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AUSLEY MCMULLEN

ATTORNEYS AND COUNSELORS AT LAW

123 SOUTH CALHOUN STREET
P.O. BOX 391 (ZIP 32302)
TALLAHASSEE, FLORIDA 32301
(850) 224-9115 FAX (850) 222-7560

September 7, 2021

VIA: ELECTRONIC FILING

Mr. Adam J. Teitzman
Commission Clerk
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, Florida 32399-0850

Re: Docket 20210034-EI, Petition for Rate Increase by Tampa Electric Company

Dear Mr. Teitzman:

Attached for filing in the above docket is Tampa Electric Company's Response to Staff's Sixth Data Request (No. 1-8), propounded on August 25, 2021.

Thank you for your assistance in connection with this matter.

Sincerely,

Malcolm N. Means

Malcolm N. Means

MNM/ne
Attachment

cc: All parties of record

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true and correct copy of the foregoing Tampa Electric Company's responses to Staff's Sixth Data Request (No. 1-8), have been furnished by electronic mail on this 7th day of September 2021 to the following:

Charles Murphy
Theresa Tan
Melinda Marzicol
Office of the General Counsel
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, FL 32399-0850
cmurphy@psc.state.fl.us
ltan@psc.state.fl.us
mmarzico@psc.state.fl.us

Richard Gentry
Charles Rehwinkel
Anastacia Pirrello
Stephanie Morse
Mary Wessling
Office of Public Counsel
c/o The Florida Legislature
111 West Madison Street, Room 812
Tallahassee, FL 32399-1400
gentry.richard@leg.state.fl.us
rehwinkel.charles@leg.state.fl.us
pirrello.anastacia@leg.state.fl.us
morse.stephanie@leg.state.fl.us
wessling.mary@leg.state.fl.us

Stephanie U. Eaton
Spilman Thomas & Battle, PLLC
110 Oakwood Drive, Suite 500
Winston-Salem, NC 27103
seaton@spilmanlaw.com

Barry A. Naum
Spilman Thomas & Battle, PLLC
1100 Bent Creek Boulevard, Suite 101
Mechanicsburg, PA 17050
bnaum@spilmanlaw.com

Florida Industrial Power Users Group
Jon Moyle
Karen Putnal
c/o Moyle Law Firm
118 N. Gadsden Street
Tallahassee, FL 32301
jmoyle@moylelaw.com
kputnal@moylelaw.com
mqualls@moylelaw.com

Federal Executive Agencies
Thomas A. Jernigan
Holly L. Buchanan, Maj, USAF
Scott L. Kirk, Maj, USAF
Arnold Braxton, TSgt, USAF
Ebony M. Payton
139 Barnes Drive, Suite 1
Tyndall Air Force Base, Florida 32403
thomas.jernigan.3@us.af.mil
holly.buchanan.1@us.af.mil
scott.kirk.2@us.af.mil
arnold.braxton@us.af.mil
ebony.payton.ctr@us.af.mil

Mr. Robert Scheffel Wright
John LaVia, III
Gardner, Bist, Wiener, Wadsworth, Bowden, Bush, Dee, LaVia & Wright, P.A.
1300 Thomaswood Drive
Tallahassee, FL 32308
shef@gbwlegal.com
jlavia@gbwlegal.com

WCF Hospital Utility Alliance
Mark F. Sundback
William M. Rappolt
Andrew P. Mina
Sheppard Mullin Richter & Hampton LLP
2099 Pennsylvania Ave., N.W., Suite 100
Washington, D.C. 20006-6801
msundback@sheppardmullin.com
wrappolt@sheppardmullin.com
amina@sheppardmullin.com

Malcolm M. Means

ATTORNEY

1. Please provide MFR schedule A-2 for 2022, bill comparisons for typical monthly bills, comparing bills under present rates and bills under the proposed Settlement rates. The cost recovery factors for present and proposed bills should be the same currently approved factors.

A. Please see attached.

TAMPA ELECTRIC COMPANY
DOCKET NO. 20210034-EI
STAFF'S SIXTH DATA REQUEST
FILED: SEPTEMBER 7, 2021

SCHEDULE A-2 — 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.

COMPANY: TAMPA ELECTRIC COMPANY

DOCKET No. 20210034 EI

Type of data shown:
XX Projected Test year Ended 12/31/2022
Projected Prior Year Ended 12/31/2021
Historical Prior Year Ended 12/31/2020
Witness: W. R. Ashburn

RS - RESIDENTIAL SERVICE

RATE SCHEDULE RS

			BILL UNDER PRESENT RATES								BILL UNDER PROPOSED RATES									INCREASE	COSTS IN CENTS/KWH		
Line No.	(1) KW	(2) TYPICAL KWH	(3) BASE RATE	(4) FUEL CHARGE	(5) ECCR CHARGE	(6) CAPACITY CHARGE	(7) ECRC CHARGE	(8) SPPCRC CHARGE	(9) GRT CHARGE	(10) TOTAL	(11) BASE RATE	(12) FUEL CHARGE	(13) ECCR CHARGE	(14) CAPACITY CHARGE	(15) ECRC CHARGE	(16) Clean Energy Trans. Mech	(17) SPPCRC CHARGE	(18) GRT CHARGE	(19) TOTAL	(20) DOLLARS (16)-(9)	(21) PERCENT (17)/(9)	(22) PRESENT (9)/(2)*100	(23) PROPOSED (16)/(2)*100
1	0	-	$ 15.05	$ -	$ -	$ -	$ -		$ 0.39	$ 15.44	$ 21.29	$ -	$ -	$ -	$ -						0.0%	-	-
2																							
3	0	100	$ 20.28	$ 2.86	$ 0.17	$ 0.00	$ 0.27	$ 0.24	$ 0.61	$ 24.42	$ 27.06	$ 2.86	$ 0.17	$ 0.00	$ 0.27	$ 0.44	$ 0.24	$ 0.80	$ 31.83	$ 7.41	30.3%	24.42	31.83
4																							
5	0	250	$ 28.11	$ 7.14	$ 0.42	$ 0.01	$ 0.67	$ 0.60	$ 0.95	$ 37.89	$ 35.71	$ 7.14	$ 0.42	$ 0.01	$ 0.67	$ 1.10	$ 0.60	$ 1.17	$ 46.81	$ 8.92	23.6%	15.16	18.73
6																							
7	0	500	$ 41.18	$ 14.28	$ 0.83	$ 0.01	$ 1.35	$ 1.20	$ 1.51	$ 60.34	$ 50.14	$ 14.28	$ 0.83	$ 0.01	$ 1.35	$ 2.20	$ 1.20	$ 1.79	$ 71.79	$ 11.45	19.0%	12.07	14.36
8																							
9	0	750	$ 54.24	$ 21.42	$ 1.25	$ 0.02	$ 2.02	$ 1.79	$ 2.07	$ 82.80	$ 64.56	$ 21.42	$ 1.25	$ 0.02	$ 2.02	$ 3.30	$ 1.79	$ 2.42	$ 96.77	$ 13.97	16.9%	11.04	12.90
10																							
11	0	1,000	$ 67.30	$ 28.56	$ 1.66	$ 0.02	$ 2.69	$ 2.39	$ 2.63	$ 105.25	$ 78.98	$ 28.56	$ 1.66	$ 0.02	$ 2.69	$ 4.41	$ 2.39	$ 3.04	$ 121.75	$ 16.50	15.7%	10.53	12.17
12																							
13	0	1,250	$ 82.86	$ 38.20	$ 2.08	$ 0.03	$ 3.36	$ 2.99	$ 3.32	$ 132.83	$ 95.90	$ 38.20	$ 2.08	$ 0.03	$ 3.36	$ 5.51	$ 2.99	$ 3.80	$ 151.86	$ 19.02	14.3%	10.63	12.15
14																							
15	0	1,500	$ 98.43	$ 47.84	$ 2.49	$ 0.03	$ 4.04	$ 3.59	$ 4.01	$ 160.42	$ 112.83	$ 47.84	$ 2.49	$ 0.03	$ 4.04	$ 6.61	$ 3.59	$ 4.55	$ 181.96	$ 21.55	13.4%	10.69	12.13
16																							
17	0	2,000	$ 129.55	$ 67.12	$ 3.32	$ 0.04	$ 5.38	$ 4.78	$ 5.39	$ 215.58	$ 146.67	$ 67.12	$ 3.32	$ 0.04	$ 5.38	$ 8.81	$ 4.78	$ 6.05	$ 242.17	$ 26.59	12.3%	10.78	12.11
18																							
19	0	3,000	$ 191.80	$ 105.68	$ 4.98	$ 0.06	$ 8.07	$ 7.17	$ 8.15	$ 325.91	$ 214.36	$ 105.68	$ 4.98	$ 0.06	$ 8.07	$ 13.22	$ 7.17	$ 9.06	$ 362.60	$ 36.69	11.3%	10.86	12.09
20																							
21	0	5,000	$ 316.30	$ 182.80	$ 8.30	$ 0.10	$ 13.45	$ 11.95	$ 13.66	$ 546.56	$ 349.74	$ 182.80	$ 8.30	$ 0.10	$ 13.45	$ 22.03	$ 11.95	$ 15.09	$ 603.45	$ 56.89	10.4%	10.93	12.07
22																							
23																							

Line		PRESENT	PROPOSED
24		PRESENT	PROPOSED
25	BASIC SERVICE CHARGE	15.05 $/Bill	21.29 $/Bill
26	DEMAND CHARGE	- $/KW	- $/KW
27	ENERGY CHARGE		
28	0 - 1,000 KWH	5.225 ¢/kWH	5.769 ¢/kWH
29	Over 1,000 KWH	6.225 ¢/kWH	6.769 ¢/kWH
30	FUEL CHARGE		
31	0 - 1,000 KWH	2.856 ¢/kWH	2.856 ¢/kWH
32	Over 1,000 KWH	3.856 ¢/kWH	3.856 ¢/kWH
33	CONSERVATION CHARGE	0.166 ¢/kWH	0.166 ¢/kWH
34	CAPACITY CHARGE	0.002 ¢/kWH	0.002 ¢/kWH
35	CLEAN ENERGY TRANSITION MECHANISM		0.441 ¢/kWH
36	ENVIRONMENTAL CHARGE	0.269 ¢/kWH	0.269 ¢/kWH
37	STORM PROTECTION PLAN	0.239 ¢/kWH	0.239 ¢/kWH
38			
39	Note: Present and proposed cost recovery clause factors are the approved January 2021 factors.		
42			

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

Recap Schedules:

SCHEDULE A-2 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 12/31/2022
Projected Prior Year Ended 12/31/2021
Historical Prior Year Ended 12/31/2020
Witness: W. R. Ashburn

COMPANY: TAMPA ELECTRIC COMPANY

GS - GENERAL SERVICE NON-DEMAND

DOCKET No. 20210034 EI

RATE SCHEDULE GS

			BILL UNDER PRESENT RATES								BILL UNDER PROPOSED RATES									INCREASE		COSTS IN CENTS/KWH	
Line No.	(1) TYPICAL KW	(2) KWH	(3) BASE RATE	(4) FUEL CHARGE	(5) ECCR CHARGE	(6) CAPACITY CHARGE	(7) ECRC CHARGE	(8) SPPCRC CHARGE	(9) GRT CHARGE	(10) TOTAL	(11) BASE RATE	(12) FUEL CHARGE	(13) ECCR CHARGE	(14) CAPACITY CHARGE	(15) ECRC CHARGE	(16) CLEAN ENR TRANS. MECH	(17) SPPCRC CHARGE	(18) GRT CHARGE	(19) TOTAL	(20) DOLLARS (16)-(9)	(21) PERCENT (17)/(9)	(22) PRESENT (9)/(2)*100	(23) PROPOSED (16)/(2)*100
1	0	-	$ 18.06	$ -	$ -	$ -	$ -		$ 0.46	$ 18.52	$ 22.51	$ -	$ -	$ -	$ -			$ 0.58	$ 23.09	$ 4.56	24.6%	-	-
2																							
3	0	100	$ 23.56	$ 3.17	$ 0.16	$ 0.00	$ 0.27	$ 0.25	$ 0.70	$ 28.11	$ 29.14	$ 3.17	$ 0.16	$ 0.00	$ 0.27	$ 0.40	$ 0.25	$ 0.86	$ 34.25	$ 6.14	21.9%	28.11	34.25
4																							
5	0	250	$ 31.80	$ 7.92	$ 0.40	$ 0.01	$ 0.67	$ 0.63	$ 1.06	$ 42.49	$ 39.10	$ 7.92	$ 0.40	$ 0.01	$ 0.67	$ 1.01	$ 0.63	$ 1.28	$ 51.00	$ 8.51	20.0%	16.99	20.40
6																							
7	0	500	$ 45.54	$ 15.84	$ 0.81	$ 0.01	$ 1.35	$ 1.26	$ 1.66	$ 66.45	$ 55.68	$ 15.84	$ 0.81	$ 0.01	$ 1.35	$ 2.01	$ 1.26	$ 1.97	$ 78.91	$ 12.46	18.8%	13.29	15.78
8																							
9	0	750	$ 59.28	$ 23.75	$ 1.21	$ 0.02	$ 2.02	$ 1.88	$ 2.26	$ 90.42	$ 72.27	$ 23.75	$ 1.21	$ 0.02	$ 2.02	$ 3.02	$ 1.88	$ 2.67	$ 106.83	$ 16.41	18.2%	12.06	14.24
10																							
11	0	1,000	$ 73.02	$ 31.67	$ 1.61	$ 0.02	$ 2.69	$ 2.51	$ 2.86	$ 114.38	$ 88.85	$ 31.67	$ 1.61	$ 0.02	$ 2.69	$ 4.02	$ 2.51	$ 3.37	$ 134.74	$ 20.36	17.8%	11.44	13.47
12																							
13	0	1,250	$ 86.76	$ 39.59	$ 2.01	$ 0.03	$ 3.36	$ 3.14	$ 3.46	$ 138.34	$ 105.44	$ 39.59	$ 2.01	$ 0.03	$ 3.36	$ 5.03	$ 3.14	$ 4.07	$ 162.66	$ 24.31	17.6%	11.07	13.01
14																							
15	0	1,500	$ 100.50	$ 47.51	$ 2.42	$ 0.03	$ 4.04	$ 3.77	$ 4.06	$ 162.31	$ 122.02	$ 47.51	$ 2.42	$ 0.03	$ 4.04	$ 6.04	$ 3.77	$ 4.76	$ 190.57	$ 28.26	17.4%	10.82	12.70
16																							
17	0	2,000	$ 127.98	$ 63.34	$ 3.22	$ 0.04	$ 5.38	$ 5.02	$ 5.26	$ 210.24	$ 155.19	$ 63.34	$ 3.22	$ 0.04	$ 5.38	$ 8.05	$ 5.02	$ 6.16	$ 246.40	$ 36.16	17.2%	10.51	12.32
18																							
19	0	3,000	$ 182.94	$ 95.01	$ 4.83	$ 0.06	$ 8.07	$ 7.53	$ 7.65	$ 306.09	$ 221.53	$ 95.01	$ 4.83	$ 0.06	$ 8.07	$ 12.07	$ 7.53	$ 8.95	$ 358.05	$ 51.96	17.0%	10.20	11.94
20																							
21	0	5,000	$ 292.86	$ 158.35	$ 8.05	$ 0.10	$ 13.45	$ 12.55	$ 12.45	$ 497.81	$ 354.21	$ 158.35	$ 8.05	$ 0.10	$ 13.45	$ 20.12	$ 12.55	$ 14.53	$ 581.36	$ 83.56	16.8%	9.96	11.63
22																							
23	0	8,500	$ 485.22	$ 269.20	$ 13.69	$ 0.17	$ 22.87	$ 21.34	$ 20.83	$ 833.30	$ 586.40	$ 269.20	$ 13.69	$ 0.17	$ 22.87	$ 34.20	$ 21.34	$ 24.30	$ 972.16	$ 138.86	16.7%	9.80	11.44
24																							
25																							

Line		PRESENT	PROPOSED
26		PRESENT	PROPOSED
27	BASIC SERVICE CHARGE	18.06 $/Bill	22.51 $/Bill
28	DEMAND CHARGE	- $/KW	- $/KW
29	ENERGY CHARGE	5.496 ¢/kWH	6.634 ¢/kWH
30	FUEL CHARGE	3.167 ¢/kWH	3.167 ¢/kWH
31	CONSERVATION CHARGE	0.161 ¢/kWH	0.161 ¢/kWH
32	CAPACITY CHARGE	0.002 ¢/kWH	0.002 ¢/kWH
33	CLEAN ENERGY TRANSITION MECHANISM		0.402 ¢/kWH
34	ENVIRONMENTAL CHARGE	0.269 ¢/kWH	0.269 ¢/kWH
35	STORM PROTECTION PLAN	0.251 ¢/kWH	0.251 ¢/kWH
36			
37			
38	Note: Present and proposed cost recovery clause factors are the approved January 2021 factors.		
41			
42			

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

Recap Schedules:

FLORIDA PUBLIC SERVICE COMMISSION

EXPLANATION: For each rate, calculate typical monthly bills for present rates and proposed rates.

COMPANY: TAMPA ELECTRIC COMPANY

DOCKET No. 20210034 EI

Type of data shown:
XX Projected Test year Ended 12/31/2022
Projected Prior Year Ended 12/31/2021
Historical Prior Year Ended 12/31/2020
Witness: W. R. Ashburn

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) SPPCRC CHARGE	(9) GRT CHARGE	(10) TOTAL	BILL UNDER PROPOSED RATES (11) BASE RATE	(12) FUEL CHARGE	(13) ECCR CHARGE	(14) CAPACITY CHARGE	(15) ECRC CHARGE	(16) CLEAN ENR TRAN.MECH	(17) SPPCRC CHARGE	(18) GRT CHARGE	(19) TOTAL	INCREASE (20) DOLLARS (16)-(9)	(21) PERCENT (17)/(9)	COSTS IN CENTS/KWH (22) PRESENT (9)/(2)*100	(23) PROPOSED (16)/(2)*100
1	75	10,950	752.25	346.79	15.11	0.22	29.02	18.40	29.79	1,191.57	805.48	346.79	15.11	0.22	29.02	28.61	18.40	31.89	1,275.51	83.94	7.0%	10.88	11.65
2	75	19,163	1,153.59	606.88	45.00	0.75	50.78	54.00	49.00	1,960.00	1,203.77	606.88	45.00	0.75	50.78	82.50	54.00	52.40	2,096.08	136.08	6.9%	10.23	10.94
3	75	32,850	1,371.09	1,040.36	45.00	0.75	87.05	54.00	66.62	2,664.87	1,303.69	1,040.36	45.00	0.75	87.05	82.50	54.00	67.01	2,680.36	15.49	0.6%	8.11	8.16
4	75	49,275	1,567.90	1,554.63	45.00	0.75	130.58	54.00	85.97	3,438.82	1,385.21	1,554.63	45.00	0.75	130.58	82.50	54.00	83.40	3,336.07	(102.75)	-3.0%	6.98	6.77
5																							
6	500	73,000	4,844.45	2,311.91	100.74	1.46	193.45	122.64	194.22	7,768.87	5,184.97	2,311.91	100.74	1.46	193.45	130.65	122.64	206.30	8,252.12	483.25	6.2%	10.64	11.30
7	500	127,750	7,520.05	4,045.84	300.00	5.00	338.54	360.00	322.29	12,891.72	7,840.21	4,045.84	300.00	5.00	338.54	550.00	360.00	344.60	13,784.19	892.47	6.9%	10.09	10.79
8	500	219,000	8,970.01	6,935.73	300.00	5.00	580.35	360.00	439.77	17,590.86	8,506.33	6,935.73	300.00	5.00	580.35	550.00	360.00	441.98	17,679.39	88.53	0.5%	8.03	8.07
9	500	328,500	10,282.07	10,364.18	300.00	5.00	870.53	360.00	568.76	22,750.53	9,049.83	10,364.18	300.00	5.00	870.53	550.00	360.00	551.27	22,050.80	(699.73)	-3.1%	6.93	6.71
10																							
11	2000	292,000	19,287.50	9,247.64	402.96	5.84	773.80	490.56	774.57	30,982.87	20,641.99	9,247.64	402.96	5.84	773.80	522.60	490.56	822.70	32,908.09	1,925.22	6.2%	10.61	11.27
12	2000	511,000	29,989.89	16,183.37	1,200.00	20.00	1,354.15	1,440.00	1,286.86	51,474.27	31,262.93	16,183.37	1,200.00	20.00	1,354.15	2,200.00	1,440.00	1,375.91	55,036.36	3,562.09	6.9%	10.07	10.77
13	2000	876,000	35,789.74	27,742.92	1,200.00	20.00	2,321.40	1,440.00	1,756.77	70,270.83	33,927.43	27,742.92	1,200.00	20.00	2,321.40	2,200.00	1,440.00	1,765.43	70,617.18	346.35	0.5%	8.02	8.06
14	2000	1,314,000	41,037.98	41,456.70	1,200.00	20.00	3,482.10	1,440.00	2,272.74	90,909.51	36,101.45	41,456.70	1,200.00	20.00	3,482.10	2,200.00	1,440.00	2,202.57	88,102.82	(2,806.69)	-3.1%	6.92	6.70
15																							
16																							

Line		PRESENT GSD	PRESENT GSDT		PRESENT GSD OPT.		PROPOSED GSD	PROPOSED GSDT		PROPOSED GSD OPT.	
19	BASIC SERVICE CHARGE	30.10	30.10	$/Bill	30.10	$/Bill	32.63	32.63		32.63	$/Bill
20	DEMAND CHARGE	10.92	-	$/KW	-	$/KW	13.75	-	$/KW	-	$/KW
21	BILLING	-	3.49	$/KW	-	$/KW	-	4.40	$/KW	-	$/KW
22	PEAK	-	7.14	$/KW	-	$/KW	-	8.99	$/KW	-	$/KW
23	ENERGY CHARGE	1.589	-	¢/KWH	6.595	¢/KWH	0.730	-	¢/KWH	7.058	¢/KWH
24	ON-PEAK	-	2.908	¢/KWH	-	¢/KWH	-	1.183	¢/KWH	-	¢/KWH
25	OFF-PEAK	-	1.049	¢/KWH	-	¢/KWH	-	0.566	¢/KWH	-	¢/KWH
26	FUEL CHARGE	3.167	-	¢/KWH	3.167	¢/KWH	3.167	-	¢/KWH	3.167	¢/KWH
27	ON-PEAK	-	3.335	¢/KWH	-	¢/KWH	-	3.335	¢/KWH	-	¢/KWH
28	OFF-PEAK	-	3.095	¢/KWH	-	¢/KWH	-	3.095	¢/KWH	-	¢/KWH
29	CONSERVATION CHARGE	0.60	0.60	$/KW	0.138	¢/KWH	0.60	0.60	$/KW	0.138	¢/KWH
30	CAPACITY CHARGE	0.01	0.01	$/KW	0.002	¢/KWH	0.01	0.01	$/KW	0.002	¢/KWH
31	CLEAN ENERGY TRANSITION MECHANISM						1.10	1.10	$/KW	0.261	¢/KWH
32	ENVIRONMENTAL CHARGE	0.265	0.265	¢/KWH	0.265	¢/KWH	0.265	0.265	¢/KWH	0.265	¢/KWH
33	STORM PROTECTION PLAN	0.72	0.72	$/KW	0.168	¢/KWH	0.72	0.72	$/KW	0.168	¢/KWH

Notes:

A. The kWh for each kW group is based on 20, 35, 60, and 90% load factors (LF).

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.

C. All calculations assume meter and service at secondary voltage.

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.

E. Present and proposed cost recovery clause factors are the approved January 2021 factors.

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

Recap Schedules:

SCHEDULE A-2 | 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 12/31/2022
Projected Prior Year Ended 12/31/2021
Historical Prior Year Ended 12/31/2020
Witness: W. R. Ashburn

COMPANY: TAMPA ELECTRIC COMPANY

GSLDPR/GSLDTPR- GENERAL SERVICE LARGE DEMAND/ TOU/ PRIMARY SERVED

DOCKET No. 20210034 EI

RATE SCHEDULE GSLDPR/GSLDTPR

Line No.	(1) TYPICAL KW	(2) TYPICAL KWH	BILL UNDER PRESENT RATES (3) BASE RATE	(4) FUEL CHARGE	(5) CCV CREDIT	(6) ECCR CHARGE	(7) CAPACITY CHARGE	(8) SPPCRC CHARGE	(9) ECRC CHARGE	(10) GRT CHARGE	(11) TOTAL
1	500	127,750	$ 7,165.39	$ 4,004.96	$ -	$ 295.00	$ 5.00	$ 355.00	$ 334.71	$ 311.80	$ 12,471.85
2	500	219,000	$ 8,615.35	$ 6,865.65	$ -	$ 295.00	$ 5.00	$ 355.00	$ 573.78	$ 428.46	$ 17,138.24
3	500	328,500	$ 9,963.11	$ 10,260.70	$ -	$ 295.00	$ 5.00	$ 355.00	$ 860.67	$ 557.42	$ 22,296.90
4											
5	1,000	255,500	$ 14,200.34	$ 8,009.93	$ -	$ 590.00	$ 10.00	$ 710.00	$ 669.41	$ 620.25	$ 24,809.92
6	1,000	438,000	$ 17,100.26	$ 13,731.30	$ -	$ 590.00	$ 10.00	$ 710.00	$ 1,147.56	$ 853.57	$ 34,142.69
7	1,000	657,000	$ 19,795.78	$ 20,521.40	$ -	$ 590.00	$ 10.00	$ 710.00	$ 1,721.34	$ 1,111.50	$ 44,460.01
8											
9	5,000	1,277,500	$ 70,479.92	$ 40,049.63	$ -	$ 2,950.00	$ 50.00	$ 3,550.00	$ 3,347.05	$ 3,087.86	$ 123,514.45
10	5,000	2,190,000	$ 84,979.54	$ 68,656.50	$ -	$ 2,950.00	$ 50.00	$ 3,550.00	$ 5,737.80	$ 4,254.45	$ 170,178.29
11	5,000	3,285,000	$ 98,457.13	$ 102,606.98	$ -	$ 2,950.00	$ 50.00	$ 3,550.00	$ 8,606.70	$ 5,544.12	$ 221,764.92

Line No.	BILL UNDER PROPOSED RATES (12) BASE RATE	(13) CCV CREDIT	(14) FUEL CHARGE	(15) ECCR CHARGE	(16) CAPACITY CHARGE	(17) ECRC CHARGE	(18) CLEAN ENR TRANS. MECH	(19) SPPCRC CHARGE	(20) GRT CHARGE	(21) TOTAL	INCREASE (22) DOLLARS (16)-(9)	(23) PERCENT (17)/(9)	COSTS IN CENTS/KWH (24) PRESENT (9)/(2)*100	(25) FINAL (16)/(2)*100
1	$ 7,659.80	$ -	$ 4,004.96	$ 295.00	$ 5.00	$ 334.71	$ 445.00	$ 355.00	$ 335.88	$ 13,435.35	$ 963.49	7.7%	9.76	10.52
2	$ 8,603.32	$ -	$ 6,865.65	$ 295.00	$ 5.00	$ 573.78	$ 445.00	$ 355.00	$ 439.56	$ 17,582.31	$ 444.07	2.6%	7.83	8.03
3	$ 9,683.59	$ -	$ 10,260.70	$ 295.00	$ 5.00	$ 860.67	$ 445.00	$ 355.00	$ 561.67	$ 22,466.63	$ 169.73	0.8%	6.79	6.84
4				$ -										
5	$ 14,730.73	$ -	$ 8,009.93	$ 590.00	$ 10.00	$ 669.41	$ 890.00	$ 710.00	$ 656.67	$ 26,266.73	$ 1,456.82	5.9%	9.71	10.28
6	$ 16,617.78	$ -	$ 13,731.30	$ 590.00	$ 10.00	$ 1,147.56	$ 890.00	$ 710.00	$ 864.02	$ 34,560.66	$ 417.97	1.2%	7.80	7.89
7	$ 18,778.33	$ -	$ 20,521.40	$ 590.00	$ 10.00	$ 1,721.34	$ 890.00	$ 710.00	$ 1,108.23	$ 44,329.29	$ (130.72)	-0.3%	6.77	6.75
8				$ -										
9	$ 71,298.21	$ -	$ 40,049.63	$ 2,950.00	$ 50.00	$ 3,347.05	$ 4,450.00	$ 3,550.00	$ 3,222.94	$ 128,917.83	$ 5,403.38	4.4%	9.67	10.09
10	$ 80,733.46	$ -	$ 68,656.50	$ 2,950.00	$ 50.00	$ 5,737.80	$ 4,450.00	$ 3,550.00	$ 4,259.68	$ 170,387.44	$ 209.15	0.1%	7.77	7.78
11	$ 91,536.20	$ -	$ 102,606.98	$ 2,950.00	$ 50.00	$ 8,606.70	$ 4,450.00	$ 3,550.00	$ 5,480.76	$ 219,230.63	$ (2,534.29)	-1.1%	6.75	6.67

Line No.		PRESENT GSD	PRESENT GSDT		PROPOSED GSLDPR	PROPOSED GSLDTPR	
12							
13							
14							
15	BASIC SERVICE CHARGE	130.44	130.44	$/Bill	588.86	588.86	$/Bill
16	DEMAND CHARGE	10.92		$/KW	11.50		$/KW
17	BILLING DEMAND		3.49	$/KW		3.65	$/KW
18	PEAK DEMAND CHARGE		7.14	$/KW	-	7.82	$/KW
19	ENERGY CHARGE	1.589		¢/kWH	1.034		¢/kWH
20	ON-PEAK		2.908	¢/kWH		1.571	¢/kWH
21	OFF-PEAK		1.049	¢/kWH	-	0.840	¢/kWH
22	DELIVERY VOLTAGE CREDIT		(0.91)	$/KW	-	-	$/KW
23	FUEL CHARGE	3.135	-	¢/kWH	3.135	-	¢/kWH
24	ON-PEAK	-	3.302	¢/kWH	-	3.302	¢/kWH
25	OFF-PEAK	-	3.064	¢/kWH	-	3.064	¢/kWH
26	CONSERVATION CHARGE	0.59	0.59	$/KW	0.59	0.59	$/KW
27	CAPACITY CHARGE	0.01	0.01	$/KW	0.01	0.01	$/KW
	CLEAN ENERGY TRANSITION MECHANISM				0.89	0.89	$/KW
28	ENVIRONMENTAL CHARGE	0.262	0.262	¢/kWH	0.262	0.262	¢/kWH
29	STORM PROTECTION PLAN	0.71	0.71	$/KW	0.71	0.71	$/KW
30	GSLM2 CONTRACT CREDIT VALUE		-	$/kW	-	-	$/kW

31
32 Notes:
33 A. The kWh for each kW group is based on 35, 60, and 90% load factors (LF).
34 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.
35 C. Calculations assume meter and service at primary voltage and a power factor of 85%.
36 D. TOD energy charges assume 25/75 on/off-peak % for 90% LF.
37 E. Present and proposed cost recovery clause factors are the approved January 2021 factors.
38
39
40
41

TAMPA ELECTRIC COMPANY
DOCKET NO. 20210034-EI
STAFF'S SIXTH DATA REQUEST
FILED: SEPTEMBER 7, 2021

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 12/31/2022
Projected Prior Year Ended 12/31/2021
Historical Prior Year Ended 12/31/2020
Witness: W. R. Ashburn

COMPANY: TAMPA ELECTRIC COMPANY

DOCKET No. 20210034 EI

GSLDSU/GSLDTSU- GENERAL SERVICE LARGE DEMAND/ TOU/ SUBTRANSMISSION SERVED

	RATE SCHEDULE GSLDSU/GSLDTSU		BILL UNDER PRESENT RATES									BILL UNDER PROPOSED RATES										INCREASE		COSTS IN CENTS/KWH	
Line No.	(1) TYPICAL KW	(2) KWH	(3) BASE RATE	(4) FUEL CHARGE	(5) CCV CREDIT	(6) ECCR CHARGE	(7) CAPACITY CHARGE	(8) SPPCRC CHARGE	(9) ECRC CHARGE	(10) GRT CHARGE	(11) TOTAL	(12) BASE RATE	(13) CCV CREDIT	(14) FUEL CHARGE	(15) ECCR CHARGE	(16) CAPACITY CHARGE	(17) ECRC CHARGE	(18) CLEAN ENR TRANS. MECH	(19) SPPCRC CHARGE	(20) GRT CHARGE	(21) TOTAL	(22) DOLLARS (16)-(9)	(23) PERCENT (17)/(9)	(24) PRESENT (9)/(2)*100	(25) FINAL (16)/(2)*100
1	500	127,750	$ 8,483.22	$ 3,965.36	$ -	$ 290.00	$ 5.00	$ 355.00	$ 332.15	$ 344.38	$ 13,775.10	8,485.26	$ -	$ 3,965.36	$ 290.00	$ 5.00	$ 332.15	$ 165.00	$ 355.00	$ 348.66	$ 13,946.43	$ 171.32	1.2%	10.78	10.92
2	500	219,000	$ 9,933.18	$ 6,797.76	$ -	$ 290.00	$ 5.00	$ 355.00	$ 569.40	$ 460.26	$ 18,410.60	9,527.33	$ -	$ 6,797.76	$ 290.00	$ 5.00	$ 569.40	$ 165.00	$ 355.00	$ 454.09	$ 18,163.58	$ (247.03)	-1.3%	8.41	8.29
3	500	328,500	$ 11,280.94	$ 10,156.40	$ -	$ 290.00	$ 5.00	$ 355.00	$ 854.10	$ 588.24	$ 23,529.68	10,774.32	$ -	$ 10,156.40	$ 290.00	$ 5.00	$ 854.10	$ 165.00	$ 355.00	$ 579.48	$ 23,179.30	$ (350.38)	-1.5%	7.16	7.06
4																									
5	1,000	255,500	$ 15,973.17	$ 7,930.72	$ -	$ 580.00	$ 10.00	$ 710.00	$ 664.30	$ 663.29	$ 26,531.47	14,439.16	$ -	$ 7,930.72	$ 580.00	$ 10.00	$ 664.30	$ 330.00	$ 710.00	$ 632.41	$ 25,296.59	$ (1,234.88)	-4.7%	10.38	9.90
6	1,000	438,000	$ 18,873.09	$ 13,595.52	$ -	$ 580.00	$ 10.00	$ 710.00	$ 1,138.80	$ 895.06	$ 35,802.47	16,523.31	$ -	$ 13,595.52	$ 580.00	$ 10.00	$ 1,138.80	$ 330.00	$ 710.00	$ 843.27	$ 33,730.90	$ (2,071.57)	-5.8%	8.17	7.70
7	1,000	657,000	$ 21,568.61	$ 20,312.80	$ -	$ 580.00	$ 10.00	$ 710.00	$ 1,708.20	$ 1,151.01	$ 46,040.62	19,017.29	$ -	$ 20,312.80	$ 580.00	$ 10.00	$ 1,708.20	$ 330.00	$ 710.00	$ 1,094.06	$ 43,762.34	$ (2,278.28)	-4.9%	7.01	6.66
8																									
9	5,000	1,277,500	$ 75,892.75	$ 39,653.60	$ -	$ 2,900.00	$ 50.00	$ 3,550.00	$ 3,321.50	$ 3,214.56	$ 128,582.40	62,070.40	$ -	$ 39,653.60	$ 2,900.00	$ 50.00	$ 3,321.50	$ 1,650.00	$ 3,550.00	$ 2,902.45	$ 116,097.95	$ (12,484.46)	-9.7%	10.07	9.09
10	5,000	2,190,000	$ 90,392.37	$ 67,977.60	$ -	$ 2,900.00	$ 50.00	$ 3,550.00	$ 5,694.00	$ 4,373.43	$ 174,937.40	72,491.15	$ -	$ 67,977.60	$ 2,900.00	$ 50.00	$ 5,694.00	$ 1,650.00	$ 3,550.00	$ 3,956.73	$ 158,269.48	$ (16,667.92)	-9.5%	7.99	7.23
11	5,000	3,285,000	$ 103,869.96	$ 101,563.99	$ -	$ 2,900.00	$ 50.00	$ 3,550.00	$ 8,541.00	$ 5,653.20	$ 226,128.14	84,961.03	$ -	$ 101,563.99	$ 2,900.00	$ 50.00	$ 8,541.00	$ 1,650.00	$ 3,550.00	$ 5,210.66	$ 208,426.67	$ (17,701.47)	-7.8%	6.88	6.34
12																									

Line		PRESENT GSD	PRESENT GSDT		PROPOSED GSLDSU	PROPOSED GSLDTSU	
15	BASIC SERVICE CHARGE	993.27	993.27	$/Bill	2,531.35	2,531.35	$/Bill
16	DEMAND CHARGE	10.92		$/KW	8.99		$/KW
17	BILLING DEMAND		3.49	$/KW		2.86	$/KW
18	PEAK DEMAND CHARGE	-	7.14	$/KW	-	6.10	$/KW
19	ENERGY CHARGE	1.589		¢/kWH	1.142		¢/kWH
20	ON-PEAK		2.908	¢/kWH		1.375	¢/kWH
21	OFF-PEAK	-	1.049	¢/kWH	-	1.069	¢/kWH
22	DELIVERY VOLTAGE CREDIT	-	-	$/KW	-	-	$/KW
23	FUEL CHARGE	3.104	-	¢/kWH	3.104	-	¢/kWH
24	ON-PEAK	-	3.268	¢/kWH	-	3.268	¢/kWH
25	OFF-PEAK	-	3.033	¢/kWH	-	3.033	¢/kWH
26	CONSERVATION CHARGE	0.58	0.58	$/KW	0.58	0.58	$/KW
27	CAPACITY CHARGE	0.01	0.01	$/KW	0.01	0.01	$/KW
	CLEAN ENERGY TRANSITION MECHANISM				0.33	0.33	$/KW
28	ENVIRONMENTAL CHARGE	0.260	0.260	¢/kWH	0.260	0.260	¢/kWH
29	STORM PROTECTION PLAN	0.71	0.71	$/KW	0.71	0.71	$/KW
30	GSLM2 CONTRACT CREDIT VALUE		-	$/kW	-	-	$/kW

32 Notes:
33 A. The kWh for each kW group is based on 35, 60, and 90% load factors (LF).
34 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.
35 C. Calculations assume meter and service at Subtransmission voltage and a power factor of 85%.
36 D. TOD energy charges assume 25/75 on/off-peak % for 90% LF.
37 E. Present and proposed cost recovery clause factors are the approved January 2021 factors.

TAMPA ELECTRIC COMPANY
DOCKET NO. 20210034-EI
STAFF'S SIXTH DATA REQUEST
REQUEST NO. 2
BATES PAGES: 7 - 8
FILED: SEPTEMBER 7, 2021

2. Please provide an MFR schedule E-8 showing how the 2022 Settlement increase was allocated to the rate classes.

A. Please see attached.

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: TAMPA ELECTRIC COMPANY

DOCKET No. 20210034-EI

EXPLANATION: Provide a schedule which shows the company-proposed increase in revenue by rate schedule and Type of data shown: the present and company-proposed class rates of return under the proposed cost of service study Provide justification for every class not left at the system rate of return. If the increase from service Projected Prior Year Ended 12/31/2008 charges by rate class does not equal that shown on Schedule E-13b or if the increase from sales of electricity does not equal that shown on Schedule E-13a, provide an explanation.

Type of data shown:
XX Projected Test Year Ended 12/31/2022
Projected Prior Year Ended 12/31/2021
Historical Prior Year Ended 12/31/2020
Witness: W. R. Ashburn / L. J. Vogt

		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
				Dollars in Thousands							
		Present COS Present Revenues		Present Class Operating Revenue	Proposed Class Operating Revenue	Increase From Serv Charges and From Sales of Electricity	Increase From Unbilled Revenue	Total Revenue Increase	Proposed COS Proposed Revenues		Percent Total Revenue Increase
Line No.	Rate Class	ROR (%)	Index						ROR (%)	Index	
1											
2	I. RS (a)	3.42%	0.88	$ 666,901	$ 773,680	$ 106,779	$ (17)	$ 106,762	5.47%	0.87	16.0%
3											
4	II. GS (b)	4.88%	1.25	$ 67,302	$ 81,752	$ 14,450	$ (2)	$ 14,448	7.66%	1.22	21.5%
5											
6	III. GSD (c)	4.06%	1.04	$ 346,606	$ 300,250	$ (46,355)	47	$ (46,308)	6.46%	1.03	-13.4%
7											
8	IV. IS (d)	6.63%	1.70	$ 30,023	$ -	$ (30,023)	-	$ (30,023)	0.00%	-	-100.0%
9											
10	V. GSLDPR (c)	0.00%	-	$ -	$ 41,834	41,834	(10)	$ 41,824	8.37%	1.34	0.0%
11											
12	VI. GSLDSU (c)	0.00%	-	$ -	$ 23,354	$ 23,354	(6)	$ 23,348	9.40%	1.50	0.0%
13											
14	VII. LS-1										
15	a. Energy Service (e)	4.34%	1.11	$ 2,884	$ 3,492	$ 608	-	$ 608	18.03%	2.88	21.1%
16	b. Facilities (f)	8.04%	2.06	$ 53,717	$ 65,750	$ 12,033	-	$ 12,033	14.36%	2.29	22.4%
17	Total VII.a. + VII. b.	7.78%	2.00	$ 56,601	$ 69,242	$ 12,641	-	$ 12,641	14.51%	2.32	22.3%
18											
19											
20	Total Retail	3.90%	1.00	$ 1,167,433	$ 1,290,112	$ 122,679	$ 12	$ 122,691	6.26%	1.00	10.5%
21											
22											
23											
24											
25											
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31											
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33											
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35											
36											
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41											

Supporting Schedules: E-1

Recap Schedules:

3. Please state the 1,000 kilowatt hour residential bill under a) the MFR rates as originally proposed and b) under the proposed Settlement rates for 2022. Show all charges and bill components separately.

A. Please see attached.

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FLORIDA PUBLIC SERVICE COMMISSION

EXPLANATION: For each rate, calculate typical monthly bills for present rates and proposed rates.

COMPANY: TAMPA ELECTRIC COMPANY

DOCKET No. 20210034 EI

Type of data shown:
XX Projected Test year Ended 12/31/2022
Projected Prior Year Ended 12/31/2021
Historical Prior Year Ended 12/31/2020
Witness: W. R. Ashburn

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)	(21)	(22)	(23)
Line No.	TYPICAL KW	KWH	BASE RATE	FUEL CHARGE	ECCR CHARGE	CAPACITY CHARGE	ECRC CHARGE	SPPCRC CHARGE	GRT CHARGE	TOTAL	BASE RATE	FUEL CHARGE	ECCR CHARGE	CAPACITY CHARGE	ECRC CHARGE	Clean Energy Trans. Mech	SPPCRC CHARGE	GRT CHARGE	TOTAL	DOLLARS (16)-(9)	PERCENT (17)/(9)	PRESENT (9)/(2)*100	PROPOSED (16)/(2)*100
1	0	-	$ 15.05	$ -	$ -	$ -	$ -		$ 0.39	$ 15.44	$ 21.29	$ -	$ -	$ -	$ -						0.0%	-	-
2																							
3	0	100	$ 20.28	$ 2.86	$ 0.17	$ 0.00	$ 0.27	$ 0.24	$ 0.61	$ 24.42	$ 27.06	$ 2.86	$ 0.17	$ 0.00	$ 0.27	$ 0.44	$ 0.24	$ 0.80	$ 31.83	$ 7.41	30.3%	24.42	31.83
4																							
5	0	250	$ 28.11	$ 7.14	$ 0.42	$ 0.01	$ 0.67	$ 0.60	$ 0.95	$ 37.89	$ 35.71	$ 7.14	$ 0.42	$ 0.01	$ 0.67	$ 1.10	$ 0.60	$ 1.17	$ 46.81	$ 8.92	23.6%	15.16	18.73
6																							
7	0	500	$ 41.18	$ 14.28	$ 0.83	$ 0.01	$ 1.35	$ 1.20	$ 1.51	$ 60.34	$ 50.14	$ 14.28	$ 0.83	$ 0.01	$ 1.35	$ 2.20	$ 1.20	$ 1.79	$ 71.79	$ 11.45	19.0%	12.07	14.36
8																							
9	0	750	$ 54.24	$ 21.42	$ 1.25	$ 0.02	$ 2.02	$ 1.79	$ 2.07	$ 82.80	$ 64.56	$ 21.42	$ 1.25	$ 0.02	$ 2.02	$ 3.30	$ 1.79	$ 2.42	$ 96.77	$ 13.97	16.9%	11.04	12.90
10																							
11	0	1,000	$ 67.30	$ 28.56	$ 1.66	$ 0.02	$ 2.69	$ 2.39	$ 2.63	$ 105.25	$ 78.98	$ 28.56	$ 1.66	$ 0.02	$ 2.69	$ 4.41	$ 2.39	$ 3.04	$ 121.75	$ 16.50	15.7%	10.53	12.17
12																							
13	0	1,250	$ 82.86	$ 38.20	$ 2.08	$ 0.03	$ 3.36	$ 2.99	$ 3.32	$ 132.83	$ 95.90	$ 38.20	$ 2.08	$ 0.03	$ 3.36	$ 5.51	$ 2.99	$ 3.80	$ 151.86	$ 19.02	14.3%	10.63	12.15
14																							
15	0	1,500	$ 98.43	$ 47.84	$ 2.49	$ 0.03	$ 4.04	$ 3.59	$ 4.01	$ 160.42	$ 112.83	$ 47.84	$ 2.49	$ 0.03	$ 4.04	$ 6.61	$ 3.59	$ 4.55	$ 181.96	$ 21.55	13.4%	10.69	12.13
16																							
17	0	2,000	$ 129.55	$ 67.12	$ 3.32	$ 0.04	$ 5.38	$ 4.78	$ 5.39	$ 215.58	$ 146.67	$ 67.12	$ 3.32	$ 0.04	$ 5.38	$ 8.81	$ 4.78	$ 6.05	$ 242.17	$ 26.59	12.3%	10.78	12.11
18																							
19	0	3,000	$ 191.80	$ 105.68	$ 4.98	$ 0.06	$ 8.07	$ 7.17	$ 8.15	$ 325.91	$ 214.36	$ 105.68	$ 4.98	$ 0.06	$ 8.07	$ 13.22	$ 7.17	$ 9.06	$ 362.60	$ 36.69	11.3%	10.86	12.09
20																							
21	0	5,000	$ 316.30	$ 182.80	$ 8.30	$ 0.10	$ 13.45	$ 11.95	$ 13.66	$ 546.56	$ 349.74	$ 182.80	$ 8.30	$ 0.10	$ 13.45	$ 22.03	$ 11.95	$ 15.09	$ 603.45	$ 56.89	10.4%	10.93	12.07

Line		PRESENT	PROPOSED
22			
23			
24		PRESENT	PROPOSED
25	BASIC SERVICE CHARGE	15.05 $/Bill	21.29 $/Bill
26	DEMAND CHARGE	- $/KW	- $/KW
27	ENERGY CHARGE		
28	0 - 1,000 KWH	5.225 ¢/kWH	5.769 ¢/kWH
29	Over 1,000 KWH	6.225 ¢/kWH	6.769 ¢/kWH
30	FUEL CHARGE		
31	0 - 1,000 KWH	2.856 ¢/kWH	2.856 ¢/kWH
32	Over 1,000 KWH	3.856 ¢/kWH	3.856 ¢/kWH
33	CONSERVATION CHARGE	0.166 ¢/kWH	0.166 ¢/kWH
34	CAPACITY CHARGE	0.002 ¢/kWH	0.002 ¢/kWH
35	CLEAN ENERGY TRANSITION MECHANISM		0.441 ¢/kWH
36	ENVIRONMENTAL CHARGE	0.269 ¢/kWH	0.269 ¢/kWH
37	STORM PROTECTION PLAN	0.239 ¢/kWH	0.239 ¢/kWH
38			
39	Note: Present and proposed cost recovery clause factors are the approved January 2021 factors.		
42			

TAMPA ELECTRIC COMPANY
DOCKET NO. 20210034-EI
STAFF'S SIXTH DATA REQUEST
FILED: SEPTEMBER 7, 2021

SCHEDULE A-2 — FULL REVENUE REQUIREMENTS BILL COMPARISON - TYPICAL MONTHLY BILLS — Page 1 of 5

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 12/31/2022
Projected Prior Year Ended 12/31/2021
Historical Prior Year Ended 12/31/2020
Witness: W. R. Ashburn

COMPANY: TAMPA ELECTRIC COMPANY

RS - RESIDENTIAL SERVICE

DOCKET No. 20210034 EI

RATE SCHEDULE RS

Line No.	(1) TYPICAL KW	(2) TYPICAL KWH	(3) BASE RATE	(4) FUEL CHARGE	(5) ECCR CHARGE	(6) CAPACITY CHARGE	(7) ECRC CHARGE	(8) SPPCRC CHARGE	(9) GRT CHARGE	(10) TOTAL	(11) BASE RATE	(12) FUEL CHARGE	(13) ECCR CHARGE	(14) CAPACITY CHARGE	(15) ECRC CHARGE	(16) SPPCRC CHARGE	(17) GRT CHARGE	(18) TOTAL	(19) DOLLARS (16)-(9)	(20) PERCENT (17)/(9)	(21) PRESENT (9)/(2)*100	(22) PROPOSED (16)/(2)*100
			BILL UNDER PRESENT RATES								BILL UNDER PROPOSED RATES								INCREASE		COSTS IN CENTS/KWH	
1	0	-	$ 15.05	$ -	$ -	$ -	$ -		$ 0.39	$ 15.44	$ 21.02	$ -	$ -	$ -	$ -					0.0%	-	-
2																						
3	0	100	$ 20.28	$ 2.86	$ 0.17	$ 0.00	$ 0.27	$ 0.24	$ 0.61	$ 24.42	$ 27.62	$ 2.86	$ 0.17	$ 0.00	$ 0.27	$ 0.24	$ 0.80	$ 31.95	$ 7.53	30.9%	24.42	31.95
4																						
5	0	250	$ 28.11	$ 7.14	$ 0.42	$ 0.01	$ 0.67	$ 0.60	$ 0.95	$ 37.89	$ 37.52	$ 7.14	$ 0.42	$ 0.01	$ 0.67	$ 0.60	$ 1.19	$ 47.54	$ 9.65	25.5%	15.16	19.02
6																						
7	0	500	$ 41.18	$ 14.28	$ 0.83	$ 0.01	$ 1.35	$ 1.20	$ 1.51	$ 60.34	$ 54.02	$ 14.28	$ 0.83	$ 0.01	$ 1.35	$ 1.20	$ 1.84	$ 73.52	$ 13.18	21.8%	12.07	14.70
8																						
9	0	750	$ 54.24	$ 21.42	$ 1.25	$ 0.02	$ 2.02	$ 1.79	$ 2.07	$ 82.80	$ 70.52	$ 21.42	$ 1.25	$ 0.02	$ 2.02	$ 1.79	$ 2.49	$ 99.50	$ 16.70	20.2%	11.04	13.27
10																						
11	0	1,000	$ 67.30	$ 28.56	$ 1.66	$ 0.02	$ 2.69	$ 2.39	$ 2.63	$ 105.25	$ 87.02	$ 28.56	$ 1.66	$ 0.02	$ 2.69	$ 2.39	$ 3.14	$ 125.48	$ 20.23	19.2%	10.53	12.55
12																						
13	0	1,250	$ 82.86	$ 38.20	$ 2.08	$ 0.03	$ 3.36	$ 2.99	$ 3.32	$ 132.83	$ 106.02	$ 38.20	$ 2.08	$ 0.03	$ 3.36	$ 2.99	$ 3.91	$ 156.59	$ 23.75	17.9%	10.63	12.53
14																						
15	0	1,500	$ 98.43	$ 47.84	$ 2.49	$ 0.03	$ 4.04	$ 3.59	$ 4.01	$ 160.42	$ 125.02	$ 47.84	$ 2.49	$ 0.03	$ 4.04	$ 3.59	$ 4.69	$ 187.69	$ 27.28	17.0%	10.69	12.51
16																						
17	0	2,000	$ 129.55	$ 67.12	$ 3.32	$ 0.04	$ 5.38	$ 4.78	$ 5.39	$ 215.58	$ 163.02	$ 67.12	$ 3.32	$ 0.04	$ 5.38	$ 4.78	$ 6.25	$ 249.91	$ 34.33	15.9%	10.78	12.50
18																						
19	0	3,000	$ 191.80	$ 105.68	$ 4.98	$ 0.06	$ 8.07	$ 7.17	$ 8.15	$ 325.91	$ 239.02	$ 105.68	$ 4.98	$ 0.06	$ 8.07	$ 7.17	$ 9.36	$ 374.34	$ 48.43	14.9%	10.86	12.48
20																						
21	0	5,000	$ 316.30	$ 182.80	$ 8.30	$ 0.10	$ 13.45	$ 11.95	$ 13.66	$ 546.56	$ 391.02	$ 182.80	$ 8.30	$ 0.10	$ 13.45	$ 11.95	$ 15.58	$ 623.20	$ 76.64	14.0%	10.93	12.46

Line No.		PRESENT		PROPOSED	
22					
23					
24		PRESENT		PROPOSED	
25	BASIC SERVICE CHARGE	15.05	$/Bill	21.02	$/Bill
26	DEMAND CHARGE	-	$/KW	-	$/KW
27	ENERGY CHARGE				
28	0 - 1,000 KWH	5.225	¢/kWH	6.600	¢/kWH
29	Over 1,000 KWH	6.225	¢/kWH	7.600	¢/kWH
30	FUEL CHARGE				
31	0 - 1,000 KWH	2.856	¢/kWH	2.856	¢/kWH
32	Over 1,000 KWH	3.856	¢/kWH	3.856	¢/kWH
33	CONSERVATION CHARGE	0.166	¢/kWH	0.166	¢/kWH
34	CAPACITY CHARGE	0.002	¢/kWH	0.002	¢/kWH
35	ENVIRONMENTAL CHARGE	0.269	¢/kWH	0.269	¢/kWH
36	STORM PROTECTION PLAN	0.239	¢/kWH	0.239	¢/kWH
37					
38	Note: Present and proposed cost recovery clause factors are the approved 2021 factors.				
39					
40					
41					

4. Referring to paragraph 6(d) of the Settlement, and the use of the 4 Coincident Peak (CP) methodology for allocating production and transmission plant, please respond to the following questions:

a. Discuss and explain why the Settlement includes the 4 CP methodology as opposed to the 12 CP and 1/13 Average Demand (AD) methodology for production as included in the original MFRs.

b. Discuss and explain why the Settlement includes the 4 CP methodology as opposed to the 12 CP methodology for transmission as included in the original MFRs.

c. State which three summer and which one winter month are being used to allocate production and transmission costs and explain why those particular months were chosen.

d. Discuss whether TECO designs and provides generation and transmission capacity needs for twelve months of the year or just four months of the year.

e. Are transmission costs to wholesale customers allocated on a 12 CP or 4 CP methodology? If on a 12 CP methodology, wouldn’t the proposed 4 CP methodology create a mismatch between the retail and wholesale jurisdiction?

f. Discuss which rate classes (residential/small commercial vs. larger commercial/industrial) are negatively impacted by the proposed 4 CP methodology (when compared to the methodology used in the MFRs), by shifting target revenue requirements to the rate class away from other rate classes.

g. Discuss why the Settlement includes a provision that in the next general base rate proceeding, the filed cost-of-service study will use the 4 CP cost allocation.

h. Clarify whether in the next general base rate proceeding, TECO will only include the 4 CP cost of service methodology, or the 4CP and 12 CP and 1/13 AD methodology.

i. Explain who are the “Precluded Parties” and why would an affiliate of TECO oppose the 4 CP and full MDS.

4a. Discuss and explain why the Settlement includes the 4 CP methodology as opposed to the 12 CP and 1/13 Average Demand (AD) methodology for production as included in the original MFRs.

A. Three preliminary points are important.

First, the cost allocation methodology that the Parties unanimously agreed upon in the 2021 Agreement was and is recognized by the Parties as reflecting cost-causation on Tampa Electric's system and as reasonable for ratemaking purposes.

Second, although the 4 CP and Full MDS methodologies were used as the starting point to guide revenue allocation and rate design in the 2021 Agreement, the Parties agreed to specific rate class revenue allocations to substantially mitigate the impact of fully applying the new methodology in this case. The agreed-to revenue allocations were used with billing determinants to develop the agreed-to rates, which were reflected in the company's updated tariffs that were filed on August 20, 2021.

Third, use of the 4 CP methodology as reflected in the 2021 Agreement is best understood as part of the settlement as a whole, in light of the reasons the 12 CP and 1/13th methodology was adopted in the 1980s (which reflected key factors that determined Tampa Electric's past investments in production, transmission, and distribution plant), and in light of the fundamental theme of this rate case, namely transformation. The part of the company's transformation relevant for cost-of service purposes is the company's transition from a generation fleet dominated by baseload coal generation in the early 1980s to its current fleet that is predominantly natural gas and some solar generation with very limited coal, to a future system that over time is planned to include solar, storage, some gas, and other low-or-no-carbon fuels.

<u>The Overall Settlement</u>
Almost every settlement agreement considered and approved by the Commission reflects give and take among the parties and reflects an integrated package of exchanged agreements and consideration. The answer to why any particular provision was included in a settlement always boils down to a simple answer, namely, because the parties, notwithstanding their diverse and often competing interests, agreed to it. In virtually every settlement, every party likely would have objected to some feature(s) of the settlement if offered individually and not as a part of a larger integrated package, but nonetheless agreed to settlement in its totality. The 2021 Agreement is no different in this regard.

<u>Adoption of 12 CP and 1/13th Methodology</u>
The 12 CP and 1/13th cost-of-service methodology has been in use for approximately 40 years and was approved for Tampa Electric as early as its 1982 rate case. See Order No. 11307, Docket No. 19820007-EU, issued November 11, 1982. That order noted: “We continue to believe that the 12 CP and one - thirteenth weighted average method is the best demand allocation methodology to use in Florida. This is so because each monthly peak is important in TECO's system planning perspective when periods of peak demands and the necessary periods of planned outages are considered.”

The 12 CP and 1/13th methodology was found appropriate in part because of the weather and the weather’s impact, in that era, on production plant operations and expansion. At the time, Florida utilities had periods of substantial summer load (driven primarily by air conditioning) that extended from May through September that required peaking coverage but depended on long and sustained energy production from mid-morning to late evening using baseload, coal-fired generating units.

Significant winter peaks occurred sporadically between December and March when arctic cold fronts reached Florida bringing temperatures below 30 degrees. During these brief periods of cold temperatures usually occurred in the mornings when customers (primarily residential) relied on resistive heating (strip heat) or the strip heating elements of heat pumps to warm their homes, thereby creating brief periods of high demand that often exceeded the summer peak load, but usually only for a couple of hours.

The remaining shoulder months (April, May, October, and November) were considered important months for meeting peaks because of the heavy reliance on coal generating plants, which in those months were often out of service for planned maintenance and thus were not available to meet cooling-driven peak loads that occurred sporadically and infrequently in those months.

The 1/13th element of the methodology (later 25 percent) was added in part to allocate some production plant to non-firm load that was not allocated production costs for recovery in their base rates but benefitted in lower fuel cost from the coal plants that served their load.

<u>Transformation Since the 1980s</u>
The reasoning and arguments in favor of the 4 CP methodology considered by the Parties when negotiating the 2021 Agreement reflect the ongoing evolution of the company’s generating fleet in the context of significant, even dramatic, advances in generating technology, equally important changes in energy policy, and the

company's changing demand profile, all of which are part of the the fundamental theme of this proceeding, namely transformation.

From the beginning, this rate case has been about the changing energy industry, the transformation of Tampa Electric and positioning the company for a future in which renewable energy, clean energy, carbon reduction, conservation, and distributed generation will be more important.

Tampa Electric is different than it was during its 2013 rate case, and far different than it was in the early 1980s when the 12 CP and 1/13th cost-of-service methodology was approved.

In the early 1980s, the company's generating fleet was dominated by large, base-load coal-fired generating units; reduction of carbon emissions was not a major policy goal; and the Commission's efforts to promote demand-side management (energy conservation) were just beginning.

Ninety-nine percent of the company's electricity was generated using coal in 1985.

By 2013, about 59 percent of Tampa Electric's electricity was generated using coal, about 41 percent was natural gas-fired, and the company had no solar generation.

By 2020, about five percent of its electricity was generated using coal, about 89 percent was natural gas-fired, and about 6 percent was from solar.

As part of this case and as reflected in the 2021 Agreement, the company has retired three of the four coal units at Big Bend Station and the fourth runs primarily on natural gas.

With the addition of the 600 MW of Future Solar facilitated by the 2021 Agreement, nearly 14 percent of the company's energy production will be from solar by 2025, which will be enough to power more than 200,000 homes.

The company's investments in solar generation make it a leader in solar energy, promote price stability for customers, increase its fuel diversity, and contribute to the reduction of carbon emissions.

The company's generation mix changes have significantly reduced its carbon emissions, which fell from 15.7 million tons in 2013 to about 8.8 million tons in 2020. By 2023, the company expects to have reduced its carbon dioxide emissions by the equivalent of removing one million cars from local roadways.

Since the early 1980s, the company's FPSC-approved DSM programs have reduced the need of 779 MW of summer peak demand, 1,289 MW of winter peak demand, and 1,722 GWh of annual energy. These demand and energy reductions have eliminated the need for seven – 180 MW peaking power plants along with the significant savings on fuel usage and emissions. The value of interruptible customers and demand response is now reflected in the company's Commission-approved conservation programs and the CCV credit.

The company's investment in Advanced Metering Infrastructure (AMI), also facilitated by the 2021 Agreement, will pave the way for the company to empower customers through technology via a smarter grid that delivers safe, more reliable, and affordable energy, and that will enable the company to accommodate larger amounts of company-owned and customer-owned distributed generation (including roof-top solar) and to offer enhanced demand response and other conservation programs.

The company's most recent Ten-Year Site Plan portends a future built primarily around battery storage and additional utility-scale solar, not large fossil fuel-fired generating stations. This future looks nothing like the 1980s and invites a fresh look and innovation in the cost-of-service methodology area.

<u>Arguments for 4 CP</u>
While there was lively and thoughtful discussion of the specifics of cost-of-service approaches during the settlement process, there was a shared belief among the Parties that movement toward a summer/winter approach with all production and transmission costs classified as demand-related would better reflect cost causation for Tampa Electric as it prepares for a future built on more solar, renewable and clean energy, and a greater emphasis on carbon reduction, conservation, and distributed generation. Notably, Tampa Electric proposed using a new summer/winter allocation methodology to be applied to its new solar production assets in its original filing.

Some of the ideas considered by the Parties as part of the settlement process included:

1. A cost-of-service study is an analysis used to determine each rate class's responsibility for a utility's costs, so it influences the revenues a rate class generates to cover a class's cost of service. How cost is defined, which cost-of-service methodology is appropriate and how costs are allocated during the preparation of a cost-of-service study are issues over which reasonable people can differ.

2. As the company has retired its coal plants, the importance of the shoulder months for base load coal-plant planned outages and cost attribution has diminished. The notion inherent in the 12 CP and 1/13th methodology that each monthly coincident peak should be given the same importance for cost-of-service purposes seems less applicable now than it was in the coal-dominated early 1980s.

3. Although Tampa Electric was once a consistently winter peaking utility, that has changed, in part because energy efficiency and conservation programs have improved energy efficiency, reduced customer reliance on resistive strip heating, and because recent winters have been milder, which trend is not reasonably expected to reverse. The company's most recent Ten-Year Site Plans show 3 of 4 annual peak periods occurring in the summer cooling season. Although it had not happened by the time the 2021 Agreement was filed, Tampa Electric recently experienced a new, all-time summer peak demand of 4,514 MW on August 18, 2021.

4. Recent history suggests that global climate change appears to be bringing hotter summers and milder winters to Florida. These changes will elevate the summer months' importance for operational planning and cost attribution purposes. Conversely, the increased reliance of solar to meet peak will increase the need to have alternative supply resources to meet the less frequent but still important winter peaks.

5. Although the company must plan for every month (indeed all 8,760 hours each year), its operational planning currently focuses on meeting both the heavy summer cooling months and the possibility of an occasional cold snap in the winter. The transition to a 4 CP methodology in the 2021 Agreement reflects a greater emphasis on the heavy summer cooling months and an occasional cold winter month. The company's recent new summer peak in August reinforces this idea.

6. Tampa Electric's Ten-Year Site Plan focuses on two system peaks for calculating reserve margin: a summer and a winter peak, and this consideration alone could support a 2CP methodology. By emphasizing the four most important monthly coincident peaks in a year, the 4 CP methodology with future innovative rate design ideas will over time move rates closer towards Tampa Electric's planning parameters, and associated cost causation, for peak demand capacity, including reserve margins, and will encourage use of the system's assets when they would be otherwise underutilized, shifting demand away from peak periods. While the Site Plan focuses on two peaks, the 2021 Agreement instead looks to 4 CP, a middle

ground between the historical 12 CP and the summer and winter peak focus implicit in the Ten-Year Site Plan.

7. The industrial and large commercial customers on Tampa Electric's system tend to be high-load factor customers consistently on a year-round basis, while residential (RS) and small commercial customers (GS) tend to be very "peaky" due to their demand for summer cooling (air conditioning) and occasional winter heating (resistive strip). Indeed, it is generally recognized that residential cooling and heating drive system peaks for utilities in the southeastern United States.

8. The manner in which the 4 CP methodology allocates costs to the RS class may incent RS customers to install additional customer-sited solar, which would lead to more clean energy overall and will become more important for achieving global, national, and company-specific carbon reduction goals. Tampa Electric believes that additional customer-sited solar, updating the rules governing customer-sited solar, and new optional programs will be part of an overall strategy for reducing carbon emissions in the future.

9. Among other things, the Tampa area currently is home to steel, construction materials, furniture, electronics, and disinfectant manufacturing facilities that employ many people. Over time, application of a 4 CP cost-of-service methodology may make manufacturers and other large employers in Tampa Electric's service territory more competitive vis-à-vis other competing regions, including those that use 4 CP or a derivative thereof. The 4 CP method or variants thereof are used in Texas, Colorado, New Mexico, Oklahoma, and Arkansas, and other jurisdictions consider 4 CP as a tool to attract businesses and jobs.

10. The 12 CP methodology, which equally values all 12 monthly coincident peaks, does not attribute the costs of solar generation to customer classes as efficiently as the 4 CP methodology. Solar PV panels are intermittent resources that generate electricity whenever the sun is shining and have zero fuel costs relative to other resources in the order of dispatch. Solar will be in place and producing energy every day of the year – including shoulder months when there may be more solar power than needed to economically meet demand. The 4 CP methodology can be viewed as a platform for future innovative pricing approaches that will more closely align incremental costs and revenues.

4b. Discuss and explain why the Settlement includes the 4 CP methodology as opposed to the 12 CP methodology for transmission as included in the original MFRs.

A. As was the case for generation, the Parties agreed to the 4 CP methodology in the 2021 Agreement for transmission investment, subject to mitigation in the class revenue allocation process, as part of the overall settlement. In addition to the general considerations described above, fixed demand related costs, such as the return on transmission plant investment and fixed transmission O&M, are incurred by a utility to meet the peak demand of its customers. Once transmission investment has been constructed, their demand-related costs are fixed and do not vary with the amount of energy they carry. As a result, economic efficiency is achieved by allocating fixed demand related costs on the basis of class peak demand.

4c. State which three summer and which one winter month are being used to allocate production and transmission costs and explain why those particular months were chosen.

A. The Parties agreed to use June, July, August, and January for the 4 CP methodology employed in the 2021 Agreement. These are the four months in which peak demand was projected to be above 4,000 MW in the company's most recent Ten-Year Site Plan. Each of these months exceed 90 percent of the company's system peak demand, whereas no other month does. As noted above, Tampa Electric recently experienced a new, all-time summer peak demand of 4,514 MW on August 18, 2021.

4d. Discuss whether TECO designs and provides generation and transmission capacity needs for twelve months of the year or just four months of the year.

A. Like other utilities, Tampa Electric must be ready to provide electricity instantaneously 24 hours a day and 365 days a year, not just once a month for 12 months or once a month for four months. However, in planning to meet system demand requirements, Tampa Electric's Ten-Year Site Plans rely on a single "Winter Peak" and a single "Summer Peak" in its projections of CP demand for determining the load and resource balances explained in the response to Request 4a, above, the company's transformation away from large, baseload, coal-fired generating units and to cleaner generating resources like solar has diminished the importance of the shoulder months for operational planning and cost attribution purposes, so it is reasonable to move away from a cost-of-service methodology that values each monthly peak in a 12-month period equally. Ultimately, Tampa Electric must build sufficient capacity (both generation and transmission) to meet its projected peak demands, with a sufficient reserve margin to ensure reliability; because Tampa Electric experiences peaks in both the summer and the winter, Tampa Electric must plan for both. Having said that, once the capacity to meet the peak is constructed, it is available to meet all demands that occur during the year, so it is appropriate to allocate costs on the basis of the critical summer and winter peaks that drive Tampa Electric's planning and investment decisions.

4e. Are transmission costs to wholesale customers allocated on a 12 CP or 4 CP methodology? If on a 12 CP methodology, wouldn't the proposed 4 CP methodology create a mismatch between the retail and wholesale jurisdiction?

A. As specified in Paragraph 6(b)(iii) of the 2021 Agreement, retail transmission costs will be allocated to rate classes using 4 CP as mitigated. Tampa Electric's current Open Access Transmission Tariff rates uses a formula that applies a 12 CP allocation; however, Tampa Electric currently has no long-term wholesale power customers, either full or partial requirements based. In addition, Tampa Electric does not currently have any retail transmission only customers. Consequently, there is no mismatch in fact between retail and wholesale power sales.

4f. Discuss which rate classes (residential/small commercial vs. larger commercial/industrial) are negatively impacted by the proposed 4 CP methodology (when compared to the methodology used in the MFRs), by shifting target revenue requirements to the rate class away from other rate classes.

A. As noted in the response to 5.c., below, whether any rate class is "negatively impacted" by a particular cost allocation technique or method is relative. The company's response to Request No. 6, below, reflects a comparison of the target revenue allocations using a 12 CP and 1/13th and 50 percent MDS approach at parity to the mitigated 4 CP and 100 percent MDS approach reflected in the 2021 Agreement. However, the response to Request No. 6 does not reflect the intangible benefits associated with a transition to 4 CP, such as encouraging more customer-sited solar, promoting carbon reduction and economic development. It is difficult to quantify the economic value of these benefits with certainty. Additionally, as further explained in the response to Request 5(c), the 2021 Agreement reduces the residential class's increased revenue responsibility by over 20 percent, or $38 million in just the first year of the 2021 Agreement, relative to the level proposed in the initial filing in this case. The 2021 Agreement produces a reduction of the level of increase in the rates of residential customers compared to the proposed rates.

4g. Discuss why the Settlement includes a provision that in the next general base rate proceeding, the filed cost-of-service study will use the 4 CP cost allocation.

A. This provision reflects the general shared belief, noted in response to Request No. 4a above, that movement toward a summer/winter allocation approach, with all production and transmission costs classified as demand-related, is reasonable and appropriate for Tampa Electric in this case. Like most provisions of any settlement, the 2021 Agreement to use the 4CP methodology in Tampa Electric's next base rate case was one of a series of interrelated agreements upon which the settlement was reached and is an integral part of the fabric of the settlement. Along with the specific revenue allocation mitigation implemented in the 2021 Agreement, this provision reflects application of the principle of gradualism in this case and an expectation that the Parties, working together, will continue to "substantially and materially improve the position of all above-parity customer classes toward parity, such that costs are allocated and revenue is collected consistent with 4 CP and full MDS methods."

4h. Clarify whether in the next general base rate proceeding, TECO will only include the 4 CP cost-of-service methodology, or the 4 CP and 12 CP and 1/13 AD methodology.

A. In Tampa Electric's next base rate case filed following Docket No. 20210034-EI, the Company will file its direct case and rate design proposal reflecting a 4 CP methodology. To the extent the Commission's rules require presentation of a 12 CP and 1/13th cost-of-service study in the MFRs, the company will seek a waiver of that requirement; however, a 12 CP and 1/13th cost-of-service study could be made available if the 4 CP or full MDS methodology is opposed in the next general base rate case by an entity other than a Party to the 2021 Agreement or an affiliate of Tampa Electric.

4i. Explain who are the "Precluded Parties" and why would an affiliate of TECO oppose the 4 CP and full MDS.

A. The term "Precluded Parties" is defined in Section 6(d) at p. 25 of the 2021 Agreement and includes Tampa Electric, its affiliates, and the Consumer Parties. The term "Affiliates of Tampa Electric" was added in an abundance of caution.

5. Referring to paragraph 6(d) of the Settlement, and the use of the full Minimum Distribution System (MDS) methodology for allocating distribution plant costs, please respond to the following questions:

a. Discuss and explain why the Settlement includes the full MDS methodology as opposed to incorporating one-half of the MDS methodology as described in Witness Vogt's direct testimony on Page 26, Lines 1-18.

b. Explain in detail the difference between the full MDS and the one-half of the MDS methodology.

c. Please discuss which rate classes (residential/small commercial vs. larger commercial/industrial) are negatively impacted by the proposed full MDS methodology compared to the methodology used in the MFRS, by shifting target revenue requirements to the rate class away from other rate classes.

5a. Discuss and explain why the Settlement includes the full MDS methodology as opposed to incorporating one-half of the MDS methodology as described in Witness Vogt's direct testimony on Page 26, Lines 1-18.

A. The 2021 Agreement includes the full MDS implementation rather than half implementation for several reasons. First, it is the disposition agreed to among all of the Parties as part of their exchange of agreements and consideration. The settlement represents an extensive series of offsetting and interrelated exchanges. Every party likely would have objected to some feature of the 2021 Agreement if that feature were offered individually and not as part of a larger, integrated package, but agreed to the totality of the 2021 Agreement terms. MDS was integral to the disposition they agreed upon.

Tampa Electric's initial filing in this case, and the 2021 Agreement, use the same methodology and study to identify minimum incremental equipment and costs incurred to connect to the grid consumers having the lowest level of consumption; the only change is the full incorporation of the MDS methodology in the class cost allocation in the 2021 Agreement, which more accurately identified class cost responsibility, while recognizing that the class rate impacts are mitigated separately in the revenue allocations presented in Exhibit K to the 2021 Agreement. In other words, rather than limiting the implementation of the MDS methodology to mitigate class rate impacts, the 2021 Agreement implements the full MDS methodology for cost allocation purposes, but mitigates the class revenue allocations as part of the comprehensive agreement.

TECO proposed to implement MDS on a 100 percent basis for costs then categorized as customer-related in its 2013 base rate case. However, in the 2013 rate case, Tampa Electric forthrightly recognized and informed the Commission that each of its proposed separations of costs between customer- and capacity-related categories, as well as the proposed MDS calculation, was "not a precise calculation." Ashburn 20130040-EI Rebuttal, p. 40:20. Mr. Ashburn further noted: "the company does expect to make refinements and attempt to improve upon these calculations in the future." Id., p. 44:24-45:2. In the 2013 Settlement, participants agreed to, and the Commission approved, implementation of MDS. See Section 3(b)(i) thereof. That approach was continued in the 2017 Agreement.

Witness Vogt's testimony states that the 2021 Agreement MDS "methodology" was "accepted by the Commission in the settlement of rate and cost of service matters in the Company's 2013 retail rate case." Vogt, p. 17:2-15. In filing the 2021 base rate case, the company refined the depth at which it had conducted the 2013 study. In the 2021 analysis, Tampa Electric applied an enhanced level of granularity, to sort facilities and costs that should qualify for inclusion in customer-based rates, thereby producing a "refined" MDS allocation. Vogt, p. 24:12-13 and more generally, Vogt, pp. 20:1-25:6 and Schedule E-Rate Schedules Class Cost-of-Service Studies, Vol. II. This more detailed study, discussed at length in Tampa Electric's 2021 base rate case, reveals that the universe of equipment considered under the company's 2013 MDS study should be expanded in the interests of obtaining an accurate quantification of cost responsibility, and thus the prior categories of costs qualifying for inclusion in the MDS methodology were incomplete. The record in this case contains a more thorough, accurate assessment of costs necessary to provide the minimum level of service to any account. Evidence notes that "the refined MDS analysis stands on its own merits for full cost causation acknowledgement." Vogt, p. 26:17-18.

According to the NARUC *Electric Utility Cost Allocation Manual:*

> When the utility installs distribution plant to provide service to a customer and to meet the individual customer's peak demand requirements, the utility must classify distribution plant data separately into demand- and customer-related costs. (NARUC Electric Utility Cost Allocation Manual, Jan. 1992, p. 90)

The full MDS methodology more accurately reflects cost causation than would a 50 percent reduction in costs classified as customer related. Nevertheless, the 2021 Agreement further mitigates the impact of cost allocation and rate design changes, so that full implementation of MDS would not occur until January 2025, at the earliest. In light of the fact that the Parties had conceptually agreed to 100 percent implementation of MDS in 2013, but comprehensive implementation nonetheless has been deferred until 2025, its execution effectively will have been subject to a dozen years of transition.

5b. Explain in detail the difference between the full MDS and the one-half of the MDS methodology.

A. The difference between full MDS in the 2021 Agreement and half MDS embodied in the direct case in this Docket, as noted above, is not a change in methodology. In either instance, the same concept is used to classify costs as customer-related or demand-related. The only difference is that when the half MDS methodology is employed, the weighting assigned to customer-related costs for the affected distribution plant accounts (poles, lines, transformers) is reduced by 50 percent, making the proportion classified on a demand basis correspondingly greater.

5c. Please discuss which rate classes (residential/small commercial vs. larger commercial/industrial) are negatively impacted by the proposed full MDS methodology compared to the methodology used in the MFRS, by shifting target revenue requirements to the rate class away from other rate classes.

A. In general, because the full MDS method will allocate all customer-related costs on a customer basis (rather than half on a customer basis and half on a demand basis), the full MDS methodology will appropriately allocate a greater share of distribution costs to residential and small commercial customer classes than would occur if half of the MDS allocation were used. However, it is important to note that "full MDS" will not be reflected in customers' bills as a result of the 2021 Agreement. While 100 percent attribution of all MDS costs is utilized under the 2021 Agreement class cost-of-service calculations, the settlement applied mitigation to the class revenue allocations used to develop rates and as discussed in the company's response to Request No. 5a, above. Consequently, from a revenue requirements perspective "full MDS" has not been instituted during the Docket No. 20210034-EI rate period. In fact, the originally requested revenue requirements, if allocated using 12 CP and 50 percent MDS, would have increased residential class cost attribution by about $187 million at a parity ratio of only 94 percent (see Revised Schedule E-8, p. 1, line 2, Col. G).

It should be noted that whether any rate class is "negatively impacted" by a particular cost allocation technique or method is relative. If it is accepted that the Full MDS methodology more accurately allocates costs to rate classes, then varying from that method can accurately be said to "negatively impact" the classes toward which cost responsibility is shifted by the half MDS method. The goal of cost allocation is widely recognized as allocating cost responsibility as closely as possible to cost causation, so that the resulting rates will provide better price signals and will also be fairer to the customers who cause and do not cause costs to be incurred.

6. Please provide a comparison, using the 2022 revenue increase proposed in the Settlement, showing what target revenue requirements for each rate class would be under the cost-of-service used in the MFRs (12 CP and 1/13 AD, one-half of the MDS methodology) vs. the Settlement. Also, show the target revenue requirements difference in dollars and percent difference.

A. Please see the table below for base rate impact.

Rate Class	Settlement Rev. Req. Increase ($000)	Settlement Parity %	Settlement 12CP&1/13 Increase ($000)	12CP &1/13 Parity %	Rev Req Diff ($000)	Rev Req Diff (%)
RS	106,779	87	117,197	100	10,418	9.8
GS	14,450	122	3,349	100	(11,101)	(76.8)
GSD	(9,587)	103	16,826	100	26,413	275.5
GSLDPR	(1,009)	134	(509)	100	500	49.5
GSLDSU	(594)	150	(1,900)	100	(1,306)	(219.8)
LG EGY	608	288	515	100	(93)	(15.2)
LS FAC	12,033	229	(12,800)	100	(24,833)	(206.3)
TOTAL	122,680	100	122,678	100	2	(0.0)

7. Please calculate and state the residential basic service charge and base energy charges if the Settlement increase for 2022 had been based on the cost-of-service methodology as used in the MFRs (12 CP and 1/13 AD, one-half of the MDS methodology).

A. Please see attached.

FLORIDA PUBLIC SERVICE COMMISSION

EXPLANATION: For each rate, calculate typical monthly bills for present rates and proposed rates.

COMPANY: TAMPA ELECTRIC COMPANY

DOCKET No. 20210034 EI

Type of data shown:
XX Projected Test year Ended 12/31/2022
Projected Prior Year Ended 12/31/2021
Historical Prior Year Ended 12/31/2020
Witness: W. R. Ashburn

RS - RESIDENTIAL SERVICE

Line	RATE SCHEDULE RS (1)	(2)	BILL UNDER PRESENT RATES (3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	BILL UNDER PROPOSED RATES (11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)	INCREASE (20)	(21)	COSTS IN CENTS/KWH (22)	(23)
		TYPICAL	BASE	FUEL	ECCR	CAPACITY	ECRC	SPPCRC	GRT	TOTAL	BASE	FUEL	ECCR	CAPACITY	ECRC	Clean Energy	SPPCRC	GRT	TOTAL	DOLLARS	PERCENT	PRESENT	PROPOSED
No.	KW	KWH	RATE	CHARGE	CHARGE	CHARGE	CHARGE	CHARGE	CHARGE		RATE	CHARGE	CHARGE	CHARGE	CHARGE	Trans. Mech	CHARGE	CHARGE		(16)-(9)	(17)/(9)	(9)/(2)*100	(16)/(2)*100
1	0	-	$ 15.05	$ -	$ -	$ -	$ -		$ 0.39	$ 15.44	$ 21.29	$ -	$ -	$ -	$ -						0.0%	-	-
2																							
3	0	100	$ 20.28	$ 2.86	$ 0.17	$ 0.00	$ 0.27	$ 0.24	$ 0.61	$ 24.42	$ 27.17	$ 2.86	$ 0.17	$ 0.00	$ 0.27	$ 0.44	$ 0.24	$ 0.80	$ 31.94	$ 7.52	30.8%	24.42	31.94
4																							
5	0	250	$ 28.11	$ 7.14	$ 0.42	$ 0.01	$ 0.67	$ 0.60	$ 0.95	$ 37.89	$ 35.98	$ 7.14	$ 0.42	$ 0.01	$ 0.67	$ 1.10	$ 0.60	$ 1.18	$ 47.09	$ 9.20	24.3%	15.16	18.84
6																							
7	0	500	$ 41.18	$ 14.28	$ 0.83	$ 0.01	$ 1.35	$ 1.20	$ 1.51	$ 60.34	$ 50.68	$ 14.28	$ 0.83	$ 0.01	$ 1.35	$ 2.20	$ 1.20	$ 1.81	$ 72.35	$ 12.00	19.9%	12.07	14.47
8																							
9	0	750	$ 54.24	$ 21.42	$ 1.25	$ 0.02	$ 2.02	$ 1.79	$ 2.07	$ 82.80	$ 65.37	$ 21.42	$ 1.25	$ 0.02	$ 2.02	$ 3.30	$ 1.79	$ 2.44	$ 97.60	$ 14.80	17.9%	11.04	13.01
10																							
11	0	1,000	$ 67.30	$ 28.56	$ 1.66	$ 0.02	$ 2.69	$ 2.39	$ 2.63	$ 105.25	$ 80.06	$ 28.56	$ 1.66	$ 0.02	$ 2.69	$ 4.41	$ 2.39	$ 3.07	$ 122.86	$ 17.61	16.7%	10.53	12.29
12																							
13	0	1,250	$ 82.86	$ 38.20	$ 2.08	$ 0.03	$ 3.36	$ 2.99	$ 3.32	$ 132.83	$ 97.25	$ 38.20	$ 2.08	$ 0.03	$ 3.36	$ 5.51	$ 2.99	$ 3.83	$ 153.24	$ 20.41	15.4%	10.63	12.26
14																							
15	0	1,500	$ 98.43	$ 47.84	$ 2.49	$ 0.03	$ 4.04	$ 3.59	$ 4.01	$ 160.42	$ 114.45	$ 47.84	$ 2.49	$ 0.03	$ 4.04	$ 6.61	$ 3.59	$ 4.59	$ 183.62	$ 23.21	14.5%	10.69	12.24
16																							
17	0	2,000	$ 129.55	$ 67.12	$ 3.32	$ 0.04	$ 5.38	$ 4.78	$ 5.39	$ 215.58	$ 148.83	$ 67.12	$ 3.32	$ 0.04	$ 5.38	$ 8.81	$ 4.78	$ 6.11	$ 244.39	$ 28.81	13.4%	10.78	12.22
18																							
19	0	3,000	$ 191.80	$ 105.68	$ 4.98	$ 0.06	$ 8.07	$ 7.17	$ 8.15	$ 325.91	$ 217.60	$ 105.68	$ 4.98	$ 0.06	$ 8.07	$ 13.22	$ 7.17	$ 9.15	$ 365.92	$ 40.02	12.3%	10.86	12.20
20																							
21	0	5,000	$ 316.30	$ 182.80	$ 8.30	$ 0.10	$ 13.45	$ 11.95	$ 13.66	$ 546.56	$ 355.14	$ 182.80	$ 8.30	$ 0.10	$ 13.45	$ 22.03	$ 11.95	$ 15.22	$ 608.99	$ 62.43	11.4%	10.93	12.18

Line		PRESENT	PROPOSED
22			
23			
24		PRESENT	PROPOSED
25	BASIC SERVICE CHARGE	15.05 $/Bill	21.29 $/Bill
26	DEMAND CHARGE	- $/KW	- $/KW
27	ENERGY CHARGE		
28	0 - 1,000 KWH	5.225 ¢/kWH	5.877 ¢/kWH
29	Over 1,000 KWH	6.225 ¢/kWH	6.877 ¢/kWH
30	FUEL CHARGE		
31	0 - 1,000 KWH	2.856 ¢/kWH	2.856 ¢/kWH
32	Over 1,000 KWH	3.856 ¢/kWH	3.856 ¢/kWH
33	CONSERVATION CHARGE	0.166 ¢/kWH	0.166 ¢/kWH
34	CAPACITY CHARGE	0.002 ¢/kWH	0.002 ¢/kWH
35	CLEAN ENERGY TRANSITION MECHANISM		0.441 ¢/kWH
36	ENVIRONMENTAL CHARGE	0.269 ¢/kWH	0.269 ¢/kWH
37	STORM PROTECTION PLAN	0.239 ¢/kWH	0.239 ¢/kWH
38			

39 Note: Present and proposed cost recovery clause factors are the approved January 2021 factors.

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8. Referring to Exhibit K of the Settlement, please provide the same table with a column added for each year to show the increase in percent to the rate classes and explain how the GBRA year 2 and year 3 increases were allocated to the rate classes.

A. Please see attached.

	2022 Adjusted Revenues	Year 1 Total Increase	Year 2 GBRA Increase	Year 3 GBRA Increase	Year 2 GBRA Increase in %	2023 (Year 2) Total Revenue Requirement	Year 3 GBRA Increase in %	2024 (Year 3) Total Revenue Requirement
RS	$773,680	$149,386	$70,116	$16,699	9.06%	$843,796	1.98%	$860,495
GS	$81,788	$18,278	$8,579	$2,043	10.49%	$90,367	2.26%	$92,410
RS & GS Combined	$855,468	$167,664	$78,695	$18,743	9.20%	$934,163	2.01%	$952,906
GSD	$300,643	$8,996	$4,223	$1,006	1.40%	$304,866	0.33%	$305,872
GSLDPR	$41,433	$1,231	$578	$138	1.40%	$42,011	0.33%	$42,149
GSLDSU	$23,350	$694	$326	$78	1.40%	$23,676	0.33%	$23,754
LSENERGY	$3,296	$610	$286	$68	8.68%	$3,582	1.90%	$3,650
LSFACILITIES	$65,750	$12,033	$5,648	$1,345	8.59%	$71,398	1.88%	$72,743
FPSC JURIS	$1,289,940	$191,228	$89,755	$21,377	6.96%	$1,379,695	1.55%	$1,401,072

Note 1: The Year 1 Total Increase amounts include the CETM and base revenue increase.
Note 2: The Year 2 and Year 3 GBRA allocation to rate class is based on the revenue allocation shown in the Year 1 Total Increase
Note 3: The percent increase for Year 2 is based on the 2022 Adjusted Revenues, the percent increase for Year 3 is based on the 2023 (yr 2) Total Revenue Requirement.