92,221	395
2028	3,919	-	89,840	396
2029	3,759	-	94,398	426
2030	3,652	-	98,467	426
2031	3,671	-	100,182	404
2032	3,986	-	97,759	427
2033	3,986	-	100,803	426
2034	3,842	-	104,892	404
2035	3,593	-	110,090	426
2036	3,025	-	121,554	282
2037	2,926	-	129,163	-
2038	2,033	-	142,076	-
2039	1,770	-	146,340	-
2040	1,981	-	141,699	-
2041	1,293	-	150,477	-
2042	995	-	154,416	-
2043	781	-	152,394	-
2044	1,017	-	145,392	-
2045	993	-	145,655	-
2046	1,006	-	145,816	-

REDACTED

9. Refer to Witness Rocha's revised testimony page 15 lines 18-24 and page 16 lines 1-7. For the Balm and Payne Creek SoBRA projects distinctly, please separate the engineering, procurement and construction costs; development costs including third party development fees, permitting fees and costs; actual land costs and land acquisition costs, taxes; utility costs to support or complete development; transmission interconnection costs; installation labor and equipment costs; costs associated with electrical balance of system, structural balance of system, inverters, and modules; AFUDC at the weighted average cost of capital and other traditionally allowed rate base costs.

A. The requested information about the Payne Creek and Balm Solar project costs are shown in the following tables.

Payne Creek Solar	
PV Modules	[redacted]
Inverters & Transformers	
Complete Project Substation	
Trackers (if applicable)	
SCADA/DAS	
Balance of Plant	
Permitting	
Engineering (Struc/Elec/Geo Tech)	
Installation (Labor, Materials, etc.)	
Site Prep & Roadworks	
Fencing and Gate	
Transmission Interconnection	4,400,000
Contingency	3,708,602
Owners Cost	419,383
Land Cost	1,290,816
Land Acquisition Costs	117,584
AFUDC	2,195,318
Total Cost	**93,073,469**

REDACTED

Balm Solar	
PV Modules	[redacted]
Inverters & Transformers	
Complete Project Substation	
Trackers (if applicable)	
SCADA/DAS	
Balance of Plant	
Permitting	
Engineering (Struc/Elec/Geo Tech)	
Installation (Labor, Materials, etc.)	
Site Prep & Roadworks	
Fencing and Gate	
Transmission Interconnection	2,500,000
Contingency	3,949,458
Owners Cost	443,970
Land Cost	18,624,873
Land Acquisition Costs	95,255
AFUDC	2,188,259
Total Cost	**110,090,442**

11. Please provide a table comparing TECO's resource plan with the 2018 Solar Tranche included and with the 2018 Solar Tranche excluded.

A. The following table describes the reference case without solar generation.

Reference No Solar

Year	Portfolio Additions	Portfolio Retirement	Reserve Margin Winter and Summer %
2018	–	–	30% 26%
2019	–	–	25% 21%
2020	–	–	23% 20%
2021	(1) GE 7FA.05 CT 244/229 MW - S	–	21% 24%
2022	–	–	25% 22%
2023	–	–	23% 20%
2024	(1) GE 7FA.05 CT 244/229 MW - S	–	22% 24%
2025	–	–	25% 22%
2026	–	–	24% 21%
2027	(1) GE 7FA.05 CT 244/229 MW - S	–	22% 25%
2028	–	–	26% 23%
2029	–	–	24% 21%
2030	–	–	22% 20%
2031	(1) GE 7FA.05 CT 244/229 MW - S	–	21% 24%
2032	–	–	25% 22%
2033	–	–	23% 21%
2034	(1) GE 7FA.05 CT 244/229 MW - S	–	22% 25%

Year	Portfolio Additions	Portfolio Retirement	Reserve Margin Winter and Summer %
2035	–	BB 1 Retires Oct 2035	25%
			23%
2036	(1) GE 1x1 7HA.02 CC 506/479 MW - W	PK 1 Retires Sep 2036	26%
			24%
2037	(1) GE 1x1 7HA.02 CC 506/479 MW - S	–	22%
			29%
2038	–	BB 2 Retires Feb 2038	32%
			21%
2039	–	–	24%
			21%
2040	–	–	24%
			21%
2041	(1) GE 1x1 7HA.02 CC 506/479 MW - S	BB 3 Retires May 2041	24%
			23%
2042	–	–	26%
			23%
2043	(1) GE 2x1 7HA.02 CC 1120/1040 MW - S	BAY 1 Retires Apr 2043	26%
			30%
2044	(1) GE 1x1 7HA.02 CC 506/479 MW - W	BAY 2 Retires Jan 2044	22%
			21%
2045	–	–	22%
			21%
2046	–	–	22%
			21%
2047	–	–	22%
			21%
2048	–	–	22%
			21%

The following table describes the reference case plus 145 MW of solar generation.

Reference w/ 145 MW of Solar

Year	Portfolio Additions	Portfolio Retirement	Reserve Margin Winter/Summer
2018	Solar 145 MW - S	–	30%
			28%
2019	–	–	25%
			23%
2020	–	–	23%
			21%
2021	(1) GE 7FA.05 CT 245/229 MW - S	–	21%
			25%
2022	–	–	25%
			24%
2023	–	–	23%
			22%
2024	–	–	22%
			20%
2025	(1) GE 7FA.05 CT 245/229 MW - S	–	20%
			24%
2026	–	–	24%
			23%
2027	–	–	22%
			21%
2028	(1) GE 7FA.05 CT 245/229 MW - S	–	20%
			25%
2029	–	–	24%
			23%
2030	–	–	22%
			22%
2031	–	–	21%
			20%
2032	(1) GE 7FA.05 CT 245/229 MW - S	–	20%
			24%
2033	–	–	23%
			23%

Year	Portfolio Additions	Portfolio Retirement	Reserve Margin Winter/Summer
2034	–	–	22%
			21%
2035	–	BB 1 Retires Oct 2035	21%
			20%
2036	(1) GE 1x1 7HA.02 CC 506/479 MW - W	PK 1 Retires Sep 2036	22%
			21%
2037	(1) GE 7FA.05 CT 245/229 MW - W	–	22%
			21%
2038	(1) GE 1x1 7HA.02 CC 506/479 MW - S	BB 2 Retires Feb 2038	22%
			23%
2039	–	–	24%
			23%
2040	–	–	24%
			23%
2041	(1) GE 1x1 7HA.02 CC 506/479 MW - S	BB 3 Retires May 2041	24%
			24%
2042	–	–	26%
			24%
2043	(1) GE 1x1 7HA.02 CC 1120/1040 MW - S	BAY 1 Retires Apr 2043	26%
			31%
2044	(1) GE 1x1 7HA.02 CC 506/479 MW - W	BAY 2 Retires Jan 2044	22%
			22%
2045	–	–	22%
			22%
2046	–	–	22%
			22%
2047	–	–	22%
			22%
2048	–	–	22%
			22%

12. Please provide the reserve margin in percentage of net firm system peak for the years 2018 to 2048 (30-year period) in an excel table comparing the reserve margin with no solar plan versus the reserve margin with the 2018 Solar Tranche.

A. The reserve margin for the years 2018 to 2048 is provided for the two cases in the company's response to Interrogatory No. 11, and the following table provides the difference in the reserve margin calculations for the two cases. See the Excel file "20170260 Staff's 3rd Set of IRR.xlsx" at tab "Q12".

Year	Change in Reserve Margin % (Winter/Summer)
2018	0.0%
	1.9%
2019	0.0%
	1.9%
2020	0.0%
	1.9%
2021	0.0%
	1.8%
2022	0.0%
	1.8%
2023	0.0%
	1.8%
2024	0.0%
	-3.6%
2025	-5.4%
	1.7%
2026	0.0%
	1.7%
2027	0.0%
	-3.5%
2028	-5.2%
	1.7%
2029	0.0%
	1.7%
2030	0.0%
	1.6%

Year	Change in Reserve Margin % (Winter/Summer)
2031	0.0%
	-3.3%
2032	-4.9%
	1.6%
2033	0.0%
	1.6%
2034	0.0%
	-3.2%
2035	-4.8%
	-3.2%
2036	-4.7%
	-3.2%
2037	0.0%
	-8.3%
2038	-9.8%
	1.5%
2039	0.0%
	1.5%
2040	0.0%
	1.5%
2041	0.0%
	1.5%
2042	0.0%
	1.5%
2043	0.0%
	1.5%
2044	0.0%
	1.5%
2045	0.0%
	1.5%
2046	0.0%
	1.5%
2047	0.0%
	1.5%
2048	0.0%
	1.5%

13. For the Payne Creek and Balm Solar projects, please provide the annual and cumulative values over a 30-year period (in nominal and net present value) for each of the following categories: Equipment and installation, Incremental fixed O&M, fuel savings, Emission savings separated by type, avoided replacement costs, avoided capacity purchases, avoided fixed O&M, avoided variable O&M and transmission upgrades. Please provide the response in electronic (Excel) format.

a. Please explain in detail the assumptions, facts, and figures used to determine the value of each of the components evaluated in this analysis.

b. Explain whether TECO's emissions savings include CO2 emissions. If so, provide a sensitivity analysis without those costs and provide the revised annual and cumulative values for each category in electronic format.

c. Explain whether TECO reviewed the cost-effectiveness of the first Solar Tranche using fuel price sensitivities. As part of this response, please provide a sensitivity of the fuel savings based upon a low fuel price forecast and a high fuel price forecast, with revised annual and cumulative values for each category in electronic format.

A. The requested information is provided in the Excel file titled "20170260 Staff's 3rd Set of IRR.xlsx" at tabs "Q13", "Q13c – High Fuel", and "Q13c – Low Fuel". There are no avoided capacity purchases. Avoided replacement power costs are already included in the system fuel line. Avoided variable O&M is provided in the System VOM line. Transmission upgrade information is provided in the company's response to Interrogatory No. 9.

a. Detailed cost analyses is performed using System Optimizer and Planning & Risk (PaR) production cost models, developed by ABB. The capital and fixed expenditures are based on a compilation of technology costs from a third-party vendor. The fuel and the operating and maintenance costs associated with each scenario are projected based on economic dispatch combined with the fixed charges to obtain the annual and total present values.

b. The first SoBRA produces cost savings of $136.6 million, not including any emissions savings. NO_X and CO_2 emission reductions produce an additional $11.4 million of savings for a total customer savings of $148.0 million. See the Excel file at tab "Q13" for the annual and cumulative values of NO_X and CO_2 emission savings.

c. Yes, as stated in the prepared direct testimony of Tampa Electric witness Rocha at page 16, lines 21-25, the company reviewed the cost-effectiveness of the first tranche of solar using high and low fuel price sensitivities. The results of these sensitivities confirmed that customer savings would occur under all scenarios.

The fuel forecast sensitivities used in the CPVRR analysis for the first tranche of solar are from the same fuel forecast used in preparing the 2018 projected costs and cost recovery factors approved in Docket No. 20170001-EI. The high and low fuel forecasts are shown in the company's response to the Staff's First Data Request, No. 9.

See the Excel file, tabs "Q13c – High Fuel" and "Q13c – Low Fuel", for the annual and cumulative values for the high fuel and low fuel sensitivities.

15. For the Balm and Payne Creek projects, please detail the depreciation life and actual life of the project.

A. The company uses a thirty-year book life, with straight line depreciation for tracking photovoltaic solar facilities. This 30-year book life was selected because it is expected to be the actual life of the unit.

For tax depreciation, the federal Modified Accelerated Cost-Recovery System ("MACRS"), establishes a set of class lives for various types of properties. Among the classes is solar energy to generate electricity which is denoted as a 5-year MACRS.

16. Please complete the table below based on your most recent planning for the life of the proposed solar tranche from 2018 to 2048 (30-year life) and provide in electronic format.

Year	Installed Capacity (MW)	Firm Import Capacity (MW)	Firm Export Capacity (MW)	QF Capacity (MW)	Total Available Capacity (MW)	System Firm Summer Peak Demand (MW)	Reserve Margin Before Maintenance (MW)	Scheduled Maintenance (MW)	Reserve Margin After Maintenance (MW)

A. The requested information is provided in the Excel file titled "20170260 Staff's 3rd Set of IRR.xlsx" at tab "Q16".

17. Please provide the avoided fossil fuels (Avoided oil barrels, avoided natural gas MMcf, avoided coal short tons) from the years 2017 to 2048 (30-year period). Please explain how calculations were made for each fuel and provide an example using 2019. Please provide response in tabular format in excel.

A. The production cost modeling performed for this analysis included 30 years of fuel and purchased power representing the period 2017 through 2046.

A base case model was prepared without the first tranche of solar generation. Next, starting from this base case, a change case model was prepared with the first tranche, 145 MW of solar generation in-service September 2018. Both the base case and change case were run with the production cost modeling software for an economic dispatch. The generation times the heat rate divided by the fuel's heating value equals the fuel used. The change case fuels were then subtracted from the base case fuels giving the avoided fuels presented below.

The avoided fossil fuels are shown in the following table. The Excel file titled "20170260 Staff's 3rd Set of IRR.xlsx" provides the avoided fossil fuels and example calculations for year 2019 at tabs "Q17", "Q17 – Coal Tons", "Q17 – NG MCF", and "Q17 – Petcoke Tons". Also see the company's response to Interrogatory No. 8 for the base case and change case fuels.

Avoided Fuels

Fuel x1,000	Coal (Ton)	Distillate (BBL)	Natural Gas (MCF)	Petcoke (Ton)
2017 Actuals	-	-	-	-
2018	2	-	(329)	-
2019	(61)	-	(940)	(0)
2020	(110)	-	(70)	-
2021	(108)	-	(2,162)	-
2022	15	-	(2,164)	-
2023	(75)	-	(1,104)	-
2024	(43)	-	(2,375)	-
2025	(13)	-	(2,418)	-
2026	(29)	-	(1,851)	(0)
2027	(11)	-	(2,920)	-
2028	26	-	(2,830)	-
2029	(27)	-	(2,000)	-
2030	(22)	-	(2,047)	0
2031	(34)	-	(2,417)	-
2032	(2)	-	(2,291)	-
2033	(4)	-	(2,390)	-
2034	(2)	-	(3,203)	-
2035	(3)	-	(3,688)	-
2036	(1)	-	(2,937)	-
2037	8	-	(183)	-
2038	(1)	-	(1,602)	-
2039	(2)	-	(2,453)	-
2040	(0)	-	(2,451)	-
2041	1	-	(2,394)	-
2042	2	-	(2,519)	-
2043	2	-	(2,286)	-
2044	1	-	(2,235)	-
2045	2	-	(2,278)	-
2046	3	-	(2,252)	-

18. Please provide the avoided air emissions (CO2, SO2, NOx) for the 30-year period. Show how each was calculated using the year 2019 as an example. Please provide response in tabular format in excel.

A. The production cost modeling performed for this analysis included 30 years of fuel and purchased power representing the period 2017 through 2046.

A base case model was prepared without the first tranche of solar generation. Next, starting from this base case, a change case model was prepared with the first tranche, 145 MW of solar generation in-service September 2018. Both the base case and change case were run with the production cost modeling software for an economic dispatch. The fuel used times the fuel's emissions rate equals the emissions. The change case emissions were then subtracted from the base case emissions giving the avoided emissions presented below.

The avoided air emissions are shown in the following tables. The Excel file titled "20170260 Staff's 3rd Set of IRR.xlsx" provides the air emissions and example calculations for year 2019 at tabs "Q18", "Q18 – Avoided CO2", "Q18 – Avoided NOx", and "Q18 – Avoided SO2".

CO_2 (Tons x1,000)

Year	Reference No Solar	Reference w/ 145 MW of Solar	Avoided CO_2
2018	12,593	12,468	(125)
2019	13,354	13,061	(293)
2020	13,897	13,557	(340)
2021	13,708	13,224	(485)
2022	14,043	13,875	(168)
2023	14,699	14,389	(310)
2024	15,398	15,099	(298)
2025	16,164	15,931	(233)
2026	15,880	15,638	(242)
2027	16,072	15,799	(273)
2028	16,475	16,297	(178)
2029	16,574	16,308	(266)
2030	16,561	16,283	(279)
2031	16,668	16,343	(326)
2032	17,279	17,034	(245)
2033	17,470	17,205	(265)
2034	17,334	17,016	(318)
2035	17,187	16,826	(361)
2036	15,910	15,614	(296)
2037	14,804	14,691	(114)
2038	13,592	13,359	(233)
2039	13,285	13,012	(273)
2040	13,497	13,232	(265)
2041	12,402	12,149	(253)
2042	11,943	11,695	(248)
2043	11,302	11,089	(212)
2044	11,428	11,228	(200)
2045	11,388	11,188	(200)
2046	11,426	11,225	(201)

NO_X (Tons x1,000)

Year	Reference No Solar	Reference w/ 145 MW of Solar	Avoided NO_X
2018	27.7	27.7	(0.0)
2019	32.2	31.6	(0.6)
2020	34.8	33.7	(1.0)
2021	32.8	31.7	(1.1)
2022	34.4	34.4	0.0
2023	37.8	37.0	(0.8)
2024	41.4	40.9	(0.5)
2025	44.8	44.6	(0.2)
2026	43.2	42.8	(0.4)
2027	43.4	43.1	(0.3)
2028	45.4	45.5	0.1
2029	45.0	44.6	(0.4)
2030	44.1	43.8	(0.3)
2031	44.3	43.8	(0.4)
2032	47.0	46.9	(0.1)
2033	47.2	47.0	(0.2)
2034	45.8	45.6	(0.2)
2035	44.1	43.9	(0.2)
2036	37.7	37.5	(0.2)
2037	33.5	33.6	0.1
2038	26.1	26.0	(0.1)
2039	24.0	23.8	(0.1)
2040	25.7	25.5	(0.1)
2041	19.8	19.7	(0.1)
2042	17.2	17.1	(0.1)
2043	15.1	15.0	(0.1)
2044	16.9	16.8	(0.1)
2045	16.7	16.6	(0.1)
2046	16.9	16.8	(0.1)

SO_2 (Tons x1,000)

Year	Reference No Solar	Reference w/ 145 MW of Solar	Avoided SO_2
2018	111.0	111.1	0.1
2019	136.0	133.1	(2.8)
2020	149.4	144.3	(5.1)
2021	137.9	132.9	(5.0)
2022	146.4	147.1	0.7
2023	164.3	160.8	(3.5)
2024	183.3	181.3	(2.0)
2025	201.4	200.9	(0.6)
2026	192.6	191.2	(1.3)
2027	192.4	191.9	(0.5)
2028	203.2	204.4	1.2
2029	200.1	198.8	(1.2)
2030	194.9	193.9	(1.0)
2031	195.0	193.4	(1.6)
2032	209.4	209.3	(0.1)
2033	209.4	209.3	(0.2)
2034	201.4	201.3	(0.1)
2035	191.3	191.2	(0.1)
2036	156.4	156.3	(0.0)
2037	134.5	134.8	0.4
2038	93.7	93.7	(0.0)
2039	81.6	81.5	(0.1)
2040	91.3	91.3	(0.0)
2041	59.5	59.6	0.0
2042	45.7	45.8	0.1
2043	35.9	36.0	0.1
2044	46.8	46.8	0.0
2045	45.6	45.7	0.1
2046	46.2	46.3	0.1

A F F I D A V I T

STATE OF FLORIDA)
)
COUNTY OF HILLSBOROUGH)

Before me the undersigned authority personally appeared Penelope Rusk who deposed and said that she is a Manager, Rates, Tampa Electric Company, and that the individuals listed in Tampa Electric Company's response to Staff's Third Set of Interrogatories, (Nos. 8-18) prepared or assisted with the responses to these interrogatories to the best of her information and belief.

Dated at Tampa, Florida this 3rd day of April, 2018.

Penelope Rusk
____

Sworn to and subscribed before me this 3RD day of April, 2018.

____

My Commission expires ______________

Notary Public State of Florida
Tison C Vega
My Commission FF 955624
Expires 02/01/2020

10

Staff's 4th set of Interrogatories 19.

(See additional file contained on Staff Hearing Exhibit CD/USB for No. 19)

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20170260-EI EXHIBIT: 10
PARTY: STAFF HEARING EXHIBITS
DESCRIPTION: Rocha

19. Please refer to TECO's Second Revised Document No. 3 to Exhibit No. RJR-1 of the Prepared Direct Testimony and Exhibit of R. James Rocha, filed with the Commission on March 6, 2017.

a. Please provide updated response to Staff's First Data Request No. 14.(a) based on the Second Revised Document No. 3.

b. Please provide updated response to Staff's Second Data Request No. 3.(a), with related work papers in Microsoft Excel with formulas intact to support your updated response, based on the Second Revised Document No. 3.

c. Please provide updated response to Staff's Second Data Request No. 3.(b) based on the Second Revised Document No. 3.

d. Please specify the amount of the Book Depreciation, which is the depreciation expense included in the Revenue Requirement for First SoBRA presented in Second Revised Document No. 3. The meaning of the Book Depreciation is defined per TECO's response to Staff's First Data Request No. 14.(d).

e. Please provide the updated amount of the "original cost" of the First SoBRA. The meaning of the original cost is defined per TECO's response to Staff's Second Date Request No. 3.(b).

A. a. Without the incentive, book depreciation is $6.1 million for a full year. With the incentive, book depreciation is $6.2 million for a full year. Bonus depreciation only affects tax depreciation. Rate base is then adjusted for cumulative deferred taxes.

b. See the included Excel file titled "(BS 3) 20170260-IRR No 19-Tranche 1 Full First Year RR.xlsx." On tab "Tranche 1 – Without Incentive" the total project costs without incentive including AFUDC are shown in cells E2 through E7. The useful life of the solar asset is listed as the book life shown on row 14 as thirty years. Annual book depreciation is 1/30th of the total capital cost of the depreciable assets. By adding the Book Depreciation for Balm Solar to Payne Creek Solar, the $6.1 million figure was derived.

On tab "Tranche 1 – With Incentive" the total project costs with incentive including AFUDC are shown in cells E3 through E15. The useful life of the solar asset is listed as the book life shown on row 23 as thirty years. Annual book depreciation is 1/30th of the total capital cost of the depreciable assets. By adding the Book Depreciation for Balm Solar to Payne Creek Solar, the $6.2 million figure was derived.

c. Original cost without incentive is the project's total capital cost including AFUDC at the in-service date. The original cost of the Payne Creek project is $91.7 million, and the original cost of the Balm Solar project is $91.4 million. The detailed breakdown of the cost components in the tables provided in the response to Staff's Second Data Request No. 3(b) do not change based on the Second Revised Document No. 3 for original cost without the incentive. These costs were also provided in Mark Ward's Direct Testimony, Exhibit No. MDW-1, Document No. 3 for Payne Creek Solar and Document No. 6 for Balm Solar. The original cost is the Total All-in-Cost less the cost for land because land is not depreciable.

   Original cost with incentive is the project's total capital cost including AFUDC and the incentive portion at the in-service date. The original cost of the Payne Creek project with incentive is $94.8 million, and the original cost of the Balm Solar project is $91.8 million. In the included Excel file titled "(BS 3) 20170260-IRR No 19-Tranche 1 Full First Year RR.xlsx" at tab "Tranche 1 – With Incentive" the sum of cells E3, E4 and E14 provide the Balm Solar original cost, and cells E5, E6, and E15 sum to Payne Creek original cost. Cells E4 and E6 show the incentive calculation. The original cost is the Total All-in-Cost less the cost for land because land is not depreciable.

d. See the company's response to subpart (a).

e. See the company's response to subpart (c).

A F F I D A V I T

STATE OF FLORIDA)
)
COUNTY OF HILLSBOROUGH)

Before me the undersigned authority personally appeared Penelope Rusk who deposed and said that she is a Manager, Rates, Tampa Electric Company, and that the individuals listed in Tampa Electric Company's response to Staff's Fourth Set of Interrogatories, (No. 19) prepared or assisted with the responses to these interrogatories to the best of her information and belief.

Dated at Tampa, Florida this 5th day of April, 2018.

Penelope Rusk
____

Sworn to and subscribed before me this 5th day of April, 2018.

Cynthia R. Kyle
____

NOTARY PUBLIC STATE OF FLORIDA
Notary Public State of Florida
Cynthia R Kyle
My Commission FF 197516
Expires 03/01/2019

My Commission expires ____________________

11

Staff's 5th set of Interrogatories 20.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20170260-EI   EXHIBIT: 11
PARTY: STAFF HEARING EXHIBITS
DESCRIPTION: Rocha

20. Please refer to the Direct Testimony of Tampa Electric Company (TECO or Company) witness R. James Rocha, page 11, lines 15-20. Please explain how the company's fuel forecast was used as an assumption in the Company's Solar Base Rate Adjustment revenue requirement calculation.

A. The fuel costs are not part of the Solar Base Rate Adjustment revenue requirement calculation. The fuel forecast was used to determine the cost-effectiveness of the first tranche of solar generation. Additionally, high and low fuel price sensitivities were evaluated, and results of these sensitivities confirmed that customer savings would occur under all scenarios.

Detailed cost analyses were performed using System Optimizer and Planning & Risk (PaR) production cost models, developed by ABB. The company's fuel forecast, along with high and low fuel sensitivities were a key input to the economic dispatch models.

The same fuel forecast was used in preparing the 2018 projected costs and cost recovery factors approved in Docket No. 20170001-EI.

A F F I D A V I T

STATE OF FLORIDA)
)
COUNTY OF HILLSBOROUGH)

Before me the undersigned authority personally appeared Penelope Rusk who deposed and said that she is a Manager, Rates, Tampa Electric Company, and that the individuals listed in Tampa Electric Company's response to Staff's Fifth Set of Interrogatories, (No. 20) prepared or assisted with the responses to these interrogatories to the best of her information and belief.

Dated at Tampa, Florida this 11th day of April, 2018.

Penelope Rusk
____

Sworn to and subscribed before me this 11th day of April, 2018.

Cynthia R. Kyle
____

NOTARY PUBLIC STATE OF FLORIDA
Notary Public State of Florida
Cynthia R Kyle
My Commission FF 197516
Expires 03/01/2019

My Commission expires ______________________

12

Staff's 6th set of Interrogatories

21, 22, 23, 24, 25, 26, 27, 28, and 29.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20170260-EI EXHIBIT: 12
PARTY: STAFF HEARING EXHIBITS
DESCRIPTION: Rocha

21. Please refer to witness Rocha's revised direct testimony, Exhibit RJR-1, Document No. 1, p. 23, titled Demand & Energy Forecast, and Schedule 3.2 of TECO's 2018 Ten Year Site Plan (TYSP).

a. The column titled "Winter (MW)" shows a forecast for 2018 of 4,285 MW, an increase of about 37% from 3,138 MW in 2017, notably greater than the annual increases for the rest of TECO's forecast (average annual increase of 1%). Similarly, the forecast base case winter peak demand depicted in Schedule 3.2 of TECO's 2018 TYSP (p. 42) indicates an increase from 2016/17 to 2017/18 of about 31%. Please identify the factors that account for this large increase in demand from 2017 to 2018.

b. The forecast base case winter peak demand through 2027 that appears in Schedule 3.2 of TECO's TYSP exceeds that shown in Exhibit RJR-1 by about 14% (average). Please identify the factors that account for this increase in TECO's winter demand forecast.

c. The forecast base case summer peak demand through 2027 that appears in schedule 3.2 of TECO's TYSP exceeds that shown in Exhibit RJR-1 by about 6.8% (average). Please identify the factor or factors that account for this large increase in TECO's summer demand forecast.

A. a. The large increase in demand from 2017 to 2018 is primarily driven by temperatures at the time of the peak. The 3,138 MW is the actual winter peak that occurred in January 2017, and the temperature at the time of the peak was 43 degrees. The 2018 peak of 4,285 MW is a projected peak based on a temperature of 31 degrees at the time of the peak. This 31-degree planning temperature was implemented after the Christmas Freeze of 1989, when the state experienced rolling brown-outs. The milder weather in 2017 resulted in a lower winter peak demand compared to future winter demands. In addition, the demands in R. James Rocha's Direct Testimony do not include cumulative residential and commercial/industrial conservation. In Schedule 3.2 of the TYSP the column labeled "Total" includes cumulative residential and commercial/industrial conservation.

b. The forecast base case winter peak demand through 2027 that appears in Schedule 3.2 of TECO's TYSP exceeds that shown in Exhibit No. RJR-1 because the column labeled "Total" in the TYSP includes cumulative residential and commercial/industrial conservation, which represents the potential peak demand if Tampa Electric did not have any conservation programs. The sum of columns (10), (8), (6) and (5) in Schedule 3.2 equal the winter peak demands shown in Exhibit No. RJR-1.

c. The forecast base case summer peak demand through 2027 that appears in Schedule 3.1 of TECO's TYSP exceeds that shown in Exhibit No. RJR-1 because the column labeled "Total" in the TYSP includes cumulative residential and commercial/industrial conservation. The sum of columns (10), (8), (6) and (5) in Schedule 3.1 equal the summer peak demands shown in Exhibit No. RJR-1.

22. Do the columns titled "Winter (MW)" and "Summer (MW)" in witness Rocha's revised direct testimony, Exhibit RJR-1, Document no. 1, p. 23 contain TECO's forecast winter and summer net firm demand (as that term is used in Schedule 3.2 of TECO's Ten Year Site Plans) from 2017-2027? If not, please describe this data in detail.

A. No. The columns titled "Winter (MW)" and "Summer (MW)" in witness Rocha's testimony are the sum of the Interruptible column, Residential Load Management column, Commercial/Industrial Load Management column, and Net Firm Demand column from the TYSP's Schedule 3.2 and 3.1, respectively.

23. Please identify the assumptions regarding population growth used by TECO in its forecast of Energy (GWh) as appears in Exhibit RJR-1 attached to witness Rocha's revised direct testimony.

A. The table below shows the population assumptions and annual growth rates used in preparing the forecast of Energy as appears in Exhibit No. RJR-1. It's company policy to use a 20-year horizon of forecasted load growth and then hold the load constant in the final 10 years for all planning analyses, as shown in Exhibit No. RJR-1.

	Hillsborough County Population	
2017	1,380,960	
2018	1,409,186	2.0%
2019	1,437,282	2.0%
2020	1,466,900	2.1%
2021	1,495,106	1.9%
2022	1,522,917	1.9%
2023	1,550,283	1.8%
2024	1,576,981	1.7%
2025	1,602,900	1.6%
2026	1,628,114	1.6%
2027	1,652,606	1.5%
2028	1,676,502	1.4%
2029	1,699,897	1.4%
2030	1,722,900	1.4%
2031	1,742,833	1.2%
2032	1,762,997	1.2%
2033	1,783,395	1.2%
2034	1,804,028	1.2%
2035	1,824,900	1.2%
2036	1,843,516	1.0%

24. Please identify any and all data sources used by TECO regarding population growth supporting the data appearing in Exhibit RJR-1 attached to witness Rocha's revised direct testimony.

A. The data source for the population growth that supports the data appearing in Exhibit No. RJR-1 is the Florida Population Studies, Bulletin 177, volume 50 which reports projections of Florida population by county. The publication is prepared by the University of Florida's Bureau of Economic and Business Research. The Hillsborough County medium level forecast was used.

25. Please identify any and all assumptions regarding cooling degree days and heating degree days used by TECO in its load forecasts appearing in Exhibit RJR-1 attached to witness Rocha's revised direct testimony.

A. The heating and cooling degree days used in preparing the load forecasts appearing in Exhibit No. 1 are listed below. The values for 2017 represent four months of actual and eight months of normal degree days. Normal degree days are based on Monte Carlo simulations using 20 years of historical data. The forecast years represent normal degree days. It's company policy to use a 20-year horizon of forecasted load growth and then hold the load constant in the final 10 years for all planning analyses, as shown in Exhibit No. RJR-1.

	Degree Days	
	Heating	Cooling
2017	222	3,993
2018	469	3,764
2019	469	3,764
2020	469	3,764
2021	469	3,764
2022	469	3,764
2023	469	3,764
2024	469	3,764
2025	469	3,764
2026	469	3,764
2027	469	3,764
2028	469	3,764
2029	469	3,764
2030	469	3,764
2031	469	3,764
2032	469	3,764
2033	469	3,764
2034	469	3,764
2035	469	3,764
2036	469	3,764

26. Please identify any and all assumptions regarding maximum and minimum temperatures used by TECO in its demand forecast appearing in Exhibit RJR-1 attached to witness Rocha's revised direct testimony.

A. The temperatures used in developing the demand forecast appearing in Exhibit No. RJR-1 are listed below. The temperature at the hour of the peak demand and the 24-hour average temperature on the peak day are used in the peak demand models. Winter 2017 data are actual temperatures. It's company policy to use a 20-year horizon of forecasted load growth and then hold the load constant in the final 10 years for all planning analyses, as shown in Exhibit No. RJR-1.

	Winter Assumptions		Summer Assumptions	
	Degrees Fahrenheit		Degrees Fahrenheit	
	Normal Temperature in Peak Hour	Normal 24-Hour Average on Peak Day	Normal Temperature in Peak Hour	Normal 24-Hour Average on Peak Day
2017	43	53	92	85
2018	31	42	92	85
2019	31	42	92	85
2020	31	42	92	85
2021	31	42	92	85
2022	31	42	92	85
2023	31	42	92	85
2024	31	42	92	85
2025	31	42	92	85
2026	31	42	92	85
2027	31	42	92	85
2028	31	42	92	85
2029	31	42	92	85
2030	31	42	92	85
2031	31	42	92	85
2032	31	42	92	85
2033	31	42	92	85
2034	31	42	92	85
2035	31	42	92	85
2036	31	42	92	85

27. Please identify any and all assumptions used by TECO regarding energy efficiency codes and standards on end-use energy efficiency used to prepare the load forecasts appearing in Exhibit RJR-1 attached to witness Rocha's revised direct testimony.

A. The table below describes the end-use energy efficiency assumptions used to prepare the load forecasts appearing in Exhibit No. RJR-1. It's company policy to use a 20-year horizon of forecasted load growth and then hold the load constant in the final 10 years for all planning analyses, as shown in Exhibit No. RJR-1.

	Residential End-Use Assumptions kWh-per-Customer		
	Heating	Cooling	NonHVAC
2017	851	3,822	8,258
2018	838	3,819	8,205
2019	825	3,816	8,161
2020	810	3,803	8,103
2021	792	3,784	8,055
2022	777	3,769	8,040
2023	763	3,764	7,976
2024	750	3,765	7,921
2025	738	3,767	7,870
2026	725	3,771	7,825
2027	713	3,771	7,787
2028	702	3,771	7,754
2029	691	3,771	7,723
2030	681	3,771	7,692
2031	672	3,771	7,660
2032	661	3,771	7,627
2033	651	3,771	7,593
2034	641	3,771	7,560
2035	631	3,771	7,529
2036	622	3,771	7,503

	Commercial End-Use Assumptions kWh-per-Customer		
	Heating	Cooling	NonHVAC
2017	5,115	21,978	59,939
2018	5,069	21,897	60,063
2019	5,030	21,838	60,299
2020	4,979	21,720	60,318
2021	4,922	21,573	60,325
2022	4,877	21,458	60,462
2023	4,840	21,382	60,692
2024	4,809	21,333	61,012
2025	4,779	21,286	61,348
2026	4,751	21,244	61,724
2027	4,725	21,209	62,116
2028	4,703	21,185	62,544
2029	4,682	21,176	62,997
2030	4,655	21,154	63,249
2031	4,631	21,135	63,533
2032	4,608	21,116	63,845
2033	4,586	21,094	64,175
2034	4,566	21,084	64,531
2035	4,551	21,099	64,968
2036	4,545	21,147	65,504

28. Please identify any and all data sources used by TECO regarding energy efficiency codes and standards used to prepare the load forecasts appearing in Exhibit RJR-1 attached to witness Rocha's revised direct testimony.

A. The end-use energy efficiency assumptions used to prepare the load forecasts appearing in Exhibit No. RJR-1 are based on the Energy Information Administration's ("EIA") National Energy Modeling System database. This is the data EIA uses to prepare its Annual Energy Outlook reference case.

29. Witness Rocha's revised direct testimony, P. 13, line 22-25, through P. 14, line 1, asserts that the December 2017 reduction of the federal corporate tax rate from 35% to 21% ...."changed the ATWACC, which is used as the discount rate for all present value calculations, from 6.81 percent to 7.08 percent." Please provide the information and calculations used by witness Rocha to arrive at this result.

A. The requested information is provided below.

Financial assumptions used to reflect TEC's projected actual costs (Pre-Tax Reform):

	Rate	Weight
Debt	4.5%	46%
Common Equity	10.25%	54%

Florida Corporate Tax Rate	5.5%
Federal Corporate Tax Rate	35.0%

Income Tax Rate = 1-(1-0.055)*(1-0.35) = 38.575%

ATWACC = 0.1025*0.54+(0.045*0.46)*(1-0.38575) = 6.81%

Financial assumptions used to reflect TEC's projected actual costs (Post Tax Reform):

	Rate	Weight
Debt	4.5%	46%
Common Equity	10.25%	54%

Florida Corporate Tax Rate	5.5%
Federal Corporate Tax Rate	21.0%

Income Tax Rate = 1-(1-0.055)*(1-0.21) = 25.345%

ATWACC = 0.1025*0.54+(0.045*0.46)*(1-0.25345) = 7.08%

A F F I D A V I T

STATE OF FLORIDA)
)
COUNTY OF HILLSBOROUGH)

Before me the undersigned authority personally appeared Penelope Rusk who deposed and said that she is a Manager, Rates, Tampa Electric Company, and that the individuals listed in Tampa Electric Company's response to Staff's Sixth Set of Interrogatories, (Nos. 21-29) prepared or assisted with the responses to these interrogatories to the best of her information and belief.

Dated at Tampa, Florida this 26th day of April, 2018.

Penelope Rusk
____

Sworn to and subscribed before me this 26th day of April, 2018.

Cynthia R. Kyle
____

Notary Public State of Florida
Cynthia R Kyle
My Commission FF 197516
Expires 03/01/2019

My Commission expires ____________________

EXHIBIT NOT MOVED

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20170260-EI   EXHIBIT: 13
PARTY: OPC
DESCRIPTION: FPL’s response to staff’s 3rd set of Interrrogatories, No. 24

EXHIBIT NOT MOVED

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20170260-EI   EXHIBIT: 14
PARTY: OPC
DESCRIPTION: NREL Q 1 2016 Benchmark Report

EXHIBIT NO. 15

DOCKET NO: 20170260-EI

WITNESS: Mark D. Ward

PARTY: Tampa Electric Company

DESCRIPTION: Final Order Approving 2017 Amended and Restated and Settlement Agreement

DOCUMENTS:

DOCKET NO. 20170210-EI
In re: Petition for limited proceeding to approve 2017 amended and restated stipulation and settlement agreement, by Tampa Electric Company.

DOCKET NO. 20160160-EI
In re: Petition for approval of energy transaction optimization mechanism, by Tampa Electric Company.

ORDER NO. PSC-2017-0456-S-EI
ISSUED: November 27, 2017

PROFFERED BY: Tampa Electric Company

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 20170260-EI EXHIBIT: 15
PARTY: OPC
DESCRIPTION: 2017 Agreement

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for limited proceeding to approve 2017 amended and restated stipulation and settlement agreement, by Tampa Electric Company.	DOCKET NO. 20170210-EI
In re: Petition for approval of energy transaction optimization mechanism, by Tampa Electric Company.	DOCKET NO. 20160160-EI ORDER NO. PSC-2017-0456-S-EI ISSUED: November 27, 2017

The following Commissioners participated in the disposition of this matter:

JULIE I. BROWN, Chairman
ART GRAHAM
RONALD A. BRISÉ
DONALD J. POLMANN
GARY F. CLARK

APPEARANCES:

JAMES D. BEASLEY and JEFFRY WAHLEN, ESQUIRES, Ausley McMullen Law Firm, P.O. Box 391, Tallahassee, Florida 32302
On behalf of Tampa Electric Company (TECO).

J.R. KELLY, VIRGINIA PONDER and CHARLES REHWINKEL, ESQUIRES, Office of Public Counsel, c/o The Florida Legislature, 111 West Madison Street, Room 812, Tallahassee, Florida 32399-1400
On behalf of the Citizens of the State of Florida (OPC).

KAREN PUTNAL and JON MOYLE, ESQUIRES, Moyle Law Firm, PA, The Perkins House, 118 North Gadsden Street, Tallahassee, Florida 32301
On behalf of the Florida Industrial Power Users Group (FIPUG).

ROBERT SCHEFFEL WRIGHT and JOHN T. LAVIA, III, ESQUIRES, Gardner, Bist, Bowden, Bush, Dee, LaVia & Wright, P.A., 1300 Thomaswood Drive, Tallahassee, Florida 32308
On behalf of the Florida Retail Federation (FRF).

SUZANNE BROWNLESS, ESQUIRE, Florida Public Service Commission, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850
On behalf of the Florida Public Service Commission (Staff).

MARY ANNE HELTON, ESQUIRE, Deputy General Counsel, Florida Public Service Commission, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850
Advisor to the Florida Public Service Commission.

KEITH HETRICK, ESQUIRE, General Counsel, Florida Public Service Commission, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850
Florida Public Service Commission General Counsel.

FINAL ORDER APPROVING 2017 AMENDED AND RESTATED STIPULATION AND SETTLEMENT AGREEMENT

BY THE COMMISSION:

BACKGROUND

On September 27, 2017, Tampa Electric Company (TECO) filed a petition for limited proceeding to approve its 2017 amended and restated stipulation and settlement agreement (Petition). In its Petition, TECO requested that the Florida Public Service Commission (Commission) hold a limited proceeding pursuant to Sections 366.076, 120.57(2) and 366.06(3), Florida Statutes (F.S.), and Rule 28-106.301, Florida Administrative Code (F.A.C.), to allow the Commission to review and approve the 2017 Amended and Restated Stipulation and Settlement Agreement (2017 Agreement) attached as an exhibit to the Petition.

The 2017 Agreement has been signed by TECO and the following: the Office of Public Counsel (OPC); Florida Industrial Power User's Group (FIPUG); Florida Retail Federation (FRF); Federal Executive Agencies (FEA); and West Central Florida Hospital Utility Alliance (HUA). TECO alleges that the 2017 Agreement amends and extends the term of its 2013 Stipulation and Settlement Agreement (2013 Agreement), which resolved all outstanding issues in its last base rate case proceeding, approved by Order No. PSC-2013-0443-FOF-EI, issued September 30, 2013, in Docket No. 20130040-EI. The 2017 Agreement also includes the asset optimization mechanism originally requested in Docket No. 20160160-EI[1], and constitutes a full resolution of all issues raised in that docket. TECO and all other parties to the 2017 Agreement agree that there are no disputed issues of material fact that must be resolved for us to grant its Petition and approve the 2017 Settlement Agreement.

Based on these representations, we issued Order No. PSC-2017-0384-PCO-EI, on October 4, 2017, setting the Petition for a final hearing, which was held on November 6, 2017. FEA and HUA were excused from attending the final hearing. At the final hearing, TECO presented the testimony of four witnesses: Carlos Aldazabal, Mark Ward, James Rocha, and Bill Ashburn. A Comprehensive Exhibit List was admitted into the record as well as the exhibits

[1] Docket No. 20160160, In re: Petition by Tampa Electric Company for approval of Energy Transaction Optimization Mechanism.

identified thereon. The parties, supporting the 2017 Agreement, waived the right to file post-hearing briefs, and a bench vote was taken at the conclusion of the hearing.

Settlement Agreement

The major elements of the 2017 Agreement are as follows:

- The 2017 Agreement term (Term) is approximately four years in duration, from the Effective Date (date of vote) through 2021, and is, by and large, a four year extension of the 2013 Agreement.

- The 2017 Agreement retains the existing return on equity (ROE) of 10.25%, with a range of 9.25% to 11.25%, and features an equity ratio of 54% for the Solar Base Rate Adjustment (SoBRA) revenue requirement calculations and TECO's actual equity ratio for surveillance reporting and setting clause rates.

- Base rates to remain at current levels initially, with solar generation cost recovery (SoBRA) included in tranches during the Term at the following dates and maximum cumulative amounts:

Year	Earliest Rate Change and In-Service Date	Maximum Cumulative SoBRA MW	Maximum Cumulative Annualized SoBRA Revenue Requirement (millions)	Maximum Cumulative Impact on 1,000 KWH Residential Bill
2018	September 1	150	$30.6 ($10.2 collected over 4 months)	$1.95
2019	January 1	400	$81.5	$3.33
2020	January 1	550	$112.1	$4.47
2021	January 1	600	$122.3*	$4.87
* Cost recovery contingent on 2018-2019 tranches constructed at a maximum average capital cost of $1475/kW$_{ac.}$				

- SoBRA total installed costs for purposes of cost recovery cannot exceed $1,500 per KWac (cap). Projects must be smaller than 75 MW and thus are not subject to the Power Plant Siting Act. Each tranche requires that a new petition for cost recovery be filed in a separate docket.

- SoBRA savings, where actual costs are below the $1,500 per KWac cap, are shared between customers and company on a 75%/25% basis. The full benefit of Renewable Energy Credits (RECs) will be flowed through to retail customers through the Environmental Cost Recovery Clause (ECRC).

- SoBRA costs are allocated equally among all rate classes with the exception of the lighting class. The lighting class is responsible for 40% of its SoBRA revenue requirement, with the remaining 60% of its revenue requirement allocated to the other customer classes.

- If federal or state tax reform is enacted before TECO's next rate case, TECO will flow back to retail customers within 120 days any impacts to revenue requirements through a one-time adjustment to base rates, uniformly applied across customer classes and charges.

- Standby Generator Credits increase from $4.75/kW/month to $5.35/kW/month. Contracted Credit Value, or CCV Credit, is increased marginally for secondary, primary, and sub-transmission voltage customers.

- If TECO's coal-fired generating assets and Automatic Meter Reading (AMR) meters are retired during the Term, the related assets will be depreciated using TECO's then-existing depreciation rates.

- The parties consent to TECO's petition to implement its proposed asset optimization/ incentive plan set forth in Docket No. 20160160-EI during the Term, but at modified percentage thresholds of achieved gains to be divided between customers and shareholders.

- TECO will enter into no new natural gas financial hedging contracts through December 31, 2022 and will file a request to close Docket No. 20170057-EI upon approval of the 2017 Agreement or as soon thereafter as practical.

- TECO will not seek recovery of any costs from its customers related to investments in oil and/or natural gas exploration, reserves, acreage and or production for a period of five years after the Effective Date.

- Carryover Provisions applicable from the 2013 Agreement include: named storm damage recovery; the Economic Development Rider; and deferral of depreciation and dismantlement studies until the year before TECO's next rate case.

DECISION

The standard for approval of a settlement agreement is whether it is in the public interest.[2] A determination of public interest requires a case-specific analysis based on consideration of the proposed settlement taken as a whole.[3] The signatories to the 2017 Agreement represent a broad segment of FPL's customer base including both residential and commercial classes. Many of the terms found in the 2017 Agreement were proposed by the signatories and are consistent with terms found in Florida Power & Light Company's, Gulf Power Company's, and Duke Energy Florida, LLC's most recent rate case settlements,[4] e.g., cessation of natural gas hedging, construction of cost-effective solar generation, implementation of an asset optimization program, implementation of a storm damage recovery mechanism, an economic development rider, and the deferral of depreciation studies until the utility's next rate case. The 2017 Agreement essentially maintains the current base rates for another four years adjusted for additions to solar generating capacity spread over the same period. Thus, the 2017 Agreement increases TECO's fuel diversity in a cost effective manner while providing rate predictability. Further, the 2017 Agreement allows ratepayers to receive the benefit of any revisions to the federal income tax code within 4 months of those benefits becoming available. Having carefully reviewed the 2017 Agreement, the exhibits entered into the record, and the testimony provided by TECO's witnesses, we find that taken as a whole it provides a reasonable resolution of all the issues addressed. We find, therefore, that the 2017 Agreement, Attachment A hereto, establishes rates that are fair, just, and reasonable and is in the public interest, and hereby approve it.

Based on the foregoing, it is

ORDERED by the Florida Public Service Commission that Tampa Electric Company's Petition for Limited Proceeding to approve 2017 Amended and Restated Stipulation and Settlement Agreement is hereby granted. It is further

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[2] Order No. PSC-13-0023-S-EI, issued on January 14, 2013, in Docket No. 120015-EI, In re: Petition for increase in rates by Florida Power & Light Company; Order No. PSC-11-0089-S-EI, issued February 1, 2011, in Docket Nos. 080677 and 090130, In re: Petition for increase in rates by Florida Power & Light Company and In re: 2009 depreciation and dismantlement study by Florida Power & Light Company; Order No. PSC-13-0023-S-EIPSC-10-0398-S-EI, issued June 18, 2010, in Docket Nos. 090079-EI, 090144-EI, 090145-EI, 100136-EI, In re: Petition for increase in rates by Progress Energy Florida, Inc., In re: Petition for limited proceeding to include Bartow repowering project in base rates, by Progress Energy Florida, Inc., In re: Petition for expedited approval of the deferral of pension expenses, authorization to charge storm hardening expenses to the storm damage reserve, and variance from or waiver of Rule 25-6.0143(1)(c), (d), and (f), F.A.C., by Progress Energy Florida, Inc., and In re: Petition for approval of an accounting order to record a depreciation expense credit, by Progress Energy Florida, Inc.; Order No. PSC-05-0945-S-EI, issued September 28, 2005, in Docket No. 050078-EI, In re: Petition for rate increase by Progress Energy Florida, Inc.

[3] Order No. PSC-13-0023-S-EI, at p. 7.

[4] Order No. PSC-16-0560-AS-EI, issued on December 15, 2016, in Docket No. 160021-EI, In re: Petition for rate increase by Florida Power & Light Company; Order No. PSC-17-0178-S-EI, issued on May 16, 2017, in Docket No. 20160186-EI, In re: Petition for rate increase by Gulf Power Company; Order No. PSC-2017-0451-AS-EI, issued on November 20, 2017, in Docket No. 20170183-EI, In re: Application for limited proceeding to approve 2017 second revised and restated settlement agreement including certain rate adjustments by Duke Energy Florida LLC .

ORDERED that the 2017 Amended and Restated Stipulation and Settlement Agreement, attached hereto as Attachment A, and incorporated by reference, is hereby approved. It is further

ORDERED that the tariff sheets, contained in Exhibit A attached to the 2017 Amended and Restated Stipulation and Settlement Agreement, are hereby approved with an effective date of the first billing cycle in January 2018. It is further

ORDERED that in the event no timely appeal is filed, Docket Nos. 20170210-EI and 20160160-EI shall be closed.

By ORDER of the Florida Public Service Commission this 27th day of November, 2017.

Carlotta S Stauffer
CARLOTTA S. STAUFFER
Commission Clerk
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, Florida 32399
(850) 413-6770
www.floridapsc.com

Copies furnished: A copy of this document is provided to the parties of record at the time of issuance and, if applicable, interested persons.

SBr

NOTICE OF FURTHER PROCEEDINGS OR JUDICIAL REVIEW

The Florida Public Service Commission is required by Section 120.569(1), Florida Statutes, to notify parties of any administrative hearing or judicial review of Commission orders that is available under Sections 120.57 or 120.68, Florida Statutes, as well as the procedures and time limits that apply. This notice should not be construed to mean all requests for an administrative hearing or judicial review will be granted or result in the relief sought.

Any party adversely affected by the Commission's final action in this matter may request: 1) reconsideration of the decision by filing a motion for reconsideration with the Office of Commission Clerk, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850, within fifteen (15) days of the issuance of this order in the form prescribed by Rule 25-22.060, Florida Administrative Code; or 2) judicial review by the Florida Supreme Court in the case of an electric, gas or telephone utility or the First District Court of Appeal in the case of a water and/or wastewater utility by filing a notice of appeal with the Office of Commission Clerk, and filing a copy of the notice of appeal and the filing fee with the appropriate court. This filing must be completed within thirty (30) days after the issuance of this order, pursuant to Rule 9.110, Florida

Rules of Appellate Procedure. The notice of appeal must be in the form specified in Rule 9.900(a), Florida Rules of Appellate Procedure.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition by Tampa Electric Company for a limited proceeding to approve 2017 Amended and Restated Stipulation and Settlement Agreement	)))	DOCKET NO. 2017 _____-EI
In re: Tampa Electric Company's Petition for Approval of Energy Transaction Optimization Mechanism	))))	DOCKET NO. 20160160-EI FILED: September 27, 2017

2017 AMENDED AND RESTATED STIPULATION AND SETTLEMENT AGREEMENT

THIS AGREEMENT is dated this 27th day of September, 2017 and is by and between Tampa Electric Company ("Tampa Electric" or the "company"), the Office of Public Counsel ("OPC" or "Citizens"), the Florida Industrial Power Users Group ("FIPUG"), the Florida Retail Federation ("FRF"), the Federal Executive Agencies ("FEA"), and the WCF Hospital Utility Alliance ("HUA"). Collectively, Tampa Electric, OPC, FIPUG, FRF, FEA, and HUA shall be referred to herein as the "Parties" and the term "Party" shall be the singular form of the term "Parties." OPC, FIPUG, FRF, FEA, and HUA will be referred to herein as the "Consumer Parties." This document shall be referred to as the "2017 Agreement."

Background

On September 8, 2013, Tampa Electric and the Consumer Parties filed a Stipulation and Settlement Agreement ("2013 Stipulation") that resolved all the issues in Tampa Electric's 2013 base rate case (Docket No. 20130040-EI). Therein, among other things, Tampa Electric agreed that the general base rates provided for in the 2013 Stipulation would remain in effect through December 31, 2017, and thereafter, until the company's next general base rate case. The 2013

Stipulation also specified that Tampa Electric would forego seeking future general base rate increases with an effective date prior to January 1, 2018, except in limited circumstances. The Florida Public Service Commission ("FPSC" or "Commission") approved the 2013 Stipulation and memorialized its decision in Order No. PSC-2013-0443-FOF-EI, issued September 30, 2013 ("2013 Stipulation Order").

In late 2016, recognizing that the period in which Tampa Electric agreed to refrain from seeking general base rate increases would expire at the end of 2017, Tampa Electric and the Consumer Parties began discussing whether the company would be willing and able to (a) refrain from seeking a general base rate increase beyond December 31, 2017 and (b) extend the terms of the 2013 Stipulation for an additional period of time. The Parties also discussed the company's desire to build 600 MW of solar photovoltaic generation with cost recovery via a solar base rate adjustment mechanism ("SoBRA").

The Parties have entered into this 2017 Agreement in compromise of positions taken in accord with their rights and interests under Chapters 350, 366 and 120, Florida Statutes, as applicable, and as part of a negotiated exchange of consideration among the Parties to this 2017 Agreement, each Party has agreed to concessions to the others with the expectation, intent, and understanding such that all provisions of the 2017 Agreement, upon approval by the Commission, will be enforced by the Commission as to all matters addressed herein with respect to all Parties.

NOW, THEREFORE, in light of the mutual covenants of the Parties and the benefits accruing to all Parties through this 2017 Agreement, and for good and valuable consideration, the receipt and sufficiency of which is hereby acknowledged, the Parties agree as follows:

1. Term.

This 2017 Agreement will become effective upon the date of the Commission's vote approving it (the "Effective Date") and continue through and including December 31, 2021, such that, except as specified in this 2017 Agreement, no base rates, charges, or credits (including the credits that are specifically the subject of this 2017 Agreement) or rate design methodologies will be changed before January 1, 2022. The period from the Effective Date through December 31, 2021 (subject to Paragraph 7(c)) shall be referred to herein as the "Term". The Parties reserve all rights, unless such rights are expressly waived or released, under the terms of this 2017 Agreement.

2. Return on Equity and Equity Ratio.

(a) Subject to the adjustment Trigger provisions in Subparagraph 2(b), Tampa Electric's authorized return on common equity ("ROE") shall be within a range of 9.25% to 11.25%, with a mid-point of 10.25%, except under the conditions specifically provided in this 2017 Agreement in Paragraphs 2(b) and 7. Tampa Electric's authorized ROE range and mid-point shall be used for all regulatory purposes during the Term, together with an equity ratio as follows: (a) a 54% equity ratio for the SoBRA revenue requirement calculations, (b) the company's actual equity ratio for earnings surveillance reporting, and (c) the actual equity ratio up to a cap of 54% for purposes of setting cost recovery clause rates, triggering an exit from this 2017 Agreement pursuant to paragraph 7, or calculating interim rates.

(b) ROE Trigger Mechanism. The purpose of the provisions in this Subparagraph 2(b) is to provide Tampa Electric with rate relief in the event that market capital costs, as indicated by the interest rate on U.S. Treasury bonds, rise above the level specified herein; these provisions are generically referred to as the "Trigger" mechanism or the "Trigger provisions," or simply as the "Trigger." If at any time during the Term, the average 30-year United States Treasury Bond yield rate for any period of six (6) consecutive months is at least 4.6039% (the "Trigger Point")[1], Tampa Electric's authorized ROE shall be increased by 25 basis points to be within a range of 9.50% to 11.50%, with a mid-point of 10.50% ("Revised Authorized ROE") from the Trigger Effective Date defined below for and through the remainder of the Term, and thereafter until the Commission resets the Company's rates and its authorized ROE. The Trigger Criterion Value ("Trigger Value") shall be calculated by summing the reported 30-year U.S. Treasury Bond rates for each day over a consecutive six-month period for which rates are reported, and dividing the resulting sum by the number of reporting days in such period. The effective date of the Revised Authorized ROE ("Trigger Effective Date") shall be the first day of the month following the day in which the Trigger Value reaches the Trigger Point. If the Trigger Point is reached and the Revised Authorized ROE becomes effective, Tampa Electric's Revised Authorized ROE range and mid-point shall be used for the remainder of the Term for all regulatory purposes, and thereafter until changed by a final non-appealable order ("Final Order") of the Commission.

(c) The ROE in effect at the expiration of the Term of this 2017 Agreement shall continue in effect until the company's ROE is next reset by a Final Order of the Commission whether by operation of Paragraph 7 or otherwise.

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[1] This value was derived as provided for in the 2013 Stipulation and reflected in Late Filed Hearing Exhibit 246, in Docket No. 130040-EI as follows: "The Trigger shall be calculated by summing the reported 30-year U.S. Treasury Bond rates for each day over any six-month period, e.g. January 1, 2014 through July 1, 2014, or March 17, 2014 through September 17, 2014, for which rates are reported, and dividing the resulting sum by the number of reporting days in such period."

3. Customer Rates.

(a) Except as specified in this 2017 Agreement, the company's general base rates, charges, credits, and rate design methodologies, for retail electric service in effect on December 31, 2017, shall remain in effect for service rendered and charges imposed through and including December 31, 2021, and thereafter until revised by a future unanimous agreement of the Parties approved by a Final Order of the Commission or a Final Order of the Commission issued as the result of a future general base rate proceeding.

(b) Except as specified in this 2017 Agreement, the company may not petition to change any of its general base rates, charges, credits, or rate design methodologies for retail electric service with an effective date for the new rates, charges, credits, or rate design methodologies earlier than January 1, 2022.

(c) Notwithstanding Subparagraphs 3(a) and 3(b), the company shall be authorized to change its base rates as set forth in Paragraphs 6 and 9, below, in accordance with procedures identified for the SoBRA mechanism and to reduce rates in accordance with Federal Income Tax Reform that may occur during the Term of this 2017 Agreement.

(d) The current lock period for the Contracted Credit Value ("CCV") shall remain 72 months (6 years).

(e) The company's standby generator credit shall be increased from \$4.75/kW/month to \$5.35/kW/month, concurrent with meter reads for the first billing cycle of January 2018. The CCV credit shall be increased from \$9.98/kW/month to \$10.23/kW/month for secondary, \$9.88/kW/month to \$10.13/kW/month for primary, and \$9.78/kW/month to \$10.03/kW/month for sub-transmission voltage customers, concurrently with meter readings for the first billing cycle of January 2018. To the extent that implementation of these revised credits results in an under-recovery or over-recovery of revenues that are subject to the Energy Conservation Cost Recovery ("ECCR") clause, the company shall be authorized to make an adjustment to remedy any such under-recovery or over-recovery in its ECCR charges for 2019 and thereafter. The level of these credits will not change during the Term and will remain in effect after the expiration of the Term until changed, if at all, by a future unanimous agreement of the Parties approved by a Final Order of the Commission or a Final Order of the Commission issued as a result of a future general base rate proceeding. The credit modifications addressed in this Subparagraph 3(e) are reflected in the revised tariff sheets set forth in Exhibit A to this 2017 Agreement, the approval of which shall constitute approval of the revised tariff sheets.

(f) The company's Economic Development Rider, which is set forth in Rate Schedule ECONOMIC DEVELOPMENT RATE – EDR of the company's retail tariff, shall remain in effect during the Term and thereafter until modified or terminated by order of the Commission. The Parties intend that the Commission's approval of this 2017 Agreement shall constitute continuing approval of the Economic Development Rider and that such approval shall satisfy the requirements of Rule 25-6.0426(3) - (6), F.A.C., and accordingly, the reductions afforded in Rate Schedule EDR shall be included as a cost in the company's cost of service for all ratemaking purposes and surveillance reporting. The rates in the Economic Development Rider shall be open for new customers and for new applications by existing customers through December 31, 2021, unless the maximum amount of economic development expenditures as specified in Rule 25-6.0426, F.A.C., is met, at which time the Economic Development Rider will be closed to new customers and to new applications by existing customers until the amount again falls below the maximum allowed.

(g) The provisions of this Paragraph 3 shall remain in effect during the Term except as otherwise permitted or provided for in this 2017 Agreement and shall continue in effect until changed by unanimous agreement of the Parties approved by a Final Order of the Commission or a Final Order of the Commission issued as a result of a future general base rate proceeding.

4. Other Cost Recovery. Nothing in this 2017 Agreement shall preclude the company from requesting the Commission to approve the recovery of costs that are: (a) of a type which traditionally or historically would be, have been, or are presently recovered through cost recovery clauses or surcharges, or (b) incremental costs not currently recovered in base rates which the Legislature expressly requires shall be clause recoverable subsequent to the approval of this 2017 Agreement. It is the intent of the Parties that, in conjunction with the provisions of Subparagraph 3(a), the company shall not seek to recover, nor shall the company be allowed to recover, through any cost recovery clause or charge, or through the functional equivalent of such cost recovery clauses and charges, costs of any type or category that have historically or traditionally been recovered in base rates, unless such costs are: (i) the direct and unavoidable result of new governmental impositions or requirements; or (ii) new or atypical costs that were unforeseeable and could not have been contemplated by the Parties resulting from significantly changed industry-wide circumstances directly affecting the company's operations. As a part of the base rate freeze agreed to herein, the company will not seek Commission approval to defer for later recovery in rates, any costs incurred or reasonably expected to be incurred from the Effective Date through and including December 31, 2021, which are of the type which historically or traditionally have been or would be recovered in base rates, unless such deferral and subsequent recovery is expressly authorized herein or otherwise agreed to by each of the Parties. The Parties are not precluded from participating in any proceedings pursuant to this

Paragraph 4, nor is any Party precluded from raising any issues pertinent to any such proceedings.

5. Storm Damage.

(a) Nothing in this 2017 Agreement shall preclude Tampa Electric from petitioning the Commission to seek recovery of costs associated with any tropical systems named by the National Hurricane Center or its successor without the application of any form of earnings test or measure and irrespective of previous or current base rate earnings. Consistent with the rate design methods approved in this 2017 Agreement, the Parties agree that recovery of storm costs from customers will begin, on an interim basis (subject to refund following a hearing or a full opportunity for a formal proceeding), sixty days following the filing of a cost recovery petition and tariff with the Commission and will be based on a 12-month recovery period if the storm costs do not exceed $4.00/1,000 kWh on monthly residential customer bills. In the event the company's reasonable and prudent storm costs exceed that level, any additional costs in excess of $4.00/1,000 kWh shall be recovered in a subsequent year or years as determined by the Commission, after hearing or after the opportunity for a formal proceeding has been afforded to all substantially affected persons or parties. All storm related costs shall be calculated and disposed of pursuant to Rule 25-6.0143, F.A.C., and shall be limited to (i) costs resulting from a tropical system named by the National Hurricane Center or its successor, (ii) the estimate of incremental storm restoration costs above the level of storm reserve prior to the storm, and (iii) the replenishment of the storm reserve to $55,860,642. The Parties to this 2017 Agreement are not precluded from participating in any such proceedings and opposing the amount of Tampa Electric's claimed costs (for example, and without limitation, on grounds that such claimed costs were not reasonable or were not prudently incurred) or whether the proposed recovery is consistent with this Paragraph 5, but not the mechanism agreed to herein.

(b) The Parties agree that the $4.00/1,000 kWh cap in this Paragraph 5 shall apply in aggregate for a calendar year; provided, however, that Tampa Electric may petition the Commission to allow Tampa Electric to increase the initial 12 month recovery at rates greater than $4.00/1,000 kWh or for a period longer than 12 months if Tampa Electric incurs in excess of $100 million of storm recovery costs that qualify for recovery in a given calendar year, inclusive of the amount needed to replenish the storm reserve to $55,860,642. All Consumer Parties reserve their right to oppose such a petition.

(c) The Parties expressly agree that any proceeding to recover costs associated with any storm shall not be a vehicle for a "rate case" type inquiry concerning the expenses, investment, or financial results of operations of Tampa Electric and shall not apply any form of earnings test or measure or consider previous or current base rate earnings. Such issues may be fully addressed in any subsequent Tampa Electric base rate case.

(d) The provisions of this Paragraph 5 shall remain in effect during the Term except as otherwise permitted or provided for in this 2017 Agreement and shall continue in effect until the company's base rates are next reset by the Commission. For clarity, this means that if this 2017 Agreement is terminated pursuant to Paragraph 7 hereof, the company's rights regarding storm cost recovery under this 2017 Agreement are terminated at the same time, except that any Commission-approved surcharge then in effect shall remain in effect until the costs subject to that surcharge are fully recovered. A storm surcharge in effect without approval of the Commission shall be terminated at the time this 2017 Agreement is terminated pursuant to Paragraph 7 hereof.

6. Solar Base Rate Adjustment Mechanism ("SoBRA").

(a) Notwithstanding the general base rate freeze specified in Paragraph 2, the company shall be allowed to recover the cost of its investment in, and operation of, certain new solar generation facilities and to make solar base rate adjustments consistent with this Paragraph 6. If the applicable federal or state income tax rate for the Company changes before any of the increases provided for in in this Paragraph 6, the Company will adjust the amount of the base rate increase to reflect the new tax rate before the implementation of such increase, pursuant to the applicable methodology in Exhibit C.

(b) Subject to the conditions in Subparagraph 6(c), the planned capacity amounts, earliest in-service and rate adjustment dates, and associated maximum annual revenue requirements (calculated at the Installed Cost Cap specified herein) are as follows:

Year	Earliest Rate Change And In-Service Date	Maximum Incremental SoBRA MW	Maximum Incremental Annualized SoBRA Revenue Requirements (millions)	Maximum Cumulative SoBRA MW	Maximum Cumulative Annualized SoBRA Revenue Requirements (millions)
2018	September 1	150	$30.6[2]	150	$30.6
2019	January 1	250	$50.9	400	$81.5
2020	January 1	150	$30.6	550	$112.1
2021	January 1	50	$10.2	600	$122.3[3]

(c) The company will seek approval of and cost recovery for specific solar generation projects in SoBRA Tranches up to the amounts as specified in this Paragraph 6. Nothing in this 2017 Agreement requires Tampa Electric to build the full amount of solar generating capacity

[2] The annual revenue requirement is approximately $30.6 million, however, since the first 150 MW Tranche is scheduled to come online September 1, 2018, the revenue requirements collected would be four months of the annual revenue requirements, or $10.2 million.
[3] The 2021 Tranche can be included in and its costs recovered under the SoBRA mechanism only if the projects constituting the 2018 and 2019 Tranches in this table are in-service and operating per design specifications as of December 31, 2019, and were constructed at an average capital cost of no more than $1475 per kW_{ac}.

allowed by this 2017 Agreement for any year or in total over the Term of this 2017 Agreement. Commission action may occur before or after expiration of the Term, but to qualify for cost recovery pursuant to these SoBRA provisions, any Tranche must be fully operational and providing service no later than December 31, 2022. A SoBRA Tranche may consist of a single project or may include multiple individual solar projects, which may be located throughout the company's retail service territory. Tampa Electric will construct and bring into full commercial operation, the full Maximum Incremental SoBRA MW for each year's Tranche by the dates shown in the table above. The Rate Change and In-Service Dates specified in the chart in Subparagraph 6(b) are "no sooner than" dates, and the SoBRA rate changes for each Tranche will be implemented effective on the earliest In-Service Date for that Tranche identified in such chart and subsequently trued up to reflect and correct for (1) any delay in the actual In-Service Dates of any of the projects in a particular Tranche beyond the applicable In-Service date for that Tranche and (2) the extent to which the actual installed costs of any project or projects vary from the projected costs used to set the SoBRA rate change but may not exceed the Maximum Incremental Annualized SoBRA Revenue Requirements or Maximum Cumulative Annualized SoBRA Revenue Requirements set forth in Subparagraph 6(b) or the Installed Cost Cap set forth in Subparagraph 6(d). Each SoBRA revenue increase shall be calculated based on the projected In-Service date, operating capacity, and estimated cost of the solar projects to which it corresponds, subject to being trued up as described in this Subparagraph 6(c). The 2021 SoBRA will only be available to the company if (i) for all projects in the 2018 and 2019 Tranches (totaling 400MW subject to the two percent (2%) variance allowance described in the following sentence), the actual average installed cost necessary to make such projects fully operational is less than or equal to \$1,475 per kW_{ac} and (ii) the 2018 and 2019 Tranches in the amount of 400

MW (subject to the 2% variance) are installed and operating at design specifications as of December 31, 2019. The SoBRA Tranches of solar generation capacity and the associated revenue requirements shown in Subparagraph 6(b) are "up to" or maximum amounts; however, the amount of revenues and MW in the 2019 SoBRA Tranche or Tranches may vary by up to 2 percent of the 2019 total (5 MW variance, either greater than or less than the specified maximum for 2019) to accommodate efficient planning and construction of the associated individual solar projects, and the 2019 Tranche or Tranches remain subject to the cost cap contained herein. Tampa Electric shall make a filing with the Commission by February 28, 2020, reflecting whether it has met the requirements to qualify for the 2021 SoBRA Tranche.

(d) For the solar projects that are approved by the Commission for cost recovery pursuant to this Paragraph 6, Tampa Electric's base rates will be increased by the incremental annualized base revenue requirement in steps, one step for each SoBRA Tranche. Each such base rate adjustment will be referred to as a SoBRA, and shall be authorized for solar projects for which Tampa Electric files for Commission approval pursuant to this Paragraph 6. Each project qualifying for SoBRA treatment must consist of either single axis tracking or other solar electric generating equipment or tracking technology that yields greater efficiency or higher capacity value, or both, for the benefit of customers all within the cost caps stated in this Paragraph 6. The types of costs of solar projects that traditionally have been allowed in rate base (including Engineering, Procurement and Construction ("EPC") costs; development costs including third party development fees, if any; permitting fees and costs; actual land costs and land acquisition costs; taxes; utility costs to support or complete development; transmission interconnection costs; installation labor and equipment costs; costs associated with electrical balance of system, structural balance of system, inverters, and modules; AFUDC at the weighted average cost of capital from Exhibit B of this 2017 Agreement; and other traditionally allowed rate base costs) shall be eligible for SoBRA cost recovery. The total installed capital cost of a project eligible for cost recovery through a SoBRA shall not exceed \$1,500 per kW_{ac} (the "Installed Cost Cap"). This Installed Cost Cap shall apply on a per project basis, and includes all costs required to make each of the projects in a Tranche fully operational. Each SoBRA will be based on a 10.25% ROE, except under the conditions specifically provided in this 2017 Agreement in Subparagraph 2(b), a 54% equity ratio (based on investor sources of capital), and the incremental capital structure components of long-term debt, short-term debt (if any), common equity, and tax credits, adjusted to reflect the inclusion of investment tax credits on a normalized basis. The debt rate utilized to calculate the revenue requirements associated with the SoBRA projects will be updated to reflect the incremental costs of prospective long-term debt issuances during the first 12 months of operation of each project. The SoBRA Installed Cost Cap is an amount agreed to by and between the Parties that reflects their negotiations regarding all relevant factors affecting or determining the installed cost of each project, including but not limited to capital costs, costs of capital, capital structure, and the other costs and expenses associated with the project.

(e) The Installed Cost Cap is not a "safe harbor" or a "build to" number for the company. The company will use reasonable efforts to design and build solar projects at installed costs below the cap. The Installed Cost Cap will limit the cost recovery of projects under a SoBRA, so if a project costs more than \$1,500 per kW_{ac}, the company can recover through a SoBRA only the installed cost up to the Installed Cost Cap, but may use the actual installed cost for purposes of preparing its periodic earnings surveillance reports; however, during the company's next general base rate proceeding, the depreciated net book value of any SoBRA project included in rate base for the test year may not exceed the Installed Cost Cap.

(f) The individual solar generation projects contemplated in this 2017 Agreement are not subject to the Florida Electrical Power Plant Siting Act, because each project will be smaller than 75 MW, and accordingly, the projects contemplated herein will be subject to the process and FPSC approval as specified herein. For each SoBRA and associated SoBRA Tranche, Tampa Electric will file a petition for approval of each SoBRA, provided that the SoBRA rate change for each Tranche shall not take effect before the dates specified in the aforementioned chart. Each petition for approval of a SoBRA or SoBRAs shall be filed in a separate stand-alone docket. The petition for approval of the first SoBRA (September 1, 2018) shall be made as soon as reasonably possible after the Commission vote to approve this 2017 Agreement. The petition for approval of each of the remaining SoBRAs shall be made in a separate stand-alone docket; the company may file the petitions for each Tranche for the following year at the time of the company's projection filings in the 2018, 2019 and 2020 Fuel and Purchased Power Cost Recovery Clause dockets ("Fuel Docket(s)") for the 2019, 2020 and 2021 factors, respectively, or the company may file each SoBRA petition at a convenient time throughout each year. The Parties contemplate that there will be a final true-up for the 2021 SoBRA, if needed. The Parties agree to request that, to the extent practicable, the deadlines and schedules in the Fuel Dockets apply to the petitions for approval of SoBRAs, so that the amount of solar generation approved for recovery through a SoBRA and related fuel cost savings can be synchronized with the Fuel Dockets.

(g) The issues for determination in each proceeding for approval of a SoBRA shall be limited to: (1) the cost effectiveness of the solar projects in the Tranche, (2) whether the installed cost of each project in the Tranche is projected to be under the Installed Cost Cap, (3) the amount of revenue requirements and appropriate increase in base rates needed to collect the estimated annual revenue requirement for the projects in a Tranche, (4) a true-up of previously approved SoBRAs for the actual cost of the previously approved projects, subject to the sharing provisions in Subparagraph 6(m), and (5) a true-up through the Capacity Cost Recovery Clause ("CCR") of previously approved SoBRAs to reflect the actual in service dates and actual installed cost for each of the previously-approved projects. The cost effectiveness for the projects in a Tranche shall be evaluated in total by considering only whether the projects in the Tranche will lower the company's projected system cumulative present value revenue requirement ("CPVRR") as compared to such CPVRR without the solar projects.

(h) The Parties expect and intend that the first SoBRA will be effective as of September 1, 2018, based on the Parties' expectation and the company's intent that all projects in the 2018 Tranche will be fully operational and providing service as of September 1, 2018. To accommodate efficient planning and construction by the company, the Consumer Parties agree that Tampa Electric may request the Commission to consider approval of the 2018 Tranche as soon as practicable following approval of this 2017 Agreement. The Parties further intend that Commission action on the remaining SoBRAs will be resolved, to the extent practicable, on a schedule that is contemporaneous with the annual, regularly scheduled Fuel and Purchased Power Cost Recovery Docket hearings, provided, however, that the Commission on its own initiative or upon good cause shown by any Party to this 2017 Agreement or any other entity satisfying the standing requirements of Florida law may set Tampa Electric's request for approval of any SoBRA or SoBRA Tranche for a separate hearing to be held at any convenient time to permit timely resolution before the company's projected In-Service date for the SoBRA Tranche that is the subject of such petition and hearing.

(i) The SoBRA increases approved pursuant to this 2017 Agreement shall be calculated based upon Tampa Electric's billing determinants used in the company's then-most-current ECCR Clause filings with the Commission for the twelve months following the effective date of any respective SoBRA. To the extent necessary, this will include projections of such billing determinants into a subsequent calendar year so as to cover the same 12 months as the first 12 months of each Tranche of solar projects' operations. The exception to this will be the first Tranche of SoBRA, which is to go into effect on September 1, 2018. In the case of this Tranche, the billing determinants used will be from the 2017 ECCR Clause filing for the 12 months of 2018 and the base rate adjustment derived on an annual basis but only applied to bills for the four months from September 2018 through December 2018 and then for the 12 months of 2019. The revenue requirement for each SoBRA Tranche shall be allocated to the rate classes using the 12 CP and $1/13^{th}$ method of allocating production plant and shall be applied to existing base rates, charges and credits using the following principles:

(i) 40% of the revenue requirements that would otherwise be allocated to the lighting class under the 12 CP and $1/13^{th}$ methodology shall be allocated to the lighting class for recovery through an increase in the lighting base energy rate and the remaining 60% shall be allocated ratably to the other customer classes.

(ii) The revenue requirement associated with a SoBRA will be recovered through increases to demand charges where demand charges are part of a rate schedule, and through energy charges where no demand charge is used in a rate schedule.

(iii) Within the GSD and IS rate classes, recovery of SoBRA revenue requirements allocated to those rate classes will be borne by non-standby demand charges only within a rate class, which methodology will not impact RS and GS rate classes.

(j) The solar capacity amounts specified in Subparagraphs 6(b) and 6(c) shall limit the maximum amount of solar capacity for which the company may recover costs through a SoBRA during each year of the Term, which may include recovery during 2022 for any SoBRA that satisfies the capacity and cost caps provided herein; provided, however, if Tampa Electric receives approval for SoBRA recovery for capacity amounts below the capacity amounts specified in Subparagraphs 6(b) and 6(c) in any year, the company can seek recovery of the unused capacity in a future petition for approval up to the Maximum Cumulative SoBRA for the applicable year as set forth in Subparagraph 6(b), provided such request is filed with the Commission during the Term of this 2017 Agreement. A SoBRA may become effective at any time during the Term or within one year after expiration of the Term, as limited by Subparagraph 6(d) and subject to the termination of the company's rights to seek SoBRA recovery if this 2017 Agreement is terminated pursuant to Paragraph 7 hereof.

(k) For each of the SoBRAs specified in Subparagraphs 6(b) and 6(c), the increased base rates shall be reflected on Tampa Electric's customer bills as specified herein. Tampa Electric will begin applying the increased base rate charges for each SoBRA concurrently with meter readings for the first billing cycle of September 2018 for the first SoBRA, subject to true-up as provided in Subparagraph 6(c). Tampa Electric will begin applying each subsequent SoBRA concurrently with meter readings for the first billing cycle of the month the Tranche is projected to go in service, subject to true-up as provided in Subparagraph 6(c). The Parties contemplate and intend that the final true-up for the 2021

SoBRA, if any, would be made to the CCR as soon as practicable following implementation of the 2021 SoBRA, if any.

(l) Subject to the revenue requirement limits in Subparagraph 6(b), the SoBRA for a Tranche will be calculated using the company's projected installed cost per kW_{ac} for each project (subject to the Installed Cost Cap); reasonable estimates for depreciation expense (based on an initial average service life of 30 years for depreciable plant), property taxes and fixed O&M expenses; an incremental capital structure reflecting the then current midpoint ROE and a 54% equity ratio adjusted to reflect the inclusion of investment tax credits on a normalized basis.

(m) If Tampa Electric's actual installed cost for a project is less than the Installed Cost Cap, the company's customers and the company will share in the beneficial difference with 75% of the difference inuring to the benefit of customers and 25% serving as an incentive to the company to seek such cost savings over the life of this 2017 Agreement. By way of illustration, if the actual installed cost of a solar project is $1,400 per kW_{ac}, the final cost to be used for purposes of computing cost recovery under this 2017 Agreement and the true-up of the initial SoBRA shall be $1,425 per kW_{ac} [0.25 times ($1,500 - $1,400) + $1,400].

(n) In order to determine the amount of each annual cost true-up, a revised SoBRA will be computed using the same data and methodology incorporated in the initial SoBRA, with the exception that the actual capital expenditures after sharing and the actual in-service date will be used in lieu of the capital expenditures on which the annualized revenue requirement was based. The difference between the cumulative base revenues since the implementation of the initial SoBRA factor and the cumulative base revenues that would have resulted if the revised SoBRA factor (for cost and In-Service date true-ups) had been in place during the same time period will be trued up with interest at the AFUDC rate shown in Exhibit B used for the projects, and will be made through a one-time, twelve-month adjustment through the CCR clause. On a going forward basis, the base rates will be adjusted to reflect the revised SoBRA factors.

(o) Tampa Electric agrees to file monthly reports that will provide the same information as that filed with the Commission in Docket No. 20170007-EI by another utility for its solar projects, in order to reflect the performance of the solar projects after they have been placed in service.

(p) Tampa Electric's base rate and credit levels applied to customer bills, including the effects of the SoBRAs implemented pursuant to this 2017 Agreement, shall continue in effect until next reset by future unanimous agreement of the Parties approved by a Final Order of the Commission or a Final Order of the Commission issued as a result of a future general base rate proceeding. Any incentive attributed to the company during the term of this 2017 Agreement under Subparagraph 6(m) above will not be included in rate base in the company's next general base rate proceeding, meaning that when a solar asset plant balance is moved to base rates in the company's next general base rate case, only the actual cost -- not any incentive -- will be included.

(q) For all new solar generation assets that Tampa Electric places in service during the Term, the lowest total installed cost per-kW solar energy resources up to the capacity amounts associated with the SoBRA mechanism will be attributed to the SoBRA mechanism in the event the company constructs more solar generation capacity than is subject to the SoBRA mechanism.

(r) Nothing in this 2017 Agreement shall preclude any Party to this 2017 Agreement or any other lawful party from participating, consistent with the full rights of an intervenor, in any proceeding that addresses any matter or issue concerning the SoBRA provisions of this 2017 Agreement.

7. Earnings.

(a) Notwithstanding Paragraph 2 and subject to the Trigger provisions in Subparagraph 2(b) above, if Tampa Electric's earned return on common equity falls below 9.25% during the Term on a monthly earnings surveillance report stated on an actual Commission thirteen-month average adjusted basis, Tampa Electric may petition the Commission to amend its base rates either through a general rate proceeding under Sections 366.06 and 366.07, Florida Statutes, or through a limited proceeding under Section 366.076, Florida Statutes. Nothing in this 2017 Agreement shall be construed as an agreement by the Consumer Parties that a limited proceeding would be appropriate, and Tampa Electric acknowledges and agrees that the Parties reserve and retain all rights to challenge the propriety of any limited proceeding or to assert that any request for base rate changes should properly be addressed through a general base rate case, as well as to challenge any substantive proposals to change the company's rates in any such future proceeding. This floor of 9.25% shall be subject to adjustment in accordance with the Trigger provision in Subparagraph 2(b). For purposes of this 2017 Agreement, "Commission actual adjusted basis" and "actual adjusted earned return" shall mean results reflecting all adjustments to Tampa Electric's books required by the Commission by rule or order, but excluding pro forma adjustments. No Consumer Parties shall be precluded from participating in any proceeding initiated by Tampa Electric to increase base rates pursuant to this Paragraph 7, and no Consumer Party is precluded from opposing Tampa Electric's request.

(b) Notwithstanding Paragraph 2 and subject to the Trigger in Subparagraph 2(b) above, if Tampa Electric's earned return on common equity exceeds 11.25% during the Term on a monthly earnings surveillance report stated on an actual Commission thirteen-month average adjusted basis, no Consumer Party shall be precluded from petitioning the Commission for a review of Tampa Electric's base rates. In any case initiated by Tampa Electric or any other Party pursuant to Paragraph 7, all Parties will retain full rights conferred by law. The ceiling of 11.25% set forth in this Subparagraph shall be subject to adjustment in accordance with the Trigger provision in Subparagraph 2(b).

(c) Notwithstanding Paragraph 2 and subject to the Trigger provisions in Subparagraph 2(b) above, this 2017 Agreement shall terminate upon the effective date of any Final Order of the Commission issued in any proceeding pursuant to Paragraph 7 that changes Tampa Electric's base rates prior to the last billing cycle of December 2021.

(d) This Paragraph 7 shall not: (i) be construed to bar Tampa Electric from requesting any recovery of costs otherwise contemplated by this 2017 Agreement; (ii) apply to any request to change Tampa Electric's base rates that would become effective after the expiration of the Term of this 2017 Agreement; (iii) limit any Party's rights in proceedings concerning changes to base rates that would become effective subsequent to the Term of this 2017 Agreement to argue that Tampa Electric's authorized ROE range should be different than as set forth in this 2017 Agreement; or (iv) affect the provisions of Subparagraphs 3(d) and 3(e) of this 2017 Agreement.

(e) Notwithstanding any other provision of this 2017 Agreement, the Parties fully and completely reserve all rights available to them under the law to challenge the level or rate structure (or the cost of service methodologies underlying them) of Tampa Electric's base rates, charges, credits, and rate design methodologies effective as of January 1, 2022 or thereafter. It is specifically understood and agreed that this 2017 Agreement does not preclude any Consumer Party from filing before January 1, 2022, an action to challenge the level or rate structure (or the cost of service methodologies underlying them) of Tampa Electric's base rates, charges and credits effective as of January 1, 2022 or thereafter.

8. Depreciation.

(a) The Parties agree and intend that, notwithstanding any requirements of Rules 25-6.0436 and 25-6.04364, F.A.C., the company shall not be required during the Term of this 2017 Agreement to file any depreciation study or dismantlement study. The depreciation and amortization accrual rates approved by the FPSC and currently in effect as of the Effective Date of this 2017 Agreement shall remain in effect during the Term or the company's next depreciation study, whichever is later. The Parties further agree that the provisions of Rules 25-6.0436 and 25-6.04364, F.A.C., which otherwise require depreciation and dismantlement studies to be filed at least every four years, will not apply to the company during the Term, and that the Commission's approval of this 2017 Agreement shall excuse the company from compliance with the filing requirement of these rules during the Term.

(b) Notwithstanding the non-deferral language in Paragraph 4, unless the company proposes a special capital recovery schedule and the Commission approves it, if coal-fired generating assets or other assets are retired or planned for retirement of a magnitude that would ordinarily or otherwise require a special capital recovery schedule, such assets will continue to be depreciated using their then existing depreciation rates and special capital recovery issues will be addressed in conjunction with the company's next depreciation study. If the company installs Automated Meter Infrastructure ("AMI") meters and retires Automated Meter Reading ("AMR") meters during the Term, such assets will continue to be depreciated using their then existing depreciation rates and special capital recovery issues will be addressed in conjunction with the company's next depreciation study.

(c) Notwithstanding the provisions of Subparagraph 8(a) above, the company shall file a depreciation and dismantlement study or studies no more than one year nor less than 90 days before the filing of its next general rate proceeding under Sections 366.06 and 366.07, Florida Statutes, such that there is a reasonable opportunity for the Consumer Parties to review, analyze and potentially rebut depreciation rates or other aspects of such depreciation and dismantlement studies contemporaneously with the company's next general rate proceeding. The depreciation and dismantlement study period shall match the test year in the company's MFRs, with all supporting data in electronic format with links, cells and formulae intact and functional, and shall be served upon all Consumer Parties and all intervenors in such subsequent rate case.

9. <u>Federal Income Tax Reform.</u>

(a) Changes in the rate of taxation of corporate income by federal or state taxing authorities ("Tax Reform") could impact the effective tax rate recognized by the company in FPSC adjusted reported net operating income and the measurement of existing and prospective deferred federal income tax assets and liabilities reflected in the FPSC adjusted capital structure.

When Congress last reduced the maximum federal corporate income tax rate in the Tax Reform Act of 1986, it included a transition rule that, as an eligibility requirement for using accelerated depreciation with respect to public utility property, provided guidance regarding returning to customers the portion of the resulting excess deferred income taxes attributable to the use of accelerated depreciation. To the extent Tax Reform includes a transition rule applicable to excess deferred federal income tax assets and liabilities ("Excess Deferred Taxes"), defined as those that arise from the re-measurement of those deferred federal income tax assets and liabilities at the new applicable corporate tax rate(s), those Excess Deferred Taxes will be governed by the Tax Reform transition rule, as applied to most promptly and effectively reduce Tampa Electric's rates consistent with the Tax Reform rules and normalization rules.

(b) If Tax Reform is enacted before the company's next general base rate proceeding, the company will quantify the impact of Tax Reform on its Florida retail jurisdictional net operating income thereby neutralizing the FPSC adjusted net operating income of the Tax Reform to a net zero. The company's forecasted earnings surveillance report for the calendar year that includes the period in which Tax Reform is effective will be the basis for determination of the impact of Tax Reform. The company will also adjust any SoBRAs that have not yet gone into effect to specifically account for Tax Reform. The impacts of Tax Reform on base revenue requirements will be flowed back to retail customers within 120 days of when the Tax Reform becomes law, through a one-time adjustment to base rates upon a thorough review of the effects of the Tax Reform on base revenue requirements consistent with Subparagraph 9(a). This adjustment shall be accomplished through a uniform percentage decrease to customer, demand and energy base rate charges for all retail customer classes. Any effects of Tax Reform on retail revenue requirements from the Effective Date through the date of the one-time base rate adjustment shall be flowed back to customers through the ECCR Clause on the same basis as used in any base rate adjustment. An illustration is included as Exhibit C. If Tax Reform results in an increase in base revenue requirements, the company will utilize deferral accounting as permitted by the Commission, thereby neutralizing the FPSC adjusted net operating income impact of the Tax Reform to a net zero, through the Term. In this situation, the company shall defer the revenue requirement impacts to a regulatory asset to be considered for prospective recovery in a change to base rates to be addressed in the company's next base rate proceeding or in a limited scope proceeding before the Commission no sooner than the end of the Term.

(c) All Excess Deferred Taxes shall be deferred to a regulatory asset or liability which shall be included in FPSC adjusted capital structure and flowed back to customers over a term consistent with law. If the same Average Rate Assumption Method used in the Tax Reform Act of 1986 is prescribed, then the regulatory asset or liability will be flowed back to customers over the remaining life of the assets associated with the Excess Deferred Taxes subject to the provisions related to FPSC adjusted operating income impacts of Tax Reform noted above. If the Tax Reform law or act is silent on the flow-back period, and there are no other statutes or rules that govern the flow-back period, then there shall be a rebuttable presumption that the following flow-back period(s) will apply: (1) if the cumulative net regulatory liability is less than \$100 million, the flow-back period will be five years; or (2) if the cumulative net regulatory liability is greater than \$100 million, the flow-back period will be ten years. The company reserves the right to demonstrate by clear and convincing evidence that such five or ten-year maximum period (as applicable) is not in the best interest of the company's customers and should be increased to no greater than 50 percent of the remaining life of the assets associated with the Excess Deferred Taxes ("50 Percent Period"). The relevant factors to support the company's demonstration include, but are not limited to, the impact the flow-back period would have on the company's cash flow and credit metrics or the optimal capitalization of the company's jurisdictional operations in Florida. If the company can demonstrate, by clear and convincing evidence, that limiting the flow-back period to the 50 Percent Period, in conjunction with the other Tax Reform provisions related to deferred taxes within this 2017 Agreement, will be the sole basis for causing a full notch credit downgrade by each of the major rating agencies (i.e. Standard & Poor's and Moody's), as expressly reflected in a publicly available report of the agencies, it may file to seek a longer flow-back period.

10. Incentive Plan. The Parties consent to the FPSC's approval of and request that the Commission approve the company's Asset Optimization/Incentive Program as set forth in its Petition in Docket No. 160160-EI, dated June 30, 2016, for a four-year period beginning January 1, 2018, but with the following sharing thresholds: (a) up to $4.5MM/year, 100% gain to customers; (b) greater than $4.5MM/year and less than $8.0MM/year, 60% to shareholders and 40% to customers; and (c) greater than $8.0MM/year, 50% to shareholders and 50% customers.

11. Other.

(a) Except as specified in this 2017 Agreement, the company will enter into no new natural gas financial hedging contracts for fuel through December 31, 2022.

(b) The company agrees that it will not seek to recover any costs from its customers related to investments in oil and/or natural gas exploration, reserves, acreage and/or production, including but not limited to investments in gas or oil exploration or production projects that utilize "fracking" (hydraulic fracturing) or similar technology, for a period of no less than five years after the Effective Date.

(c) The company may not make separated/stratified sales from energy generated by solar assets being recovered through a SoBRA during the Term.

(d) For any non-separated or non-stratified wholesale energy sales during the Term, the company will credit its fuel clause for an amount equal to the company's incremental cost of generating or purchasing the amount of energy sold during the hours that any such sale was made.

(e) The full benefits of solar renewable energy credits ("RECs") (including any and all rights attaching to environmental attributes) associated with the solar projects subject to this 2017 Agreement, if any, will be retained for, and flowed through to, retail customers through the Environmental Cost Recovery Clause.

(f) All dollar values, asset determinations, rate impact values and revenue requirements in this 2017 Agreement are intended by the Parties to be retail jurisdictional in amount or formulation basis, unless otherwise specified.

12. New Tariffs. Nothing in this 2017 Agreement shall prelude Tampa Electric from filing and the Commission from approving any new or revised tariff provisions or rate schedules requested by Tampa Electric, provided that any such tariff request does not increase any existing base rate component of a tariff or rate schedule, or any other charge imposed on customers during the Term unless the application of such new or revised tariff, rate schedule, or charge is optional to Tampa Electric's customers.

13. Application of 2017 Agreement. No Party to this 2017 Agreement will request, support, or seek to impose a change to any term or provision of this 2017 Agreement. Except as provided in Paragraph 7, no Party to this 2017 Agreement will either seek or support any reduction in Tampa Electric's base rates, charges, or credits, including limited, limited-scope,

interim, or any other rate decreases, or changes to rate design methodologies, that would take effect prior to the first billing cycle for January 2022, except for any such reduction in base rates or charges (but not credits) requested by Tampa Electric or as otherwise provided for in this 2017 Agreement. Tampa Electric shall not seek interim, limited, or general base rate relief during the Term except as provided for in Paragraphs 6 or 7 of this 2017 Agreement. Tampa Electric is not precluded from seeking interim, limited or general base rate relief that would be effective during or after the first billing cycle in January 2022, nor are the Consumer Parties precluded from opposing such relief. Such interim relief may be based on time periods before January 1, 2022, consistent with Section 366.071, Florida Statutes, and calculated without regard to the provisions of this 2017 Agreement. Tampa Electric will not seek to adjust either the standby generator credit or the CCV credit either during the Term of this 2017 Agreement or thereafter, except by unanimous Agreement of the Parties approved by a Final Order of the Commission or a Final Order of the Commission issued as a result of a future general base rate proceeding.

14. Commission Approval.

(a) The provisions of this 2017 Agreement are contingent on approval of this 2017 Agreement in its entirety by the Commission without modification. The Parties further agree that this 2017 Agreement is in the public interest, that they will support this 2017 Agreement and that they will not request or support any order, relief, outcome, or result in conflict with the terms of this 2017 Agreement in any administrative or judicial proceeding relating to, reviewing, or challenging the establishment, approval, adoption, or implementation of this 2017 Agreement or the subject matter hereof.

(b) No Party will assert in any proceeding before the Commission that this 2017 Agreement or any of the terms in the 2017 Agreement shall have any precedential value. The

Parties' agreement to the terms in the 2017 Agreement shall be without prejudice to any Party's ability to advocate a different position in future proceedings not involving this 2017 Agreement. The Parties further expressly agree that no individual provision, by itself, necessarily represents a position of any Party in any future proceeding, and the Parties further agree that no Party shall assert or represent in any future proceeding in any forum that another Party endorses any specific provision of this 2017 Agreement by virtue of that Party's signature on, or participation in, this 2017 Agreement. It is the intent of the Parties to this 2017 Agreement that the Commission's approval of all the terms and provisions of this 2017 Agreement is an express recognition that no individual term or provision, by itself, necessarily represents a position, in isolation, of any Party or that a Party to this 2017 Agreement endorses a specific provision, in isolation, of this 2017 Agreement by virtue of that Party's signature on, or participation in, this 2017 Agreement.

(c) The Parties intend, and agree to request that the Commission's order state that approval of this 2017 Agreement in its entirety will resolve all matters in Docket No. 20160160-EI pursuant to and in accordance with Section 120.57(4), Florida Statutes, and that Docket No. 20160160-EI will be closed effective on the date the Commission's order approving this 2017 Agreement becomes final. The Parties further agree to request that Docket No. 20170057-EI be closed upon approval of this 2017 Agreement or as soon thereafter as is reasonably practical.

(d) No Party shall seek appellate review of any Commission order approving this 2017 Agreement.

15. Disputes. To the extent a dispute arises among the Parties about the provisions, interpretation, or application of this 2017 Agreement, the Parties agree to meet and confer in an effort to resolve the dispute. To the extent that the Parties cannot resolve any dispute, the matter may be submitted to the Commission for resolution.

16. Execution. This 2017 Agreement is dated as of September 27, 2017. It may be executed in counterpart originals and a facsimile of an original signature shall be deemed an original.

[Remainder of page intentionally left blank]

IN WITNESS WHEREOF, the Parties evidence their acceptance and agreement with the provisions of this 2017 Agreement by their signature(s):

Tampa Electric Company
702 N. Franklin Street
Tampa, FL 33601

By ______________________
Gordon L. Gillette, President

Signature Page to 2017 Agreement

Office of Public Counsel
J. R. Kelly, Esquire
Public Counsel
Charles Rewinkle, Esquire
Associate Public Counsel
c/o The Florida Legislature
111 West Madison Street, Room 812
Tallahassee, FL 32399-1400

By: ______________________
J.R. Kelly

Signature Page to 2017 Agreement

The Florida Industrial Power Users Group
Jon C. Moyle, Jr., Esquire
Moyle Law Firm
The Perkins House
118 North Gadsden Street
Tallahassee, FL 32301

By: ______________________ Sept. 27, 2017
Jon C. Moyle, Jr.

Signature Page to 2017 Agreement

WCF Hospital Utility Alliance
Mark F. Sundback, Esquire
Kenneth L. Wiseman, Esquire
Andrews Kurth, LLP
1350 I Street, N.W., Suite 1100
Washington, D.C. 20005

Kenneth L. Wiseman

Signature Page to 2017 Agreement

Federal Executive Agencies
Lanny L. Zieman, Capt, USAF, Esquire
AFLOA/JACL-ULFSC
139 Barnes Drive, Suite 1
Tyndall Air Force Base, FL 32403

By: ______________________
Lanny L. Zieman

Signature Page to 2017 Agreement

Florida Retail Federation
Robert Scheffel Wright
Gardner, Bist, Bowden, Bush, Dee, LaVia & Wright, P.A.
1300 Thomaswood Drive
Tallahassee, FL 32308

By: Robert Scheffel Wright
Robert Scheffel Wright

Tampa Electric Company

2017 Agreement

Exhibit A

Tariffs

TAMPA ELECTRIC

~~NINTH~~ TENTH REVISED SHEET NO. 3.200
CANCELS ~~EIGHTH~~ NINTH REVISED SHEET NO. 3.200

STANDBY GENERATOR RIDER

SCHEDULE: GSSG-1

AVAILABLE: At the option of the customer, available to commercial and industrial customers on rate schedule GSD, GSDT, SBF, and SBFT who sign a Tariff Agreement for the Provision of Standby Generator Transfer Service.

CHARACTER OF SERVICE: Upon notification by Tampa Electric Company, electric service to all or a portion of the customer's firm load will be transferred by the customer to a standby generator(s) for service.

MONTHLY CREDITS: Credits will be applied each billing period to the regular bill submitted under the GSD, GSDT, SBF, or SBFT rate schedule, for credits generated in the previous billing period.

Credit:
$~~4.75~~5.35/KW/Month payment for Average Transferable Demand of a customer's load to a standby generator(s).

INITIAL TRANSFERABLE DEMAND: To begin participation under this tariff, Initial Transferable Demand will be determined by Tampa Electric in the field at the customer's site by transferring the customer's normal load to the standby generator(s).

AVERAGE TRANSFERABLE DEMAND: For a control month, Transferable Demand is calculated by totaling the KWH produced by the standby generator(s) during all the control(s) in the month divided by the total control hours in the month (less the 30 minute customer response time to transfer load per control). This demand is then averaged with the calculated Transferable Demands from the previous service months (for a maximum of eleven) to determine the Average Transferable Demand. For non-control months, the Average Transferable Demand is the average of the calculated Transferable Demands of the previous twelve months.

NOTIFICATION SCHEDULE: All time periods stated in clock time. (Meters are programmed to automatically adjust for changes from standard to daylight savings time and vice versa.)

Normally the Company will notify customers to transfer load to standby generator(s) during the prime hours. These periods are:

Continued to Sheet No. 3.201

ISSUED BY: G. L. Gillette, President **DATE EFFECTIVE:** ~~November 1, 2013~~

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

~~SEVENTY-THIRD~~SEVENTY-FOURTH REVISED SHEET NO. 6.020
CANCELS ~~SEVENTY-SECOND~~SEVENTY-THIRD REVISED SHEET NO. 6.020

ADDITIONAL BILLING CHARGES

TOTAL FUEL AND PURCHASED POWER COST RECOVERY CLAUSE: The total fuel and purchased power cost recovery factor shall be applied to each kilowatt-hour delivered, and shall be computed in accordance with the formula prescribed by the Florida Public Service Commission. The following fuel recovery factors by rate schedule have been approved by the Commission:

RECOVERY PERIOD
(January ~~2017~~ 2018 through December ~~2017~~2018)

		¢/kWh Fuel		¢/kWh Energy Conservation	¢/kWh Capacity	¢/kWh Environmental
Rate Schedules	Standard	Peak	Off-Peak			
RS (up to 1,000 kWh)	2.642	-	-	~~0.225~~0.246	0.088	0.389
RS (over 1,000 kWh)	3.642	-	-	~~0.225~~0.246	0.088	0.389
RSVP-1 (P_1)	2.956	-	-	~~(2.501)~~(3.002)	0.088	0.389
(P_2)	2.956	-	-	~~(0.719)~~(1.058)	0.088	0.389
(P_3)	2.956	-	-	~~7.054~~6.906	0.088	0.389
(P_4)	2.956	-	-	~~28.645~~40.852	0.088	0.389
GS, GST	2.956	3.166	2.865	~~0.203~~0.232	0.076	0.388
CS	2.956	-	-	~~0.203~~0.232	0.076	0.388
LS-1	2.916	-	-	~~0.099~~0.125	0.017	0.381
GSD Optional						
Secondary	2.956	-	-	~~0.180~~0.201	0.063	0.386
Primary	2.926	-	-	~~0.178~~0.199	0.062	0.382
Subtransmission	2.897	-	-	~~0.176~~0.197	-	0.378

		¢/kWh Fuel		$/kW Energy Conservation	$/kW Capacity	¢/kWh Environmental
Rate Schedules	Standard	Peak	Off-Peak			
GSD, GSDT, SBF, SBFT						
Secondary	2.956	3.166	2.865	~~0.77~~0.87	0.27	0.386
Primary	2.926	3.134	2.836	~~0.76~~0.86	0.27	0.382
Subtransmission	2.897	3.103	2.808	~~0.75~~0.85	0.26	0.378
IS, IST, SBI						
Primary	2.926	3.134	2.836	~~0.48~~0.67	0.14	0.375
Subtransmission	2.897	3.103	2.808	~~0.47~~0.66	0.14	0.371

Continued to Sheet No. 6.021

ISSUED BY: G. L. Gillette, President

DATE EFFECTIVE: ~~December 30, 2016~~

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

~~THIRTY-THIRD~~THIRTY-FOURTH REVISED SHEET NO. 6.021
CANCELS ~~THIRTY-SECOND~~THIRTY-THIRD REVISED
SHEET NO. 6.021

Continued from Sheet No. 6.020

CONTRACT CREDIT VALUE (CCV): This incentive is applicable to any commercial or industrial customer with interruptible loads of 500 kW or greater who qualify to participate in the company's GSLM 2 & 3 load management programs. The credit is updated annually. The ~~2017~~ 2018 and prior six years of historical CCVs per kW reduction at secondary voltage are:

Year	Secondary	Primary	Subtransmission
~~2017~~2018	~~9.98~~10.23	~~9.88~~10.13	~~9.78~~10.03
~~2016~~2017	~~8.81~~9.98	~~8.72~~9.88	~~8.63~~9.78
~~2015~~2016	~~8.14~~8.81	~~8.06~~8.72	~~7.98~~8.63
~~2014~~2015	~~7.72~~8.14	~~7.64~~8.06	~~7.57~~7.98
~~2013~~2014	~~6.81~~7.72	~~6.74~~7.64	~~6.67~~7.57
~~2012~~2013	~~9.82~~6.81	~~9.72~~6.74	~~9.62~~6.67
~~2011~~2012	~~9.21~~9.82	~~9.12~~9.72	~~9.03~~9.62

Refer to Tariff sheets 3.210 and 3.230 for additional contract details.

FUEL CHARGE: Fuel charges are adjusted annually by the Florida Public Service Commission, normally in January.

ENERGY CONSERVATION COST RECOVERY CLAUSE: Energy conservation cost recovery factors recover the conservation related expenditures of the Company. The procedure for the review, approval, recovery and recording of such costs and revenues is set forth in Commission Rule 25-17.015, F.A.C. For rate schedules, RS, RSVP, GS, GST, and GSD Optional, cost recovery factors shall be applied to each kilowatt-hour delivered. For rate schedules, GSD, GSDT, IS, IST, SBF, SBFT, and SBI, cost recovery factors shall be applied on a kilowatt basis to the billing demand or supplemental billing demand and to the greater of the standby demand times 12% or the actual standby demand times 4.76%.

CAPACITY COST RECOVERY CLAUSE: In accordance with Commission Order No. 25773, Docket No. 910794-EQ, issued February 24, 1992, the capacity cost recovery factors shall be applied to each kilowatt-hour delivered for rate schedules, RS, RSVP, GS, GST, and GSD Optional. For rate schedules, GSD, GSDT, IS, IST, SBF, SBFT, and SBI the cost recovery factors shall be applied to each kilowatt of billing demand and supplemental billing demand and to the greater of the standby demand times 12% or the actual standby demand times 4.76%.

ENVIRONMENTAL COST RECOVERY CLAUSE: In accordance with Commission Order No. PSC-96-1048-FOF-EI, Docket No. 960688-EI, issued August 14, 1996, the environmental cost recovery factors shall be applied to each kilowatt-hour delivered.

Continued to Sheet No. 6.022

ISSUED BY: G. L. Gillette, President **DATE EFFECTIVE:** ~~December 30, 2016~~

Tampa Electric Company

2017 Agreement

Exhibit B

AFUDC

TAMPA ELECTRIC COMPANY, INC.
Capital Structure Used for AFUDC Calculation
FPSC Order No. PSC-14-0176-PAA-EI

	Capital Ratio	Cost Rates	AFUDC Weighted Average Cost of Capital
Long Term Debt	36.2860%	5.61%	2.04%
Short Term Debt	0.0000%	0.60%	0.00%
Customer Deposits	2.7010%	2.24%	0.06%
Common Equity	42.6030%	10.25%	4.37%
Deferred Income Taxes	18.2040%	-	0.00%
Tax Credits -Weighted Cost	0.2060%	-	0.00%
Total	100.00%		6.46%

Tampa Electric Company

2017 Agreement

Exhibit C

Tax Reform Illustration

Methodology of Income Tax Change (Illustrative)

			Scenario A	Scenario B	Scenario C	Scenario D
1	INCOME TAX INPUTS AND ASSUMPTIONS					
2	New federal statutory tax rate	Input	35%	30%	30%	20%
3	Current federal statutory tax rate	Given	35%	35%	35%	35%
4	Current State statutory tax rate	Given	5.5%	5.5%	5.5%	5.5%
5	New combined feredal & state statutory tax rate	Line 2 + Line 4 - (Line 2 x Line 4)	38.6%	33.9%	33.9%	24.4%
6	Current combined federal & state statutory tax rate	Line 3 + Line 4 - (Line 3 x Line 4)	38.6%	38.6%	38.6%	38.6%
7	Disallowed Interest (or other) expense deduction	Input	-	100.0	-	-
8						
9	PARAGRAPH 9 - TAX REFORM SHARING					
10	Step 1 - Calculate Income tax expense BEFORE tax reform					
11	FPSC adjusted NOI before tax (per Forcasted Surveillance)	Input	500	500	500	500
12	Less interest expense	Input	(100)	(100)	(100)	(100)
13	Permanent differences	Input	5	5	5	5
14	FPSC adjusted taxable income	Sum of Lines 11 through 13	405	405	405	405
15	Current combined statutory tax rate	Line 6	38.6%	38.6%	38.6%	38.6%
16	Income tax expense	Line 14 x Line 15	156	156	156	156
17						
18	Step 2 - Calculate Income tax expense AFTER tax reform					
19	FPSC adjusted NOI before tax (per Forecasted Surveillence)	Input	500	500	500	500
20	Less interest expense	Input	(100)	-	(100)	(100)
21	Permanent differences	Input	5	5	5	5
22	FPSC adjusted taxable income	Sum of Lines 19 through 21	405	505	405	405
23	New combined statutory tax rate	Line 5	38.6%	33.9%	33.9%	24.4%
24	Income tax expense	Line 22 x Line 23	156	171	137	99
25						
26	Step 3 - Calculate impact on FPSC Adjusted NOI					
27	Income tax expense BEFORE tax reform - step 1	Line 16	156	156	156	156
28	Income tax expense AFTER tax reform - step 2	Line 24	156	171	137	99
29	Difference - FPSC Adjusted NOI increase/(decrease) from tax reform	Line 27 - Line 28	-	(15)	19	57
30						
31	Step 4 - Calculate adjustment for base increase implemented at new combined statutory tax rate					
32	Solar base rate adjustment - "All Tranches"	Input	tbd	tbd	tbd	tbd
33	Change in combined statutory tax rate	Line 5 - Line 6	0.0%	-4.7%	-4.7%	-14.2%
34	Adj. for base rate increases at new combined statutory tax rate	Line 32 x Line 33	-	-	-	-
35						
36	Step 5 - Calculate net favorable/(unfavorable) FPSC adjusted NOI Impact					
37	Impact on NOI - Step 3	Line 29	-	(15)	19	57
38	Impact on NOI - Step 4	Line 34	-	-	-	-
39	Net favorable/(nonfavorable) FPSC adjusted NOI import - after tax	Line 37 + Line 38	-	(15)	19	57
40	Divide by one minus new combined statutory tax rate	1 - Line 5	61.4%	66.2%	66.2%	75.6%
41	Net favorable/(nonfavorable) FPSC adjusted NOI import - pretax	Line 39/Line 40	-	(22)	29	76
42						
43	Step 6 - Calculate annual pretax impacts					
44	Annual flowback to customers	If line 41>0, then line 41	-	-	29	76
45	Annual deferral to Regulatory Asset	If line 41<0, then line 41	-	(22)	-	-
46	Total	Ln 44 + Ln 45	-	(22)	29	76