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

July 24, 2020

VIA: ELECTRONIC FILING

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

Re: Storm Protection Plan Cost Recovery Clause; Docket No. 20200092-EI

Dear Mr. Teitzman:

Attached for filing in the above docket is Tampa Electric Company's Petition to the Commission for approval of the company's costs associated with its 2020-2029 Storm Protection Plan.

Thank you for your assistance in connection with this matter.

Sincerely,

Malcolm N. Means

Malcolm N. Means

MNM/bmp
Attachment

cc: All Parties of Record (w/attachment)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Storm Protection Plan Cost Recovery Clause	)))	DOCKET NO. 20200092-EI FILED: July 24, 2020

PETITION OF TAMPA ELECTRIC COMPANY

Tampa Electric Company ("Tampa Electric" or "company"), hereby petitions the Commission for approval of the company's costs associated with its 2020-2029 Storm Protection Plan, and in support thereof, says:

I. Preliminary Information

1. The Petitioner's name and address are:

Tampa Electric Company
702 North Franklin Street
Tampa, Florida 33602

2. Any pleading, motion, notice, order or other document required to be served upon Tampa Electric or filed by any party to this proceeding shall be served upon the following individuals:

James D. Beasley
jbeasley@ausley.com
J. Jeffry Wahlen
jwahlen@ausley.com
Malcolm N. Means
mmeans@ausley.com
Ausley McMullen
Post Office Box 391
Tallahassee, FL 32302
(850) 224-9115
(850) 222-7560 (fax)

Paula K. Brown
regdept@tecoenergy.com
Manager, Regulatory Coordination
Tampa Electric Company
Post Office Box 111
Tampa, FL 33601
(813) 228-1444
(813) 228-1770 (fax)

3. Tampa Electric is an investor-owned public utility subject to the Commission's jurisdiction pursuant to Chapter 366, Florida Statutes, and is a wholly owned subsidiary of Emera, Inc.

4. Tampa Electric serves almost 800,000 retail customers in Hillsborough and portions of Polk, Pinellas and Pasco Counties, Florida.

5. This petition is filed consistent with Rule 28-106.201, F.A.C. The agency affected is the Florida Public Service Commission, located at 2540 Shumard Oak Boulevard, Tallahassee, Florida, 32399. This Petition represents an original proceeding and does not involve reversal or modification of an agency decision or any proposed agency action.

II. Storm Protection Plan Cost Recovery Clause – Rule 25-6.031

6. Pursuant to Rule 25-6.031, once a utility has filed a Transmission and Distribution Storm Protection Plan, the utility may file a petition for recovery of associated costs through the Storm Protection Plan Cost Recovery Clause ("SPPCRC"). *See* R. 25-6.031(2), F.A.C.

7. This Petition includes all of the information required by Rule 25-6.031(7), except that it does not include a final true-up for the previous year, an estimated true-up for the current year, and a true-up of variances because this is the first annual Storm Protection Plan Cost Recovery Clause docket. *See* R. 25-6.031(a)-(b) and (d), F.A.C.

III. Statement on Disputed Issues of Material Fact

8. In compliance with paragraph (2)(d) of Rule 28-106.201, F.A.C., Tampa Electric states that it is not aware of any disputed issues of material fact at this time but acknowledges the

possibility that the Office of Public Counsel and other parties could assert disputed issues of material fact during this proceeding.

IV. Statement of Ultimate Facts Alleged and Providing the Basis for Relief

Tampa Electric's Storm Protection Plan

9. On April 10, 2020, Tampa Electric filed its 2020-2029 Transmission and Distribution Storm Protection Plan in Commission Docket No. 20200067-EI. Tampa Electric's Petition, therefore, is timely and proper under Rule 25-6.031(2).

10. Tampa Electric's Storm Protection Plan is comprised of eight Storm Protection Programs. The company is not seeking cost recovery for the Legacy Storm Hardening Initiatives Program through this clause filing. The company hereby seeks cost recovery for activities associated with the other seven Storm Protection Programs. These activities are consistent with the company's Plan.

SPPCRC Testimony

11. The testimony of Mark R. Roche, attached, presents for Commission approval: (1) the calculation of the January 2020 through December 2020 Storm Protection Plan actual/estimated amounts to be recovered in the January 2021 through December 2021 projection period; (2) the calculation of the January 2021 through December 2021 Storm Protection Plan projected amounts to be recovered in the January 2021 through December 2021 projection period; and (3) the proposed 2021 SPPCRC cost recovery factors.

12. The testimony of David L. Plusquellic, attached, describes these programs and provides specific detail regarding the work actually performed in 2020 and projected to be performed in the remainder of 2020 and in 2021 for these programs. This detail includes costs, a

description of the work to be performed, and an explanation of how the activities are consistent with Tampa Electric's Storm Protection Plan.

13. The testimony of A. Sloan Lewis, attached, describes the annual revenue requirements associated with the company's actual and projected Storm Protection Plan activities, and explains that the revenue requirements were developed with cost estimates for each of the SPP Programs plus depreciation and return on SPP assets as outlined in Rule 25-6.031, F.A.C. The testimony of A. Sloan Lewis also describes the steps taken by Tampa Electric to promote transparency and to avoid double recovery as required by Section 366.96(8) of the Florida Statutes. Her testimony also discusses how the applicability and effect of the 2020 Settlement Agreement approved by this Commission in Docket No. 20200145.

14. The testimony of William R. Ashburn, attached, describes the appropriate revenue allocation and rate design methodologies to developing this factor.

15. The company does not propose Storm Protection Projects for the Vegetation Management and Infrastructure Inspection Programs because they are not comprised of individual projects and the company does not propose any projects under the Substation Extreme Weather Hardening Program in 2020 or 2021, but instead plans to perform a study to further analyze this program.

16. The company seeks cost recovery for projects associated with four Storm Protection Programs. The following table sets out the Programs for which the company plans to initiate projects in 2020 and 2021 as well as the number of projects planned for each of those years.

Program	2020 Projects	2021 Projects
Distribution Lateral Undergrounding	134	516
Transmission Asset Upgrades	21	37
Distribution Overhead Feeder Hardening	13	27
Transmission Access Enhancement	0	18

17. Tampa Electric also seeks recovery of certain common costs that cannot be attributed to a specific Program. These represent the incremental costs associated with developing the company's Storm Protection Plan, some of which were incurred before the Plan was filed on April 10, 2020.

Storm Protection Plan Cost Recovery

18. During the period January through December 2020, the company anticipates incurring expenses of $16,435,191. (See Exhibit No. MRR-1; Schedule P-3).

19. For the forthcoming cost recovery period January through December 2021, Tampa Electric projects its total incremental storm protection plan costs to be $33,908,399. (See Exhibit No. MRR-1; Schedule P-2). Tampa Electric's total actual/estimated 2020 and projected 2021 expenditures for the projection period are estimated to be $39,460,120 which includes a $10,400,000 adjustment for Tampa Electric's 2020 Settlement Agreement, Federal Energy Regulatory Commission transmission jurisdictional separation, and revenue tax factor. Utilizing the rate design and cost allocation as put forth in Docket No. 20130040-EI, the required storm protection plan cost recovery factors are as follows:

Rate Schedule	Cost Recovery Factors (cents per kWh)
RS	0.239
GS and CS	0.251
GSD Optional–Secondary	0.168
GSD Optional–Primary	0.166
GSD Optional–Subtransmission	0.164
LS-1, LS-2	0.354

Rate Schedule	Cost Recovery Factors (dollars per kW)
GSD-Secondary	0.72
GSD-Primary	0.71
GSD-Subtransmission	0.71
SBF–Secondary	0.72
SBF–Primary	0.71
SBF–Subtransmission	0.71
IS-Primary	0.17
IS–Subtransmission	0.17

(See Exhibit No. MRR-1; Schedule P-1, Page 1 of 1)

V. Relief Requested

20. Tampa Electric is not aware of any disputed issues of material fact regarding the matters in this petition.

21. Tampa Electric respectfully requests that the Commission find that the above actual costs are prudent, that the company's estimated Storm Protection Plan costs are reasonable, and that the company's cost recovery factors are consistent with Rule 25-6.031, F.A.C.

WHEREFORE, Tampa Electric Company requests the Commission's approval of the company's actual/estimated 2020 and projected 2021 projected storm protection plan cost recovery charges to be collected during the period January 1, 2021 through December 31, 2021.

DATED this 24th day of July 2020.

Respectfully submitted,

Malcolm N. Means

JAMES D. BEASLEY
jbeasley@ausley.com
J. JEFFRY WAHLEN
jwahlen@ausley.com
MALCOLM N. MEANS
mmeans@ausley.com
Ausley McMullen
Post Office Box 391
Tallahassee, Florida 32302
(850) 224-9115

ATTORNEYS FOR TAMPA ELECTRIC COMPANY

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true and correct copy of the foregoing Petition, filed on behalf of Tampa Electric Company, has been furnished by electronic mail on this 24th day of July 2020 to the following:

Ms. Rachael Dziechciarz
Mr. Charles Murphy
Attorneys
Office of General Counsel
Florida Public Service Commission
Room 390L – Gerald L. Gunter Building
2540 Shumard Oak Boulevard
Tallahassee, FL 32399-0850
RDziechc@psc.state.fl.us
CMurphy@psc.state.fl.us

Mr. J. R. Kelly
Mireille Fall-Fry
Office of Public Counsel
111 West Madison Street – Room 812
Tallahassee, FL 32399-1400
kelly.jr@leg.state.fl.us
fall-fry.mireille@leg,state,fl.us

Dianna M. Triplett
Duke Energy
299 First Avenue North
St. Petersburg, FL 33701
Dianne.triplett@duke-energy.com

Matthew R. Bernier
Duke Energy
106 Eat College Avenue, Suite 800
Tallahassee, FL 32301
Matt.Bernier@duke-energy.com
Robert.Pickels@duke-energy.com
FLRegulatoryLegal@duke-energy.com

Mr. Ken Hoffman
Florida Power & Light Company
134 West Jefferson Street
Tallahassee, FL 32301-1713
Ken.hoffman@fpl.com

Mr. Mike Cassel
Florida Power Utility Company
208 Wildlight Ave.
Yulee, FL 32097
mcassel@fpuc.com

Mark Bubriski
Gulf Power Company
134 West Jefferson Street
Tallahassee, FL 32301
Mark.bubriski@nexteraenergy.com

Russell A. Badders
Gulf Power Company
One Energy Place
Pensacola, FL 32520
Russell.Badders@nexteraenergy.com

James W. Brew
Laura Wynn Baker
c/o Stone Law Firm
1025 Thomas Jefferson Street, NW
Suite 800 West
Washington, DC 20007-5201
jbrew@smxblaw.com
lwb@smxblaw.com

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

Derrick Price Williamson
Spilman Thomas & Battle, PLLC
1100 Bent Creek Blvd., Suite 101
Mechanicsburg, PA 17050
dwilliamson@spilmanlaw.com

John Burnett
Christopher Wright
Jason Higginbotham
Florida Power & Light Company
700 Universe Blvd.
Juno Beach, FL 3408-0420
Christopher.Wright@fpl.com
John.T.Burnett@fpl.com
Jason.Higginbotham@fpl.com

Jon C. Moyle
Karen Putnal
Moyle Law Firm
118 North Gadsden Street
Tallahassee, FL 32301
jmoyle@moylelaw.com
kputnal@moylelaw.com
mqualls@moylelaw.com

Katie Chiles Ottenweller
Vote Solar
151 Estoria Street SE
Atlanta GA 30316
katie@votesolar.org

Zayne Smith
AARP
360 Central Ave., Suite 1750
St. Petersburg, FL 33701
zsmith@aarp.org

Malcolm N. Means

ATTORNEY

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 20200092-EI

IN RE: STORM PROTECTION PLAN COST RECOVERY CLAUSE

TESTIMONY AND EXHIBIT

OF

MARK R. ROCHE

FILED: July 24, 2020

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

MARK R. ROCHE

Q. Please state your name, address, occupation and employer.

A. My name is Mark R. Roche. My business address is 702 North Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "the company") as Manager, Regulatory Rates in the Regulatory Affairs Department.

Q. Please provide a brief outline of your educational background and business experience.

A. I graduated from Thomas Edison State College in 1994 with a Bachelor of Science degree in Nuclear Engineering Technology and from Colorado State University in 2009 with a Master's degree in Business Administration. My work experience includes twelve years with the US Navy in nuclear operations as well as twenty-two years of electric utility experience. My utility work has included various positions in Marketing and Sales, Customer Service, Distributed Resources, Load Management, Power Quality, Distribution Control Center Operations, Meter Department, Meter Field Operations, Service Delivery, Revenue Assurance, Commercial and Industrial Energy Management Services, and Demand Side Management ("DSM") Planning and Forecasting. In my current position, I am responsible for Tampa Electric's Energy Conservation Cost Recovery ("ECCR") Clause and Storm Protection Plan Cost Recovery Clause ("SPPCRC").

Q. Have you previously testified before the Florida Public Service Commission ("Commission")?

A. Yes. I have testified before this Commission on conservation and load management activities, DSM goal and plan approval dockets and other ECCR dockets.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to present, for Commission approval: (1) the calculation of the January 2020 through December 2020 Storm Protection Plan actual/estimated amounts to be recovered in the January 2021 through December 2021 projection period; (2) the calculation of the January 2021 through December 2021 Storm Protection Plan projected amounts to be recovered in the January

2021 through December 2021 projection period; and (3) the proposed 2021 SPPCRC cost recovery factors. I will describe the process used to develop the company's SPPCRC projections, which complies with Rule 25-6.031, Florida Administrative Code ("F.A.C.") and Section 366.96, Florida Statutes. The projected 2021 SPPCRC factors have been calculated based on the current approved allocation methodology.

Q. Did you prepare any exhibits in support of your testimony?

A. Yes. Exhibit No. MRR-1 was prepared under my direction and supervision. Exhibit No. MRR-1 includes Schedules P-1 through P-4 and associated data which support the development of the storm protection plan cost recovery factors for January through December 2021 using the Commission approved cost of service allocation factors that were approved in Tampa Electric's 2013 Cost of Service Study prepared in Docket No. 20130040-EI, which was used for the company's current (non-SoBRA) base rate design.

Q. Does the Exhibit No. MRR-1 meet the requirements of Rule 25-6.031(b), which requires the actual/estimated filing to include revenue requirements based on a comparison of current year actual/estimated costs and the previously-filed projected costs and revenue requirements for the current year?

A. Yes, it does, but with the caveat that there were no previously filed projected costs for 2020 because this is the initial SPPCRC filing.

Q. Does the Exhibit No. MRR-1 meet the requirement of Rule 25-6.031(b) to include a description of the work projected to be performed during the current year for each program and project in the utility's cost recovery petition?

A. Yes, it does.

Q. Does the Exhibit No. MRR-1 meet the requirements of Rule 25-6.031(c), which requires the projected year to include costs and revenue requirements for the subsequent year for each program filed in the company's cost recovery petition?

A. Yes, it does.

Q. Does the Exhibit No. MRR-1 meet the requirements of Rule 25-6.031(c), which requires the projected year to include identification of each of the utility’s Storm Protection Plan programs for which costs will be incurred during the subsequent year, including a description of the work projected to be performed during such year, for each program in the utility’s cost recovery petition?

A. Yes, it does.

Q. Will any other witnesses testify in support of Tampa Electric’s Proposed Storm Protection Plan Cost Recovery Clause?

A. Yes. Three additional witnesses will testify.

David L. Plusquellic will testify regarding the company’s storm protection programs and provide specific detail regarding the work actually performed in 2020 and projected to be performed in the remainder of 2020 and in 2021 for each Storm Protection Program in the company’s cost recovery petition. This detail includes costs, a description of the work to be performed, and an explanation how the activities are consistent with Tampa Electric’s Storm Protection Plan.

A. Sloan Lewis will testify regarding the estimated annual jurisdictional revenue requirements associated with the company's actual and projected Storm Protection Plan activities and the steps taken by Tampa Electric to promote transparency and ensure that the costs (i.e., O&M expenses and return and depreciation expense on capital projects) the company will recover through the SPPCRC do not include costs being recovered through the utility's existing base rates or any other cost recovery mechanism as required by Rule 25-6.031(6)(b), F.A.C., and Section 366.96(8), Florida Statutes. She will also discuss how the revenue requirements were adjusted for the SPPCRC in accordance with Tampa Electric's 2020 Settlement Agreement that was approved by the Commission on June 9, 2020.

William R. Ashburn will testify regarding the appropriate revenue allocation and rate design methodologies to develop the resulting SPPCRC factors. His testimony will also include the associated rate calculations of the $15 million dollar base rate adjustment that will occur beginning simultaneously with the implementation of the SPPCRC factors in January 2021 as approved in Tampa Electric's Settlement Agreement that was approved by the Commission on June 9, 2020.

Process to Develop the Company's SPPCRC Projections

Q. What costs are encompassed in Tampa Electric's 2020 annual estimated/actual filing?

A. Tampa Electric developed its 2020 annual estimated/actual true-up filing showing actual and projected common costs, individual program costs based upon six months of actuals and six months of estimates.

Q. Will you please describe the Storm Protection Plan costs that Tampa Electric projects it will incur during the period January through December 2020?

A. The actual costs incurred by Tampa Electric through June 2020 and projected for July through December 2020 are $16,435,191. A summary of these costs and estimates are fully detailed in Exhibit No. MRR-1, Storm Protection Plan Costs Projected – Actual and Projected, pages 41 through 56.

Q. Does this 2020 actual and projected amount include the reduction of the $10.4 million adjustment as included in Tampa Electric's Settlement Agreement that was approved by the Commission on June 9, 2020. If not, what is the amount?

A. No, the 2020 actual and projected amount that includes the $10.4 million dollar reduction as per the 2020 Settlement is $6,035,191.

Q. Has Tampa Electric proposed any new or modified Storm Protection Programs for SPPCRC cost recovery for the period January through December 2021 that were not included in the company's proposed Storm Protection Plan that is currently being reviewed for approval by the Florida Public Service Commission in Docket No. 20200067-EI?

A. No, at this time Tampa Electric is not proposing any new or modified programs for SPPCRC cost recovery for the period January through December 2021.

Q. Will you please describe the Storm Protection Plan costs that Tampa Electric projects it will incur during the period of January through December 2021?

A. Tampa Electric has estimated that the total storm protection costs during the 2021 period will be $33,908,399. A summary of these costs and estimates are fully detailed in Exhibit No. MRR-1, Storm Protection Plan Costs - Projected, pages 20 through 40.

Q. How were the cost projections developed?

A. As explained in the testimony of David L. Plusquellic and A. Sloan Lewis, the projected costs were developed with cost estimates for each of the SPP Programs plus depreciation and return on SPP assets, as outlined in Rule 25-6.031(6), F.A.C., the SPPCRC Rule.

Q. Do the actual and projected costs include any costs that are currently recovered in base rates?

A. No, as explained in A. Sloan Lewis' testimony, the company has entered into the 2020 settlement agreement that was approved by the Commission on June 9, 2020 which will ensure that no costs recovered through the SPPCRC are also recovered through base rates.

Q. What cost allocation methodology was used to prepare the company's proposed SPPCRC cost recovery factors?

A. As explained in William R. Ashburn's testimony, the company itemized the Storm Protection Program costs and identified those costs as either substation, transmission, or distribution. Each of those functionalized costs was then allocated to the appropriate rate class using the allocation factors for that function.

Q. What allocation factors were utilized?

A. Tampa Electric utilized the allocation factors from the company’s 2013 Cost of Service Study prepared in Docket No. 20130040-EI, which was used for the company’s current (non-SoBRA) base rate design.

Q. Were there any other needed adjustments to the total costs that Tampa Electric is seeking to recover in the SPPCRC?

A. Yes, the Storm Protection Programs associated with the Transmission System also needed to be adjusted to reflect Tampa Electric’s Open Access Transmission Tariff. These costs were reduced by the current Federal Energy Regulatory Commission Jurisdictional Factor to recognize that this portion of costs was already being recovered.

Q. What were the total proposed storm protection costs for the period January 2020 through December 2021 prior to and after using the appropriate jurisdictional factor to recognize those transmission costs?

A. The total proposed storm protection costs for the period January 2020 through December 2021 prior to the jurisdictional separation for transmission was $39,943,590. After performing the transmission jurisdictional separation, the total costs are $39,431,730. After performing the transmission jurisdictional separation, this value is adjusted by the revenue tax factor to obtain the total proposed costs that will be sought for approval through the SPPCRC in 2021. The details of these calculations are included in my Exhibit No. MRR-1, 2021 Billing Determinants and Allocation Factors and Summary of Cost Recovery Clause Calculation, pages 18 and 19.

SPPCRC Factors for 2021

Q. Please summarize the total proposed storm protection costs for the period January 2020 through December 2021 and the annualized recovery factors applicable for the period January through December 2021.

A. Tampa Electric has estimated that the total storm protection jurisidictionalized costs, including adjustment by the revenue tax factor during the period will be $39,460,120. The January through December 2021 cost recovery factors allocated based upon the company's

2013 Cost of Service Study prepared in Docket No. 20130040-EI, which was used for the company's current (non-SoBRA) base rate for firm retail rate classes are as follows:

Rate Schedule	**Cost Recovery Factors (cents per kWh)**
RS	0.239
GS and CS	0.251
GSD Optional – Secondary	0.168
GSD Optional – Primary	0.166
GSD Optional – Subtransmission	0.164
LS-1 and LS-2	0.354

Rate Schedule	**Cost Recovery Factors (dollars per kW)**
GSD – Secondary	0.72
GSD – Primary	0.71
GSD – Subtransmission	0.71
SBF – Secondary	0.72
SBF – Primary	0.71
SBF – Subtransmission	0.71
IS - Primary	0.17
IS - Subtransmission	0.17

Exhibit No. MRR-1, Summary of Cost Recovery Clause Calculation, page 19 detail these estimates.

Q. Has Tampa Electric complied with the SPPCRC cost allocation methodology that used the allocation factors from Tampa Electric's 2013 Cost of Service Study prepared in Docket No. 20130040-EI, which was used for the company's current (non-SoBRA) base rate design?

A. Yes, it has.

Q. Are the factors that you provided above the incremental increase that customers will see on their electric bills?

A. No, as described in the testimony of A. Sloan Lewis, the 2020 Settlement Agreement includes a reduction of $15 million from base rates that will start concurrently with the SPPCRC factors going onto customers' bills.

Q. How much will this $15 million reduction to base rates lower base customers rates? Please provide for residential, general service demand and interruptible service rates.

A. This $15 million reduction of base rates is detailed in the Exhibit of William R. Ashburn's testimony. The base rate reduction at secondary service for residential and general service demand and at primary service for interruptible service rates are as follows:

Rate Schedule	"Reduction" in Base Rates (cents per kWh)
RS	0.090

Rate Schedule	"Reduction" in Base Rates (dollars per kW)
GSD – Secondary	0.27
IS - Primary	0.06

Q. Going back to the SPPCRC clause factors that you are proposing, would you provide the electric bill impact for these same rate classes for a typical customer bill?

A. Yes, using the same typical bill assumptions that were provided in the company Storm Protection Plan filing, the typical monthly electric bill increases for residential, general service demand at secondary service and at primary service for an interruptible service class customer are as follows:

Residential customer using 1,000 kWh: $2.39

Commercial customer using 1,000 kW of Demand at 60 percent load factor: $722

Industrial customer using 10,000 kW of Demand at 60 percent load factor: $1,710

Q. Does this conclude your testimony?

A. Yes, it does.

EXHIBIT

OF

MARK R. ROCHE

STORM PROTECTION PLAN COSTS
PROJECTED

INDEX

TAMPA ELECTRIC COMPANY
STORM PROTECTION PLAN
BILLING DETERMINANTS AND ALLOCATION % BY RATE CLASS
JANUARY 2021 THROUGH DECEMBER 2021
PROJECTED

	BILLING DETERMINANTS		ALLOCATION FACTORS	
	MWh	**kW**	**DISTRIBUTION**	**TRANSMISSION**
RS (Tier 1, Tier 2, RSVP)	9,684,803		59.1870%	55.4154%
GS & CS	902,049		5.6709%	6.0893%
GSD, SBF		17,528,483	31.6709%	34.1821%
GSD Optional	360,212		1.5122%	1.6321%
IS		1,986,004	0.5405%	2.5863%
LS1, LS2	134,246		1.4185%	0.0948%
LTG-FAC	0		0.0000%	0.0000%

TRANSMISSION DEMAND SEPARATION FACTOR

FPSC Jurisdictional Factor	92.5292%
FERC Jurisdictional Factor	7.4708%

TAMPA ELECTRIC COMPANY
DOCKET NO. 20200092-EI
EXHIBIT NO. MRR-1
DOCUMENT NO. 2
WITNESS: ROCHE
PAGE 1 OF 1
FILED: 07/24/2020

Storm Protection Program	Function	SPPCRC Revenue Requirement	RS (Tier 1, Tier 2, RSVP)	GS & CS	GSD, SBF	GSD Optional	IS	LS1, LS2	LTG-FAC	Total
Capital										
Distribution Lateral Undergrounding	Dist	$4,501,574	$2,664,345.72	$255,281.87	$1,425,689.48	$68,072.58	$24,329.23	$63,855.12	0	$4,501,574.00
Transmission Asset Upgrades	Trans Retail	$1,545,849	$856,638.38	$94,131.44	$528,404.33	$25,229.79	$39,979.55	$1,465.76	0	$1,545,849.26
Substation Extreme Weather Protection	Dist	$0	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	0	$0.00
Distribution Overhead Feeder Hardening	Dist	$1,777,761	$1,052,203.05	$100,815.88	$563,033.10	$26,883.22	$9,608.10	$25,217.66	0	$1,777,761.00
Transmission Access Enhancements	Trans Retail	$24,300	$13,465.95	$1,479.70	$8,306.27	$396.60	$628.46	$23.04	0	$24,300.02
O&M										
Distribution Vegetation Management - planned	Dist	$23,219,170	$13,742,725.86	$1,316,746.80	$7,353,722.73	$351,119.17	$125,490.47	$329,365.45	0	$23,219,170.47
Transmission Vegetation Management - planned	Trans Retail	$3,270,537	$1,812,380.86	$199,152.91	$1,117,939.51	$53,378.41	$84,584.32	$3,101.09	0	$3,270,537.10
Transmission Asset Upgrades	Trans Retail	$816,005	$452,192.13	$49,688.99	$278,927.82	$13,318.00	$21,103.93	$773.73	0	$816,004.61
Substation Extreme Weather Protection	Dist	$250,000	$147,967.45	$14,177.37	$79,177.28	$3,780.49	$1,351.15	$3,546.27	0	$250,000.00
Distribution Overhead Feeder Hardening	Dist	$521,179	$308,469.98	$29,555.77	$165,062.07	$7,881.24	$2,816.77	$7,392.96	0	$521,178.78
Distribution Infrastructure Inspections	Dist	$1,003,600	$594,000.53	$56,913.62	$317,849.26	$15,176.39	$5,424.06	$14,236.13	0	$1,003,600.00
Transmission Infrastructure Inspections	Trans Retail	$682,935	$378,451.15	$41,585.99	$233,441.82	$11,146.18	$17,662.42	$647.55	0	$682,935.11
SPP Planning & Common	Dist	$1,818,819	$1,076,504.19	$103,144.27	$576,036.62	$27,504.10	$9,830.00	$25,800.07	0	$1,818,819.24
Total		$39,431,729.58	$23,099,345.24	$2,262,674.61	$12,647,590.28	$603,886.16	$342,808.47	$475,424.82	$0.00	$39,431,729.58
Revenue Tax Factor		1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	
Total with Revenue Tax Factor		$39,460,120.43	$23,115,976.77	$2,264,303.74	$12,656,696.54	$604,320.96	$343,055.29	$475,767.12	$0.00	$39,460,120.43
Billing Determinants			9,684,803	902,049	17,528,483	360,212	1,986,004	134,246	0	

After Taxes	**RS (Tier 1, Tier 2, RSVP)**	**GS & CS**	**GSD, SBF**	**GSD Optional**	**IS**	**LS1, LS2**	**LTG-FAC**
Charges (per kWh)	$0.002387	$0.002510		$0.001678		$0.003544	$0.000000
Charges (per kW)			$0.722065		$0.172736		

Clause Charges (per kWh)	**RS (Tier 1, Tier 2, RSVP)**	**GS & CS**		**GSD Optional**		**LS1, LS2**	**LTG-FAC**
Secondary	$0.002387	$0.002510		$0.001678		$0.003544	$0.000000
Primary				$0.001661			
Sub-Transmission				$0.001644			

Clause Charges (per kW)			**GSD, SBF**		**IS**		
Secondary			$0.722065				
Primary			$0.714844		$0.171009		
Sub-Transmission			$0.707623		$0.169282		

Tampa Electric Company
Storm Protection Plan Cost Recovery Clause (SPPCRC)
Initial Projection
Projected Period: January through December 2021

Summary of Projected Period Recovery Amount
(in Dollars)

Line		Demand ($)	Energy ($)	Total ($)
1.	Total Jurisdictional Revenue Requirements for the Projected Period			
a.	Vegetation Management O&M Programs (Form 2P, Lines 13.a thru 13.c)	$ 23,062,187	$ -	$ 23,062,187
b.	Asset Upgrade O&M Programs (Form 2P, Line 13.d)	$ 415,791	$ -	$ 415,791
c.	Substation Protection O&M Programs (Form 2P, Line 13.e)	$ 250,000	$ -	$ 250,000
d.	Overhead Feeder Hardening O&M Programs (Form 2P, Line 13.f)	$ 345,191	$ -	$ 345,191
e.	Transmission Access O&M Programs (Form 2P, Line 13.g)	$ -	$ -	$ -
f.	Infrastructure Inspections O&M Programs (Form 2P, Lines 13.h thru 13.i)	$ 1,541,593	$ -	$ 1,541,593
g.	Common SPP O&M Programs (Form 2P, Line 13.j)	$ 402,400	$ -	$ 402,400
h.	Distribution Lateral Undergrounding Capital Program (Form 3P, Line 1)	$ 4,342,580	$ -	$ 4,342,580
i.	Transmission Asset Upgrades Capital Program (Form 3P, Line 2)	$ 1,390,775	$ -	$ 1,390,775
j.	Substation Extreme Weather Capital Program (Form 3P, Line 3)	$ -	$ -	$ -
k.	Distribution Overhead Feeder Hardening Capital Program (Form 3P, Line 4)	$ 1,678,258	$ -	$ 1,678,258
l.	Transmission Access Enhancement Capital Program (Form 3P, Line 5)	$ 24,300	$ -	$ 24,300
m.	Total Projected Period Revenue Requirement	$ 33,453,075	$ -	$ 33,453,075
2.	Estimated True up of Over/(Under) Recovery for the Current Period (SPPCRC Form 1E, Line 4)	$ (5,986,696)	$ -	$ (5,986,696)
3.	Final True Up of Over/(Under) Recovery for the Prior Period (SPPCRC Form 1A, Line 5c)	$ -	$ -	$ -
4.	Jurisdictional Amount to Recovered/(Refunded) (Line 1m - Line 2 - Line 3)	$ 39,439,771	$ -	$ 39,439,771
5.	Jurisdictional Amount to Recovered/(Refunded) Adjusted for Taxes	$ 39,468,167	$ -	$ 39,468,167
	Revenue Tax Multiplier: 1.00072			

TAMPA ELECTRIC COMPANY
DOCKET NO. 20200092-EI
EXHIBIT NO. MRR-1
DOCUMENT NO. 3
WITNESS: ROCHE
PAGE 2 OF 21
FILED: 07/24/2020

Tampa Electric Company
Storm Protection Plan Cost Recovery Clause (SPPCRC)
Initial Projection
Projected Period: January through December 2021

Calculation of Annual Revenue Requirements for O&M Programs
(in Dollars)

Line	O&M Activities	T/D	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Total	Method of Classification Demand %	Method of Classification Energy %
1.	Vegetation Management Programs																
	1. Distribution Vegetation Management - Planned	D	1,566,001	1,566,051	1,565,901	1,677,112	1,677,011	1,677,011	1,677,111	1,677,161	1,677,011	1,677,110	1,677,010	1,677,160	19,791,650	100%	0%
	2. Transmission Vegetation Management - Planned	T	294,617	294,517	294,517	294,617	294,517	294,517	294,617	294,517	294,516	294,616	294,516	294,516	3,534,600	100%	0%
	3. Transmission Vegetation Management - ROW	T	-	-	-	-	-	-	-	-	-	-	-	-	0	100%	0%
1.a	Adjustments														0	100%	0%
1.b	Subtotal of Vegetation Management Programs		1,860,618	1,860,568	1,860,418	1,971,729	1,971,528	1,971,528	1,971,728	1,971,678	1,971,527	1,971,726	1,971,526	1,971,676	23,326,250	-	
2	Asset Upgrade Programs																
	1. Transmission Asset Upgrades	T	32,091	31,066	31,079	37,495	34,823	43,739	45,183	44,918	45,471	36,808	33,302	33,387	449,362	100%	0%
2.a	Adjustments														0	100%	0%
2.b	Subtotal of Asset Upgrade programs		32,091	31,066	31,079	37,495	34,823	43,739	45,183	44,918	45,471	36,808	33,302	33,387	449,362		
3	Substation Protection Programs																
	1. Substation Extreme Weather Protection	D	0	0	0	125,000	125,000	0	0	0	0	0	0	0	250,000	100%	0%
3.a	Adjustments														0	100%	0%
3.b	Subtotal of Substation Protection Programs		0	0	0	125,000	125,000	0	0	0	0	0	0	0	250,000		
4.	Overhead Feeder Hardening Programs																
	1. Distribution Overhead Feeder Hardening	D	8,530	17,228	45,423	51,539	60,769	39,940	15,969	23,368	20,291	21,043	20,189	20,903	345,191	100%	0%
4.a	Adjustments														0	100%	0%
4.b	Subtotal of Transmission Access Programs		8,530	17,228	45,423	51,539	60,769	39,940	15,969	23,368	20,291	21,043	20,189	20,903	345,191		
5.	Transmission Access Programs																
	1. Transmission Access Enhancement	T	0	0	0	0	0	0	0	0	0	0	0	0	0	100%	0%
5.a.	Adjustments														0	100%	0%
5.b.	Subtotal of Transmission Access Programs		0	0	0	0	0	0	0	0	0	0	0	0	0		
6.	Infrastructure Inspection Programs																
	1. Distribution Infrastructure Inspections	D	175,800	175,800	175,800	175,800	100,200	100,200	98,500	300	300	300	300	300	1,003,600	100%	0%
	2. Transmission Infrastructure Inspections	T	24,140	64,750	51,290	38,450	25,850	45,485	38,600	37,175	112,490	70,500	34,450	38,250	581,430	100%	0%
6.a.	Adjustments														0	100%	0%
6.b.	Subtotal of Infrastructure Inspection Programs		199,940	240,550	227,090	214,250	126,050	145,685	137,100	37,475	112,790	70,800	34,750	38,550	1,585,030		
7.	Common SPP Programs																
	1. Common O&M	D	32,150	43,150	32,550	32,450	34,350	32,250	32,150	32,550	32,150	34,350	32,150	32,150	402,400	100%	0%
7.a.	Adjustments														0	100%	0%
7.b.	Subtotal of Common SPP Programs		32,150	43,150	32,550	32,450	34,350	32,250	32,150	32,550	32,150	34,350	32,150	32,150	402,400		
8.	Total of O&M Programs		2,133,329	2,192,562	2,196,559	2,432,463	2,352,520	2,233,142	2,202,130	2,109,988	2,182,229	2,134,727	2,091,917	2,096,666	26,358,233	-	-
	a. Total Distribution O&M Programs		1,782,481	1,802,229	1,819,674	2,061,901	1,997,330	1,849,401	1,823,730	1,733,379	1,729,752	1,732,803	1,729,649	1,730,513	21,792,841		
	b. Total Transmission O&M Programs		350,848	390,333	376,886	370,562	355,190	383,741	378,400	376,610	452,477	401,924	362,268	366,153	4,565,392		
9.	Allocation of O&M Costs																
	a. Distribution O&M Allocated to Demand		1,782,481	1,802,229	1,819,674	2,061,901	1,997,330	1,849,401	1,823,730	1,733,379	1,729,752	1,732,803	1,729,649	1,730,513	21,792,841	-	
	b. Transmission O&M Allocated to Demand		350,848	390,333	376,886	370,562	355,190	383,741	378,400	376,610	452,477	401,924	362,268	366,153	4,565,392	-	
	c. Distribution O&M Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0		
	d. Transmission O&M Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0		
10.	Retail Jurisdictional Factors																
	a. Distribution Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000			
	b. Transmission Demand Jurisdictional Factor		0.9252920	0.9252920	0.9252920	0.9252920	0.9252920	0.9252920	0.9252920	0.9252920	0.9252920	0.9252920	0.9252920	0.9252920			
	c. Distribution Energy Jurisdictional Factor		0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000			
	d. Transmission Energy Jurisdictional Factor		0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000			
11.	Jurisdictional Revenue Requirements																
	a. Jurisdictional Distribution Demand Revenue Requirement		1,782,481	1,802,229	1,819,674	2,061,901	1,997,330	1,849,401	1,823,730	1,733,379	1,729,752	1,732,803	1,729,649	1,730,513	21,792,841		
	b. Jurisdictional Transmission Demand Revenue Requirement		324,637	361,172	348,729	342,878	328,654	355,073	350,130	348,474	418,673	371,897	335,204	338,798	4,224,321		
	c. Jurisdictional Distribution Energy Revenue Requirement		-	-	-	-	-	-	-	-	-	-	-	-	-		
	d. Jurisdictional Transmission Energy Revenue Requirement		-	-	-	-	-	-	-	-	-	-	-	-	-		
12.	Total Jurisdictional O&M Revenue Requirements		2,107,118	2,163,401	2,168,403	2,404,779	2,325,984	2,204,474	2,173,860	2,081,852	2,148,425	2,104,701	2,064,853	2,069,312	26,017,162	-	
13	Jurisdictional Demand Revenue Requirements by Program																
	a. Distribution Vegetation Management - Planned		1,566,001	1,566,051	1,565,901	1,677,112	1,677,011	1,677,011	1,677,111	1,677,161	1,677,011	1,677,110	1,677,010	1,677,160	19,791,650		
	b. Transmission Vegetation Management - Planned		272,607	272,514	272,514	272,607	272,514	272,514	272,607	272,514	272,513	272,606	272,513	272,513	3,270,537		
	c. Transmission Vegetation Management - ROW		0	0	0	0	0	0	0	0	0	0	0	0	0		
	d. Trans Asset Upgrade O&M Programs		29,693	28,745	28,757	34,694	32,221	40,472	41,807	41,562	42,074	34,058	30,814	30,893	415,791		
	e. Substation Protection O&M Programs		0	0	0	125,000	125,000	0	0	0	0	0	0	0	250,000		
	f. Overhead Feeder Hardening Programs		8,530	17,228	45,423	51,539	60,769	39,940	15,969	23,368	20,291	21,043	20,189	20,903	345,191		
	g. Transmission Access O&M Programs		0	0	0	0	0	0	0	0	0	0	0	0	0		
	h. Distr. Infrastructure Inspections		175,800	175,800	175,800	175,800	100,200	100,200	98,500	300	300	300	300	300	1,003,600		
	i. Trans. Infrastructure Inspections		22,337	59,913	47,458	35,577	23,919	42,087	35,716	34,398	104,086	65,233	31,876	35,392	537,993		
	j. Common SPP O&M		32,150	43,150	32,550	32,450	34,350	32,250	32,150	32,550	32,150	34,350	32,150	32,150	402,400		
			2,107,118	2,163,401	2,168,403	2,404,779	2,325,984	2,204,474	2,173,860	2,081,852	2,148,425	2,104,701	2,064,853	2,069,312	26,017,162		

Tampa Electric Company
Storm Protection Plan Cost Recovery Clause (SPPCRC)
Initial Projection
Projected Period: January through December 2021
Project Listing by Each O&M Program

Line	O&M Activities	T or D
1.	Vegetation Management O&M Programs	
1.1	Distribution Vegetation Management - Planned	
1.1.1	PRE - Dist Line - Tree Trimming - Planned	D
1.1.2	Dist SPP Supplemental	D
1.1.3	Dist SPP Mid-Cycle	D
1.2	Transmission Vegetation Management - Planned	
1.2.1	PRE - ROW Clearance	T
1.2.2	PRE - Trans Line - Tree Trimming/Removals - Planned	T
1.2.3	Trans SPP 69kV Reclamation	T
2.	Asset Upgrade O&M Programs	
2.1	Transmission Asset Upgrades	
2.1.1	SPP TAU - Circuit 230008	T
2.1.2	SPP TAU - Circuit 230010	T
2.1.3	SPP TAU - Circuit 230038	T
2.1.4	SPP TAU - Circuit 230003	T
2.1.5	SPP TAU - Circuit 230005	T
2.1.6	SPP TAU - Circuit 230004	T
2.1.7	SPP TAU - Circuit 230625	T
2.1.8	SPP TAU - Circuit 230021	T
2.1.9	SPP TAU - Circuit 230052	T
2.1.10	SPP TAU - Circuit 66024	T
2.1.11	SPP TAU - Circuit 230608	T
2.1.12	SPP TAU - Circuit 230603	T
2.1.13	SPP TAU - Circuit 66407	T
2.1.14	SPP TAU - Circuit 66033	T
2.1.15	SPP TAU - Circuit 66016	T
2.1.16	SPP TAU - Circuit 66427	T
2.1.17	SPP TAU - Circuit 66415	T
2.1.18	SPP TAU - Circuit 66834	T
2.1.19	SPP TAU - Circuit 66022	T
2.1.20	SPP TAU - Circuit 66060	T
2.1.21	SPP TAU - Circuit 66048	T
2.1.22	SPP TAU - Circuit 66031	T
2.1.23	SPP TAU - Circuit 66036	T
2.1.24	SPP TAU - Circuit 230402	T
2.1.25	SPP TAU - Circuit 230401	T
2.1.26	SPP TAU - Circuit 230602	T
2.1.27	SPP TAU - Circuit 230012	T
2.1.28	SPP TAU - Circuit 230606	T
2.1.29	SPP TAU - Circuit 230033	T
2.1.30	SPP TAU - Circuit 230609	T
2.1.31	SPP TAU - Circuit 230013	T
2.1.32	SPP TAU - Circuit 66030	T
2.1.33	SPP TAU - Circuit 66025	T
2.1.34	SPP TAU - Circuit 66020	T
2.1.35	SPP TAU - Circuit 66027	T
2.1.36	SPP TAU - Circuit 66008	T
2.1.37	SPP TAU - Circuit 66001	T
3.	Substation Protection O&M Programs	
3.1	Substation Extreme Weather Protection	
3.1.1	Substation Study	D

4	Overhead Feeder Hardening O&M Programs		
4.1	Distribution Overhead Feeder Hardening		
	4.1.1	SPP FH - 13461	D
	4.1.2	SPP FH - 14121	D
	4.1.3	SPP FH - 13939	D
	4.1.4	SPP FH - 13890	D
	4.1.5	SPP FH - 13443	D
	4.1.6	SPP FH - 13227	D
	4.1.7	SPP FH - 13462	D
	4.1.8	SPP FH - 13633	D
	4.1.9	SPP FH - 13101	D
	4.1.10	SPP FH - 13104	D
	4.1.11	SPP FH - 13111	D
	4.1.12	SPP FH - 13309	D
	4.1.13	SPP FH - 13313	D
	4.1.14	SPP FH - 13314	D
	4.1.15	SPP FH - 13339	D
	4.1.16	SPP FH - 13433	D
	4.1.17	SPP FH - 13808	D
	4.1.18	SPP FH - 13964	D
	4.1.19	SPP FH - 13148	D
	4.1.20	SPP FH - 13048	D
	4.1.21	SPP FH - 13094	D
	4.1.22	SPP FH - 13770	D
	4.1.23	SPP FH - 13118	D
	4.1.24	SPP FH - 13296	D
	4.1.25	SPP FH - 13989	D
	4.1.26	SPP FH - 13984	D
	4.1.27	SPP FH - 14123	D
5	Transmission Access O&M Programs		
5.1	Transmission Access Enhancement		
	5.1.1	none	T
6	Infrastructure Inspection O&M Programs		
6.1	Distribution Infrastructure Inspections		
	6.1.1	PRE - Dist Line - Pole Inspection Program	D
6.2	Transmission Infrastructure Inspections		
	6.2.1	PRE - Trans Line - Routine Patrols	T
	6.2.2	PRE - Trans Line - Above-Ground Inspections	T
	6.2.3	PRE - Trans Line - Infared Inspections	T
	6.2.4	PRE - Trans Line - Pole Inspection Program	T
	6.2.5	PRE - Substation - Transmission - Inspection, Test	T
	6.2.6	PRE - Substation - Transmission - Inspect, Test - GSU	T
7	Common SPP O&M Programs		
7.1	Common O&M Programs		
	7.1.1	SPP Common O&M - ED	D
	7.1.2	SPP Common O&M - Regulatory	D
	7.1.3	Planning & Admin	D

TAMPA ELECTRIC COMPANY
DOCKET NO. 20200092-EI
EXHIBIT NO. MRR-1
DOCUMENT NO. 3
WITNESS: ROCHE
PAGE 5 OF 21
FILED: 07/24/2020

Form 3P
Page 1 of 1

Tampa Electric Company
Storm Protection Plan Cost Recovery Clause (SPPCRC)
Initial Projection
Projected Period: January through December 2021

Calculation of Annual Revenue Requirements for Capital Investment Programs
(in Dollars)

Line	Capital Investment Activities	T/D	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Total
1.	Distribution Lateral Undergrounding Program	D	$ 85,427	$ 130,349	$ 175,608	$ 232,253	$ 282,351	$ 331,023	$ 384,238	$ 436,747	$ 490,076	$ 544,943	$ 600,280	$ 649,285	$ 4,342,580
1.a.	Adjustments	D	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1.b.	Subtotal of Distribution Lateral Undergrounding Program	D	$ 85,427	$ 130,349	$ 175,608	$ 232,253	$ 282,351	$ 331,023	$ 384,238	$ 436,747	$ 490,076	$ 544,943	$ 600,280	$ 649,285	$ 4,342,580
1.c.	Jurisdictional Demand Revenue Requirements		$ 85,427	$ 130,349	$ 175,608	$ 232,253	$ 282,351	$ 331,023	$ 384,238	$ 436,747	$ 490,076	$ 544,943	$ 600,280	$ 649,285	$ 4,342,580
1.d.	Jurisdictional Energy Revenue Requirements		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2	Transmission Asset Upgrades Program	T	$ 62,086	$ 72,635	$ 83,005	$ 93,690	$ 105,413	$ 115,842	$ 130,242	$ 144,775	$ 156,119	$ 170,330	$ 181,095	$ 187,834	$ 1,503,066
2.a.	Adjustments	T	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2.b.	Subtotal of Transmission Asset Upgrades Program	T	$ 62,086	$ 72,635	$ 83,005	$ 93,690	$ 105,413	$ 115,842	$ 130,242	$ 144,775	$ 156,119	$ 170,330	$ 181,095	$ 187,834	$ 1,503,066
2.c.	Jurisdictional Demand Revenue Requirements		$ 57,448	$ 67,209	$ 76,804	$ 86,691	$ 97,538	$ 107,188	$ 120,512	$ 133,959	$ 144,456	$ 157,605	$ 167,566	$ 173,801	$ 1,390,775
2.d.	Jurisdictional Energy Revenue Requirements		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3	Substation Extreme Weather Program	D	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3.a.	Adjustments	D	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3.b.	Subtotal of Substation Extreme Weather Program	D	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3.c. b	Jurisdictional Demand Revenue Requirements		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3.d. a	Jurisdictional Energy Revenue Requirements		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4	Distribution Overhead Feeder Hardening Program	D	$ 66,657	$ 73,897	$ 88,958	$ 108,430	$ 129,027	$ 144,368	$ 161,486	$ 166,117	$ 174,014	$ 182,761	$ 189,030	$ 193,513	$ 1,678,258
4.a.	Adjustments	D	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4.b.	Subtotal of Distribution Overhead Feeder Hardening Program	D	$ 66,657	$ 73,897	$ 88,958	$ 108,430	$ 129,027	$ 144,368	$ 161,486	$ 166,117	$ 174,014	$ 182,761	$ 189,030	$ 193,513	$ 1,678,258
4.c.	Jurisdictional Demand Revenue Requirements		$ 66,657	$ 73,897	$ 88,958	$ 108,430	$ 129,027	$ 144,368	$ 161,486	$ 166,117	$ 174,014	$ 182,761	$ 189,030	$ 193,513	$ 1,678,258
4.d.	Jurisdictional Energy Revenue Requirements		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5	Transmission Access Enhancement Program	T	$ -	$ -	$ -	$ 149	$ 447	$ 745	$ 1,328	$ 2,198	$ 3,068	$ 4,371	$ 6,109	$ 7,847	$ 26,262
5.a.	Adjustments	T	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5.b.	Subtotal of Transmission Access Enhancement Program	T	$ -	$ -	$ -	$ 149	$ 447	$ 745	$ 1,328	$ 2,198	$ 3,068	$ 4,371	$ 6,109	$ 7,847	$ 26,262
5.c.	Jurisdictional Demand Revenue Requirements		$ -	$ -	$ -	$ 138	$ 414	$ 689	$ 1,229	$ 2,034	$ 2,839	$ 4,044	$ 5,653	$ 7,261	$ 24,300
5.d.	Jurisdictional Energy Revenue Requirements		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
6	Retail Jurisdictional Factors														
6.a.	Distribution Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
6.b.	Transmission Demand Jurisdictional Factor		0.9252920	0.9252920	0.9252920	0.9252920	0.9252920	0.9252920	0.9252920	0.9252920	0.9252920	0.9252920	0.9252920	0.9252920	
6.c.	Distribution Energy Jurisdictional Factor		0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	
6.d.	Transmission Energy Jurisdictional Factor		0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	
7	Total of Capital Investment Programs		$ 214,170	$ 276,881	$ 347,571	$ 434,522	$ 517,238	$ 591,978	$ 677,294	$ 749,837	$ 823,277	$ 902,405	$ 976,514	$ 1,038,479	$ 7,550,166
7.a.	Jurisdictional Distribution Demand Revenue Requirements		$ 152,084	$ 204,246	$ 264,566	$ 340,683	$ 411,378	$ 475,391	$ 545,724	$ 602,864	$ 664,090	$ 727,704	$ 789,310	$ 842,798	$ 6,020,838
7.b.	Jurisdictional Transmission Demand Revenue Requirements		$ 57,448	$ 67,209	$ 76,804	$ 86,828	$ 97,951	$ 107,877	$ 121,741	$ 135,993	$ 147,294	$ 161,649	$ 173,218	$ 181,062	$ 1,415,075
7.c.	Total Jurisdictional Demand Revenue Requirements		$ 209,532	$ 271,455	$ 341,370	$ 427,511	$ 509,329	$ 583,268	$ 667,465	$ 738,857	$ 811,384	$ 889,353	$ 962,528	$ 1,023,860	$ 7,435,913
			-	-	-	-	-	-	-	-	-	-	-	-	-

Notes:
Jurisdictional Energy and Demand Revenue Requirements are calculated on the detailed 3P tabs.

Tampa Electric Company
Storm Protection Plan Cost Recovery Clause (SPPCRC)
Initial Projection
January 2021 to December 2021

Return on Capital Investments, Depreciation and Taxes
For Program: Distribution Lateral Undergrounding
(in Dollars)

Line	Description	Beginning of Period Amount	2021 January	2021 February	2021 March	2021 April	2021 May	2021 June	2021 July	2021 August	2021 September	2021 October	2021 November	2021 December	2021 TOTAL
1.	Investments														
	a. Expenditures/Additions		$6,782,717	$6,911,282	$6,862,955	$6,781,763	$6,870,733	$6,880,143	$6,912,150	$7,363,423	$7,401,741	$7,649,654	$7,262,243	$6,422,899	$84,101,703
	b. Clearings to Plant		$0	$69,948	$11,539,087	$5,234,144	$3,569,434	$7,873,088	$5,698,957	$4,972,711	$5,587,837	$6,524,407	$4,333,730	$22,962,439	$78,365,783
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2.	Plant-in-Service/Depreciation Base	$1,418,599	1,418,599	1,488,547	13,027,634	18,261,778	21,831,213	29,704,300	35,403,258	40,375,969	45,963,806	52,488,213	56,821,943	79,784,382	
3.	Less: Net Accumulated Depreciation	0	(1,466)	(2,932)	(4,470)	(17,932)	(36,802)	(59,361)	(90,056)	(126,639)	(168,361)	(215,857)	(270,095)	(328,811)	
4.	CWIP - Non-Interest Bearing	7,668,081	14,450,797	21,292,132	16,615,999	18,163,618	21,464,916	20,471,972	21,685,164	24,075,876	25,889,780	27,015,027	29,943,540	13,404,001	
5.	Net Investment (Lines 2 + 3 + 4)	$9,086,680	15,867,931	22,777,747	29,639,164	36,407,464	43,259,327	50,116,911	56,998,367	64,325,207	71,685,226	79,287,384	86,495,389	92,859,572	
6.	Average Net Investment		12,477,305	19,322,839	26,208,455	33,023,314	39,833,395	46,688,119	53,557,639	60,661,787	68,005,216	75,486,305	82,891,386	89,677,480	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (A)		63,874	98,918	134,168	169,055	203,917	239,008	274,175	310,543	348,136	386,433	424,342	459,081	3,111,650
	b. Debt Component Grossed Up For Taxes (B)		18,006	27,884	37,821	47,655	57,483	67,375	77,288	87,540	98,137	108,933	119,619	129,412	877,153
			81,880	126,802	171,989	216,710	261,400	306,383	351,463	398,083	446,273	495,366	543,961	588,493	3,988,803
8.	Investment Expenses														
	a. Depreciation (C)		3,547	3,547	3,721	32,569	45,654	54,578	74,261	88,508	100,940	114,910	131,221	142,055	795,510
	b. Depreciation Savings (D)		(2,081)	(2,081)	(2,183)	(19,107)	(26,784)	(32,019)	(43,566)	(51,925)	(59,218)	(67,414)	(76,983)	(83,339)	(466,699)
	c. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Property Taxes (E)		2,081	2,081	2,081	2,081	2,081	2,081	2,081	2,081	2,081	2,081	2,081	2,076	24,967
	f. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		85,427	130,349	175,608	232,253	282,351	331,023	384,238	436,747	490,076	544,943	600,280	649,285	4,342,580
	a. Recoverable Costs Allocated to Demand		85,427	130,349	175,608	232,253	282,351	331,023	384,238	436,747	490,076	544,943	600,280	649,285	4,342,580
	b. Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Distribution Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Distribution Energy Jurisdictional Factor		0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	
12.	Retail Distribution Demand-Related Recoverable Costs (F)		85,427	130,349	175,608	232,253	282,351	331,023	384,238	436,747	490,076	544,943	600,280	649,285	4,342,580
13.	Retail Distribution Energy-Related Recoverable Costs (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$85,427	$130,349	$175,608	$232,253	$282,351	$331,023	$384,238	$436,747	$490,076	$544,943	$600,280	$649,285	$4,342,580

-

Notes:
(A) Line 6 x 6.1431% x 1/12 (Jan-Dec). Based on ROE of 10.25% and weighted income tax rate of 24.522% (expansion factor of 1.32830)
(B) Line 6 x 1.7317% x 1/12 (Jan-Dec)
(C) Applicable depreciation group for additions is 367.0 and applicable depreciation rate is 3.0%
(D) Applicable depreciation group for retirements is 364.0 and applicable depreciation savings rate is 4.4%
(E) Ad Valorem Tax Rate is 1.76%
(F) Line 9a x line 10
(G) Line 9b x line 11

Tampa Electric Company
Storm Protection Plan Cost Recovery Clause (SPPCRC)
Initial Projection
January 2021 to December 2021

Return on Capital Investments, Depreciation and Taxes
For Program: Transmission Asset Upgrades
(in Dollars)

Line	Description	Beginning of Period Amount	2021 January	2021 February	2021 March	2021 April	2021 May	2021 June	2021 July	2021 August	2021 September	2021 October	2021 November	2021 December	2021 TOTAL
1.	Investments														
	a. Expenditures/Additions		$1,071,720	$1,077,000	$1,077,000	$1,303,620	$1,209,120	$1,495,320	$1,495,320	$1,495,320	$1,525,020	$1,248,720	$1,077,000	$1,077,000	$15,152,160
	b. Clearings to Plant		$1,333,000	$1,268,500	$1,118,000	$1,350,150	$644,100	$1,775,200	$1,836,380	$627,340	$1,997,100	$1,276,140	$0	$1,653,250	$14,879,160
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2.	Plant-in-Service/Depreciation Base	$5,004,398	6,337,398	7,605,898	8,723,898	10,074,048	10,718,148	12,493,348	14,329,728	14,957,068	16,954,168	18,230,308	18,230,308	19,883,558	
3.	Less: Net Accumulated Depreciation	($39,735)	(53,247)	(70,358)	(90,894)	(114,448)	(141,648)	(170,587)	(204,319)	(243,010)	(283,394)	(329,170)	(378,392)	(427,614)	
4.	CWIP - Non-Interest Bearing	$798,550	537,270	345,770	304,770	258,240	823,260	543,380	202,320	1,070,300	598,220	570,800	1,647,800	1,071,550	
5.	Net Investment (Lines 2 + 3 + 4)	$5,763,213	6,821,421	7,881,310	8,937,774	10,217,839	11,399,760	12,866,141	14,327,728	15,784,358	17,268,994	18,471,938	19,499,716	20,527,494	
6.	Average Net Investment		6,292,317	7,351,365	8,409,542	9,577,807	10,808,799	12,132,950	13,596,934	15,056,043	16,526,676	17,870,466	18,985,827	20,013,605	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (A)		32,212	37,633	43,051	49,031	55,333	62,112	69,606	77,076	84,604	91,483	97,193	102,455	801,789
	b. Debt Component Grossed Up For Taxes (B)		9,080	10,609	12,136	13,822	15,598	17,509	19,622	21,727	23,849	25,789	27,398	28,881	226,020
			41,292	48,242	55,187	62,853	70,931	79,621	89,228	98,803	108,453	117,272	124,591	131,336	1,027,809
8.	Investment Expenses														
	a. Depreciation (C)		15,013	19,012	22,818	26,172	30,222	32,154	37,480	42,989	44,871	50,863	54,691	54,691	430,976
	b. Depreciation Savings (D)		(1,501)	(1,901)	(2,282)	(2,617)	(3,022)	(3,215)	(3,748)	(4,299)	(4,487)	(5,086)	(5,469)	(5,469)	(43,098)
	c. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Property Taxes (E)		7,282	7,282	7,282	7,282	7,282	7,282	7,282	7,282	7,282	7,282	7,282	7,276	87,378
	f. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		62,086	72,635	83,005	93,690	105,413	115,842	130,242	144,775	156,119	170,330	181,095	187,834	1,503,066
	a. Recoverable Costs Allocated to Demand		62,086	72,635	83,005	93,690	105,413	115,842	130,242	144,775	156,119	170,330	181,095	187,834	1,503,066
	b. Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Transmission Demand Jurisdictional Factor		0.9252920	0.9252920	0.9252920	0.9252920	0.9252920	0.9252920	0.9252920	0.9252920	0.9252920	0.9252920	0.9252920	0.9252920	
11.	Transmission Energy Jurisdictional Factor		0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	
12.	Retail Transmission Demand-Related Recoverable Costs (F)		57,448	67,209	76,804	86,691	97,538	107,188	120,512	133,959	144,456	157,605	167,566	173,801	1,390,775
13.	Retail Transmission Energy-Related Recoverable Costs (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$57,448	$67,209	$76,804	$86,691	$97,538	$107,188	$120,512	$133,959	$144,456	$157,605	$167,566	$173,801	$1,390,775

Notes:
(A) Line 6 x 6.1431% x 1/12 (Jan-Dec). Based on ROE of 10.25% and weighted income tax rate of 24.522% (expansion factor of 1.32830)
(B) Line 6 x 1.7317% x 1/12 (Jan-Dec)
(C) Applicable depreciation group for additions is 355.0 and applicable depreciation rate is 3.6%
(D) Applicable depreciation group for retirements is 355.0 and applicable depreciation savings rate is 3.6%
(E) Ad Valorem Tax Rate is 1.76%
(F) Line 9a x line 10
(G) Line 9b x line 11

Tampa Electric Company
Storm Protection Plan Cost Recovery Clause (SPPCRC)
Initial Projection
January 2021 to December 2021

Return on Capital Investments, Depreciation and Taxes
For Program: Substation Extreme Weather Protection
(in Dollars)

Line	Description	Beginning of Period Amount	2021 January	2021 February	2021 March	2021 April	2021 May	2021 June	2021 July	2021 August	2021 September	2021 October	2021 November	2021 December	2021 TOTAL
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2.	Plant-in-Service/Depreciation Base	$0	0	0	0	0	0	0	0	0	0	0	0	0	
3.	Less: Net Accumulated Depreciation	0	0	0	0	0	0	0	0	0	0	0	0	0	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$0	0	0	0	0	0	0	0	0	0	0	0	0	
6.	Average Net Investment		0	0	0	0	0	0	0	0	0	0	0	0	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (A)		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Debt Component Grossed Up For Taxes (B)		0	0	0	0	0	0	0	0	0	0	0	0	0
			0	0	0	0	0	0	0	0	0	0	0	0	0
8.	Investment Expenses														
	a. Depreciation (C)		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Depreciation Savings (D)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Property Taxes (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
	f. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		0	0	0	0	0	0	0	0	0	0	0	0	0
	a. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Distribution Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Distribution Energy Jurisdictional Factor		0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	
12.	Retail Distribution Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
13.	Retail Distribution Energy-Related Recoverable Costs (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

Notes:
(A) Line 6 x 6.1431% x 1/12 (Jan-Dec). Based on ROE of 10.25% and weighted income tax rate of 24.522% (expansion factor of 1.32830)
(B) Line 6 x 1.7317% x 1/12 (Jan-Dec)
(C) Applicable depreciation group for additions is 362.0 and applicable depreciation rate is 2.4%
(D) No retirements are anticipated for this program
(E) Ad Valorem Tax Rate is 1.76%
(F) Line 9a x line 10
(G) Line 9b x line 11

TAMPA ELECTRIC COMPANY
DOCKET NO. 20200092-EI
EXHIBIT NO. MRR-1
DOCUMENT NO. 3
WITNESS: ROCHE
PAGE 8 OF 21
FILED: 07/24/2020

TAMPA ELECTRIC COMPANY
DOCKET NO. 20200092-EI
EXHIBIT NO. MRR-1
DOCUMENT NO. 3
WITNESS: ROCHE
PAGE 9 OF 21
FILED: 07/24/2020

Tampa Electric Company
Storm Protection Plan Cost Recovery Clause (SPPCRC)
Initial Projection
January 2021 to December 2021

Return on Capital Investments, Depreciation and Taxes
For Program: Distribution Overhead Feeder Hardening
(in Dollars)

Line	Description	Beginning of Period Amount	2021 January	2021 February	2021 March	2021 April	2021 May	2021 June	2021 July	2021 August	2021 September	2021 October	2021 November	2021 December	2021 TOTAL
1.	Investments														
	a. Expenditures/Additions		$648,679	$1,585,307	$3,031,556	$2,930,259	$1,761,722	$1,134,861	$719,848	$721,749	$785,625	$864,130	$612,283	$538,441	$15,334,461
	b. Clearings to Plant		$0	$0	$0	$2,412,724	$2,718,756	$5,104,963	$62,734	$1,454,012	$1,638,559	$778,340	$455,826	$367,705	$14,993,619
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2.	Plant-in-Service/Depreciation Base (A)	$6,156,888	6,156,888	6,156,888	6,156,888	8,569,612	11,288,368	16,393,331	16,456,065	17,910,077	19,548,635	20,326,975	20,782,802	21,150,507	
3.	Less: Net Accumulated Depreciation	0	(13,545)	(27,090)	(40,635)	(54,181)	(73,034)	(97,868)	(133,934)	(170,137)	(209,539)	(252,546)	(297,265)	(342,988)	
4.	CWIP - Non-Interest Bearing	242,868	891,547	2,476,855	5,508,411	6,025,946	5,068,912	1,098,810	1,755,925	1,023,661	170,728	256,518	412,975	583,711	
5.	Net Investment (Lines 2 + 3 + 4)	$6,399,756	7,034,890	8,606,653	11,624,663	14,541,378	16,284,246	17,394,273	18,078,056	18,763,601	19,509,824	20,330,947	20,898,511	21,391,230	
6.	Average Net Investment		6,717,323	7,820,771	10,115,658	13,083,020	15,412,812	16,839,260	17,736,164	18,420,828	19,136,713	19,920,386	20,614,729	21,144,870	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (A)		34,388	40,036	51,785	66,975	78,902	86,204	90,796	94,301	97,966	101,977	105,532	108,246	957,108
	b. Debt Component Grossed Up For Taxes (B)		9,694	11,286	14,598	18,880	22,242	24,300	25,595	26,583	27,616	28,747	29,749	30,514	269,804
			44,082	51,322	66,383	85,855	101,144	110,504	116,391	120,884	125,582	130,724	135,281	138,760	1,226,912
8.	Investment Expenses														
	a. Depreciation (C)		22,575	22,575	22,575	22,575	31,422	41,391	60,109	60,339	65,670	71,678	74,532	76,204	571,646
	b. Depreciation Savings (D)		(9,030)	(9,030)	(9,030)	(9,030)	(12,569)	(16,556)	(24,044)	(24,136)	(26,268)	(28,671)	(29,813)	(30,481)	(228,658)
	c. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Property Taxes (E)		9,030	9,030	9,030	9,030	9,030	9,030	9,030	9,030	9,030	9,030	9,030	9,031	108,361
	f. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		66,657	73,897	88,958	108,430	129,027	144,368	161,486	166,117	174,014	182,761	189,030	193,513	1,678,258
	a. Recoverable Costs Allocated to Demand		66,657	73,897	88,958	108,430	129,027	144,368	161,486	166,117	174,014	182,761	189,030	193,513	1,678,258
	b. Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Distribution Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Distribution Energy Jurisdictional Factor		0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	
12.	Retail Distribution Demand-Related Recoverable Costs (F)		66,657	73,897	88,958	108,430	129,027	144,368	161,486	166,117	174,014	182,761	189,030	193,513	1,678,258
13.	Retail Distribution Energy-Related Recoverable Costs (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$66,657	$73,897	$88,958	$108,430	$129,027	$144,368	$161,486	$166,117	$174,014	$182,761	$189,030	$193,513	$1,678,258

Notes:
(A) Line 6 x 6.1431% x 1/12 (Jan-Dec). Based on ROE of 10.25% and weighted income tax rate of 24.522% (expansion factor of 1.32830)
(B) Line 6 x 1.7317% x 1/12 (Jan-Dec)
(C) Applicable depreciation group for additions is 364.0 and applicable depreciation rate is 4.4%
(D) Applicable depreciation group for retirements is 364.0 and applicable depreciation savings rate is 4.4%
(E) Ad Valorem Tax Rate is 1.76%
(F) Line 9a x line 10
(G) Line 9b x line 11

TAMPA ELECTRIC COMPANY
DOCKET NO. 20200092-EI
EXHIBIT NO. MRR-1
DOCUMENT NO. 3
WITNESS: ROCHE
PAGE 10 OF 21
FILED: 07/24/2020

Tampa Electric Company
Storm Protection Plan Cost Recovery Clause (SPPCRC)
Initial Projection
January 2021 to December 2021

Return on Capital Investments, Depreciation and Taxes
For Program: Transmission Access Enhancements
(in Dollars)

Line	Description	Beginning of Period Amount	2021 January	2021 February	2021 March	2021 April	2021 May	2021 June	2021 July	2021 August	2021 September	2021 October	2021 November	2021 December	2021 TOTAL
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$45,385	$45,385	$45,385	$132,508	$132,508	$132,508	$264,819	$264,819	$264,819	$1,328,137
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2.	Plant-in-Service/Depreciation Base	$0	0	0	0	0	0	0	0	0	0	0	0	0	
3.	Less: Net Accumulated Depreciation	0	0	0	0	0	0	0	0	0	0	0	0	0	
4.	CWIP - Non-Interest Bearing	0	0	0	0	45,385	90,770	136,155	268,664	401,172	533,680	798,499	1,063,318	1,328,137	
5.	Net Investment (Lines 2 + 3 + 4)	$0	0	0	0	45,385	90,770	136,155	268,664	401,172	533,680	798,499	1,063,318	1,328,137	
6.	Average Net Investment		0	0	0	22,693	68,078	113,463	202,409	334,918	467,426	666,090	930,908	1,195,727	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (A)		0	0	0	116	349	581	1,036	1,715	2,393	3,410	4,766	6,121	20,487
	b. Debt Component Grossed Up For Taxes (B)		0	0	0	33	98	164	292	483	675	961	1,343	1,726	5,775
			0	0	0	149	447	745	1,328	2,198	3,068	4,371	6,109	7,847	26,262
8.	Investment Expenses														
	a. Depreciation (C)		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Depreciation Savings (D)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Property Taxes (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
	f. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		0	0	0	149	447	745	1,328	2,198	3,068	4,371	6,109	7,847	26,262
	a. Recoverable Costs Allocated to Demand		0	0	0	149	447	745	1,328	2,198	3,068	4,371	6,109	7,847	26,262
	b. Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Transmission Demand Jurisdictional Factor		0.9252920	0.9252920	0.9252920	0.9252920	0.9252920	0.9252920	0.9252920	0.9252920	0.9252920	0.9252920	0.9252920	0.9252920	
11.	Transmission Energy Jurisdictional Factor		0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	
12.	Retail Transmission Demand-Related Recoverable Costs (F)		0	0	0	138	414	689	1,229	2,034	2,839	4,044	5,653	7,261	24,300
13.	Retail Transmission Energy-Related Recoverable Costs (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$0	$0	$0	$138	$414	$689	$1,229	$2,034	$2,839	$4,044	$5,653	$7,261	$24,300

Notes:
(A) Line 6 x 6.1431% x 1/12 (Jan-Dec). Based on ROE of 10.25% and weighted income tax rate of 24.522% (expansion factor of 1.32830)
(B) Line 6 x 1.7317% x 1/12 (Jan-Dec)
(C) Applicable depreciation group for additions is 359.0 and applicable depreciation rate is 1.5%
(D) No retirements are anticipated for this program
(E) Ad Valorem Tax Rate is 1.76%
(F) Line 9a x line 10
(G) Line 9b x line 11

Tampa Electric Company
Storm Protection Plan Cost Recovery Clause (SPPCRC)
Initial Projection
Projected Period: January through December 2021
Project Listing by Each Capital Program

Line	Capital Activities	T or D
1	Distribution Lateral Undergrounding Program	
1.1	LUG PCA 13961.92829453	D
1.2	LUG PCA 13724.90911087	D
1.3	LUG PCA 13146.10629014	D
1.4	LUG WHA 13972.92421291	D
1.5	LUG WHA 13312.60182741	D
1.6	LUG WHA 13972.90241880	D
1.7	LUG PCA 13961.92820848	D
1.8	LUG PCA 13961.60193482	D
1.9	LUG PCA 13785.10676209	D
1.10	LUG PCA 13462.60458175	D
1.11	LUG PCA 14121.93159006	D
1.12	LUG PCA 13462.60180762	D
1.13	LUG PCA 13462.91407512	D
1.14	LUG PCA 13390.10643541	D
1.15	LUG PCA 13120.60015632	D
1.16	LUG PCA 13785.92466250	D
1.17	LUG CSA 14040.10786382	D
1.18	LUG CSA 13840.93019714	D
1.19	LUG CSA 14040.10786374	D
1.20	LUG CSA 13836.91406672	D
1.21	LUG DCA 13815.92407065	D
1.22	LUG DCA 13815.90288627	D
1.23	LUG DCA 13815.93026469	D
1.24	LUG CSA 13183.60036344	D
1.25	LUG CSA 13205.60059346	D
1.26	LUG CSA 13934.10467606	D
1.27	LUG CSA 13633.92740152	D
1.28	LUG CSA 13592.10402239	D
1.29	LUG CSA 13351.93283733	D
1.30	LUG CSA 13099.90882614	D
1.31	LUG CSA 13093.91004837	D
1.32	LUG CSA 13630.10429536	D
1.33	LUG CSA 13205.90998414	D
1.34	LUG CSA 13948.91837409	D
1.35	LUG CSA 13093.91004843	D
1.36	LUG CSA 13836.91377944	D
1.37	LUG CSA 13102.60123654	D
1.38	LUG CSA 13158.92874802	D
1.39	LUG CSA 13176.10375134	D
1.40	LUG CSA 13107.10376173	D
1.41	LUG CSA 13057.10121709	D
1.42	LUG CSA 13418.92357188	D
1.43	LUG CSA 13592.91213055	D
1.44	LUG CSA 13100.91340554	D
1.45	LUG CSA 13715.90737020	D
1.46	LUG CSA 13176.91029163	D
1.47	LUG CSA 13835.60131429	D
1.48	LUG CSA 13593.93057902	D
1.49	LUG CSA 13105.10580678	D
1.50	LUG CSA 13188.10655453	D
1.51	LUG CSA 13592.10402259	D
1.52	LUG CSA 13948.10442385	D
1.53	LUG ESA 13710.92881445	D
1.54	LUG ESA 13509.60287236	D
1.55	LUG SHA 13897.10933151	D
1.56	LUG ESA 13174.10913196	D
1.57	LUG ESA 13171.90598389	D
1.58	LUG ESA 13211.60044019	D
1.59	LUG ESA 13231.10868138	D

1.60	LUG ESA 13230.10471354	D
1.61	LUG ESA 13502.92679861	D
1.62	LUG ESA 13796.10842826	D
1.63	LUG ESA 13454.60140423	D
1.64	LUG ESA 13509.10501132	D
1.65	LUG ESA 13433.10466911	D
1.66	LUG ESA 13230.92208546	D
1.67	LUG ESA 13171.93104605	D
1.68	LUG ESA 13509.90504849	D
1.69	LUG ESA 13502.92573944	D
1.70	LUG ESA 13799.60395568	D
1.71	LUG ESA 13226.10462583	D
1.72	LUG ESA 14116.60140011	D
1.73	LUG ESA 13797.93188519	D
1.74	LUG ESA 13226.92664597	D
1.75	LUG ESA 13796.92728705	D
1.76	LUG ESA 13230.60258173	D
1.77	LUG ESA 13171.90374558	D
1.78	LUG ESA 13796.92884623	D
1.79	LUG ESA 13502.92577310	D
1.80	LUG ESA 13225.60139973	D
1.81	LUG ESA 13796.10842823	D
1.82	LUG ESA 13226.92670950	D
1.83	LUG ESA 13226.92665539	D
1.84	LUG ESA 13883.91179506	D
1.85	LUG ESA 13509.91772133	D
1.86	LUG ESA 13509.10501150	D
1.87	LUG ESA 13454.90429155	D
1.88	LUG ESA 13454.90397369	D
1.89	LUG ESA 13454.10472634	D
1.90	LUG ESA 13433.93369551	D
1.91	LUG ESA 13174.92555763	D
1.92	LUG ESA 13883.92008787	D
1.93	LUG ESA 13230.92180224	D
1.94	LUG WSA 14032.10820614	D
1.95	LUG WSA 13071.90738378	D
1.96	LUG WSA 14032.92634300	D
1.97	LUG WSA 13071.91245761	D
1.98	LUG WSA 14032.91487301	D
1.99	LUG WSA 14032.10339836	D
1.100	LUG WSA 14032.92803239	D
1.101	LUG WSA 13071.91432110	D
1.102	LUG WSA 13071.91432109	D
1.103	LUG WSA 14032.92729035	D
1.104	LUG WSA 13198.92183966	D
1.105	LUG WSA 13678.90514649	D
1.106	LUG WSA 13425.10244449	D
1.107	LUG WSA 13670.93124410	D
1.108	LUG WSA 13428.91540495	D
1.109	LUG WSA 13332.91335523	D
1.110	LUG WSA 13544.10053266	D
1.111	LUG WSA 13109.90641822	D
1.112	LUG WSA 13747.10299739	D
1.113	LUG WSA 13756.60165357	D
1.114	LUG WSA 13491.10230118	D
1.115	LUG WSA 13141.92630916	D
1.116	LUG WSA 13673.10277744	D
1.117	LUG WSA 13138.60079254	D
1.118	LUG WSA 13141.92442349	D
1.119	LUG WSA 13333.10007582	D
1.120	LUG WSA 13586.92298267	D
1.121	LUG WSA 13138.10145625	D
1.122	LUG WSA 13140.10013916	D
1.123	LUG WSA 13113.90796385	D
1.124	LUG WSA 13138.10145628	D

1.125	LUG WSA 13164.10158909	D
1.126	LUG WSA 13140.91873275	D
1.127	LUG WSA 13605.91052996	D
1.128	LUG WSA 13071.60170422	D
1.129	LUG WSA 13111.92999604	D
1.130	LUG WSA 13586.60303627	D
1.131	LUG PCA 13785.90239166	D
1.132	LUG PCA 13961.10696431	D
1.133	LUG PCA 13961.10696419	D
1.134	LUG PCA 13785.92299245	D
1.135	LUG PCA 13961.92834683	D
1.136	LUG PCA 13462.91412064	D
1.137	LUG PCA 13961.10696486	D
1.138	LUG PCA 13961.91967308	D
1.139	LUG PCA 13961.10696417	D
1.140	LUG WHA 13916.60279623	D
1.141	LUG WHA 13297.10560430	D
1.142	LUG WHA 13314.92426509	D
1.143	LUG WHA 13118.92612349	D
1.144	LUG WHA 13313.90084626	D
1.145	LUG WHA 13699.10637242	D
1.146	LUG WHA 13313.10684614	D
1.147	LUG WHA 13296.92376304	D
1.148	LUG WHA 13313.60568375	D
1.149	LUG WHA 13297.60269456	D
1.150	LUG WHA 13699.10637259	D
1.151	LUG WHA 13473.60168916	D
1.152	LUG WHA 13296.10562356	D
1.153	LUG WHA 13916.92509975	D
1.154	LUG WHA 13297.10560425	D
1.155	LUG WHA 13296.60531111	D
1.156	LUG WHA 13699.10637247	D
1.157	LUG WHA 13473.60168942	D
1.158	LUG WHA 13118.92659353	D
1.159	LUG WHA 13118.10676209	D
1.160	LUG WHA 13699.10637240	D
1.161	LUG WHA 13313.93103371	D
1.162	LUG WHA 13118.92204382	D
1.163	LUG WHA 13118.92659172	D
1.164	LUG WHA 13473.92097460	D
1.165	LUG WHA 13296.90010289	D
1.166	LUG WHA 13313.92097460	D
1.167	LUG WHA 13118.10535999	D
1.168	LUG WHA 13699.60165416	D
1.169	LUG WHA 13916.91386005	D
1.170	LUG WHA 13314.10567076	D
1.171	LUG WHA 13296.10562361	D
1.172	LUG WHA 13297.10560432	D
1.173	LUG WHA 13972.10618037	D
1.174	LUG PCA 13724.10671283	D
1.175	LUG PCA 13722.60360851	D
1.176	LUG PCA 13268.91633548	D
1.177	LUG PCA 13724.10671319	D
1.178	LUG PCA 13243.10791853	D
1.179	LUG PCA 13724.10671334	D
1.180	LUG PCA 13243.91351288	D
1.181	LUG PCA 13655.90431393	D
1.182	LUG PCA 13243.90684154	D
1.183	LUG PCA 13268.10705945	D
1.184	LUG PCA 13724.10671229	D
1.185	LUG PCA 13268.92962459	D
1.186	LUG PCA 13724.93103251	D
1.187	LUG PCA 13243.90586047	D
1.188	LUG PCA 13724.91049435	D
1.189	LUG CSA 13205.90929181	D

1.190	LUG CSA 13021.10051153	D
1.191	LUG CSA 13026.60059524	D
1.192	LUG CSA 13835.10429522	D
1.193	LUG CSA 13204.91532149	D
1.194	LUG CSA 13836.91406642	D
1.195	LUG CSA 13099.60563698	D
1.196	LUG CSA 13590.91231633	D
1.197	LUG CSA 13102.91293905	D
1.198	LUG CSA 13104.10362869	D
1.199	LUG CSA 13831.10427677	D
1.200	LUG CSA 14040.60233886	D
1.201	LUG CSA 13939.60144164	D
1.202	LUG CSA 13158.90816343	D
1.203	LUG CSA 13021.60058683	D
1.204	LUG CSA 13158.93317809	D
1.205	LUG CSA 13104.91643108	D
1.206	LUG CSA 13106.91795934	D
1.207	LUG CSA 13835.60314670	D
1.208	LUG CSA 13107.10376186	D
1.209	LUG CSA 13592.91365233	D
1.210	LUG CSA 13993.10372414	D
1.211	LUG CSA 13100.10371703	D
1.212	LUG CSA 13354.10582069	D
1.213	LUG CSA 13418.92292295	D
1.214	LUG CSA 13468.60128378	D
1.215	LUG CSA 13632.60305848	D
1.216	LUG CSA 13104.10362882	D
1.217	LUG CSA 13176.10375148	D
1.218	LUG CSA 13099.60125388	D
1.219	LUG CSA 13102.60123660	D
1.220	LUG CSA 14102.91582612	D
1.221	LUG CSA 13468.60128362	D
1.222	LUG CSA 13399.60037987	D
1.223	LUG CSA 13835.91773975	D
1.224	LUG CSA 13418.92018190	D
1.225	LUG CSA 13158.60011810	D
1.226	LUG CSA 13105.10580690	D
1.227	LUG CSA 13205.90022802	D
1.228	LUG CSA 13418.91924595	D
1.229	LUG CSA 13105.60164901	D
1.230	LUG CSA 13934.10467597	D
1.231	LUG CSA 13205.90442230	D
1.232	LUG CSA 13158.92290015	D
1.233	LUG CSA 14040.10786358	D
1.234	LUG CSA 13836.93321406	D
1.235	LUG CSA 13105.10580689	D
1.236	LUG CSA 13107.10376201	D
1.237	LUG CSA 13633.90633859	D
1.238	LUG CSA 13105.10580676	D
1.239	LUG CSA 13836.60133704	D
1.240	LUG CSA 13100.10371697	D
1.241	LUG CSA 13993.10433144	D
1.242	LUG CSA 13939.60144172	D
1.243	LUG CSA 13158.91461782	D
1.244	LUG CSA 13633.91847345	D
1.245	LUG CSA 13934.10467575	D
1.246	LUG CSA 13188.92070695	D
1.247	LUG CSA 13836.60133698	D
1.248	LUG CSA 13948.10442391	D
1.249	LUG CSA 14040.90485522	D
1.250	LUG CSA 13158.92347931	D
1.251	LUG CSA 13633.90564142	D
1.252	LUG DCA 13006.92949400	D
1.253	LUG DCA 13432.10761257	D
1.254	LUG CSA 13826.60127680	D

1.255	LUG CSA 13632.10408290	D
1.256	LUG CSA 13204.60170504	D
1.257	LUG CSA 13176.10375141	D
1.258	LUG CSA 13948.10442379	D
1.259	LUG CSA 13835.10429505	D
1.260	LUG CSA 13026.60059509	D
1.261	LUG CSA 13021.92350282	D
1.262	LUG CSA 13106.10361901	D
1.263	LUG CSA 13468.91640192	D
1.264	LUG CSA 13106.91722510	D
1.265	LUG CSA 13026.60059452	D
1.266	LUG CSA 13632.10408272	D
1.267	LUG CSA 13102.90748252	D
1.268	LUG CSA 13093.60029740	D
1.269	LUG CSA 13102.60123656	D
1.270	LUG CSA 13026.60059457	D
1.271	LUG CSA 13099.10368943	D
1.272	LUG CSA 13104.91668251	D
1.273	LUG CSA 13026.91490707	D
1.274	LUG CSA 13176.10375136	D
1.275	LUG CSA 13104.91241032	D
1.276	LUG ESA 13230.10471377	D
1.277	LUG ESA 13509.60346595	D
1.278	LUG ESA 13502.10497396	D
1.279	LUG ESA 13174.93310101	D
1.280	LUG ESA 13796.92356181	D
1.281	LUG ESA 13509.92890860	D
1.282	LUG ESA 13171.10455414	D
1.283	LUG ESA 13230.92496254	D
1.284	LUG ESA 13509.10501141	D
1.285	LUG ESA 13454.91522987	D
1.286	LUG ESA 13509.10501110	D
1.287	LUG ESA 13231.10868120	D
1.288	LUG ESA 13174.10913197	D
1.289	LUG ESA 13225.92750192	D
1.290	LUG ESA 13797.93185703	D
1.291	LUG ESA 14116.91073265	D
1.292	LUG SHA 13900.10717269	D
1.293	LUG SHA 13652.92748361	D
1.294	LUG SHA 13001.93346473	D
1.295	LUG SHA 14022.90591555	D
1.296	LUG SHA 13001.60179144	D
1.297	LUG SHA 13001.10663246	D
1.298	LUG SHA 13645.91519309	D
1.299	LUG SHA 13780.10723993	D
1.300	LUG SHA 13001.92048269	D
1.301	LUG SHA 13001.60179191	D
1.302	LUG SHA 13001.10663240	D
1.303	LUG SHA 13900.92336596	D
1.304	LUG SHA 13645.92207754	D
1.305	LUG SHA 13900.91863298	D
1.306	LUG SHA 13001.10663269	D
1.307	LUG SHA 13001.10663262	D
1.308	LUG SHA 13001.90251758	D
1.309	LUG ESA 13127.90334707	D
1.310	LUG ESA 13229.10457704	D
1.311	LUG ESA 13878.10105723	D
1.312	LUG ESA 13911.92679866	D
1.313	LUG ESA 13229.92525393	D
1.314	LUG ESA 13909.92173076	D
1.315	LUG ESA 14355.60258173	D
1.316	LUG ESA 13457.10482593	D
1.317	LUG ESA 13127.90334731	D
1.318	LUG ESA 13906.10096968	D
1.319	LUG ESA 13909.90380435	D

1.320	LUG ESA 13127.10836901	D
1.321	LUG ESA 13906.92282884	D
1.322	LUG ESA 13911.60157737	D
1.323	LUG ESA 13710.92354144	D
1.324	LUG ESA 13793.92685255	D
1.325	LUG ESA 13906.10096960	D
1.326	LUG ESA 13793.92686002	D
1.327	LUG ESA 13686.10840133	D
1.328	LUG ESA 13906.10096964	D
1.329	LUG ESA 13911.90130568	D
1.330	LUG ESA 13911.91276385	D
1.331	LUG ESA 13906.90137810	D
1.332	LUG ESA 13793.92686712	D
1.333	LUG ESA 13127.92663180	D
1.334	LUG ESA 13457.90291488	D
1.335	LUG ESA 13911.10544635	D
1.336	LUG ESA 13911.10544633	D
1.337	LUG ESA 13911.92018843	D
1.338	LUG ESA 13457.90176591	D
1.339	LUG ESA 13911.10554588	D
1.340	LUG ESA 14355.92354352	D
1.341	LUG ESA 13911.91556649	D
1.342	LUG ESA 13793.92686736	D
1.343	LUG ESA 13911.10554595	D
1.344	LUG ESA 13911.91995336	D
1.345	LUG ESA 13127.92661768	D
1.346	LUG ESA 13796.92884644	D
1.347	LUG ESA 13878.10105726	D
1.348	LUG ESA 13454.90188551	D
1.349	LUG ESA 13878.10105717	D
1.350	LUG ESA 13231.10868121	D
1.351	LUG ESA 13911.60157736	D
1.352	LUG ESA 13509.10501133	D
1.353	LUG ESA 13171.10455381	D
1.354	LUG ESA 13878.10105728	D
1.355	LUG ESA 13911.91665193	D
1.356	LUG SHA 13003.10895225	D
1.357	LUG SHA 14024.10747874	D
1.358	LUG SHA 13342.91010293	D
1.359	LUG SHA 14020.60223573	D
1.360	LUG SHA 13342.10925094	D
1.361	LUG SHA 14024.90116190	D
1.362	LUG SHA 13817.10722417	D
1.363	LUG SHA 13003.10895211	D
1.364	LUG SHA 13342.90527363	D
1.365	LUG WSA 13605.90568909	D
1.366	LUG WSA 13162.92185426	D
1.367	LUG WSA 13194.90645535	D
1.368	LUG WSA 13079.60077624	D
1.369	LUG WSA 13586.91748729	D
1.370	LUG WSA 13162.10158432	D
1.371	LUG WSA 13864.10310477	D
1.372	LUG WSA 13113.92909503	D
1.373	LUG WSA 13516.60169592	D
1.374	LUG WSA 13192.90932106	D
1.375	LUG WSA 13333.91785740	D
1.376	LUG WSA 13863.60279838	D
1.377	LUG WSA 13109.90643551	D
1.378	LUG WSA 13332.91700188	D
1.379	LUG WSA 13756.90207831	D
1.380	LUG WSA 13672.60106849	D
1.381	LUG WSA 13860.10307215	D
1.382	LUG WSA 13756.60165355	D
1.383	LUG WSA 13672.10493801	D
1.384	LUG WSA 13864.10310468	D

1.385	LUG WSA 13864.10310497	D
1.386	LUG WSA 13586.92442286	D
1.387	LUG WSA 13672.91971930	D
1.388	LUG WSA 13192.90932283	D
1.389	LUG WSA 13678.10254063	D
1.390	LUG WSA 13141.10147344	D
1.391	LUG WSA 13756.10589587	D
1.392	LUG WSA 13864.10310505	D
1.393	LUG WSA 13860.10307212	D
1.394	LUG WSA 13111.60072751	D
1.395	LUG WSA 13605.90427351	D
1.396	LUG WSA 13333.10007588	D
1.397	LUG WSA 13164.90252716	D
1.398	LUG WSA 13491.91827162	D
1.399	LUG WSA 13113.90422522	D
1.400	LUG WSA 13756.10589595	D
1.401	LUG WSA 13586.10255333	D
1.402	LUG WSA 13428.90423835	D
1.403	LUG WSA 13113.60340774	D
1.404	LUG WSA 13141.91575422	D
1.405	LUG WSA 13678.90514672	D
1.406	LUG WSA 13164.10158912	D
1.407	LUG WSA 13586.10255361	D
1.408	LUG WSA 13544.10053269	D
1.409	LUG WSA 13864.60380454	D
1.410	LUG WSA 13141.92442350	D
1.411	LUG WSA 13141.10147371	D
1.412	LUG WSA 13678.10288738	D
1.413	LUG WSA 13612.90440184	D
1.414	LUG WSA 13533.91957169	D
1.415	LUG WSA 14030.60131389	D
1.416	LUG WSA 13865.90531031	D
1.417	LUG WSA 13535.92983670	D
1.418	LUG WSA 13589.93177909	D
1.419	LUG WSA 13522.91934653	D
1.420	LUG WSA 13522.10392924	D
1.421	LUG WSA 13737.10297943	D
1.422	LUG WSA 14030.90886759	D
1.423	LUG WSA 13207.90147316	D
1.424	LUG WSA 13207.90216846	D
1.425	LUG WSA 13059.60302601	D
1.426	LUG WSA 13738.10298299	D
1.427	LUG WSA 13059.93006225	D
1.428	LUG WSA 13207.90146892	D
1.429	LUG WSA 13162.10158434	D
1.430	LUG WSA 13079.60077605	D
1.431	LUG WSA 13870.90428273	D
1.432	LUG WSA 13737.91960399	D
1.433	LUG WSA 13674.10277747	D
1.434	LUG WSA 13078.10127958	D
1.435	LUG WSA 13162.60154843	D
1.436	LUG WSA 13510.10218990	D
1.437	LUG WSA 13669.60107076	D
1.438	LUG WSA 14030.90242104	D
1.439	LUG WSA 13873.60311122	D
1.440	LUG WSA 13207.90613782	D
1.441	LUG WSA 13612.90266817	D
1.442	LUG WSA 13208.92767537	D
1.443	LUG WSA 13737.60311396	D
1.444	LUG WSA 13198.92655424	D
1.445	LUG WSA 13514.10624934	D
1.446	LUG WSA 13535.92959083	D
1.447	LUG WSA 13669.92774744	D
1.448	LUG WSA 13483.60393455	D
1.449	LUG WSA 13520.10242257	D

1.450	LUG WSA 13892.10338448	D
1.451	LUG WSA 13612.90312305	D
1.452	LUG WSA 13522.91947423	D
1.453	LUG WSA 13334.91645657	D
1.454	LUG WSA 13490.92815117	D
1.455	LUG WSA 13522.10392902	D
1.456	LUG WSA 14030.60341032	D
1.457	LUG WSA 13574.10250638	D
1.458	LUG WSA 13138.10145602	D
1.459	LUG WSA 13220.10191173	D
1.460	LUG WSA 13612.60022877	D
1.461	LUG WSA 13220.90901917	D
1.462	LUG WSA 13535.92983661	D
1.463	LUG WSA 13535.91618829	D
1.464	LUG WSA 13669.92770538	D
1.465	LUG WSA 13208.90449608	D
1.466	LUG WSA 13079.60104344	D
1.467	LUG WSA 13575.90054924	D
1.468	LUG WSA 13750.60110680	D
1.469	LUG WSA 13198.10051875	D
1.470	LUG WSA 13612.92956326	D
1.471	LUG WSA 13514.91361858	D
1.472	LUG WSA 13522.10392905	D
1.473	LUG WSA 14030.92669942	D
1.474	LUG WSA 13483.10173513	D
1.475	LUG WSA 13612.60003135	D
1.476	LUG WSA 13071.93035682	D
1.477	LUG WSA 13522.92169062	D
1.478	LUG WSA 13575.90054386	D
1.479	LUG WSA 13522.10392882	D
1.480	LUG WSA 13198.10051851	D
1.481	LUG WSA 14030.92670479	D
1.482	LUG WSA 13522.10392874	D
1.483	LUG WSA 13162.93124277	D
1.484	LUG WSA 13535.92969194	D
1.485	LUG WSA 13198.10051896	D
1.486	LUG WSA 13109.10846390	D
1.487	LUG WSA 13612.60002970	D
1.488	LUG WSA 14030.60125643	D
1.489	LUG WSA 14030.92669080	D
1.490	LUG WSA 13071.92377934	D
1.491	LUG WSA 13138.60170460	D
1.492	LUG WSA 13483.60079455	D
1.493	LUG WSA 13535.92952190	D
1.494	LUG WSA 13198.10051852	D
1.495	LUG WSA 13162.90435139	D
1.496	LUG WSA 13873.10820612	D
1.497	LUG WSA 13138.10145618	D
1.498	LUG WSA 13737.90740214	D
1.499	LUG WSA 13138.10145629	D
1.500	LUG WSA 13737.90740699	D
1.501	LUG WSA 13079.90517178	D
1.502	LUG WSA 13078.10127955	D
1.503	LUG WSA 14030.92669557	D
1.504	LUG WSA 13522.10392864	D
1.505	LUG WSA 13674.90420693	D
1.506	LUG WSA 13612.90291123	D
1.507	LUG WSA 13109.60233901	D
1.508	LUG WSA 13737.10297934	D
1.509	LUG WSA 13589.93162023	D
1.510	LUG WSA 13198.92585443	D
1.511	LUG WSA 14030.92669914	D
1.512	LUG WSA 13612.90312570	D
1.513	LUG WSA 13138.10145606	D
1.514	LUG WSA 14030.92669923	D

	1.515	LUG WSA 13522.60305728	D
	1.516	LUG WSA 13522.60305720	D
2	Transmission Asset Upgrades Program		
	2.1	SPP TAU - Circuit 230008	T
	2.2	SPP TAU - Circuit 230010	T
	2.3	SPP TAU - Circuit 230038	T
	2.4	SPP TAU - Circuit 230003	T
	2.5	SPP TAU - Circuit 230005	T
	2.6	SPP TAU - Circuit 230004	T
	2.7	SPP TAU - Circuit 230625	T
	2.8	SPP TAU - Circuit 230021	T
	2.9	SPP TAU - Circuit 230052	T
	2.10	SPP TAU - Circuit 66024	T
	2.11	SPP TAU - Circuit 230608	T
	2.12	SPP TAU - Circuit 230603	T
	2.13	SPP TAU - Circuit 66407	T
	2.14	SPP TAU - Circuit 66033	T
	2.15	SPP TAU - Circuit 66016	T
	2.16	SPP TAU - Circuit 66427	T
	2.17	SPP TAU - Circuit 66415	T
	2.18	SPP TAU - Circuit 66834	T
	2.19	SPP TAU - Circuit 66022	T
	2.20	SPP TAU - Circuit 66060	T
	2.21	SPP TAU - Circuit 66048	T
	2.22	SPP TAU - Circuit 66031	T
	2.23	SPP TAU - Circuit 66036	T
	2.24	SPP TAU - Circuit 230402	T
	2.25	SPP TAU - Circuit 230401	T
	2.26	SPP TAU - Circuit 230602	T
	2.27	SPP TAU - Circuit 230012	T
	2.28	SPP TAU - Circuit 230606	T
	2.29	SPP TAU - Circuit 230033	T
	2.30	SPP TAU - Circuit 230609	T
	2.31	SPP TAU - Circuit 230013	T
	2.32	SPP TAU - Circuit 66030	T
	2.33	SPP TAU - Circuit 66025	T
	2.34	SPP TAU - Circuit 66020	T
	2.35	SPP TAU - Circuit 66027	T
	2.36	SPP TAU - Circuit 66008	T
	2.37	SPP TAU - Circuit 66001	T
3	Substation Extreme Weather Program		
	3.1	none	D
4	Distribution Overhead Feeder Hardening Program		
	4.1	SPP FH - 13461	D
	4.2	SPP FH - 14121	D
	4.3	SPP FH - 13939	D
	4.4	SPP FH - 13890	D
	4.5	SPP FH - 13443	D
	4.6	SPP FH - 13227	D
	4.7	SPP FH - 13462	D
	4.8	SPP FH - 13633	D
	4.9	SPP FH - 13148	D
	4.10	SPP FH - 13048	D
	4.11	SPP FH - 13094	D
	4.12	SPP FH - 13770	D
	4.13	SPP FH - 13118	D
	4.14	SPP FH - 13296	D
	4.15	SPP FH - 13989	D
	4.16	SPP FH - 13984	D
	4.17	SPP FH - 14123	D
	4.18	SPP FH - 13101	D
	4.19	SPP FH - 13104	D

	4.20	SPP FH - 13111	D
	4.21	SPP FH - 13309	D
	4.22	SPP FH - 13313	D
	4.23	SPP FH - 13314	D
	4.24	SPP FH - 13339	D
	4.25	SPP FH - 13433	D
	4.26	SPP FH - 13808	D
	4.27	SPP FH - 13964	D
5	Transmission Access Enhancement Program		
	5.1	SPP TXE - Site Access-230008	T
	5.2	SPP TXE - Site Access-230623	T
	5.3	SPP TXE - Site Access-Proposed Bridge P	T
	5.4	SPP TXE - Site Access-Hampton Substation	T
	5.5	SPP TXE - Site Access-230033	T
	5.6	SPP TXE - Site Access-Morris Bridge Rd	T
	5.7	SPP TXE - Site Access-66007	T
	5.8	SPP TXE - Site Access-230037	T
	5.9	SPP TXE - Site Access-66839	T
	5.10	SPP TXE - Site Access-230606	T
	5.11	SPP TXE - Site Access-Columbus Drive #2	T
	5.12	SPP TXE - Site Access-West Of Forbes Rd	T
	5.13	SPP TXE - Site Access-Columbus Drive #1	T
	5.14	SPP TXE - Site Access-Tampa Palms #1	T
	5.15	SPP TXE - Site Access-19th Av NE	T
	5.16	SPP TXE - Site Access-East Of Sydney Washer Rd	T
	5.17	SPP TXE - Site Access-Tampa Palms #3	T
	5.18	SPP TXE - Site Access-Proposed Bridge M	T

Tampa Electric Company
Storm Protection Plan Cost Recovery Clause (SPPCRC)
Initial Projection
Projected Period: January through December 2021

Form 7P
Page 1 of 1

Approved Capital Structure and Cost Rates
(in Dollars)

	(1) Jurisdictional Rate Base *2021 Adj. FESR* ($000)	(2) Ratio %	(3) Cost Rate %	(4) Weighted Cost Rate %
Long Term Debt	$ 2,505,932	35.87%	4.33%	1.5517%
Short Term Debt	152,497	2.18%	2.50%	0.0546%
Preferred Stock	0	0.00%	0.00%	0.0000%
Customer Deposits	89,536	1.28%	2.43%	0.0311%
Common Equity	3,076,748	44.04%	10.25%	4.5140%
Accum. Deferred Inc. Taxes & Zero Cost ITC's	969,489	13.88%	0.00%	0.0000%
Deferred ITC - Weighted Cost	192,214	2.75%	7.46%	0.2051%
Total	$ 6,986,416	100.00%		6.36%

ITC split between Debt and Equity:

Long Term Debt	$ 2,505,932	Long Term Debt	46.00%
Equity - Preferred	0	Equity - Preferred	0.00%
Equity - Common	3,076,748	Equity - Common	54.00%
Total	$ 5,582,680	Total	100.00%

Deferred ITC - Weighted Cost:

Debt = 0.2051% * 46.00%	0.0943%
Equity = 0.2051% * 54.00%	0.1108%
Weighted Cost	0.2051%

Total Equity Cost Rate:

Preferred Stock	0.0000%
Common Equity	4.5140%
Deferred ITC - Weighted Cost	0.1108%
	4.6248%
Times Tax Multiplier	1.32830
Total Equity Component	6.1431%

Total Debt Cost Rate:

Long Term Debt	1.5517%
Short Term Debt	0.0546%
Customer Deposits	0.0311%
Deferred ITC - Weighted Cost	0.0943%
Total Debt Component	1.7317%
	7.8748%

Notes:
Column (1) - Per Order No. PSC-2020-0165-PAA-EU, issued May 20, 2020, approving amended joint motion modifying WACC methodology.
Column (2) - Column (1) / Total Column (1)
Column (3) - Per Order No. PSC-2020-0165-PAA-EU, issued May 20, 2020, approving amended joint motion modifying WACC methodology..
Column (4) - Column (2) x Column (3)

Tampa Electric Company
Storm Protection Plan Cost Recovery Clause
Calculation of Current Period Actual/Estimated Amount
Current Period: January through December 2020

Summary of Current Period Estimated True-Up
(in Dollars)

Line		Period Amount
1.	Over/(Under) Recovery for the Current Period (Form 2E, Line 5)	$ (5,978,656)
2.	Interest Provision (Form 2E, Line 6)	$ (8,040)
3.	Sum of Prior Period Adjustments (Form 2E, Line 10)	$ -
4.	Prior Period True-Up Amount to be Refunded/(Recovered) in the Projection Period January - December 2021 (Lines 1 + 2 + 3)	$ (5,986,696)

TAMPA ELECTRIC COMPANY
DOCKET NO. 20200092-EI
EXHIBIT NO. MRR-1
DOCUMENT NO. 4
WITNESS: ROCHE
PAGE 2 OF 16
FILED: 07/24/2020

Form 2E
Page 1 of 1

Tampa Electric Company
Storm Protection Plan Cost Recovery Clause
Calculation of Current Period Actual/Estimated Amount
Current Period: January through December 2020

Calculation of True-Up Amount
(in Dollars)

Line		Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimate July	Estimate August	Estimate September	Estimate October	Estimate November	Estimate December	End of Period Total
1.	Clause Revenues (net of Revenue Taxes)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2.	True-Up Provision	0	0	0	0	0	0	0	0	0	0	0	0	0
3.	Clause Revenues Applicable to Period (Lines 1 + 2)	0	0	0	0	0	0	0	0	0	0	0	0	0
4.	Jurisdictional SPPCRC Costs													
	a. O&M Activities (Form 5E, Line 13) (A)	111,566	14,183	467,638	400,504	644,584	414,448	896,948	492,050	726,641	782,818	290,567	323,139	5,565,085
	b. Capital Investment Projects (Form 7E, Line 7.c.)	0	0	0	4	105	1,073	8,427	26,223	48,785	80,031	111,218	137,706	413,571
	c. Total Jurisdictional SPPCRC Costs	111,566	14,183	467,638	400,508	644,689	415,521	905,374	518,273	775,426	862,848	401,784	460,846	5,978,656
5.	Over/Under Recovery (Line 3 - Line 4c)	(111,566)	(14,183)	(467,638)	(400,508)	(644,689)	(415,521)	(905,374)	(518,273)	(775,426)	(862,848)	(401,784)	(460,846)	(5,978,656)
6.	Interest Provision (Form 3E, Line 10)	0	0	0	0	(79)	(148)	(501)	(1,030)	(1,238)	(1,500)	(1,703)	(1,841)	(8,040)
7.	Beginning Balance True-Up & Interest Provision	0	(111,566)	(125,749)	(593,387)	(993,895)	(1,638,663)	(2,054,332)	(2,960,207)	(3,479,510)	(4,256,174)	(5,120,522)	(5,524,009)	0
	a. Deferred True-Up from January to December 2019 (Order No. PSC-20xx-xxxx-FOF-EI)	0	0	0	0	0	0	0	0	0	0	0	0	0
8.	True-Up Collected/(Refunded) (see Line 2)	0	0	0	0	0	0	0	0	0	0	0	0	0
9.	End of Period Total True-Up (Lines 5+6+7+7a+8)	(111,566)	(125,749)	(593,387)	(993,895)	(1,638,663)	(2,054,332)	(2,960,207)	(3,479,510)	(4,256,174)	(5,120,522)	(5,524,009)	(5,986,696)	(5,986,696)
10.	Adjustment to Period True-Up Including Interest	0	0	0	0	0	0	0	0	0	0	0	0	0
11.	End of Period Total True-Up (Lines 9 + 10)	$ (111,566)	$ (125,749)	$ (593,387)	$ (993,895)	$ (1,638,663)	$ (2,054,332)	$ (2,960,207)	$ (3,479,510)	$ (4,256,174)	$ (5,120,522)	$ (5,524,009)	$ (5,986,696)	$ (5,986,696)

Notes:
(A) Included in line 4a above, are costs related to the planning and design of the Storm Protection Plan and its associated projects and activities.

TAMPA ELECTRIC COMPANY
DOCKET NO. 20200092-EI
EXHIBIT NO. MRR-1
DOCUMENT NO. 4
WITNESS: ROCHE
PAGE 3 OF 16
FILED: 07/24/2020

Form 3E

Tampa Electric Company
Storm Protection Plan Cost Recovery Clause
Calculation of Current Period Actual/Estimated Amount
Current Period: January through December 2020

Calculation of Interest Provision for True-Up Amount
(in Dollars)

Line	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimate July	Estimate August	Estimate September	Estimate October	Estimate November	Estimate December	End of Period Total
1. Beginning True-Up Amount (Form 2E, Line 7+7a+10)	$ -	$ (111,566)	$ (125,749)	$ (593,387)	$ (993,895)	$ (1,638,663)	$ (2,054,332)	$ (2,960,207)	$ (3,479,510)	$ (4,256,174)	$ (5,120,522)	$ (5,524,009)	
2. Ending True-Up Amount Before Interest	(111,566)	(125,749)	(593,387)	(993,895)	(1,638,584)	(2,054,184)	(2,959,706)	(3,478,480)	(4,254,936)	(5,119,022)	(5,522,306)	(5,984,855)	
3. Total of Beginning & Ending True-Up (Lines 1 + 2)	(111,566)	(237,315)	(719,136)	(1,587,282)	(2,632,479)	(3,692,847)	(5,014,038)	(6,438,687)	(7,734,446)	(9,375,196)	(10,642,828)	(11,508,864)	
4. Average True-Up Amount (Line 3 x 1/2)	(55,783)	(118,658)	(359,568)	(793,641)	(1,316,240)	(1,846,424)	(2,507,019)	(3,219,344)	(3,867,223)	(4,687,598)	(5,321,414)	(5,754,432)	
5. Interest Rate (First Day of Reporting Business Month)	1.71%	1.64%	1.56%	2.21%	0.06%	0.08%	0.11%	0.38%	0.38%	0.38%	0.38%	0.38%	
6. Interest Rate (First Day of Subsequent Business Month)	1.64%	1.56%	2.21%	0.06%	0.08%	0.11%	0.38%	0.38%	0.38%	0.38%	0.38%	0.38%	
7. Total of Beginning & Ending Interest Rates (Lines 5 + 6)	3.35%	3.20%	3.77%	2.27%	0.14%	0.19%	0.49%	0.76%	0.76%	0.76%	0.76%	0.76%	
8. Average Interest Rate (Line 7 x 1/2)	1.675%	1.600%	1.885%	1.135%	0.070%	0.095%	0.245%	0.380%	0.380%	0.380%	0.380%	0.380%	
9. Monthly Average Interest Rate (Line 8 x 1/12)	0.140%	0.133%	0.157%	0.095%	0.006%	0.008%	0.020%	0.032%	0.032%	0.032%	0.032%	0.032%	
10. Interest Provision for the Month (Line 4 x Line 9)	$ -	$ -	$ -	$ -	$ (79)	$ (148)	$ (501)	$ (1,030)	$ (1,238)	$ (1,500)	$ (1,703)	$ (1,841)	$ (8,040)

Form 5E
Page 1 of 1

Tampa Electric Company
Storm Protection Plan Cost Recovery Clause
Calculation of Current Period Actual/Estimated Amount
Current Period: January through December 2020

Calculation of Annual Revenue Requirements for O&M Programs
(in Dollars)

Line	O&M Activities	T/D	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimate July	Estimate August	Estimate September	Estimate October	Estimate November	Estimate December	End of Period Total	Method of Classification Demand	Method of Classification Energy
1.	Vegetation Management O&M Programs																
	1. Distribution Vegetation Management - Planned	D	$ -	$ -	$ -	$ -	$ 1,656,458	$ 1,275,346	$ 1,751,901	$ 1,442,978	$ 1,381,183	$ 1,774,090	$ 1,567,316	$ 1,889,280	$ 12,738,553	100%	0%
	2. Transmission Vegetation Management - Planned	T	$ -	$ -	$ -	$ -	$ 96,954	$ 90,527	$ 106,903	$ 72,675	$ 72,675	$ 13,367	$ 45,868	$ 45,868	$ 544,837	100%	0%
	3. Transmission Vegetation Management - ROW	T	$ -	$ -	$ -	$ -	$ 42,700	$ 36,506	$ 43,081	$ 52,159	$ 52,159	$ 64,039	$ 52,159	$ 64,039	$ 406,842	100%	0%
1.a.	Adjustment		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	100%	0%
1.b.	Subtotal of Vegetation Management Programs		$ -	$ -	$ -	$ -	$ 1,796,112	$ 1,402,378	$ 1,901,885	$ 1,567,812	$ 1,506,017	$ 1,851,496	$ 1,665,343	$ 1,999,187	$ 13,690,231	-	
2.	Asset Upgrade O&M Programs		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -			
	1. Transmission Asset Upgrades	T	$ -	$ -	$ -	$ -	$ -	$ -	$ 29,254	$ 29,348	$ 37,593	$ 25,789	$ 25,572	$ 17,564	$ 165,120	100%	0%
2.a.	Adjustment		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	100%	0%
2.b.	Subtotal of Asset Upgrade O&M Programs		$ -	$ -	$ -	$ -	$ -	$ -	$ 29,254	$ 29,348	$ 37,593	$ 25,789	$ 25,572	$ 17,564	$ 165,120		
3.	Substation Protection O&M Programs																
	1. Substation Extreme Weather Protection	D	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	100%	0%
3.a.	Adjustment		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	100%	0%
3.b.	Subtotal of Substation Protection O&M Programs		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		
4.	Overhead Feeder Hardening Programs																
	1. Distribution Overhead Feeder Hardening	D	$ -	$ -	$ -	$ -	$ 289	$ -	$ -	$ 5,546	$ 29,183	$ 50,641	$ 50,044	$ 40,285	$ 175,988	100%	0%
4.a.	Adjustment		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	100%	0%
4.b.	Subtotal of Vegetation Management O&M Programs		$ -	$ -	$ -	$ -	$ 289	$ -	$ -	$ 5,546	$ 29,183	$ 50,641	$ 50,044	$ 40,285	$ 175,988		
5.	Transmission Access O&M Programs																
	1. Transmission Access Enhancement	T	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	100%	0%
5.a.	Adjustment		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	100%	0%
5.b.	Subtotal of Transmission Access O&M Programs		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		
6.	Infrastructure Inspection O&M Programs																
	1. Distribution Infrastructure Inspections	D	$ -	$ -	$ -	$ -	$ 83,786	$ 56,229	$ 250	$ 250	$ 250	$ 250	$ 250	$ 250	$ 141,515	100%	0%
	2. Transmission Infrastructure Inspections	T	$ -	$ -	$ -	$ -	$ 19,387	$ 25,616	$ 67,255	$ 50,150	$ 114,065	$ 73,150	$ 34,250	$ 35,954	$ 419,827	100%	0%
6.a.	Adjustment		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	100%	0%
6.b.	Subtotal of Infrastructure Inspection O&M Programs		$ -	$ -	$ -	$ -	$ 103,173	$ 81,845	$ 67,505	$ 50,400	$ 114,315	$ 73,400	$ 34,500	$ 36,204	$ 561,341		
7.	Common SPP O&M Programs																
	1. Common O&M (A)	D	$ 111,566	$ 14,183	$ 467,638	$ 400,504	$ 79,892	$ 48,317	$ 45,520	$ 55,220	$ 45,220	$ 57,920	$ 45,220	$ 45,220	$ 1,416,419	100%	0%
7.a.	Adjustment		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	100%	0%
7.b.	Subtotal of Common SPP O&M Programs		$ 111,566	$ 14,183	$ 467,638	$ 400,504	$ 79,892	$ 48,317	$ 45,520	$ 55,220	$ 45,220	$ 57,920	$ 45,220	$ 45,220	$ 1,416,419		
8.	Total of O&M Programs		111,566	14,183	467,638	400,504	1,979,466	1,532,540	2,044,165	1,708,326	1,732,328	2,059,246	1,820,679	2,138,460	16,009,101		
	a. Total Distribution O&M Programs		111,566	14,183	467,638	400,504	1,820,425	1,379,892	1,797,672	1,503,994	1,455,836	1,882,901	1,662,830	1,975,035	14,472,476		
	b. Total Transmission O&M Programs		0	0	0	0	159,041	152,648	246,493	204,332	276,492	176,345	157,849	163,425	1,536,625		
9.	Allocation of O&M Costs																
	a. Distribution O&M Allocated to Demand		111,566	14,183	467,638	400,504	1,820,425	1,379,892	1,797,672	1,503,994	1,455,836	1,882,901	1,662,830	1,975,035	14,472,476		
	b. Transmission O&M Allocated to Demand		0	0	0	0	159,041	152,648	246,493	204,332	276,492	176,345	157,849	163,425	1,536,625		
	c. Distribution O&M Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0		
	d. Transmission O&M Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0		
10.	a. Less 2020 Base Revenue O&M Threshold - Distribution		0	0	0	0	(1,203,233)	(998,795)	(1,079,524)	(1,137,196)	(842,053)	(1,144,186)	(1,374,598)	(1,672,961)	(9,452,547)		
	b. Less 2020 Base Revenue O&M Threshold - Transmission		0	0	0	0	(129,437)	(116,604)	(53,257)	(68,968)	(154,522)	(128,682)	(155,325)	(140,659)	(947,453)		
	c. Total Threshold Amount Removed (B)		0	0	0	0	(1,332,670)	(1,115,399)	(1,132,781)	(1,206,164)	(996,575)	(1,272,868)	(1,529,924)	(1,813,620)	(10,400,000)		
															-		
11.	Retail Jurisdictional Factors																
	a. Distribution Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000			
	b. Transmission Demand Jurisdictional Factor		0.9252920	0.9252920	0.9252920	0.9252920	0.9252920	0.9252920	0.9252920	0.9252920	0.9252920	0.9252920	0.9252920	0.9252920			
	c. Distribution Energy Jurisdictional Factor		0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000			
	d. Transmission Energy Jurisdictional Factor		0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000			
12.	Jurisdictional Revenue Requirements																
	a. Jurisdictional Distribution Demand Revenue Requirement		111,566	14,183	467,638	400,504	617,192	381,096.96	718,148	366,798	613,783	738,715	288,232	302,074	5,019,929		
	b. Jurisdictional Transmission Demand Revenue Requirement		-	-	-	-	27,392	33,351.30	178,800	125,251	112,858	44,103	2,335	21,065	545,156		
	c. Jurisdictional Distribution Energy Revenue Requirement		-	-	-	-	-	-	-	-	-	-	-	-	-		
	d. Jurisdictional Transmission Energy Revenue Requirement		-	-	-	-	-	-	-	-	-	-	-	-	-		
13.	Total Jurisdictional O&M Revenue Requirements		111,566	14,183	467,638	400,504	644,584	414,448	896,948	492,050	726,641	782,818	290,567	323,139	5,565,085	-	
							-	-	-	-	-	-	-	-			

Notes:
(A) Included in line 7.1 above, are costs related to the planning and design of the Storm Protection Plan and its associated projects and activities.
(B) As per the Order No. PSC-2020-0224-AS-EI, issued June 30, 2020 - Final Order Approving Settlement Agreement

Tampa Electric Company
Storm Protection Plan Cost Recovery Clause
Calculation of Current Period Actual/Estimated Amount
Current Period: January through December 2020
Project Listing by Each O&M Program

Line	O&M Activities	T or D
1.	Vegetation Management O&M Programs	
	1.1 Distribution Vegetation Management - Planned	
	1.1.1 PRE - Dist Line - Tree Trimming - Planned	D
	1.1.2 Dist SPP Supplemental	D
	1.1.3 Dist SPP Mid-Cycle	D
	1.2 Transmission Vegetation Management - Planned	
	1.2.1 PRE - ROW Clearance	T
	1.2.2 PRE - Trans Line - Tree Trimming/Removals - Planned	T
	1.2.3 Trans SPP 69kV Reclamation	T
2.	Asset Upgrade O&M Programs	
	2.1 Transmission Asset Upgrades	
	2.1.1 SPP TAU - Circuit 66654	T
	2.1.2 SPP TAU - Circuit 66840	T
	2.1.3 SPP TAU - Circuit 66007	T
	2.1.4 SPP TAU - Circuit 66019	T
	2.1.5 SPP TAU - Circuit 66425	T
	2.1.6 SPP TAU - Circuit 230403	T
	2.1.7 SPP TAU - Circuit 66413	T
	2.1.8 SPP TAU - Circuit 66046	T
	2.1.9 SPP TAU - Circuit 66059	T
	2.1.10 SPP TAU - Circuit 230008	T
	2.1.11 SPP TAU - Circuit 230010	T
	2.1.12 SPP TAU - Circuit 230038	T
	2.1.13 SPP TAU - Circuit 230003	T
	2.1.14 SPP TAU - Circuit 230005	T
	2.1.15 SPP TAU - Circuit 230004	T
	2.1.16 SPP TAU - Circuit 230625	T
	2.1.17 SPP TAU - Circuit 230021	T
	2.1.18 SPP TAU - Circuit 230052	T
	2.1.19 SPP TAU - Circuit 66024	T
	2.1.20 SPP TAU - Circuit 230608	T
	2.1.21 SPP TAU - Circuit 230603	T
3.	Substation Protection O&M Programs	
	3.1 Substation Extreme Weather Protection	
	3.1.1 none	D
4	Overhead Feeder Hardening O&M Programs	
	4.1 Distribution Overhead Feeder Hardening	
	4.1.1 SPP FH - E Winterhaven 13308	D
	4.1.2 SPP FH - Knights 13807	D
	4.1.3 SPP FH - Knights 13805	D
	4.1.4 SPP FH - Casey Road 13745	D
	4.1.5 SPP FH - Coolidge 13533	D
	4.1.6 SPP FH - 13461	D
	4.1.7 SPP FH - 14121	D
	4.1.8 SPP FH - 13939	D
	4.1.9 SPP FH - 13890	D
	4.1.10 SPP FH - 13443	D
	4.1.11 SPP FH - 13227	D
	4.1.12 SPP FH - 13462	D
	4.1.13 SPP FH - 13633	D
5	Transmission Access O&M Programs	
	5 Transmission Access Enhancement	
	5.1.1 none	T
6	Infrastructure Inspection O&M Programs	
	6 Distribution Infrastructure Inspections	
	6.1.1 PRE - Dist Line - Pole Inspection Program	D
	6 Transmission Infrastructure Inspections	
	6.2.1 PRE - Trans Line - Routine Patrols	T
	6.2.2 PRE - Trans Line - Above-Ground Inspections	T
	6.2.3 PRE - Trans Line - Infared Inspections	T
	6.2.4 PRE - Trans Line - Pole Inspection Program	T
	6.2.5 PRE - Substation - Transmission - Inspection, Test	T
	6.2.6 PRE - Substation - Transmission - Inspect, Test - GSU	T
7	Common SPP O&M Programs	
	7 Common O&M Programs	
	7.1.1 SPP Common O&M - ED	D
	7.1.2 SPP Common O&M - Regulatory	D
	7.1.3 Planning & Admin	D

TAMPA ELECTRIC COMPANY
DOCKET NO. 20200092-EI
EXHIBIT NO. MRR-1
DOCUMENT NO. 4
WITNESS: ROCHE
PAGE 6 OF 16
FILED: 07/24/2020

Tampa Electric Company
Storm Protection Plan Cost Recovery Clause (SPPCRC)
Calculation of the Current Period Actual/Estimated Amount
Current Period: January through December 2020

Summary of Monthly Revenue Requirements for Capital Investment Programs
(in Dollars)

Line	Capital Investment Activities	T/D	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimate July	Estimate August	Estimate September	Estimate October	Estimate November	Estimate December	End of Period Total
1.	Distribution Lateral Undergrounding Program	D	$ -	$ -	$ -	$ -	$ -	$ -	$ 3,452	$ 11,025	$ 19,699	$ 29,787	$ 41,576	$ 53,455	$ 158,994
1.a.	Adjustments	D	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1.b.	Subtotal of Distribution Lateral Undergrounding Program	D	$ -	$ -	$ -	$ -	$ -	$ -	$ 3,452	$ 11,025	$ 19,699	$ 29,787	$ 41,576	$ 53,455	$ 158,994
1.c.	Jurisdictional Demand Revenue Requirements		$ -	$ -	$ -	$ -	$ -	$ -	$ 3,452	$ 11,025	$ 19,699	$ 29,787	$ 41,576	$ 53,455	$ 158,994
1.d.	Jurisdictional Energy Revenue Requirements		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2	Transmission Asset Upgrades Program	T	$ -	$ -	$ -	$ 4	$ 66	$ 977	$ 5,052	$ 14,472	$ 22,724	$ 33,306	$ 41,819	$ 49,175	$ 167,595
2.a.	Adjustments	T	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2.b.	Subtotal of Transmission Asset Upgrades Program	T	$ -	$ -	$ -	$ 4	$ 66	$ 977	$ 5,052	$ 14,472	$ 22,724	$ 33,306	$ 41,819	$ 49,175	$ 167,595
2.c.	Jurisdictional Demand Revenue Requirements		$ -	$ -	$ -	$ 4	$ 61	$ 904	$ 4,675	$ 13,391	$ 21,026	$ 30,818	$ 38,695	$ 45,501	$ 155,074
2.d.	Jurisdictional Energy Revenue Requirements		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3	Substation Extreme Weather Program	D	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3.a.	Adjustments	D	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3.b.	Subtotal of Substation Extreme Weather Program	D	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3.c. b	Jurisdictional Demand Revenue Requirements		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3.d. a	Jurisdictional Energy Revenue Requirements		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4	Distribution Overhead Feeder Hardening Program	D	$ -	$ -	$ -	$ -	$ 44	$ 169	$ 300	$ 1,807	$ 8,060	$ 19,426	$ 30,947	$ 38,750	$ 99,503
4.a.	Adjustments	D	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4.b.	Subtotal of Distribution Overhead Feeder Hardening Program	D	$ -	$ -	$ -	$ -	$ 44	$ 169	$ 300	$ 1,807	$ 8,060	$ 19,426	$ 30,947	$ 38,750	$ 99,503
4.c.	Jurisdictional Demand Revenue Requirements		$ -	$ -	$ -	$ -	$ 44	$ 169	$ 300	$ 1,807	$ 8,060	$ 19,426	$ 30,947	$ 38,750	$ 99,503
4.d.	Jurisdictional Energy Revenue Requirements		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5	Transmission Access Enhancement Program	T	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5.a.	Adjustments	T	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5.b.	Subtotal of Transmission Access Enhancement Program	T	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5.c.	Jurisdictional Demand Revenue Requirements		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5.d.	Jurisdictional Energy Revenue Requirements		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
6	Retail Jurisdictional Factors														
6.a.	Distribution Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
6.b.	Transmission Demand Jurisdictional Factor		0.9252920	0.9252920	0.9252920	0.9252920	0.9252920	0.9252920	0.9252920	0.9252920	0.9252920	0.9252920	0.9252920	0.9252920	
6.c.	Distribution Energy Jurisdictional Factor		0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	
6.d.	Transmission Energy Jurisdictional Factor		0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	
7	Total of Capital Investment Programs		$ -	$ -	$ -	$ 4	$ 110	$ 1,146	$ 8,804	$ 27,304	$ 50,483	$ 82,519	$ 114,342	$ 141,380	$ 426,092
7.a.	Jurisdictional Distribution Demand Revenue Requirements		$ -	$ -	$ -	$ -	$ 44	$ 169	$ 3,752	$ 12,832	$ 27,759	$ 49,213	$ 72,523	$ 92,205	$ 258,497
7.b.	Jurisdictional Transmission Demand Revenue Requirements		$ -	$ -	$ -	$ 4	$ 61	$ 904	$ 4,675	$ 13,391	$ 21,026	$ 30,818	$ 38,695	$ 45,501	$ 155,074
7.c.	Total Jurisdictional Demand Revenue Requirements		$ -	$ -	$ -	$ 4	$ 105	$ 1,073	$ 8,427	$ 26,223	$ 48,785	$ 80,031	$ 111,218	$ 137,706	$ 413,571
			-	-	-	-	-	-	-	-	-	-	-	-	-

Notes:
Jurisdictional Energy and Demand Revenue Requirements are calculated on the detailed 7E tabs.

TAMPA ELECTRIC COMPANY
DOCKET NO. 20200092-EI
EXHIBIT NO. MRR-1
DOCUMENT NO. 4
WITNESS: ROCHE
PAGE 7 OF 16
FILED: 07/24/2020

Tampa Electric Company
Storm Protection Plan Cost Recovery Clause (SPPCRC)
Calculation of the Current Period Actual/Estimated Amount
January 2020 to December 2020

Return on Capital Investments, Depreciation and Taxes
For Program: Distribution Lateral Undergrounding
(in Dollars)

Line	Description	Beginning of Period Amount	2020 January	2020 February	2020 March	2020 April	2020 May	2020 June	2020 July	2020 August	2020 September	2020 October	2020 November	2020 December	2020 TOTAL
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$1,061,948	$1,267,585	$1,400,368	$1,702,714	$1,923,774	$1,730,291	$9,086,680
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1,418,599	$1,418,599
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2.	Plant-in-Service/Depreciation Base	$0	0	0	0	0	0	0	0	0	0	0	0	1,418,599	
3.	Less: Net Accumulated Depreciation	0	0	0	0	0	0	0	0	0	0	0	0	0	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	1,061,948	2,329,533	3,729,901	5,432,615	7,356,389	7,668,081	
5.	Net Investment (Lines 2 + 3 + 4)	$0	0	0	0	0	0	0	1,061,948	2,329,533	3,729,901	5,432,615	7,356,389	9,086,680	
														-	
6.	Average Net Investment		0	0	0	0	0	0	530,974	1,695,741	3,029,717	4,581,258	6,394,502	8,221,535	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (A)		0	0	0	0	0	0	2,659	8,492	15,173	22,943	32,024	41,173	122,464
	b. Debt Component Grossed Up For Taxes (B)		0	0	0	0	0	0	793	2,533	4,526	6,844	9,552	12,282	36,530
			0	0	0	0	0	0	3,452	11,025	19,699	29,787	41,576	53,455	158,994
8.	Investment Expenses														
	a. Depreciation (C)		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Depreciation Savings (D)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Property Taxes (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
	f. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		0	0	0	0	0	0	3,452	11,025	19,699	29,787	41,576	53,455	158,994
	a. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	3,452	11,025	19,699	29,787	41,576	53,455	158,994
	b. Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Distribution Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Distribution Energy Jurisdictional Factor		0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	
12.	Retail Distribution Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	3,452	11,025	19,699	29,787	41,576	53,455	158,994
13.	Retail Distribution Energy-Related Recoverable Costs (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$0	$0	$0	$0	$0	$0	$3,452	$11,025	$19,699	$29,787	$41,576	$53,455	$158,994
															-

Notes:
(A) Line 6 x 5.9635% x 1/12 (Jan-Jun) and Line 6 x 6.0096% x 1/12 (Jul-Dec). Based on ROE of 10.25% and weighted income tax rate of 24.522% (expansion factor of 1.32830)
(B) Line 6 x 1.7369% x 1/12 (Jan-Jun) and Line 6 x 1.7926% x 1/12 (Jul-Dec).
(C) Applicable depreciation group for additions is 367.0 and applicable depreciation rate is 3.0%
(D) Applicable depreciation group for retirements is 364.0 and applicable depreciation savings rate is 4.4%
(E) Ad Valorem Tax Rate is 1.76%
(F) Line 9a x line 10
(G) Line 9b x line 11

Tampa Electric Company
Storm Protection Plan Cost Recovery Clause (SPPCRC)
Calculation of the Current Period Actual/Estimated Amount
January 2020 to December 2020

Return on Capital Investments, Depreciation and Taxes
For Program: Transmission Asset Upgrades
(in Dollars)

Line	Description	Beginning of Period Amount	2020 January	2020 February	2020 March	2020 April	2020 May	2020 June	2020 July	2020 August	2020 September	2020 October	2020 November	2020 December	2020 TOTAL
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$1,360	$17,764	$266,399	$982,915	$948,240	$1,241,600	$897,000	$877,920	$569,750	$5,802,948
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$1,167,526	$428,260	$1,359,526	$1,038,369	$1,010,716	$0	$5,004,398
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2.	Plant-in-Service/Depreciation Base	$0	0	0	0	0	0	0	1,167,526	1,595,786	2,955,312	3,993,682	5,004,398	5,004,398	
3.	Less: Net Accumulated Depreciation	0	0	0	0	0	0	0	0	(3,152)	(7,461)	(15,440)	(26,223)	(39,735)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	1,360	19,124	285,523	100,911	620,891	502,966	361,596	228,800	798,550	
5.	Net Investment (Lines 2 + 3 + 4)	$0	0	0	0	1,360	19,124	285,523	1,268,438	2,213,526	3,450,817	4,339,838	5,206,975	5,763,213	
														-	
6.	Average Net Investment		0	0	0	680	10,242	152,324	776,981	1,740,982	2,832,171	3,895,327	4,773,406	5,485,094	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (A)		0	0	0	3	51	757	3,891	8,719	14,184	19,508	23,905	27,469	98,487
	b. Debt Component Grossed Up For Taxes (B)		0	0	0	1	15	220	1,161	2,601	4,231	5,819	7,131	8,194	29,373
			0	0	0	4	66	977	5,052	11,320	18,415	25,327	31,036	35,663	127,860
8.	Investment Expenses														
	a. Depreciation (C)		0	0	0	0	0	0	0	3,503	4,787	8,866	11,981	15,013	44,150
	b. Depreciation Savings (D)		0	0	0	0	0	0	0	(350)	(479)	(887)	(1,198)	(1,501)	(4,415)
	c. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Property Taxes (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
	f. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		0	0	0	4	66	977	5,052	14,472	22,724	33,306	41,819	49,175	167,595
	a. Recoverable Costs Allocated to Demand		0	0	0	4	66	977	5,052	14,472	22,724	33,306	41,819	49,175	167,595
	b. Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Transmission Demand Jurisdictional Factor		0.9252920	0.9252920	0.9252920	0.9252920	0.9252920	0.9252920	0.9252920	0.9252920	0.9252920	0.9252920	0.9252920	0.9252920	
11.	Transmission Energy Jurisdictional Factor		0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	
12.	Retail Distribution Demand-Related Recoverable Costs (F)		0	0	0	4	61	904	4,675	13,391	21,026	30,818	38,695	45,501	155,074
13.	Retail Distribution Energy-Related Recoverable Costs (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$0	$0	$0	$4	$61	$904	$4,675	$13,391	$21,026	$30,818	$38,695	$45,501	$155,074
															-

Notes:
(A) Line 6 x 5.9635% x 1/12 (Jan-Jun) and Line 6 x 6.0096% x 1/12 (Jul-Dec). Based on ROE of 10.25% and weighted income tax rate of 24.522% (expansion factor of 1.32830)
(B) Line 6 x 1.7369% x 1/12 (Jan-Jun) and Line 6 x 1.7926% x 1/12 (Jul-Dec).
(C) Applicable depreciation group for additions is 355.0 and applicable depreciation rate is 3.6%
(D) Applicable depreciation group for retirements is 355.0 and applicable depreciation savings rate is 3.6%
(E) Ad Valorem Tax Rate is 1.76%
(F) Line 9a x line 10
(G) Line 9b x line 11

TAMPA ELECTRIC COMPANY
DOCKET NO. 20200092-EI
EXHIBIT NO. MRR-1
DOCUMENT NO. 4
WITNESS: ROCHE
PAGE 9 OF 16
FILED: 07/24/2020

Tampa Electric Company
Storm Protection Plan Cost Recovery Clause (SPPCRC)
Calculation of the Current Period Actual/Estimated Amount
January 2020 to December 2020

Return on Capital Investments, Depreciation and Taxes
For Program: Substation Extreme Weather Protection
(in Dollars)

Line	Description	Beginning of Period Amount	2020 January	2020 February	2020 March	2020 April	2020 May	2020 June	2020 July	2020 August	2020 September	2020 October	2020 November	2020 December	2020 TOTAL
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2.	Plant-in-Service/Depreciation Base	$0	0	0	0	0	0	0	0	0	0	0	0	0	
3.	Less: Net Accumulated Depreciation	0	0	0	0	0	0	0	0	0	0	0	0	0	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$0	0	0	0	0	0	0	0	0	0	0	0	0	
6.	Average Net Investment		0	0	0	0	0	0	0	0	0	0	0	0	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (A)		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Debt Component Grossed Up For Taxes (B)		0	0	0	0	0	0	0	0	0	0	0	0	0
			0	0	0	0	0	0	0	0	0	0	0	0	0
8.	Investment Expenses														
	a. Depreciation (C)		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Depreciation Savings (D)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Property Taxes (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
	f. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		0	0	0	0	0	0	0	0	0	0	0	0	0
	a. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Distribution Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Distribution Energy Jurisdictional Factor		0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	
12.	Retail Distribution Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
13.	Retail Distribution Energy-Related Recoverable Costs (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

Notes:
(A) Line 6 x 5.9635% x 1/12 (Jan-Jun) and Line 6 x 6.0096% x 1/12 (Jul-Dec). Based on ROE of 10.25% and weighted income tax rate of 24.522% (expansion factor of 1.32830)
(B) Line 6 x 1.7369% x 1/12 (Jan-Jun) and Line 6 x 1.7926% x 1/12 (Jul-Dec).
(C) Applicable depreciation group for additions is 362.0 and applicable depreciation rate is 2.4%
(D) No retirements are anticipated for this program
(E) Ad Valorem Tax Rate is 1.76%
(F) Line 9a x line 10
(G) Line 9b x line 11

Tampa Electric Company
Storm Protection Plan Cost Recovery Clause (SPPCRC)
Calculation of the Current Period Actual/Estimated Amount
January 2020 to December 2020

Return on Capital Investments, Depreciation and Taxes
For Program: Distribution Overhead Feeder Hardening
(in Dollars)

Line	Description	Beginning of Period Amount	2020 January	2020 February	2020 March	2020 April	2020 May	2020 June	2020 July	2020 August	2020 September	2020 October	2020 November	2020 December	2020 TOTAL
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$13,653	$25,482	$14,000	$449,802	$1,473,194	$2,023,263	$1,520,662	$879,700	$6,399,756
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$6,156,888	$6,156,888
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2.	Plant-in-Service/Depreciation Base (A)	$0	0	0	0	0	0	0	0	0	0	0	0	6,156,888	
3.	Less: Net Accumulated Depreciation	0	0	0	0	0	0	0	0	0	0	0	0	0	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	13,653	39,135	53,135	502,937	1,976,131	3,999,394	5,520,056	242,868	
5.	Net Investment (Lines 2 + 3 + 4)	$0	0	0	0	0	13,653	39,135	53,135	502,937	1,976,131	3,999,394	5,520,056	6,399,756	
														-	
6.	Average Net Investment		0	0	0	0	6,826	26,394	46,135	278,036	1,239,534	2,987,762	4,759,725	5,959,906	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (A)		0	0	0	0	34	131	231	1,392	6,208	14,963	23,837	29,847	76,643
	b. Debt Component Grossed Up For Taxes (B)		0	0	0	0	10	38	69	415	1,852	4,463	7,110	8,903	22,860
			0	0	0	0	44	169	300	1,807	8,060	19,426	30,947	38,750	99,503
8.	Investment Expenses														
	a. Depreciation (C)		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Depreciation Savings (D)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Property Taxes (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
	f. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
	a. Recoverable Costs Allocated to Demand		0	0	0	0	44	169	300	1,807	8,060	19,426	30,947	38,750	99,503
	b. Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Distribution Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Distribution Energy Jurisdictional Factor		0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	
12.	Retail Distribution Demand-Related Recoverable Costs (F)		0	0	0	0	44	169	300	1,807	8,060	19,426	30,947	38,750	99,503
13.	Retail Distribution Energy-Related Recoverable Costs (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$0	$0	$0	$0	$44	$169	$300	$1,807	$8,060	$19,426	$30,947	$38,750	$99,503
															-

Notes:
(A) Line 6 x 5.9635% x 1/12 (Jan-Jun) and Line 6 x 6.0096% x 1/12 (Jul-Dec). Based on ROE of 10.25% and weighted income tax rate of 24.522% (expansion factor of 1.32830)
(B) Line 6 x 1.7369% x 1/12 (Jan-Jun) and Line 6 x 1.7926% x 1/12 (Jul-Dec).
(C) Applicable depreciation group for additions is 364.0 and applicable depreciation rate is 4.4%
(D) Applicable depreciation group for retirements is 364.0 and applicable depreciation savings rate is 4.4%
(E) Ad Valorem Tax Rate is 1.76%
(F) Line 9a x line 10
(G) Line 9b x line 11

TAMPA ELECTRIC COMPANY
DOCKET NO. 20200092-EI
EXHIBIT NO. MRR-1
DOCUMENT NO. 4
WITNESS: ROCHE
PAGE 11 OF 16
FILED: 07/24/2020

Tampa Electric Company
Storm Protection Plan Cost Recovery Clause (SPPCRC)
Calculation of the Current Period Actual/Estimated Amount
January 2020 to December 2020

Return on Capital Investments, Depreciation and Taxes
For Program: Transmission Access Enhancements
(in Dollars)

Line	Description	Beginning of Period Amount	2020 January	2020 February	2020 March	2020 April	2020 May	2020 June	2020 July	2020 August	2020 September	2020 October	2020 November	2020 December	2020 TOTAL
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2.	Plant-in-Service/Depreciation Base	$0	0	0	0	0	0	0	0	0	0	0	0	0	
3.	Less: Net Accumulated Depreciation	0	0	0	0	0	0	0	0	0	0	0	0	0	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$0	0	0	0	0	0	0	0	0	0	0	0	0	
6.	Average Net Investment		0	0	0	0	0	0	0	0	0	0	0	0	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (A)		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Debt Component Grossed Up For Taxes (B)		0	0	0	0	0	0	0	0	0	0	0	0	0
			0	0	0	0	0	0	0	0	0	0	0	0	0
8.	Investment Expenses														
	a. Depreciation (C)		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Depreciation Savings (D)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Property Taxes (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
	f. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		0	0	0	0	0	0	0	0	0	0	0	0	0
	a. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Transmission Demand Jurisdictional Factor		0.9252920	0.9252920	0.9252920	0.9252920	0.9252920	0.9252920	0.9252920	0.9252920	0.9252920	0.9252920	0.9252920	0.9252920	
11.	Transmission Energy Jurisdictional Factor		0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	
12.	Retail Distribution Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
13.	Retail Distribution Energy-Related Recoverable Costs (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

Notes:
(A) Line 6 x 5.9635% x 1/12 (Jan-Jun) and Line 6 x 6.0096% x 1/12 (Jul-Dec). Based on ROE of 10.25% and weighted income tax rate of 24.522% (expansion factor of 1.32830)
(B) Line 6 x 1.7369% x 1/12 (Jan-Jun) and Line 6 x 1.7926% x 1/12 (Jul-Dec).
(C) Applicable depreciation group for additions is 359.0 and applicable depreciation rate is 1.5%
(D) No retirements are anticipated for this program
(E) Ad Valorem Tax Rate is 1.76%
(F) Line 9a x line 10
(G) Line 9b x line 11

Tampa Electric Company
Storm Protection Plan Cost Recovery Clause
Calculation of Current Period Actual/Estimated Amount
Current Period: January through December 2020
Project Listing by Each Capital Program

Line	Capital Activities	Revenue Requirement	T or D
1.	Distribution Lateral Undergrounding Program		
1.1	LUG PCA 13390.92599119		D
1.2	LUG PCA 13961.92829453		D
1.3	LUG PCA 13724.90911087		D
1.4	LUG PCA 13146.10629014		D
1.5	LUG WHA 13972.92421291		D
1.6	LUG WHA 13312.60182741		D
1.7	LUG WHA 13972.90241880		D
1.8	LUG PCA 13961.92820848		D
1.9	LUG PCA 13961.60193482		D
1.10	LUG PCA 13785.10676209		D
1.11	LUG PCA 13462.60458175		D
1.12	LUG PCA 14121.93159006		D
1.13	LUG PCA 13462.60180762		D
1.14	LUG PCA 13462.91407512		D
1.15	LUG PCA 13390.10643541		D
1.16	LUG PCA 13120.60015632		D
1.17	LUG PCA 13785.92466250		D
1.18	LUG CSA 14040.10786382		D
1.19	LUG CSA 13840.93019714		D
1.20	LUG CSA 14040.10786374		D
1.21	LUG CSA 13836.91406672		D
1.22	LUG DCA 13815.92407065		D
1.23	LUG DCA 13815.90288627		D
1.24	LUG DCA 13815.93026469		D
1.25	LUG CSA 13183.60036344		D
1.26	LUG CSA 13205.60059346		D
1.27	LUG CSA 13934.10467606		D
1.28	LUG CSA 13633.92740152		D
1.29	LUG CSA 13592.10402239		D
1.30	LUG CSA 13351.93283733		D
1.31	LUG CSA 13099.90882614		D
1.32	LUG CSA 13093.91004837		D
1.33	LUG CSA 13630.10429536		D
1.34	LUG CSA 13205.90998414		D
1.35	LUG CSA 13948.91837409		D
1.36	LUG CSA 13093.91004843		D
1.37	LUG CSA 13836.91377944		D
1.38	LUG CSA 13102.60123654		D
1.39	LUG CSA 13158.92874802		D
1.40	LUG CSA 13176.10375134		D
1.41	LUG CSA 13107.10376173		D
1.42	LUG CSA 13057.10121709		D
1.43	LUG CSA 13418.92357188		D
1.44	LUG CSA 13592.91213055		D
1.45	LUG CSA 13100.91340554		D
1.46	LUG CSA 13715.90737020		D
1.47	LUG CSA 13176.91029163		D
1.48	LUG CSA 13835.60131429		D
1.49	LUG CSA 13593.93057902		D
1.50	LUG CSA 13105.10580678		D
1.51	LUG CSA 13188.10655453		D
1.52	LUG CSA 13592.10402259		D
1.53	LUG CSA 13948.10442385		D
1.54	LUG ESA 13174.60588225		D
1.55	LUG ESA 13454.90755954		D
1.56	LUG ESA 13174.60451701		D
1.57	LUG ESA 13710.92881445		D
1.58	LUG ESA 13509.60287236		D
1.59	LUG SHA 13897.10933151		D
1.60	LUG ESA 13174.10913196		D
1.61	LUG ESA 13171.90598389		D
1.62	LUG ESA 13211.60044019		D
1.63	LUG ESA 13231.10868138		D
1.64	LUG ESA 13230.10471354		D
1.65	LUG ESA 13502.92679861		D
1.66	LUG ESA 13796.10842826		D
1.67	LUG ESA 13454.60140423		D
1.68	LUG ESA 13509.10501132		D
1.69	LUG ESA 13433.10466911		D
1.70	LUG ESA 13230.92208546		D
1.71	LUG ESA 13171.93104605		D
1.72	LUG ESA 13509.90504849		D
1.73	LUG ESA 13502.92573944		D
1.74	LUG ESA 13799.60395568		D

1.75	LUG ESA 13226.10462583	D
1.76	LUG ESA 14116.60140011	D
1.77	LUG ESA 13797.93188519	D
1.78	LUG ESA 13226.92664597	D
1.79	LUG ESA 13796.92728705	D
1.80	LUG ESA 13230.60258173	D
1.81	LUG ESA 13171.90374558	D
1.82	LUG ESA 13796.92884623	D
1.83	LUG ESA 13502.92577310	D
1.84	LUG ESA 13225.60139973	D
1.85	LUG ESA 13796.10842823	D
1.86	LUG ESA 13226.92670950	D
1.87	LUG ESA 13226.92665539	D
1.88	LUG ESA 13883.91179506	D
1.89	LUG ESA 13509.91772133	D
1.90	LUG ESA 13509.10501150	D
1.91	LUG ESA 13454.90429155	D
1.92	LUG ESA 13454.90397369	D
1.93	LUG ESA 13454.10472634	D
1.94	LUG ESA 13433.93369551	D
1.95	LUG ESA 13174.92555763	D
1.96	LUG ESA 13883.92008787	D
1.97	LUG ESA 13230.92180224	D
1.98	LUG WSA 14032.10820614	D
1.99	LUG WSA 13071.90738378	D
1.100	LUG WSA 14032.92634300	D
1.101	LUG WSA 13071.91245761	D
1.102	LUG WSA 14032.91487301	D
1.103	LUG WSA 14032.10339836	D
1.104	LUG WSA 14032.92803239	D
1.105	LUG WSA 13071.91432110	D
1.106	LUG WSA 13071.91432109	D
1.107	LUG WSA 14032.92729035	D
1.108	LUG WSA 13198.92183966	D
1.109	LUG WSA 13678.90514649	D
1.110	LUG WSA 13425.10244449	D
1.111	LUG WSA 13670.93124410	D
1.112	LUG WSA 13428.91540495	D
1.113	LUG WSA 13332.91335523	D
1.114	LUG WSA 13544.10053266	D
1.115	LUG WSA 13109.90641822	D
1.116	LUG WSA 13747.10299739	D
1.117	LUG WSA 13756.60165357	D
1.118	LUG WSA 13491.10230118	D
1.119	LUG WSA 13141.92630916	D
1.120	LUG WSA 13673.10277744	D
1.121	LUG WSA 13138.60079254	D
1.122	LUG WSA 13141.92442349	D
1.123	LUG WSA 13333.10007582	D
1.124	LUG WSA 13586.92298267	D
1.125	LUG WSA 13138.10145625	D
1.126	LUG WSA 13140.10013916	D
1.127	LUG WSA 13113.90796385	D
1.128	LUG WSA 13138.10145628	D
1.129	LUG WSA 13164.10158909	D
1.130	LUG WSA 13140.91873275	D
1.131	LUG WSA 13605.91052996	D
1.132	LUG WSA 13071.60170422	D
1.133	LUG WSA 13111.92999604	D
1.134	LUG WSA 13586.60303627	D

2. Transmission Asset Upgrades Program

2.1	SPP TAU - Circuit 66654	T
2.2	SPP TAU - Circuit 66840	T
2.3	SPP TAU - Circuit 66007	T
2.4	SPP TAU - Circuit 66019	T
2.5	SPP TAU - Circuit 66425	T
2.6	SPP TAU - Circuit 230403	T
2.7	SPP TAU - Circuit 66413	T
2.8	SPP TAU - Circuit 66046	T
2.9	SPP TAU - Circuit 66059	T
2.10	SPP TAU - Circuit 230008	T
2.11	SPP TAU - Circuit 230010	T
2.12	SPP TAU - Circuit 230038	T
2.13	SPP TAU - Circuit 230003	T
2.14	SPP TAU - Circuit 230005	T
2.15	SPP TAU - Circuit 230004	T
2.16	SPP TAU - Circuit 230625	T
2.17	SPP TAU - Circuit 230021	T
2.18	SPP TAU - Circuit 230052	T
2.19	SPP TAU - Circuit 66024	T
2.20	SPP TAU - Circuit 230608	T
2.21	SPP TAU - Circuit 230603	T

3.	Substation Extreme Weather Program	
3.1	none	D
4	Distribution Overhead Feeder Hardening Program	
4.1	SPP FH - E Winterhaven 13308	D
4.2	SPP FH - Knights 13807	D
4.3	SPP FH - Knights 13805	D
4.4	SPP FH - Casey Road 13745	D
4.5	SPP FH - Coolidge 13533	D
4.6	SPP FH - 13461	D
4.7	SPP FH - 14121	D
4.8	SPP FH - 13939	D
4.9	SPP FH - 13890	D
4.10	SPP FH - 13443	D
4.11	SPP FH - 13227	D
4.12	SPP FH - 13462	D
4.13	SPP FH - 13633	D
5.	Transmission Access Enhancement Program	
5.1	none	T

Form 8E (Jan-Jun)
Page 1 of 2

Tampa Electric Company
Storm Protection Plan Cost Recovery Clause (SPPCRC)
Calculation of the Current Period Actual/Estimated Amount
Current Period: January through June 2020

Approved Capital Structure and Cost Rates
(in Dollars)

	(1) Jurisdictional Rate Base 2019 May SR ($000)	(2) Ratio %	(3) Cost Rate %	(4) Weighted Cost Rate %
Long Term Debt	$ 1,897,597	31.57%	4.89%	1.5435%
Short Term Debt	211,895	3.52%	2.97%	0.1047%
Preferred Stock	0	0.00%	0.00%	0.0000%
Customer Deposits	94,966	1.58%	2.38%	0.0376%
Common Equity	2,598,065	43.22%	10.25%	4.4297%
Accum. Deferred Inc. Taxes & Zero Cost ITC's	1,125,550	18.72%	0.00%	0.0000%
Deferred ITC - Weighted Cost	83,633	1.39%	7.98%	0.1110%
Total	$ 6,011,707	100.00%		6.23%

ITC split between Debt and Equity:

Long Term Debt	$ 1,897,597	Long Term Debt	46.00%
Equity - Preferred	0	Equity - Preferred	0.00%
Equity - Common	2,598,065	Equity - Common	54.00%
Total	$ 4,495,662	Total	100.00%

Deferred ITC - Weighted Cost:

Debt = 0.1110% * 46.00%	0.0511%
Equity = 0.1110% * 54.00%	0.0599%
Weighted Cost	0.1110%

Total Equity Cost Rate:

Preferred Stock	0.0000%
Common Equity	4.4297%
Deferred ITC - Weighted Cost	0.0599%
	4.4896%
Times Tax Multiplier	1.32830
Total Equity Component	5.9635%

Total Debt Cost Rate:

Long Term Debt	1.5435%
Short Term Debt	0.1047%
Customer Deposits	0.0376%
Deferred ITC - Weighted Cost	0.0511%
Total Debt Component	1.7369%
	7.7004%

Notes:
Column (1) - Per WACC Stipulation & Settlement Agreement Dated July 17, 2012, and 2017 Base Rates Settlement Agreement Dated September 27, 2017.
Column (2) - Column (1) / Total Column (1)
Column (3) - Per WACC Stipulation & Settlement Agreement Dated July 17, 2012, and 2017 Base Rates Settlement Agreement Dated September 27, 2017.
Column (4) - Column (2) x Column (3)

Tampa Electric Company
Storm Protection Plan Cost Recovery Clause (SPPCRC)
Calculation of the Current Period Actual/Estimated Amount
Current Period: July through December 2020

Approved Capital Structure and Cost Rates
(in Dollars)

	(1) Jurisdictional Rate Base 2020 May SR ($000)	(2) Ratio %	(3) Cost Rate %	(4) Weighted Cost Rate %
Long Term Debt	$ 2,209,385	33.98%	4.71%	1.6003%
Short Term Debt	196,185	3.02%	2.19%	0.0661%
Preferred Stock	0	0.00%	0.00%	0.0000%
Customer Deposits	93,706	1.44%	2.36%	0.0340%
Common Equity	2,801,776	43.08%	10.25%	4.4160%
Accum. Deferred Inc. Taxes & Zero Cost ITC's	1,034,859	15.91%	0.00%	0.0000%
Deferred ITC - Weighted Cost	166,903	2.57%	7.81%	0.2005%
Total	$ 6,502,815	100.00%		6.32%

ITC split between Debt and Equity:

Long Term Debt	$ 2,209,385	Long Term Debt	46.00%
Equity - Preferred	0	Equity - Preferred	0.00%
Equity - Common	2,801,776	Equity - Common	54.00%
Total	$ 5,011,162	Total	100.00%

Deferred ITC - Weighted Cost:

Debt = 0.2005% * 46.00%	0.0922%
Equity = 0.2005% * 54.00%	0.1083%
Weighted Cost	0.2005%

Total Equity Cost Rate:

Preferred Stock	0.0000%
Common Equity	4.4160%
Deferred ITC - Weighted Cost	0.1083%
	4.5243%
Times Tax Multiplier	1.32830
Total Equity Component	6.0096%

Total Debt Cost Rate:

Long Term Debt	1.6003%
Short Term Debt	0.0661%
Customer Deposits	0.0340%
Deferred ITC - Weighted Cost	0.0922%
Total Debt Component	1.7926%
	7.8022%

Notes:
Column (1) - Per WACC Stipulation & Settlement Agreement Dated July 17, 2012, and 2017 Base Rates Settlement Agreement Dated September 27, 2017.
Column (2) - Column (1) / Total Column (1)
Column (3) - Per WACC Stipulation & Settlement Agreement Dated July 17, 2012, and 2017 Base Rates Settlement Agreement Dated September 27, 2017.
Column (4) - Column (2) x Column (3)

PROGRAM DESCRIPTION AND PROGRESS

Program Title: DISTRIBUTION LATERAL UNDERGROUNDING

Program Description: This program will convert existing overhead distribution lateral facilities to underground to increase the resiliency and reliability of the distribution system serving the company's customers.

Program Projections: April 10, 2020 to December 31, 2020
During this period, there are 134 projected projects.

January 1, 2021 to December 31, 2021
During this period, there are 516 projected projects.
Note: 2021 includes 130 projects that will start in 2020.

Program Fiscal Expenditures: April 10, 2020 to December 31, 2020
Expenditures are estimated to be $9.1 million.

January 1, 2021 to December 31, 2021
Expenditures are estimated to be $84.1 million.

PROGRAM DESCRIPTION AND PROGRESS

Program Title: VEGETATION MANAGEMENT (VM)

Program Description: This program consists of the following VM activities and initiatives:

- Distribution four-year cycle
- Transmission two-year cycle
- Initiative 1: Supplemental Distribution Circuit VM
- Initiative 2: Mid-Cycle Distribution VM
- Initiative 3: 69 kV VM Reclamation

Program Projections: January 1, 2020 to December 31, 2020

Distribution VM:	1,720 miles
Transmission VM:	530 miles

April 10, 2020 to December 31, 2020

Initiative 1:	402.3 miles and 62,332 projected customers
Initiative 2:	0 miles and 0 projected customers
Initiative 3:	0 miles and 0 projected customers

January 1, 2021 to December 31, 2021

Distribution VM:	1,560 miles
Transmission VM:	530 miles
Initiative 1:	510.2 miles and 65,008 projected customers
Initiative 2:	243.1 miles and 95,733 projected customers
Initiative 3:	27 miles and 26,975 projected customers

Program Fiscal Expenditures: April 10, 2020 to December 31, 2020

Expenditures are estimated to be:

Distribution VM:	\$9.7 million
Transmission VM:	\$0.9 million
Initiative 1:	\$2.9 million
Initiative 2:	\$0.1 million
Initiative 3:	\$0.1 million

Note: These numbers are prior to the \$10.4m adjustment as agreed upon in the Tampa Electric Company 2020 settlement.

January 1, 2021 to December 31, 2021

Expenditures are estimated to be:

Distribution VM:	\$13.0 million
Transmission VM:	\$2.8 million
Initiative 1:	\$5.5 million
Initiative 2:	\$1.3 million
Initiative 3:	\$0.7 million

PROGRAM DESCRIPTION AND PROGRESS

Program Title: TRANSMISSION ASSET UPGRADES

Program Description: This program will proactively and systematically replace the remaining wood transmission poles with non-wood material.

Program Projections: April 10, 2020 to December 31, 2020
During this period, there are 21 projected projects.

January 1, 2021 to December 31, 2021
During this period, there are 37 projected projects.
Note: 2021 includes 13 projects that will start in 2020.

Program Fiscal Expenditures: April 10, 2020 to December 31, 2020
Expenditures are estimated to be $6.0 million.

January 1, 2021 to December 31, 2021
Expenditures are estimated to be $15.6 million.

PROGRAM DESCRIPTION AND PROGRESS

Program Title: SUBSTATION EXTREME WEATHER HARDENING

Program Description: This program will harden and protect the company's substation assets that are vulnerable to flood or storm surge.

Program Projections: April 10, 2020 to December 31, 2020
During this period, there are 0 projected projects.

January 1, 2021 to December 31, 2021
During this period, there is 1 projected project.

Program Fiscal Expenditures: April 10, 2020 to December 31, 2020
Expenditures are estimated to be $0.0 million.

January 1, 2021 to December 31, 2021
Expenditures are estimated to be $0.3 million.

PROGRAM DESCRIPTION AND PROGRESS

Program Title: DISTRIBUTION OVERHEAD FEEDER HARDENING

Program Description: This program will include strategies to further enhance the resiliency and reliability of the distribution network by further hardening the grid to minimize interruptions and reduce customer outage counts during extreme weather events and abnormal system conditions.

Program Projections: April 10, 2020 to December 31, 2020
During this period, there are 13 projected projects.

January 1, 2021 to December 31, 2021
During this period, there are 27 projected projects.
Note: 2021 includes 8 projects that will start in 2020.

Program Fiscal Expenditures: April 10, 2020 to December 31, 2020
Expenditures are estimated to be $6.6 million.

January 1, 2021 to December 31, 2021
Expenditures are estimated to be $15.7 million.

PROGRAM DESCRIPTION AND PROGRESS

Program Title: TRANSMISSION ACCESS ENHANCEMENT

Program Description: This program will ensure the company always has access to its transmission facilities so it can promptly restore its transmission system when outages occur.

Program Projections: April 10, 2020 to December 31, 2020
During this period, there are 0 projected projects.

January 1, 2021 to December 31, 2021
During this period, there are 18 projected projects.

Program Fiscal Expenditures: April 10, 2020 to December 31, 2020
Expenditures are estimated to be $0.0 million.

January 1, 2021 to December 31, 2021
Expenditures are estimated to be $1.3 million.

PROGRAM DESCRIPTION AND PROGRESS

Program Title: INFRASTRUCTURE INSPECTIONS

Program Description: This program covers the following infrastructure inspections performed on the company's transmission and distribution system:

- Distribution wood pole
- Distribution groundline
- Transmission wood pole/groundline
- Transmission above ground
- Transmission aerial infrared
- Transmission ground patrol
- Substation
- Joint Use Pole Attachments Audit

Program Projections: January 1, 2020 to December 31, 2020

Distribution wood pole:	22,500 inspections
Distribution groundline:	13,275 inspections
Transmission wood pole/groundline:	702 inspections
Transmission above ground:	2,949 inspections
Transmission aerial infrared:	1,328 inspections
Transmission ground patrol:	25,416 inspections
Substation:	72 inspections

January 1, 2021 to December 31, 2021

Distribution wood pole:	22,500 inspections
Distribution groundline:	13,275 inspections
Transmission wood pole/groundline:	367 inspections
Transmission above ground:	3,895 inspections
Transmission aerial infrared:	1,328 inspections
Transmission ground patrol:	25,416 inspections
Substation:	75 inspections

Program Fiscal Expenditures: April 10, 2020 to December 31, 2020
Expenditures are estimated to be:

Distribution Infrastructure Inspections:	$0.1 million
Transmission Infrastructure Inspections:	$0.4 million

Note 1: These numbers are prior to the $10.4m adjustment as agreed upon in the Tampa Electric Company 2020 settlement.

January 1, 2021 to December 31, 2021
Expenditures are estimated to be:

Distribution Infrastructure Inspections:	$1.0 million
Transmission Infrastructure Inspections:	$0.6 million

PROGRAM DESCRIPTION AND PROGRESS

Program Title: COMMON EXPENSES

Program Description: These are expenses common to all programs.

Program Projections: N/A

Program Fiscal Expenditures:

January 1, 2020 to December 31, 2020
Expenditures are estimated to be $1.4 million.

January 1, 2021 to December 31, 2021
Expenditures are estimated to be $0.4 million.

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 20200092-EI

IN RE: STORM PROTECTION PLAN COST RECOVERY CLAUSE

TESTIMONY AND EXHIBIT

OF

DAVID L. PLUSQUELLIC

FILED: July 24, 2020

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

DAVID L. PLUSQUELLIC

Q. Please state your name, address, occupation, and employer.

A. My name is David L. Plusquellic. I am employed by Tampa Electric Company ("Tampa Electric" or "company") as Storm Protection Program Manager. The Tampa Electric business address is 820 South 78th Street, Tampa, FL 33619.

Q. Please describe your duties and responsibilities in that position.

A. My duties and responsibilities include the governance and oversight of Tampa Electric's Storm Protection Plan ("SPP" or "the Plan") development and implementation. This includes leading the development of the Plan, prioritization of projects within each of the programs, development of project and program costs and overall implementation of the Plan.

Q. Please describe your educational background and professional experience.

A. I graduated from Kent State University in June 1996 with a Bachelor's degree in Finance. In December of 2000, I graduated from the University of Akron with a Master of Business Administration specializing again in Finance. I have been employed at Tampa Electric since November of 2019. Prior to joining Tampa Electric, I was employed at FirstEnergy from 1999 to 2018 in a variety of roles. During my 19 years, I progressed from an Analyst to a Director through roles covering financial reporting & analysis, business analytics, fossil fuel generation, renewable portfolio management, process & performance improvement, and Transmission & Distribution ("T&D") operations. For the final four years, I was a Director of Operations Support at Ohio Edison, one of the FirstEnergy T&D operating companies. Throughout the 19 years, I played a leadership role in efforts that ranged from valuing businesses, entering into 20-year purchase agreements, evaluating and implementing storm process improvements, evaluating asset investments, and improving operational and safety performance.

Q. What is the purpose of your direct testimony in this proceeding?

A. The purpose of my direct testimony is to provide a description of each Storm Protection Plan ("SPP") Program and to provide the detailed listing of the associated SPP Projects and the activities that supports each SPP program. I will also provide an overview of how the projected Capital and Operating and Maintenance ("O&M") costs were developed.

Q. Are you sponsoring any exhibits in this proceeding?

A. Yes. I have prepared one exhibit entitled, "Exhibit of David L Plusquellic." It consists of eight documents and has been identified as Exhibit No. DLP-1, which contains the following documents:

- Document No. 1 provides Tampa Electric's Distribution Lateral Undergrounding Program's 2020–2021 Project List and Summary of Costs.
- Document No. 2 provides Tampa Electric's Transmission Asset Upgrades Program's 2020–2021 Project List and Summary of Costs.
- Document No. 3 provides Tampa Electric's Substation Extreme Weather Hardening Program's 2020–2021 Project List and Summary of Costs.

- Document No. 4 provides Tampa Electric's Distribution Overhead Feeder Hardening Program's 2020–2021 Project List and Summary of Costs.
- Document No. 5 provides Tampa Electric's Transmission Access Enhancement Program's 2020–2021 Project List and Summary of Costs.
- Document No. 6 provides Tampa Electric's Vegetation Management Program's 2020–2021 Activities and Summary of Costs.
- Document No. 7 provides Tampa Electric's Infrastructure Inspections Program's 2020-2021 Activities and Summary of Costs.
- Document No. 8 provides Tampa Electric's Common Storm Protection Plan 2020-2021 Activities and Summary of Costs.

Q. How is your testimony organized?

A. My testimony is organized by each of the company's SPP Programs, which includes a description of the program, a summary of the program's costs, and how project-level costs were developed.

Q. Will your testimony address these topics for each of the SPP Programs for which the company is seeking cost recovery?

A. Yes, my testimony is organized to cover all these topics for each of the eight programs in the company's proposed SPP, in addition to the projected company's Storm Protection Plan Planning and Common expenditures.

Q. Will your testimony address how project-level costs were developed within each of the company's SPP Programs for which the company is seeking cost recovery?

A. Yes, my testimony will explain how the company developed the required Project-level details for the first two years of the Plan for this Storm Protection Plan Cost Recovery Clause ("SPPCRC").

Distribution Lateral Undergrounding

Q. Please provide a description of the Distribution Lateral Undergrounding Program.

A. Tampa Electric's Distribution Lateral Undergrounding Program will convert existing overhead distribution lateral facilities to underground to increase the resiliency and reliability of the distribution system serving the company’s customers.

Q. How many Distribution Lateral Underground projects are planned for 2020 and 2021?

A. Tampa Electric plans for the following activity in calendar years 2020 and 2021:

- During the period, April 10, 2020 to December 31, 2020, there are 134 projected projects that will be initiated.
- During the period January 1, 2021 to December 31, 2021 there are 516 projected projects, 130 of which will be carried over from 2020.

This project detail is fully detailed in my Exhibit No. DLP-1, Document No. 1.

Q. Can you explain why this project count is different than the company’s SPP April 10, 2020 filing, which reflected 24 projects in 2020 and 281 projects in 2021?

A. Yes, following the April 10, 2020 filing, Tampa Electric has been working through the necessary functions to establish the SPP programs to initiate construction. As the company was working through the contracts and procurement functions to support the distribution lateral undergrounding program, it became evident that further refinement of the engineering and construction schedules was necessary. In addition, while not a significant impact at the time, the current COVID-19 pandemic was placing additional pressure to refine the schedule that was previously provided.

Q. Did Tampa Electric communicate these changes?

A. Yes, Tampa Electric served the supplemental response to the Office of Public Counsel's Interrogatory No. 6 on June 18, 2020 on all affected parties in Docket 20200067-EI. The supplemental response communicated that the company refined its project schedules for the company's distribution lateral undergrounding program. As a part of this refinement, the start dates and completion dates for construction of some projects were changed. In addition, the company is accelerating the activities to design and secure land rights further in advance of construction than what was originally filed.

Q. Do the new project counts reflect the prioritization that served as the basis for the original filing?

A. Yes, the prioritization of the projects is the same as what was filed on April 10, 2020 with a refined strategy for engineering and acquiring land rights further in advance of construction.

Q. What are the total projected expenditures for this Program?

A. Tampa Electric estimates expenditures for this program during calendar years 2020 and 2021 as follows:

- During the period, April 10, 2020 to December 31, 2020, estimated expenditures are $9.1 million.
- During the period, January 1, 2021 to December 31, 2021, estimated expenditures are $84.1 million.

Q. Do these projected expenditures match what was filed on April 10, 2020?

A. No, the schedule refinement that I explained above resulted in front loading more engineering work on more projects which raised the cost estimate by approximately $600,000 in 2020 and $2.2 million in 2021. Additionally, the company projects incremental labor dollars of $600,000 in 2020 and $1.9 million in 2021.

Q. Did any of these project expenditures occur before April 10, 2020?

A. No.

Q. Can you provide a breakdown of the projected expenditures by categories such as capital and operating and maintenance ("O&M") expenses?

A. The Distribution Lateral Undergrounding Program expenditures are 100 percent capital. There are no expected O&M expenses.

Q. What are the different components that make up the cost of a distribution lateral underground conversion project?

A. The projects will be completed primarily by external contractor partners. The main components of the project's cost will be contractor labor, materials, as well as some internal costs to administer and manage the program. The internal costs reflect labor dedicated to the Program as well as a small amount of O&M for things like office supplies and incidental travel associated with the program.

Q. How did you develop a cost estimate for each of these components?

A. The company developed cost assumptions based on internal historical data, an internal cost estimation tool, and information obtained from industry sources with experience in this type of work. This data was used to develop a unit rate or activity rate for each type of asset.

Q. Does each project have its own unique cost estimate profile?

A. Yes, each project is assigned characteristics based on its location, the number of phases, the number of customers, and the number and type of assets that will need to be converted.

Q. Were the distribution undergrounding lateral conversion project's costs estimated using a single average that was then applied to all projects?

A. No, the company used the individual component pricing data to develop an estimate for each project based on its unique characteristics, the number of assets, and the type of assets.

Q. Were the same underlying cost assumptions used to develop the cost estimate for each project?

A. Yes, the company used the same unit rate or activity rate for each type of asset.

Q. Can you explain how the cost assumptions were used to develop a cost estimate?

A. Yes, the number of each asset type would be multiplied by the activity or unit rate to determine a cost estimate for each asset type. The project-level estimate represents the sum of the estimates for each asset type. The activity rates include the external labor rates as well as materials.

Q. How do the project characteristics such as number of customers, number of phases and location of existing assets factor into the cost estimates?

A. These characteristics directly affect the necessary volume of work, the number and types of assets within the project scope, and the activity rate that is used for the project-level cost estimate.

Transmission Asset Upgrades

Q. Can you please provide a description of the Transmission Asset Upgrades Program?

A. The Transmission Asset Upgrades Program will proactively and systematically replace the company's remaining wood transmission poles with non-wood material.

Q. How many Transmission Asset Upgrade projects are planned for 2020 and 2021?

A. Tampa Electric plans for the following activity in calendar years 2020 and 2021:

- April 10, 2020 to December 31, 2020 – 21 projects
- January 1, 2021 to December 31, 2021 – 37 projects

This project detail is fully detailed in my Exhibit No. DLP-1, Document No. 2.

Q. Will you please explain how this aligns with the projects counts and prioritization reflected in the filing made on April 10, 2020 for the 2020 and 2021 periods?

A. Yes, the company’s filed Plan called for 21 projects in 2020 and 35 projects in 2021. In addition to these 56 projects, the company has added two additional projects in 2021 that were originally scheduled for 2022. The 58 projects scheduled in 2020 and 2021 keep the same prioritization that was used to develop the first three years of the company’s 2020-2029 SPP that was filed on April 10, 2020.

Q. Does the company’s filing in this docket include any different projects other than those included in the SPP filing dated April 10, 2020, with the exception of the two new projects being proposed?

A. No, all the projects are the same with the exception of the two new additional projects that were moved from 2022 into 2021.

Q. What are the total projected expenditures for this Program for the 2020 and 2021 periods?

A. Tampa Electric estimates expenditures for this program during 2020 and 2021 as follows:

- During the period April 10, 2020 to December 31, 2020, estimated expenditures are $5.8 million.

- During the period January 1, 2021 to December 31, 2021, estimated expenditures are $15.6 million.

Q. Do these projected expenditures match what was filed on April 10, 2020?

A. Yes, the current projected costs align with the cost estimates filed on April 10, 2020. The projected costs for 2020 were increased by less than $100,000 due to projected increased transfer costs. The projected costs for 2021 were increased by approximately $400,000 due to the projected increased transfer costs of $200,000 and $200,000 for two additional projects. Transfer costs are the cost incurred when moving existing wires from the existing wood structure to the newly constructed non-wood structure.

Q. Did any of these project expenditures occur before April 10, 2020?

A. No.

Q. Can you provide a breakdown of the projected expenditures by categories such as capital and O&M expenses?

A. Yes, the Transmission Asset Upgrade Program is predominantly capital, with some minimal O&M costs. The breakdown for each year is as follows:

- For the period April 10, 2020 to December 31, 2020:
  - Capital of $5.8 million
  - O&M of $0.2 million
- For the period January 1, 2021 to December 31, 2021:
  - Capital of $15.2 million
  - O&M of $0.4 million

Q. What are the activities that are associated with the O&M costs with this program?

A. The activity of transferring existing wires to the new non-wood material pole from the existing wooden pole being replaced is accounted for as an O&M cost.

Q. How did the company develop a cost estimate for each of these components?

A. The company has reactively replaced wood transmission poles that fail an inspection with non-wood material for many years. Because of these reactive replacements, the company has developed an extensive set of historical data for transmission pole replacements and upgrades. The historical data was used as a foundation for the project-level costs estimates.

Q. Were your project costs estimated using a single average that was then applied to all projects?

A. No.

Q. Does each transmission asset upgrade project have its own unique cost estimate profile?

A. Yes, each transmission asset upgrade project represents a transmission circuit, with a unique number of poles, unique terrain, and a unique location.

Substation Extreme Weather Hardening

Q. Can you please provide a description of the Substation Extreme Weather Hardening Program?

A. This program will harden and protect the company’s substation assets that are vulnerable to flooding or storm surge.

Q. How many Substation Extreme Weather Hardening projects are planned for 2020 and 2021?

A. The company is proposing no projects for the period April 10, 2020 to December 31, 2020. The company is, however, planning to conduct a formal study in 2021 to further identify and evaluate other potential hardening solutions beyond the single solution that was modeled on the company's substations during the initial development of the company's Plan. This project detail is fully detailed in my Exhibit No. DLP-1, Document No. 3.

Q. Does this represent the same number of projects you included in the filing made on April 10, 2020 for the 2020 and 2021 periods?

A. Yes.

Q. What are the total projected expenditures for this Program for the 2020 and 2021 periods?

A. Tampa Electric estimates expenditures for this Program during calendar years 2020 and 2021 as follows:

- During the period, April 10, 2020 to December 31, 2020, estimated expenditures are $0.

- During the period, January 1, 2021 to December 31, 2021, estimated expenditures are $0.3 million.

Q. Do these projected expenditures match what was filed on April 10, 2020?

A. Yes.

Q. Did any of these project expenditures occur before April 10, 2020?

A. No.

Q. Can you provide a breakdown of the projected expenditures by categories such as Capital and O&M expenses?

A. The 2021 study cost will be charged to O&M. At this time, the composition of future potential projects costs is not known.

Distribution Overhead Feeder Hardening

Q. Can you please provide a description of the Distribution Overhead Feeder Hardening Program?

A. This program will include strategies to further enhance the resiliency and reliability of the distribution network by further hardening the grid to minimize interruptions and reduce customer outage counts during extreme weather events and abnormal system conditions.

Q. How many Distribution Overhead Feeder Hardening projects are planned for 2020 and 2021?

A. Tampa Electric plans for the following activity in calendar years 2020 and 2021:

- April 10, 2020 to December 31, 2020 – 13 projects.
- January 1, 2021 to December 31, 2021 – 27 projects.

This project detail is fully detailed in my Exhibit No. DLP-1, Document No. 4.

Q. Does this represent the same number of projects you included in the company's Plan filing made on April 10, 2020 for the 2020 and 2021 periods?

A. No.

Q. Will you please explain how this number is different than the number of projects the company included in the filing made on April 10, 2020 for the period 2020 and 2021?

A. Yes, the plan filed on April 10, 2020 called for five projects in 2020 and 18 projects in 2021. The company plans to complete those 23 projects and will begin work on early stages of an additional six future projects.

Q. Why did the company decide to begin the six projects earlier?

A. The additional six projects were added to the 2021 work plan in order to ensure the projects would be completed in 2022. This alternation to the schedule resulted from a long-term work forecast that aligned with anticipated resource availability and project schedules for 2021 and 2022 and will also allow the company to provide the benefits reflected in the April 10 filing.

Q. Will the projects still have the same construction start and end dates as listed in the company's April 10, 2020 SPP filing?

A. The company did not provide a list of construction start and completion dates for 2021 and 2022 in the company's April 10, 2020 filing. The company is keeping the same initial projects that were projected to begin and complete in addition to the starting of the six additional projects as explained above to be completed in 2022.

Q. Does the company’s filing in this docket include different projects than those included in the SPP filing dated April 10, 2020?

A. No, other than starting the engineering work in late 2021 on the additional six projects all of the projects are the same.

Q. What are the total projected expenditures for this program in the 2020 and 2021 periods?

A. Tampa Electric estimates expenditures for this Program during calendar years 2020 and 2021 as follows:

- During the period April 10, 2020 to December 31, 2020, estimated expenditures are $6.6 million.
- During the period January 1, 2021 to December 31, 2021, estimated expenditures are $15.7 million.

Q. Do these projected expenditures match what was filed on April 10, 2020?

A. The current projected costs align with the cost estimates filed on April 10, 2020. The projected costs for 2020 align with the filing at $6.5 million. The projected costs for 2021 have increased from $15.4 to $15.7 driven almost entirely by an expected higher cost of transferring assets to the new pole and the engineering of the six additional projects.

Q. Do any of these project expenditures occur before April 10, 2020?

A. No.

Q. Can you provide a breakdown of the projected expenditures by categories such as capital and O&M expenses?

A. The Distribution Overhead Feeder Hardening Program is predominantly capital with some minimal O&M costs. The breakdown for each year is as follows:

- For the period April 10, 2020 to December 31, 2020:
  - Capital of $6.4 million
  - O&M of $0.2 million
- For the period January 1, 2021 to December 31, 2021:

- Capital of $15.3 million
- O&M of $0.4 million

Q. What are the activities that are associated with the O&M costs with this program?

A. The activity of transferring existing wires to the new overhead feeder hardening equipment from the existing equipment being replaced is accounted for as an O&M cost.

Q. Does each overhead feeder hardening project have its own unique cost estimate profile?

A. Yes, each overhead feeder hardening project represents a distribution overhead feeder that will be hardened. The underlying project information is specific to each feeder. This includes location, asset type, work scope, number of assets to be installed or hardened and other information that is unique to each circuit.

Q. How were the cost assumptions used to develop cost estimates for each project?

A. The company first defined the attributes of a hardened feeder, which includes poles meeting National Electrical

Safety Code ("NESC") Extreme Wind loading criteria; no poles lower than a class 2; no conductor size smaller than 336 aluminum conductor, steel reinforced ("ACSR"); single phase reclosers or trip savers on laterals; feeder segmented and automated with no more than 200-400 customers per section and no segment longer than 2-3 miles; no more than two to three megawatts of load served on each segment; and circuit ties to other feeders with available switching capacity. These criteria were then applied to each potential overhead feeder project to develop an estimate of the cost to harden that feeder.

Transmission Access Enhancement

Q. Please provide a description of the Transmission Access Enhancement Program.

A. This program will ensure the company always has access to its transmission facilities so it can promptly restore its transmission system when outages occur.

Q. How many Transmission Access Enhancement projects are planned for 2020 and 2021?

A. Tampa Electric plans for the following activity in calendar years 2020 and 2021:

- April 10, 2020 to December 31, 2020 – 0 projected projects.
- January 1, 2021 to December 31, 2021 – 18 projected projects.

This project detail is fully detailed in my Exhibit No. DLP-1, Document No. 5.

Q. Does this represent the same number of projects you included in the filing made on April 10, 2020 for the period 2020 and 2021?

A. No, the company is still projecting to begin zero projects in 2020 but has increased the number of projects from eight to eighteen for 2021.

Q. Can you please explain why the number of projects has increased for 2021?

A. Since Tampa Electric filed its Plan, the company determined that it could achieve efficiency and avoid potential delays in construction by beginning engineering, design and permitting for future projects earlier than originally planned. As a result, the company will begin work in 2021 on projects that were originally scheduled to begin in 2022 and 2023.

Q. Does the company's filing in this docket include different projects than those included in the SPP filing dated April 10, 2020?

A. No, with the exception of the additional projects that are beginning earlier, the projects and the prioritization are consistent with the filing made on April 10, 2020.

Q. What are the total projected expenditures for this Program in the 2020 and 2021 periods?

A. Tampa Electric estimates expenditures for this Program during calendar years 2020 and 2021 as follows:

- During the period April 10, 2020 to December 31, 2020, estimated expenditures are $0.
- During the period January 1, 2021 to December 31, 2021, estimated expenditures are $1.3 million.

Q. Do these projected expenditures match what was filed on April 10, 2020?

A. No, the refined schedule results in a slight reduction to 2021 spend compared to the company's Plan filing.

Q. Did any of these project expenditures occur before April 10, 2020?

A. No.

Q. Can you provide a breakdown of the projected expenditures by categories such as capital and O&M expenses?

A. The Transmission Asset Enhancement Program is 100 percent capital. There are no expected O&M expenses.

Q. What is the basis for your 2021 project-level cost estimates?

A. The company has both historical and recent experience with road and bridge projects. This information was the foundation for preparing estimates for the permitting, surveying, engineering, and construction costs.

Q. Does each project have its own unique cost estimate profile?

A. Yes, each project has a unique project cost estimate based on factors such as project type, type of construction, location, permits required and the quantity of material.

Vegetation Management

Q. Can you please provide a description of the Vegetation Management ("VM") Program?

A. The VM Program consists of three parts including existing legacy storm hardening VM activities and three new VM initiatives that will impact the SPPCRC. The three parts of existing legacy storm hardening VM activities include the following:

- Four-year distribution VM cycle (Planned)
- Two-year transmission VM cycle (Planned)
- Transmission VM Right of Way Maintenance (Planned)

The three new VM initiatives are:

- Initiative 1: Supplemental Distribution Circuit VM
- Initiative 2: Mid-Cycle Distribution VM
- Initiative 3: 69 kV VM Reclamation

Q. What VM programs does the company have that will not impact the SPPCRC?

A. The company performs unplanned VM on both the distribution and transmission system. Both of these VM activities will remain in base rates and not in the SPPCRC.

Q. Does this represent the same number of initiatives you included in the filing made on April 10, 2020 for the period 2020 and 2021?

A. Yes.

Q. What level of activity are you projecting for each initiative during the period 2020?

A. For the period January 1, 2020 to December 31, 2020, the company projects the following activities:

- Distribution VM: 1,720 miles
- Transmission VM: 530 miles

For the period April 10, 2020 to December 31, 2020, the company projects the following activities:

- Initiative 1: 402.3 miles and 62,332 customers
- Initiative 2: 0 miles and 0 customers
- Initiative 3: 0 miles and 0 customers

This activity detail is fully detailed in my Exhibit No. DLP-1, Document No. 6.

Q. What level of activity are you projecting for each initiative during the period 2021?

A. For the period January 1, 2021 to December 31, 2021, the company projects the following activities:

- Distribution VM: 1,560 miles
- Transmission VM: 530 miles
- Initiative 1: 510.2 miles and 65,008 customers
- Initiative 2: 243.1 miles and 95,733 customers
- Initiative 3: 27 miles and 26,975 customers

This activity detail is fully detailed in my Exhibit No. DLP-1, Document No. 6.

Q. Does this represent the same projected activity levels included in the filing made on April 10, 2020 for the period 2020 and 2021?

A. Yes.

Q. What are the total projected expenditures for this Program during the period April 1 to December 31, 2020?

A. For the period April 10, 2020 to December 31, 2020, expenditures are estimated to be:

- Distribution VM: $9.7 million
- Transmission VM: $0.9 million
- Initiative 1: $2.9 million
- Initiative 2: $0.1 million
- Initiative 3: $0.1 million

Q. Do these figures represent the amount that is deemed incremental and recoverable through the SPPCRC under the 2020 Settlement Agreement?

A. No, as explained further in the testimony of A. Sloan Lewis, the 2020 Settlement Agreement sets out a threshold test to determine what portion of the VM costs are incremental and recoverable through the SPPCRC. These numbers represent the total projected expenditures for each activity for 2020, not just the incremental portion.

Q. What are the total projected expenditures for this Program during the period 2021?

A. For the period January 1, 2021 to December 31, 2021, expenditures are estimated to be:

- Distribution VM: $13.0 million

- Transmission VM: $2.8 million
- Initiative 1: $5.5 million
- Initiative 2: $1.3 million
- Initiative 3: $0.7 million

Q. Have these estimated expenditures been adjusted to account for the 2020 Settlement Agreement?

A. No. Under the 2020 Settlement Agreement, the company agreed to reduce base rates beginning in January of 2021. These figures are the total, projected costs for which the company is seeking cost recovery through the SPPCRC.

Q. Do these projected expenditures match what was filed on April 10, 2020?

A. Yes.

Q. Did any of these expenditures occur before April 10, 2020?

A. No, per the terms of the 2020 Settlement Agreement, the incremental costs incurred after April 10, 2020 can be included in the SPPCRC, while at the same time an adjustment will be made so that only agreed upon incremental VM costs are included in the SPPCRC.

Q. Can you provide a breakdown of the projected expenditures by categories such as Capital and O&M expenses?

A. The VM Program is 100 percent O&M expenses. There are no expected capital expenses.

Q. How were the estimated costs of this program developed?

A. The company used historical data along with current labor and equipment rates to develop the cost estimates for each component of this program. The company also engaged Accenture to assist in the development of the new VM initiatives, including the level of incremental work and the cost for each initiative.

Q. Can you explain how that information was used to develop a cost estimate for each initiative?

A. Yes, the activity levels for each initiative were multiplied by the labor and equipment rates associated with each activity within that initiative. The company relied on the historical data as well as current estimates of labor and equipment rates.

Infrastructure Inspections

Q. Can you please provide a description of the Infrastructure Inspections Program?

A. This SPP program involves the inspections performed on the company's T&D infrastructure including all wooden distribution and transmission poles, transmission structures and substations, as well as the audit of all joint use attachments.

Q. How many infrastructure inspection projects does the company plan to complete in 2020 and 2021?

A. Tampa Electric conducts thousands of inspections each year. The number of inspections by type planned for 2020 and 2021 are as follows:

Distribution:	2020	2021
Wood Pole:	22,500	22,500
Groundline:	13,275	13,275

Transmission:	2020	2021
Wood Pole/Groundline:	702	367
Above Ground:	2,949	3,895

Aerial Infrared Patrol:	Annually	Annually
Ground Patrol:	Annually	Annually
Substations:	Annually	Annually

This activity detail is fully detailed in my Exhibit No. DLP-1, Document No. 7.

Q. Does this represent the same number of projects you included in the filing made on April 10, 2020 for the period 2020 and 2021?

A. Yes.

Q. What are the total projected expenditures for this Program in the 2020 and 2021 periods?

A. The estimated costs for this program for April 10, 2020 through December 2020 is $0.5 million, and $1.6 million for 2021.

Q. Do any of these project expenditures occur before April 10, 2020?

A. No.

Q. Can you provide a breakdown of the projected expenditures by categories such as capital and O&M expenses?

A. All costs associated with this program are 100 percent O&M. There are no Capital expenditures with this program.

Q. What is the basis for your cost estimates?

A. The company has long-standing inspection programs with a large data set of historical activity and spend. The projected spend for each inspection type is based on projected activity and historical spending.

LEGACY STORM HARDENING INITIATIVES

Q. What are the legacy storm hardening initiatives?

A. These are storm hardening activities that were mandated by the Commission as components of the company’s prior storm hardening plan.

Q. Are the legacy storm hardening initiatives the same for the company’s SPP as they were in the company’s most recent 2019-2021 three-year Storm Plan that was approved by the Commission?

A. Yes, they are the same, but Tampa Electric extracted the following legacy storm hardening initiatives to be separate SPP Programs and will seek cost-recovery for these through the SPPCRC:

- Four-year distribution vegetation management
- Two-year transmission vegetation management
- Transmission Right of Way vegetation management
- Distribution infrastructure inspections
- Transmission infrastructure inspections
- Transmission asset upgrades

Q. What are the other legacy storm hardening initiatives that will not go through the SPPCRC?

Q. The other legacy storm hardening initiatives that will not go through the SPPCRC include the following:

- Unplanned distribution vegetation management
- Unplanned transmission vegetation management
- Geographic Information System
- Post-Storm Data Collection
- Outage Data – Overhead and Underground Systems
- Increased Coordination with Local Governments
- Collaborative Research
- Disaster Preparedness and Recovery Plan
- Distribution Wood Pole Replacements

Q. Does the company have individual project detail for these ongoing storm hardening initiatives for the period 2020 and 2021?

A. No, these “other” ongoing storm hardening initiatives are well-established, steady state programs for which the company does not propose any specific Storm Protection Projects at this time.

Q. Is the company seeking cost recovery for any of these “Other” ongoing legacy storm hardening in this SPPCRC proceeding?

A. No.

COMMON STORM PROTECTION PLAN ACTIVITIES AND COSTS

Q. Will you please provide a description of the Common Costs?

A. Yes, the costs in the Common Costs category represent those costs that cannot be attributed to a specific Program. They are an accumulation of incremental costs associated with developing, implementing, managing, and administering the SPP.

Q. What type of costs are in the Common Costs category?

A. The Common Costs reflect those SPP costs that cannot be assigned to a specific SPP program or those costs which bring benefits to the entire portfolio of SPP programs. Examples of this include incremental internal labor to support the administration of the SPP as a whole. In addition, because the company has never prepared an SPP before and has never performed the level of work necessary for a successful SPP, Tampa Electric brought in outside consultants to assist in the development of the SPP. These consultants' costs were charged to Common Costs as they provide benefits to more than one SPP Program.

Q. Were these costs reflected in the company's SPP filing on April 10, 2020?

A. Yes.

Q. How much does the company project to spend on common expenses in the 2020 and 2021 periods?

A. The company projects spending $1.4 million in 2020 and $0.4 million in 2021.

Q. Please provide a breakdown of these common costs in each calendar year.

A. The following is a summary level breakdown of the costs in each calendar year:

- Calendar year 2020 costs reflect $1.0 million of external consulting costs and $0.4 million of internal labor costs.
- Calendar year 2021 costs reflect $0.4 million of internal labor costs.

Q. Does this include any costs incurred prior to April 10, 2020?

A. Yes, the company engaged three consultants to assist with the development of the SPP, as described in the company's plan filing. In addition, the company added a small number of incremental positions, such as a Program Manager, to administer the Plan development and implementation process. This activity detail is fully detailed in my Exhibit No. DLP-1, Document No. 8.

Q. How much of the 2020 costs were incurred prior to April 10, 2020?

A. The company spent approximately $1.0 million on external consultants and incremental internal labor prior to April 10, 2020 which is detailed in Exhibit No. MRR-1 of Mark R. Roche's direct testimony.

CONCLUSIONS

Q. Please summarize your direct testimony.

A. My testimony identifies the programs for which Tampa Electric is seeking cost recovery for expenditures occurring in 2020 and 2021. My testimony describes the number and types of activities that will be carried out under the company's SPP in 2020 and 2021 and explains how the company developed estimates of the cost of each of these activities. My testimony also demonstrates that the estimated costs are reasonable since they are based on sound methods and because the company has a high level of confidence in its projections.

Q. Are the company's planned activities and projected costs consistent with the company's Storm Protection Plan?

A. Yes, as I explained in my testimony, the company has begun implementation of each of the Programs in a manner consistent with the filing made on April 10, 2020. While schedules have been refined in some cases, the planned activities are prioritized consistently with the SPP and the projected costs are largely consistent at both the Program and project levels.

Q. Should the Commission approve the company’s projected expenditures for its Distribution Lateral Undergrounding, Transmission Asset Upgrades, Substation Extreme Weather Hardening, Distribution Overhead Feeder Hardening, Transmission Access Enhancement, Vegetation Management, Infrastructure Inspections Programs and Common SPP costs?

A. Yes, these projected expenditures should be approved. The projected costs are reasonable and consistent with the company’s SPP.

Q. Does this conclude your testimony?

A. Yes.

EXHIBIT

OF

DAVE L. PLUSQUELLIC

Table of Contents

	2020 Cost Estimate	2021 Cost Estimate
Distribution Lateral Undergrounding Program Total	**9,086,680**	**84,101,703**
LUG PCA 13390.92599119	796,475	-
LUG PCA 13961.92829453	49,923	246,167
LUG PCA 13724.90911087	82,900	348,208
LUG PCA 13146.10629014	83,474	536,971
LUG WHA 13972.92421291	71,444	185,831
LUG WHA 13312.60182741	24,435	80,362
LUG WHA 13972.90241880	148,000	560,562
LUG PCA 13961.92820848	81,203	79,467
LUG PCA 13961.60193482	79,163	293,298
LUG PCA 13785.10676209	156,103	493,862
LUG PCA 13462.60458175	108,764	237,141
LUG PCA 14121.93159006	94,132	45,946
LUG PCA 13462.60180762	22,005	147,443
LUG PCA 13462.91407512	46,255	227,521
LUG PCA 13390.10643541	193,242	936,326
LUG PCA 13120.60015632	33,660	116,716
LUG PCA 13785.92466250	119,051	371,032
LUG CSA 14040.10786382	50,384	100,062
LUG CSA 13840.93019714	26,730	21,523
LUG CSA 14040.10786374	59,816	279,540
LUG CSA 13836.91406672	77,422	174,910
LUG DCA 13815.92407065	89,426	245,648
LUG DCA 13815.90288627	209,877	230,933
LUG DCA 13815.93026469	117,836	269,942
LUG CSA 13183.60036344	22,662	67,487
LUG CSA 13205.60059346	41,500	61,774
LUG CSA 13934.10467606	73,128	17,355
LUG CSA 13633.92740152	66,304	128,070
LUG CSA 13592.10402239	39,055	57,251
LUG CSA 13351.93283733	42,287	66,087
LUG CSA 13099.90882614	56,771	125,391
LUG CSA 13093.91004837	44,266	170,877
LUG CSA 13630.10429536	19,618	33,068
LUG CSA 13205.90998414	20,071	44,583
LUG CSA 13948.91837409	34,570	59,710
LUG CSA 13093.91004843	62,072	272,875
LUG CSA 13836.91377944	141,689	326,780
LUG CSA 13102.60123654	45,875	57,559
LUG CSA 13158.92874802	36,000	72,330
LUG CSA 13176.10375134	32,638	129,031
LUG CSA 13107.10376173	105,051	262,810
LUG CSA 13057.10121709	39,409	13,580
LUG CSA 13418.92357188	113,504	369,203
LUG CSA 13592.91213055	65,640	221,537

	2020 Cost Estimate	2021 Cost Estimate
LUG CSA 13100.91340554	99,221	233,640
LUG CSA 13715.90737020	19,707	49,161
LUG CSA 13176.91029163	16,755	35,129
LUG CSA 13835.60131429	65,372	207,866
LUG CSA 13593.93057902	109,604	495,871
LUG CSA 13105.10580678	55,880	206,113
LUG CSA 13188.10655453	29,539	144,273
LUG CSA 13592.10402259	47,861	60,094
LUG CSA 13948.10442385	73,550	249,628
LUG ESA 13174.60588225	129,021	-
LUG ESA 13454.90755954	249,658	-
LUG ESA 13174.60451701	243,444	-
LUG ESA 13710.92881445	148,469	265,506
LUG ESA 13509.60287236	14,520	150,914
LUG SHA 13897.10933151	78,098	819,089
LUG ESA 13174.10913196	21,202	220,960
LUG ESA 13171.90598389	21,314	222,141
LUG ESA 13211.60044019	52,247	548,005
LUG ESA 13231.10868138	53,466	560,796
LUG ESA 13230.10471354	43,823	459,656
LUG ESA 13502.92679861	17,588	182,986
LUG ESA 13796.10842826	15,182	157,800
LUG ESA 13454.60140423	50,746	532,264
LUG ESA 13509.10501132	10,692	112,349
LUG ESA 13433.10466911	70,075	733,147
LUG ESA 13230.92208546	17,257	181,411
LUG ESA 13171.93104605	35,837	377,602
LUG ESA 13509.90504849	95,257	996,558
LUG ESA 13502.92573944	61,461	642,778
LUG ESA 13799.60395568	45,162	475,155
LUG ESA 13226.10462583	12,040	126,519
LUG ESA 14116.60140011	32,440	338,629
LUG ESA 13797.93188519	65,640	684,665
LUG ESA 13226.92664597	30,659	321,463
LUG ESA 13796.92728705	44,850	467,066
LUG ESA 13230.60258173	15,886	163,879
LUG ESA 13171.90374558	58,311	603,744
LUG ESA 13796.92884623	130,381	1,348,427
LUG ESA 13502.92577310	16,430	170,961
LUG ESA 13225.60139973	80,845	836,109
LUG ESA 13796.10842823	44,911	465,069
LUG ESA 13226.92670950	20,216	209,297
LUG ESA 13226.92665539	8,838	91,104
LUG ESA 13883.91179506	7,543	77,753
LUG ESA 13509.91772133	5,200	53,602

	2020 Cost Estimate	2021 Cost Estimate
LUG ESA 13509.10501150	51,013	527,546
LUG ESA 13454.90429155	64,006	662,333
LUG ESA 13454.90397369	49,168	509,034
LUG ESA 13454.10472634	38,503	398,732
LUG ESA 13433.93369551	60,723	628,725
LUG ESA 13174.92555763	2,708	27,893
LUG ESA 13883.92008787	5,874	60,548
LUG ESA 13230.92180224	28,064	290,273
LUG WSA 14032.10820614	50,373	182,279
LUG WSA 13071.90738378	20,699	123,740
LUG WSA 14032.92634300	44,731	351,779
LUG WSA 13071.91245761	40,831	144,330
LUG WSA 14032.91487301	44,385	218,872
LUG WSA 14032.10339836	20,519	102,353
LUG WSA 14032.92803239	38,280	184,072
LUG WSA 13071.91432110	35,791	34,156
LUG WSA 13071.91432109	22,770	145,226
LUG WSA 14032.92729035	57,723	329,290
LUG WSA 13198.92183966	26,579	127,651
LUG WSA 13678.90514649	80,902	391,263
LUG WSA 13425.10244449	110,436	534,756
LUG WSA 13670.93124410	113,251	547,696
LUG WSA 13428.91540495	36,855	178,973
LUG WSA 13332.91335523	46,166	224,189
LUG WSA 13544.10053266	45,928	199,892
LUG WSA 13109.90641822	34,513	239,896
LUG WSA 13747.10299739	15,876	77,057
LUG WSA 13756.60165357	43,077	323,248
LUG WSA 13491.10230118	82,188	219,437
LUG WSA 13141.92630916	64,979	398,153
LUG WSA 13673.10277744	160,607	387,250
LUG WSA 13138.60079254	14,818	148,890
LUG WSA 13141.92442349	64,642	646,504
LUG WSA 13333.10007582	48,952	206,414
LUG WSA 13586.92298267	72,204	298,777
LUG WSA 13138.10145625	48,246	298,319
LUG WSA 13140.10013916	16,545	148,859
LUG WSA 13113.90796385	82,559	362,032
LUG WSA 13138.10145628	48,421	232,971
LUG WSA 13164.10158909	127,434	791,983
LUG WSA 13140.91873275	84,717	522,314
LUG WSA 13605.91052996	53,365	197,018
LUG WSA 13071.60170422	159,183	709,194
LUG WSA 13111.92999604	67,045	194,813
LUG WSA 13586.60303627	171,003	636,882

	2020 Cost Estimate	2021 Cost Estimate
LUG PCA 13785.90239166	-	1,693,427
LUG PCA 13961.10696431	-	156,431
LUG PCA 13961.10696419	-	520,975
LUG PCA 13785.92299245	-	603,560
LUG PCA 13961.92834683	-	417,220
LUG PCA 13462.91412064	-	57,321
LUG PCA 13961.10696486	-	373,732
LUG PCA 13961.91967308	-	494,230
LUG PCA 13961.10696417	-	62,669
LUG WHA 13916.60279623	-	52,027
LUG WHA 13297.10560430	-	288,332
LUG WHA 13314.92426509	-	316,757
LUG WHA 13118.92612349	-	429,940
LUG WHA 13313.90084626	-	88,779
LUG WHA 13699.10637242	-	492,535
LUG WHA 13313.10684614	-	170,096
LUG WHA 13296.92376304	-	244,597
LUG WHA 13313.60568375	-	406,619
LUG WHA 13297.60269456	-	255,711
LUG WHA 13699.10637259	-	62,735
LUG WHA 13473.60168916	-	391,983
LUG WHA 13296.10562356	-	68,253
LUG WHA 13916.92509975	-	290,996
LUG WHA 13297.10560425	-	321,741
LUG WHA 13296.60531111	-	659,226
LUG WHA 13699.10637247	-	69,127
LUG WHA 13473.60168942	-	187,540
LUG WHA 13118.92659353	-	272,194
LUG WHA 13118.10676209	-	715,013
LUG WHA 13699.10637240	-	481,397
LUG WHA 13313.93103371	-	90,127
LUG WHA 13118.92204382	-	408,416
LUG WHA 13118.92659172	-	471,116
LUG WHA 13473.92097460	-	171,085
LUG WHA 13296.90010289	-	882,447
LUG WHA 13313.92097460	-	483,358
LUG WHA 13118.10535999	-	357,163
LUG WHA 13699.60165416	-	248,986
LUG WHA 13916.91386005	-	105,329
LUG WHA 13314.10567076	-	84,634
LUG WHA 13296.10562361	-	44,898
LUG WHA 13297.10560432	-	85,814
LUG WHA 13972.10618037	-	50,155
LUG PCA 13724.10671283	-	75,738
LUG PCA 13722.60360851	-	42,414

	2020 Cost Estimate	2021 Cost Estimate
LUG PCA 13268.91633548	-	177,677
LUG PCA 13724.10671319	-	350,407
LUG PCA 13243.10791853	-	83,855
LUG PCA 13724.10671334	-	114,061
LUG PCA 13243.91351288	-	56,997
LUG PCA 13655.90431393	-	245,290
LUG PCA 13243.90684154	-	45,508
LUG PCA 13268.10705945	-	279,747
LUG PCA 13724.10671229	-	59,327
LUG PCA 13268.92962459	-	86,499
LUG PCA 13724.93103251	-	87,973
LUG PCA 13243.90586047	-	54,784
LUG PCA 13724.91049435	-	397,422
LUG CSA 13205.90929181	-	231,481
LUG CSA 13021.10051153	-	73,992
LUG CSA 13026.60059524	-	191,271
LUG CSA 13835.10429522	-	326,047
LUG CSA 13204.91532149	-	563,584
LUG CSA 13836.91406642	-	103,374
LUG CSA 13099.60563698	-	203,278
LUG CSA 13590.91231633	-	301,130
LUG CSA 13102.91293905	-	175,969
LUG CSA 13104.10362869	-	518,963
LUG CSA 13831.10427677	-	337,110
LUG CSA 14040.60233886	-	51,168
LUG CSA 13939.60144164	-	250,779
LUG CSA 13158.90816343	-	199,568
LUG CSA 13021.60058683	-	278,902
LUG CSA 13158.93317809	-	148,139
LUG CSA 13104.91643108	-	506,035
LUG CSA 13106.91795934	-	690,997
LUG CSA 13835.60314670	-	374,768
LUG CSA 13107.10376186	-	64,031
LUG CSA 13592.91365233	-	309,043
LUG CSA 13993.10372414	-	390,086
LUG CSA 13100.10371703	-	367,082
LUG CSA 13354.10582069	-	178,861
LUG CSA 13418.92292295	-	215,879
LUG CSA 13468.60128378	-	723,680
LUG CSA 13632.60305848	-	429,955
LUG CSA 13104.10362882	-	135,924
LUG CSA 13176.10375148	-	509,452
LUG CSA 13099.60125388	-	235,837
LUG CSA 13102.60123660	-	97,365
LUG CSA 14102.91582612	-	180,748

	2020 Cost Estimate	2021 Cost Estimate
LUG CSA 13468.60128362	-	625,526
LUG CSA 13399.60037987	-	251,666
LUG CSA 13835.91773975	-	235,053
LUG CSA 13418.92018190	-	284,173
LUG CSA 13158.60011810	-	766,131
LUG CSA 13105.10580690	-	475,147
LUG CSA 13205.90022802	-	50,527
LUG CSA 13418.91924595	-	53,918
LUG CSA 13105.60164901	-	28,682
LUG CSA 13934.10467597	-	140,015
LUG CSA 13205.90442230	-	63,078
LUG CSA 13158.92290015	-	15,671
LUG CSA 14040.10786358	-	107,076
LUG CSA 13836.93321406	-	33,288
LUG CSA 13105.10580689	-	32,007
LUG CSA 13107.10376201	-	33,811
LUG CSA 13633.90633859	-	45,349
LUG CSA 13105.10580676	-	33,194
LUG CSA 13836.60133704	-	45,745
LUG CSA 13100.10371697	-	96,201
LUG CSA 13993.10433144	-	29,854
LUG CSA 13939.60144172	-	37,440
LUG CSA 13158.91461782	-	83,725
LUG CSA 13633.91847345	-	21,589
LUG CSA 13934.10467575	-	22,869
LUG CSA 13188.92070695	-	42,521
LUG CSA 13836.60133698	-	111,428
LUG CSA 13948.10442391	-	53,935
LUG CSA 14040.90485522	-	28,195
LUG CSA 13158.92347931	-	73,242
LUG CSA 13633.90564142	-	18,302
LUG DCA 13006.92949400	-	322,088
LUG DCA 13432.10761257	-	303,034
LUG CSA 13826.60127680	-	68,400
LUG CSA 13632.10408290	-	254,929
LUG CSA 13204.60170504	-	95,096
LUG CSA 13176.10375141	-	156,193
LUG CSA 13948.10442379	-	34,508
LUG CSA 13835.10429505	-	50,806
LUG CSA 13026.60059509	-	21,473
LUG CSA 13021.92350282	-	79,547
LUG CSA 13106.10361901	-	187,545
LUG CSA 13468.91640192	-	26,731
LUG CSA 13106.91722510	-	27,154
LUG CSA 13026.60059452	-	40,998

	2020 Cost Estimate	2021 Cost Estimate
LUG CSA 13632.10408272	-	24,533
LUG CSA 13102.90748252	-	58,536
LUG CSA 13093.60029740	-	74,519
LUG CSA 13102.60123656	-	37,302
LUG CSA 13026.60059457	-	52,223
LUG CSA 13099.10368943	-	60,804
LUG CSA 13104.91668251	-	50,834
LUG CSA 13026.91490707	-	71,238
LUG CSA 13176.10375136	-	164,623
LUG CSA 13104.91241032	-	37,734
LUG ESA 13230.10471377	-	544,479
LUG ESA 13509.60346595	-	167,511
LUG ESA 13502.10497396	-	335,609
LUG ESA 13174.93310101	-	49,190
LUG ESA 13796.92356181	-	25,749
LUG ESA 13509.92890860	-	32,564
LUG ESA 13171.10455414	-	57,716
LUG ESA 13230.92496254	-	28,179
LUG ESA 13509.10501141	-	15,912
LUG ESA 13454.91522987	-	4,218
LUG ESA 13509.10501110	-	8,749
LUG ESA 13231.10868120	-	40,497
LUG ESA 13174.10913197	-	7,516
LUG ESA 13225.92750192	-	9,118
LUG ESA 13797.93185703	-	4,347
LUG ESA 14116.91073265	-	9,007
LUG SHA 13900.10717269	-	40,659
LUG SHA 13652.92748361	-	46,366
LUG SHA 13001.93346473	-	78,709
LUG SHA 14022.90591555	-	73,737
LUG SHA 13001.60179144	-	64,897
LUG SHA 13001.10663246	-	48,802
LUG SHA 13645.91519309	-	48,141
LUG SHA 13780.10723993	-	26,264
LUG SHA 13001.92048269	-	23,188
LUG SHA 13001.60179191	-	35,434
LUG SHA 13001.10663240	-	43,942
LUG SHA 13900.92336596	-	44,660
LUG SHA 13645.92207754	-	71,235
LUG SHA 13900.91863298	-	25,911
LUG SHA 13001.10663269	-	11,491
LUG SHA 13001.10663262	-	8,950
LUG SHA 13001.90251758	-	57,316
LUG ESA 13127.90334707	-	35,068
LUG ESA 13229.10457704	-	6,703

	2020 Cost Estimate	2021 Cost Estimate
LUG ESA 13878.10105723	-	30,438
LUG ESA 13911.92679866	-	54,009
LUG ESA 13229.92525393	-	20,900
LUG ESA 13909.92173076	-	30,292
LUG ESA 14355.60258173	-	15,339
LUG ESA 13457.10482593	-	13,314
LUG ESA 13127.90334731	-	42,609
LUG ESA 13906.10096968	-	54,191
LUG ESA 13909.90380435	-	19,538
LUG ESA 13127.10836901	-	43,364
LUG ESA 13906.92282884	-	9,281
LUG ESA 13911.60157737	-	64,078
LUG ESA 13710.92354144	-	27,584
LUG ESA 13793.92685255	-	18,468
LUG ESA 13906.10096960	-	36,624
LUG ESA 13793.92686002	-	22,243
LUG ESA 13686.10840133	-	39,182
LUG ESA 13906.10096964	-	65,757
LUG ESA 13911.90130568	-	83,420
LUG ESA 13911.91276385	-	48,851
LUG ESA 13906.90137810	-	78,008
LUG ESA 13793.92686712	-	4,308
LUG ESA 13127.92663180	-	59,982
LUG ESA 13457.90291488	-	10,568
LUG ESA 13911.10544635	-	22,022
LUG ESA 13911.10544633	-	17,408
LUG ESA 13911.92018843	-	11,858
LUG ESA 13457.90176591	-	30,225
LUG ESA 13911.10554588	-	39,031
LUG ESA 14355.92354352	-	30,923
LUG ESA 13911.91556649	-	49,240
LUG ESA 13793.92686736	-	3,126
LUG ESA 13911.10554595	-	12,649
LUG ESA 13911.91995336	-	29,213
LUG ESA 13127.92661768	-	51,828
LUG ESA 13796.92884644	-	27,696
LUG ESA 13878.10105726	-	52,425
LUG ESA 13454.90188551	-	20,381
LUG ESA 13878.10105717	-	30,359
LUG ESA 13231.10868121	-	26,501
LUG ESA 13911.60157736	-	5,051
LUG ESA 13509.10501133	-	26,667
LUG ESA 13171.10455381	-	12,092
LUG ESA 13878.10105728	-	22,565
LUG ESA 13911.91665193	-	47,643

	2020 Cost Estimate	2021 Cost Estimate
LUG SHA 13003.10895225	-	64,638
LUG SHA 14024.10747874	-	14,634
LUG SHA 13342.91010293	-	34,982
LUG SHA 14020.60223573	-	46,757
LUG SHA 13342.10925094	-	31,803
LUG SHA 14024.90116190	-	12,334
LUG SHA 13817.10722417	-	173,386
LUG SHA 13003.10895211	-	239,763
LUG SHA 13342.90527363	-	15,177
LUG WSA 13605.90568909	-	364,721
LUG WSA 13162.92185426	-	366,501
LUG WSA 13194.90645535	-	855,965
LUG WSA 13079.60077624	-	400,697
LUG WSA 13586.91748729	-	378,612
LUG WSA 13162.10158432	-	151,344
LUG WSA 13864.10310477	-	123,686
LUG WSA 13113.92909503	-	12,623
LUG WSA 13516.60169592	-	45,315
LUG WSA 13192.90932106	-	33,616
LUG WSA 13333.91785740	-	40,502
LUG WSA 13863.60279838	-	81,760
LUG WSA 13109.90643551	-	116,172
LUG WSA 13332.91700188	-	18,851
LUG WSA 13756.90207831	-	65,975
LUG WSA 13672.60106849	-	46,598
LUG WSA 13860.10307215	-	48,576
LUG WSA 13756.60165355	-	14,435
LUG WSA 13672.10493801	-	100,880
LUG WSA 13864.10310468	-	36,647
LUG WSA 13864.10310497	-	26,102
LUG WSA 13586.92442286	-	85,088
LUG WSA 13672.91971930	-	33,879
LUG WSA 13192.90932283	-	26,761
LUG WSA 13678.10254063	-	47,851
LUG WSA 13141.10147344	-	17,137
LUG WSA 13756.10589587	-	24,983
LUG WSA 13864.10310505	-	87,988
LUG WSA 13860.10307212	-	43,896
LUG WSA 13111.60072751	-	35,461
LUG WSA 13605.90427351	-	50,126
LUG WSA 13333.10007588	-	27,842
LUG WSA 13164.90252716	-	37,530
LUG WSA 13491.91827162	-	41,617
LUG WSA 13113.90422522	-	19,111
LUG WSA 13756.10589595	-	43,364

	2020 Cost Estimate	2021 Cost Estimate
LUG WSA 13586.10255333	-	21,153
LUG WSA 13428.90423835	-	45,811
LUG WSA 13113.60340774	-	35,495
LUG WSA 13141.91575422	-	16,610
LUG WSA 13678.90514672	-	93,232
LUG WSA 13164.10158912	-	36,583
LUG WSA 13586.10255361	-	48,909
LUG WSA 13544.10053269	-	28,145
LUG WSA 13864.60380454	-	27,486
LUG WSA 13141.92442350	-	15,259
LUG WSA 13141.10147371	-	81,831
LUG WSA 13678.10288738	-	100,550
LUG WSA 13612.90440184	-	43,865
LUG WSA 13533.91957169	-	42,514
LUG WSA 14030.60131389	-	26,367
LUG WSA 13865.90531031	-	45,910
LUG WSA 13535.92983670	-	37,013
LUG WSA 13589.93177909	-	20,797
LUG WSA 13522.91934653	-	81,860
LUG WSA 13522.10392924	-	20,172
LUG WSA 13737.10297943	-	35,166
LUG WSA 14030.90886759	-	93,594
LUG WSA 13207.90147316	-	35,628
LUG WSA 13207.90216846	-	47,295
LUG WSA 13059.60302601	-	88,220
LUG WSA 13738.10298299	-	54,477
LUG WSA 13059.93006225	-	49,164
LUG WSA 13207.90146892	-	45,935
LUG WSA 13162.10158434	-	66,430
LUG WSA 13079.60077605	-	31,371
LUG WSA 13870.90428273	-	69,890
LUG WSA 13737.91960399	-	75,292
LUG WSA 13674.10277747	-	98,649
LUG WSA 13078.10127958	-	129,644
LUG WSA 13162.60154843	-	46,396
LUG WSA 13510.10218990	-	62,309
LUG WSA 13669.60107076	-	21,320
LUG WSA 14030.90242104	-	13,774
LUG WSA 13873.60311122	-	137,811
LUG WSA 13207.90613782	-	66,066
LUG WSA 13612.90266817	-	36,509
LUG WSA 13208.92767537	-	31,928
LUG WSA 13737.60311396	-	33,411
LUG WSA 13198.92655424	-	16,376
LUG WSA 13514.10624934	-	40,916

	2020 Cost Estimate	2021 Cost Estimate
LUG WSA 13535.92959083	-	17,793
LUG WSA 13669.92774744	-	48,359
LUG WSA 13483.60393455	-	229,675
LUG WSA 13520.10242257	-	78,414
LUG WSA 13892.10338448	-	193,272
LUG WSA 13612.90312305	-	16,508
LUG WSA 13522.91947423	-	91,489
LUG WSA 13334.91645657	-	84,169
LUG WSA 13490.92815117	-	29,081
LUG WSA 13522.10392902	-	115,693
LUG WSA 14030.60341032	-	23,027
LUG WSA 13574.10250638	-	29,706
LUG WSA 13138.10145602	-	38,293
LUG WSA 13220.10191173	-	89,992
LUG WSA 13612.60022877	-	10,640
LUG WSA 13220.90901917	-	85,130
LUG WSA 13535.92983661	-	57,908
LUG WSA 13535.91618829	-	87,294
LUG WSA 13669.92770538	-	52,375
LUG WSA 13208.90449608	-	38,887
LUG WSA 13079.60104344	-	24,510
LUG WSA 13575.90054924	-	18,620
LUG WSA 13750.60110680	-	32,241
LUG WSA 13198.10051875	-	16,910
LUG WSA 13612.92956326	-	40,696
LUG WSA 13514.91361858	-	28,195
LUG WSA 13522.10392905	-	82,457
LUG WSA 14030.92669942	-	96,929
LUG WSA 13483.10173513	-	94,965
LUG WSA 13612.60003135	-	52,723
LUG WSA 13071.93035682	-	110,195
LUG WSA 13522.92169062	-	55,029
LUG WSA 13575.90054386	-	17,661
LUG WSA 13522.10392882	-	119,474
LUG WSA 13198.10051851	-	36,866
LUG WSA 14030.92670479	-	18,909
LUG WSA 13522.10392874	-	27,362
LUG WSA 13162.93124277	-	27,263
LUG WSA 13535.92969194	-	12,729
LUG WSA 13198.10051896	-	23,026
LUG WSA 13109.10846390	-	41,888
LUG WSA 13612.60002970	-	43,109
LUG WSA 14030.60125643	-	15,490
LUG WSA 14030.92669080	-	47,354
LUG WSA 13071.92377934	-	170,781

	2020 Cost Estimate	2021 Cost Estimate
LUG WSA 13138.60170460	-	45,947
LUG WSA 13483.60079455	-	44,497
LUG WSA 13535.92952190	-	44,701
LUG WSA 13198.10051852	-	27,030
LUG WSA 13162.90435139	-	51,765
LUG WSA 13873.10820612	-	17,509
LUG WSA 13138.10145618	-	12,342
LUG WSA 13737.90740214	-	17,590
LUG WSA 13138.10145629	-	21,206
LUG WSA 13737.90740699	-	28,782
LUG WSA 13079.90517178	-	22,544
LUG WSA 13078.10127955	-	31,008
LUG WSA 14030.92669557	-	1,551
LUG WSA 13522.10392864	-	18,427
LUG WSA 13674.90420693	-	56,247
LUG WSA 13612.90291123	-	23,214
LUG WSA 13109.60233901	-	82,204
LUG WSA 13737.10297934	-	34,269
LUG WSA 13589.93162023	-	56,850
LUG WSA 13198.92585443	-	15,596
LUG WSA 14030.92669914	-	35,354
LUG WSA 13612.90312570	-	32,279
LUG WSA 13138.10145606	-	44,537
LUG WSA 14030.92669923	-	36,045
LUG WSA 13522.60305728	-	16,649
LUG WSA 13522.60305720	-	11,910

	2020 Cost Estimate	2021 Cost Estimate
Transmission Asset Upgrades Program Total	**5,682,545**	**15,601,522**
SPP TAU - Circuit 66654	321,606	-
SPP TAU - Circuit 66840	1,087,084	-
SPP TAU - Circuit 66007	1,364,157	-
SPP TAU - Circuit 66019	684,839	-
SPP TAU - Circuit 66425	97,834	-
SPP TAU - Circuit 230403	108,739	-
SPP TAU - Circuit 66413	163,057	-
SPP TAU - Circuit 66046	966,922	-
SPP TAU - Circuit 66059	65,223	-
SPP TAU - Circuit 230008	721,855	585,969
SPP TAU - Circuit 230010	926	43,310
SPP TAU - Circuit 230038	463	21,655
SPP TAU - Circuit 230003	16,203	757,932
SPP TAU - Circuit 230005	11,111	519,725
SPP TAU - Circuit 230004	18,518	866,208
SPP TAU - Circuit 230625	5,555	259,862
SPP TAU - Circuit 230021	7,870	368,138
SPP TAU - Circuit 230052	2,778	194,897
SPP TAU - Circuit 66024	28,548	786,737
SPP TAU - Circuit 230608	7,407	389,793
SPP TAU - Circuit 230603	1,852	263,566
SPP TAU - Circuit 66407	-	978,341
SPP TAU - Circuit 66033	-	847,896
SPP TAU - Circuit 66016	-	1,339,991
SPP TAU - Circuit 66427	-	225,996
SPP TAU - Circuit 66415	-	326,114
SPP TAU - Circuit 66834	-	645,376
SPP TAU - Circuit 66022	-	1,634,135
SPP TAU - Circuit 66060	-	195,668
SPP TAU - Circuit 66048	-	163,057
SPP TAU - Circuit 66031	-	65,223
SPP TAU - Circuit 66036	-	1,004,101
SPP TAU - Circuit 230402	-	308,728
SPP TAU - Circuit 230401	-	1,704,501
SPP TAU - Circuit 230602	-	811,552
SPP TAU - Circuit 230012	-	7,407
SPP TAU - Circuit 230606	-	12,962
SPP TAU - Circuit 230033	-	3,704
SPP TAU - Circuit 230609	-	2,315
SPP TAU - Circuit 230013	-	9,259
SPP TAU - Circuit 66030	-	56,076
SPP TAU - Circuit 66025	-	89,264
SPP TAU - Circuit 66020	-	11,419
SPP TAU - Circuit 66027	-	20,554
SPP TAU - Circuit 66008	-	6,851
SPP TAU - Circuit 66001	-	73,242

	2020 Cost Estimate	2021 Cost Estimate
Substation Extreme Weather Hardening Program Total	**-**	**250,000**
Substation Extreme Weather Protection Study		250,000

	2020 Cost Estimate	2021 Cost Estimate
Distribution Overhead Feeder Hardening Program Total	**6,536,320**	**15,679,652**
SPP FH - E Winterhaven 13308	1,108,255	-
SPP FH - Knights 13807	2,049,907	-
SPP FH - Knights 13805	1,622,865	-
SPP FH - Casey Road 13745	499,187	-
SPP FH - Coolidge 13533	1,001,094	-
SPP FH - 13461	54,878	2,616,405
SPP FH - 14121	15,656	3,800,999
SPP FH - 13939	25,752	1,180,575
SPP FH - 13890	11,979	1,244,198
SPP FH - 13443	32,487	2,401,626
SPP FH - 13227	36,425	1,226,716
SPP FH - 13462	42,512	1,417,924
SPP FH - 13633	35,322	1,493,641
SPP FH - 13101	-	-
SPP FH - 13104	-	-
SPP FH - 13111	-	-
SPP FH - 13309	-	-
SPP FH - 13313	-	-
SPP FH - 13314	-	-
SPP FH - 13339	-	-
SPP FH - 13433	-	-
SPP FH - 13808	-	-
SPP FH - 13964	-	-
SPP FH - 13148	-	297,568
SPP FH - 13048	-	-
SPP FH - 13094	-	-
SPP FH - 13770	-	-
SPP FH - 13118	-	-
SPP FH - 13296	-	-
SPP FH - 13989	-	-
SPP FH - 13984	-	-
SPP FH - 14123	-	-

	2020 Cost Estimate	2021 Cost Estimate
Transmission Access Enhancement Program Total	**-**	**1,328,137**
SPP TXE - Site Access-230008	-	10,710
SPP TXE - Site Access-230623	-	31,442
SPP TXE - Site Access-Proposed Bridge P	-	108,180
SPP TXE - Site Access-Hampton Substation	-	93,677
SPP TXE - Site Access-230033	-	16,547
SPP TXE - Site Access-Morris Bridge Rd	-	92,766
SPP TXE - Site Access-66007	-	20,202
SPP TXE - Site Access-230037	-	22,576
SPP TXE - Site Access-66839	-	40,093
SPP TXE - Site Access-230606	-	26,926
SPP TXE - Site Access-Columbus Drive #2	-	107,152
SPP TXE - Site Access-West Of Forbes Rd	-	96,749
SPP TXE - Site Access-Columbus Drive #1	-	107,152
SPP TXE - Site Access-Tampa Palms #1	-	95,725
SPP TXE - Site Access-19th Av NE	-	84,546
SPP TXE - Site Access-East Of Sydney Washer Rd	-	109,038
SPP TXE - Site Access-Tampa Palms #3	-	108,180
SPP TXE - Site Access-Proposed Bridge M	-	156,474

	2020 Cost Estimate	2021 Cost Estimate
Vegetation Management Program Total	**10,491,741**	**23,326,250**
Distribution SPP Veg Mgmnt Subtotal	**9,806,749**	**19,791,650**
Planned	6,775,318	13,028,364
Supplemental	2,931,431	5,495,330
Mid-cycle	100,000	1,267,956
Transmission SPP Veg Mgmnt Subtotal	**684,992**	**3,534,600**
Planned	257,356	2,839,600
ROW Maintenance (Mowing, etc)	327,636	-
69kv Incremental	100,000	695,000

	2020 Cost Estimate	2021 Cost Estimate
Infrastructure Inspections Program Total	**376,324**	**1,585,030**
Distribution Wood Pole Inspections	1,500	1,003,600
Routine Ground Patrol - Trans	90,000	204,000
Infrared Thermography - Trans	110,000	112,000
Above Ground Inspection - Trans	4,500	10,000
Ground Line Inspections - Trans	60,000	61,000
Substation Inspections	110,324	194,430

	2020 Cost Estimate	2021 Cost Estimate
Common Storm Protection Plan Program Total	**1,384,078**	**402,400**
SPP Common (Internal Labor, material, other, etc.)	354,172	402,400
Accenture	337,002	
1898 & Co.	562,471	
Power Engineers	130,433	

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 20200092-EI

IN RE: STORM PROTECTION PLAN COST RECOVERY CLAUSE

TESTIMONY AND EXHIBIT

OF

A. SLOAN LEWIS

FILED: July 24, 2020

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

A. SLOAN LEWIS

INTRODUCTION:

Q. Please state your name, address, occupation and employer.

A. My name is A. Sloan Lewis. My business address is 702 N. Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "the Company") in the Finance Department as Director, Regulatory Accounting.

Q. Please describe your duties and responsibilities in that position.

A. My duties and responsibilities include the accounting oversight of all cost recovery clauses and riders for Tampa Electric and Peoples Gas, the settlement of all fuel and power transactions for Tampa Electric and Peoples Gas System and the accounts payable department for Tampa Electric, Peoples Gas System and New Mexico

Gas Company.

Q. Please describe your educational background and professional experience.

A. I received a Bachelor of Science degree in accounting from Florida State University in 1994 and a Master of Education from the University of North Florida in 1996. I joined Tampa Electric in 2000 as a Fuels Accountant and over the past 19 years have expanded my cost recovery clause responsibilities. Then in 2015, I was promoted to Manager, Regulatory Accounting with responsibilities for all the recovery clauses and riders for Tampa Electric and Peoples Gas System. I was promoted to my current role as Director, Regulatory Accounting in 2017.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony in this proceeding is to present and explain how the company developed the projected total annual revenue requirements associated with the company's 2020 actual and estimated and projected 2021 Storm Protection Plan activities, and to describe the steps taken by Tampa Electric to promote transparency and ensure that the costs the company will recover through the Storm Protection Plan Cost Recovery Clause ("SPPCRC") do not include costs that are currently recovered through the utility's existing base rates or any other cost recovery mechanism.

Q. Have you prepared an exhibit to accompany your direct testimony?

A. Yes. I have two exhibits that were prepared under my direction and supervision. Exhibit No. ASL-1, entitled "Tampa Electric's 2020-2021 SPP Total Revenue Requirements by Program" shows the Annual Revenue Requirement for the company's 2020-2021 SPP Programs. Exhibit No. ASL-2, entitled "Final Order Approving Tampa Electric's 2020 Settlement Agreement" is a settlement agreement entered into by Tampa Electric and consumer parties that was approved by the Commission on June 9, 2020 and the Commission's Order No. PSC-2020-0224-AS-EI that was issued on June 20, 2020.

DEVELOPMENT AND CALCULATION OF THE PROJECTED ANNUAL REVENUE REQUIREMENTS FOR 2020 and 2021

Q. What are the projected annual revenue requirements for

Tampa Electric's SPP activities in 2020 and 2021?

A. The projected annual revenue requirements for the company's SPP activities for 2020 and 2021 are included below.

<u>Total Projected SPP Revenue Requirement (2020-2021)</u>

2020	$6,035,191
2021	$33,908,399

The revenue requirements of each SPP program are detailed further in my Exhibit No. ASL-1.

Q. Would you explain how these projected annual revenue requirements were developed?

A. Yes, the projected annual revenue requirements were developed with cost estimates for each of the SPP programs plus depreciation and return on SPP assets, as outlined in Rule 25-6.031(6), Florida Administrative Code ("F.A.C."), the SPP Cost Recovery Clause Rule.

Q. Do these revenue requirements include any costs that are currently recovered in base rates?

A. No, as I discuss further below, the company has agreed to procedures designed to avoid double recovery of SPP costs through both base rates and the SPPCRC.

Q. Do the projected annual revenue requirements include SPP capital expenditures made prior to the plan filing date in the depreciation and return calculations?

A. No, only capital expenditures for SPP projects to be initiated after April 10, 2020 were included in the depreciation and return calculations included in the estimated annual jurisdictional revenue requirements.

Q. Do the projected annual revenue requirements include the annual depreciation expense on SPP capital expenditures?

A. Yes, Rule 25-6.031 states that the annual depreciation expense is a cost that may be recovered through the SPPCRC. As a result, the projected annual revenue requirements include the annual depreciation expense calculated on the SPP capital expenditures initiated after April 10, 2020, using the depreciation rates from Tampa Electric's most current Depreciation Study, approved by Order No. PSC-12-0175-PAA-EI issued April 3, 2012 within Docket No. 20110131-EI.

Q. Were the depreciation savings on the retirement of assets removed from service during the SPP capital projects considered in the development of the revenue requirement?

A. Yes, in the development of the revenue requirements, depreciation expense from the SPP capital asset additions were reduced by the depreciation expense savings resulting from the estimated retirement of assets removed from service during the SPP capital projects.

Q. Do the projected annual revenue requirements include a return on the undepreciated balance of the SPP assets?

A. Yes, Rule 25-6.031 6(c) states that the utility may recover a return on the undepreciated balance of the asset costs through the SPPCRC. As a result, this return was included in the estimated annual jurisdictional revenue requirement. In accordance with the Order No. PSC-2020-0165-PAA-EU issued on May 20, 2020 within Docket No. 20200118-EU, Amended unopposed joint motion to modify Order PSC-2012-0425-PAA-EU regarding weighted average cost of capital methodology, Tampa Electric calculated a return on the undepreciated balance of the asset costs for 2020 using the existing methodology outlined in Order No. PSC-2012-0425-PAA-EU and for 2021 using the projected mid-point return on equity 13-month average weighted average cost of capital for 2021.

Q. Did the company include Allowance for Funds Used During Construction ("AFUDC") in the calculation of the projected annual revenue requirements?

A. No, per Rule 25-6.0141, F.A.C, in order for projects to be eligible for AFUDC, they must involve "gross additions to plant in excess of 0.5 percent of the sum of the total balance in Account 101, Electric Plant in Service, and Account 106, Completed Construction not Classified, at the time the project commences and are expected to be completed in excess of one year after commencement of construction." None of the projects proposed in Tampa Electric's 2020-2021 SPP meet the criteria for AFUDC eligibility.

AVOIDANCE OF DOUBLE RECOVERY

Q. Rule 25-6.031(7), F.A.C. states that costs recoverable through the SPPCRC "shall not include costs recovered through the utility's base rates or any other cost recovery mechanism." What steps has Tampa Electric taken to ensure that the costs presented for recovery in this docket do not include any costs that are already recovered in base rates?

A. The company has taken two main steps to ensure that the costs recovered through the SPPCRC do not include any costs that are already recovered through base rates. First, the company has implemented internal procedures to accurately track SPP costs. Second, the company entered into an agreement approved by the Commission known as the 2020 Settlement Agreement. This Agreement includes a method for avoiding double recovery of SPP costs.

Q. What internal procedures has the company implemented to accurately track SPP costs to avoid potential double recovery through the SPPCRC?

A. All SPP Programs and SPP Projects are identified using the company's accounting system attributes including Funding Projects, Work Orders and Plant Maintenance Orders ("PMOs")/work requests. Each SPP Project is assigned a specific Funding Project number, which is "tagged" with a code indicating which SPP Program the costs are attributable to. This code clearly differentiates the SPP Capital investments from the company's other Capital assets in the accounting system. The company has also developed a set of charging guidelines for the SPP and several layers of internal review are performed on these costs. Additional measures to avoid double recovery are covered in the 2020 Settlement Agreement, discussed in detail below.

Q. What is the Tampa Electric 2020 Settlement Agreement?

A. The 2020 Settlement Agreement is an agreement entered into by Tampa Electric, the Office of Public Counsel, the Florida Industrial Power Users Group, the Florida Retail Federation, the Federal Executive Agencies, and the West Central Florida Hospital Utility Alliance. The 2020 Settlement Agreement resolves issues in several Commission dockets involving Tampa Electric, including this docket. The Commission approved the 2020 Settlement Agreement in a hearing held on June 9, 2020 and was approved by the Commission's Order No. PSC-2020-0224-AS-EI. I also have included a copy of the Commission's Final Order Approving the 2020 Settlement Agreement as my Exhibit No. ASL-2.

Q. What provisions in the 2020 Settlement Agreement affect this docket?

A. The 2020 Settlement Agreement contains provisions governing cost recovery for incremental SPP operations and maintenance ("O&M") expenses, capital expenditures and assets related to the SPP, and distribution pole replacements. The purpose of these provisions is to set out a method for avoiding double recovery of SPP costs through both base rates and through the SPPCRC.

Q. How does the 2020 Settlement Agreement ensure there is no double recovery of SPP O&M costs?

A. The company's SPP is comprised of both existing and new storm protection activities. Under the 2020 Settlement Agreement, Tampa Electric will recover all SPP O&M expenses, including expenses associated with existing activities, through the SPPCRC.

Q. How will the company recover O&M expenses associated with existing activities through the SPPCRC while avoiding double recovery of those costs?

A. There are six existing activities included in the company's SPP, the costs of which are currently recovered through base rates. The company will reduce base rate revenues by an amount equal to the average actual O&M expense for the most recent two years – grossed up for the regulatory assessment fee – for these six activities. The ultimate result of this agreement is that Tampa Electric will reduce base rates by an annual amount of $14,876,228.78 beginning in 2021. The calculation that results in this total reduction is detailed in the Exhibit of William R. Ashburn.

Q. Does the 2020 Settlement Agreement address recovery of costs associated with these six activities in 2020?

A. Yes. Pursuant to the Agreement, the company may seek recovery of 2020 SPP O&M expense for the six activities for the period from May to December 2020, but only to the extent that total expense for those activities exceeds the average of the total expense for those activities in May through December of 2018 and May through December of 2019. This means that the company may seek recovery of any SPP O&M expense for the six activities exceeding $10.4 million.

Q. Is the threshold for recovery of SPP O&M expense in 2020 a total amount, or is it comprised of six individual threshold amounts, one for each activity?

A. It is a total threshold. Every dollar above $10.4

expended on the six activities for the period May through December 2020 is incremental and eligible for cost recovery through the SPPCRC.

Q. How does the 2020 Settlement Agreement avoid potential double recovery for capital expenditures?

A. The Agreement establishes a bright line test for determining which SPP capital projects are eligible for SPPCRC recovery. Under the Agreement, all SPP capital projects initiated after April 10, 2020 are eligible for recovery through the SPPCRC, subject to a prudency review in this docket. Cost recovery for projects initiated prior to that date will remain through base rates.

Q. Are there any other provisions of the 2020 Settlement Agreement that will avoid potential double recovery?

A. Yes. The Agreement requires the company to recover costs associated with distribution pole replacements through base rates. This avoids potential challenges associated with accounting for mass asset additions and retirements. Likewise, the company will also not seek recovery of the O&M expenses from asset transfers related to distribution pole replacements through the SPPCRC. The Agreement also requires the company to implement four accounting protocols for capital items to avoid double recovery.

Q. What are those four accounting protocols for capital items?

A. First, when assets are retired and replaced as a part of a SPP program, the company will not seek to recover the cost of removal net of salvage associated with the related assets through the SPPCRC. Instead, the net cost of removal will be debited to the company's accumulated depreciation reserve. Second, depreciation expense from SPP capital asset addition will be reduced by depreciation expense savings that result from the retirement of assets removed from service during the SPP project. Only the net of the two amounts will be recovered through the SPPCRC. Third, project records and fixed asset records for SPP capital projects will be maintained in a manner that clearly distinguishes between rate base and SPPCRC assets. Finally, the company has the option to remove items from the SPPCRC and include them in retail base rates if the Commission determined that they were prudent through a final true-up in the SPPCRC docket.

Q. Are there any other provisions of the 2020 Settlement Agreement that affect cost recovery for SPP activities?

A. Yes, the Agreement does contain provisions governing the eligibility of SPP projects for accrual of AFUDC. As I explained previously, however, Tampa Electric is not seeking cost recovery for AFUDC for any SPP Projects at this time.

Q. Did Tampa Electric follow all of the requirements of the 2020 Settlement Agreement in developing its request for cost recovery in this docket?

A. Yes, the company followed all of the requirements of the Agreement in developing our request for cost recovery in the SPPCRC.

Q. Were jurisdictional distribution or transmission factors applied to the projected annual revenue requirements?

A. Yes, the company applied the most recent jurisdictional transmission factor to the O&M and capital transmission costs to recognize the retail portion of the revenue requirements ensuring the SPPCRC did not double recover those amounts collected from the company’s Open Access

Transmission Tariff. It was not necessary to adjust any distribution costs by any jurisdictional factor.

CONCLUSION:

Q. Please summarize your direct testimony.

A. My testimony and exhibits demonstrate that Tampa Electric's projected annual revenue requirements associated with the company's 2020 actual and estimated and projected 2021 Storm Protection Plan activities are based on calculations performed in compliance with Rule 25-6.031 of the F.A.C. and the Commission approved 2020 Settlement Agreement.

Q. Does this conclude your testimony?

A. Yes.

EXHIBIT

OF

A. SLOAN LEWIS

Tampa Electric Company
Storm Protection Plan Cost Recovery Clause (SPPCRC)
Initial Projection
Projected Period: January through December 2021

Calculation of Annual Revenue Requirements for O&M Programs
(in Dollars)

Line	O&M Activities	T/D	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Total	Method of Classification Demand %	Method of Classification Energy %
1.	Vegetation Management Programs																
	1. Distribution Vegetation Management - Planned	D	1,566,001	1,566,051	1,565,901	1,677,112	1,677,011	1,677,011	1,677,111	1,677,161	1,677,011	1,677,110	1,677,010	1,677,160	19,791,650	100%	0%
	2. Transmission Vegetation Management - Planned	T	294,617	294,517	294,517	294,617	294,517	294,517	294,617	294,517	294,516	294,616	294,516	294,516	3,534,600	100%	0%
	3. Transmission Vegetation Management - ROW	T	-	-	-	-	-	-	-	-	-	-	-	-	0	100%	0%
1.a	Adjustments														0	100%	0%
1.b	Subtotal of Vegetation Management Programs		1,860,618	1,860,568	1,860,418	1,971,729	1,971,528	1,971,528	1,971,728	1,971,678	1,971,527	1,971,726	1,971,526	1,971,676	23,326,250	-	
2	Asset Upgrade Programs																
	1. Transmission Asset Upgrades	T	32,091	31,066	31,079	37,495	34,823	43,739	45,183	44,918	45,471	36,808	33,302	33,387	449,362	100%	0%
2.a	Adjustments														0	100%	0%
2.b	Subtotal of Asset Upgrade programs		32,091	31,066	31,079	37,495	34,823	43,739	45,183	44,918	45,471	36,808	33,302	33,387	449,362		
3	Substation Protection Programs																
	1. Substation Extreme Weather Protection	D	0	0	0	125,000	125,000	0	0	0	0	0	0	0	250,000	100%	0%
3.a	Adjustments														0	100%	0%
3.b	Subtotal of Substation Protection Programs		0	0	0	125,000	125,000	0	0	0	0	0	0	0	250,000		
4.	Overhead Feeder Hardening Programs																
	1. Distribution Overhead Feeder Hardening	D	8,530	17,228	45,423	51,539	60,769	39,940	15,969	23,368	20,291	21,043	20,189	20,903	345,191	100%	0%
4.a	Adjustments														0	100%	0%
4.b	Subtotal of Transmission Access Programs		8,530	17,228	45,423	51,539	60,769	39,940	15,969	23,368	20,291	21,043	20,189	20,903	345,191		
5.	Transmission Access Programs																
	1. Transmission Access Enhancement	T	0	0	0	0	0	0	0	0	0	0	0	0	0	100%	0%
5.a.	Adjustments														0	100%	0%
5.b.	Subtotal of Transmission Access Programs		0	0	0	0	0	0	0	0	0	0	0	0	0		
6.	Infrastructure Inspection Programs																
	1. Distribution Infrastructure Inspections	D	175,800	175,800	175,800	175,800	100,200	100,200	98,500	300	300	300	300	300	1,003,600	100%	0%
	2. Transmission Infrastructure Inspections	T	24,140	64,750	51,290	38,450	25,850	45,485	38,600	37,175	112,490	70,500	34,450	38,250	581,430	100%	0%
6.a.	Adjustments														0	100%	0%
6.b.	Subtotal of Infrastructure Inspection Programs		199,940	240,550	227,090	214,250	126,050	145,685	137,100	37,475	112,790	70,800	34,750	38,550	1,585,030		
7.	Common SPP Programs																
	1. Common O&M	D	32,150	43,150	32,550	32,450	34,350	32,250	32,150	32,550	32,150	34,350	32,150	32,150	402,400	100%	0%
7.a.	Adjustments														0	100%	0%
7.b.	Subtotal of Common SPP Programs		32,150	43,150	32,550	32,450	34,350	32,250	32,150	32,550	32,150	34,350	32,150	32,150	402,400		
8.	Total of O&M Programs		2,133,329	2,192,562	2,196,559	2,432,463	2,352,520	2,233,142	2,202,130	2,109,988	2,182,229	2,134,727	2,091,917	2,096,666	26,358,233	-	-
	a. Total Distribution O&M Programs		1,782,481	1,802,229	1,819,674	2,061,901	1,997,330	1,849,401	1,823,730	1,733,379	1,729,752	1,732,803	1,729,649	1,730,513	21,792,841		
	b. Total Transmission O&M Programs		350,848	390,333	376,886	370,562	355,190	383,741	378,400	376,610	452,477	401,924	362,268	366,153	4,565,392		
9.	Allocation of O&M Costs																
	a. Distribution O&M Allocated to Demand		1,782,481	1,802,229	1,819,674	2,061,901	1,997,330	1,849,401	1,823,730	1,733,379	1,729,752	1,732,803	1,729,649	1,730,513	21,792,841	-	
	b. Transmission O&M Allocated to Demand		350,848	390,333	376,886	370,562	355,190	383,741	378,400	376,610	452,477	401,924	362,268	366,153	4,565,392	-	
	c. Distribution O&M Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0		
	d. Transmission O&M Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0		
10.	Retail Jurisdictional Factors																
	a. Distribution Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000			
	b. Transmission Demand Jurisdictional Factor		0.9252920	0.9252920	0.9252920	0.9252920	0.9252920	0.9252920	0.9252920	0.9252920	0.9252920	0.9252920	0.9252920	0.9252920			
	c. Distribution Energy Jurisdictional Factor		0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000			
	d. Transmission Energy Jurisdictional Factor		0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000			
11.	Jurisdictional Revenue Requirements																
	a. Jurisdictional Distribution Demand Revenue Requirement		1,782,481	1,802,229	1,819,674	2,061,901	1,997,330	1,849,401	1,823,730	1,733,379	1,729,752	1,732,803	1,729,649	1,730,513	21,792,841		
	b. Jurisdictional Transmission Demand Revenue Requirement		324,637	361,172	348,729	342,878	328,654	355,073	350,130	348,474	418,673	371,897	335,204	338,798	4,224,321		
	c. Jurisdictional Distribution Energy Revenue Requirement		-	-	-	-	-	-	-	-	-	-	-	-	-		
	d. Jurisdictional Transmission Energy Revenue Requirement		-	-	-	-	-	-	-	-	-	-	-	-	-		
12.	Total Jurisdictional O&M Revenue Requirements		2,107,118	2,163,401	2,168,403	2,404,779	2,325,984	2,204,474	2,173,860	2,081,852	2,148,425	2,104,701	2,064,853	2,069,312	26,017,162	-	
13	Jurisdictional Demand Revenue Requirements by Program																
	a. Distribution Vegetation Management - Planned		1,566,001	1,566,051	1,565,901	1,677,112	1,677,011	1,677,011	1,677,111	1,677,161	1,677,011	1,677,110	1,677,010	1,677,160	19,791,650		
	b. Transmission Vegetation Management - Planned		272,607	272,514	272,514	272,607	272,514	272,514	272,607	272,514	272,513	272,606	272,513	272,513	3,270,537		
	c. Transmission Vegetation Management - ROW		0	0	0	0	0	0	0	0	0	0	0	0	0		
	d. Trans Asset Upgrade O&M Programs		29,693	28,745	28,757	34,694	32,221	40,472	41,807	41,562	42,074	34,058	30,814	30,893	415,791		
	e. Substation Protection O&M Programs		0	0	0	125,000	125,000	0	0	0	0	0	0	0	250,000		
	f. Overhead Feeder Hardening Programs		8,530	17,228	45,423	51,539	60,769	39,940	15,969	23,368	20,291	21,043	20,189	20,903	345,191		
	g. Transmission Access O&M Programs		0	0	0	0	0	0	0	0	0	0	0	0	0		
	h. Distr. Infrastructure Inspections		175,800	175,800	175,800	175,800	100,200	100,200	98,500	300	300	300	300	300	1,003,600		
	i. Trans. Infrastructure Inspections		22,337	59,913	47,458	35,577	23,919	42,087	35,716	34,398	104,086	65,233	31,876	35,392	537,993		
	j. Common SPP O&M		32,150	43,150	32,550	32,450	34,350	32,250	32,150	32,550	32,150	34,350	32,150	32,150	402,400		
			2,107,118	2,163,401	2,168,403	2,404,779	2,325,984	2,204,474	2,173,860	2,081,852	2,148,425	2,104,701	2,064,853	2,069,312	26,017,162		

TAMPA ELECTRIC COMPANY
DOCKET NO. 20200092-EI
EXHIBIT NO. ASL-1
DOCUMENT NO. 1
WITNESS: LEWIS
PAGE 2 OF 14
FILED: 07/24/2020

Tampa Electric Company
Storm Protection Plan Cost Recovery Clause (SPPCRC)
Initial Projection
Projected Period: January through December 2021

Calculation of Annual Revenue Requirements for Capital Investment Programs
(in Dollars)

Line	Capital Investment Activities	T/D	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Total
1.	Distribution Lateral Undergrounding Program	D	$ 85,427	$ 130,349	$ 175,608	$ 232,253	$ 282,351	$ 331,023	$ 384,238	$ 436,747	$ 490,076	$ 544,943	$ 600,280	$ 649,285	$ 4,342,580
1.a.	Adjustments	D	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1.b.	Subtotal of Distribution Lateral Undergrounding Program	D	$ 85,427	$ 130,349	$ 175,608	$ 232,253	$ 282,351	$ 331,023	$ 384,238	$ 436,747	$ 490,076	$ 544,943	$ 600,280	$ 649,285	$ 4,342,580
1.c.	Jurisdictional Demand Revenue Requirements		$ 85,427	$ 130,349	$ 175,608	$ 232,253	$ 282,351	$ 331,023	$ 384,238	$ 436,747	$ 490,076	$ 544,943	$ 600,280	$ 649,285	$ 4,342,580
1.d.	Jurisdictional Energy Revenue Requirements		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2	Transmission Asset Upgrades Program	T	$ 62,086	$ 72,635	$ 83,005	$ 93,690	$ 105,413	$ 115,842	$ 130,242	$ 144,775	$ 156,119	$ 170,330	$ 181,095	$ 187,834	$ 1,503,066
2.a.	Adjustments	T	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2.b.	Subtotal of Transmission Asset Upgrades Program	T	$ 62,086	$ 72,635	$ 83,005	$ 93,690	$ 105,413	$ 115,842	$ 130,242	$ 144,775	$ 156,119	$ 170,330	$ 181,095	$ 187,834	$ 1,503,066
2.c.	Jurisdictional Demand Revenue Requirements		$ 57,448	$ 67,209	$ 76,804	$ 86,691	$ 97,538	$ 107,188	$ 120,512	$ 133,959	$ 144,456	$ 157,605	$ 167,566	$ 173,801	$ 1,390,775
2.d.	Jurisdictional Energy Revenue Requirements		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3	Substation Extreme Weather Program	D	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3.a.	Adjustments	D	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3.b.	Subtotal of Substation Extreme Weather Program	D	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3.c. b	Jurisdictional Demand Revenue Requirements		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3.d. a	Jurisdictional Energy Revenue Requirements		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4	Distribution Overhead Feeder Hardening Program	D	$ 66,657	$ 73,897	$ 88,958	$ 108,430	$ 129,027	$ 144,368	$ 161,486	$ 166,117	$ 174,014	$ 182,761	$ 189,030	$ 193,513	$ 1,678,258
4.a.	Adjustments	D	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4.b.	Subtotal of Distribution Overhead Feeder Hardening Program	D	$ 66,657	$ 73,897	$ 88,958	$ 108,430	$ 129,027	$ 144,368	$ 161,486	$ 166,117	$ 174,014	$ 182,761	$ 189,030	$ 193,513	$ 1,678,258
4.c.	Jurisdictional Demand Revenue Requirements		$ 66,657	$ 73,897	$ 88,958	$ 108,430	$ 129,027	$ 144,368	$ 161,486	$ 166,117	$ 174,014	$ 182,761	$ 189,030	$ 193,513	$ 1,678,258
4.d.	Jurisdictional Energy Revenue Requirements		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5	Transmission Access Enhancement Program	T	$ -	$ -	$ -	$ 149	$ 447	$ 745	$ 1,328	$ 2,198	$ 3,068	$ 4,371	$ 6,109	$ 7,847	$ 26,262
5.a.	Adjustments	T	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5.b.	Subtotal of Transmission Access Enhancement Program	T	$ -	$ -	$ -	$ 149	$ 447	$ 745	$ 1,328	$ 2,198	$ 3,068	$ 4,371	$ 6,109	$ 7,847	$ 26,262
5.c.	Jurisdictional Demand Revenue Requirements		$ -	$ -	$ -	$ 138	$ 414	$ 689	$ 1,229	$ 2,034	$ 2,839	$ 4,044	$ 5,653	$ 7,261	$ 24,300
5.d.	Jurisdictional Energy Revenue Requirements		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
6	Retail Jurisdictional Factors														
6.a.	Distribution Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
6.b.	Transmission Demand Jurisdictional Factor		0.9252920	0.9252920	0.9252920	0.9252920	0.9252920	0.9252920	0.9252920	0.9252920	0.9252920	0.9252920	0.9252920	0.9252920	
6.c.	Distribution Energy Jurisdictional Factor		0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	
6.d.	Transmission Energy Jurisdictional Factor		0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	
7	Total of Capital Investment Programs		$ 214,170	$ 276,881	$ 347,571	$ 434,522	$ 517,238	$ 591,978	$ 677,294	$ 749,837	$ 823,277	$ 902,405	$ 976,514	$ 1,038,479	$ 7,550,166
7.a.	Jurisdictional Distribution Demand Revenue Requirements		$ 152,084	$ 204,246	$ 264,566	$ 340,683	$ 411,378	$ 475,391	$ 545,724	$ 602,864	$ 664,090	$ 727,704	$ 789,310	$ 842,798	$ 6,020,838
7.b.	Jurisdictional Transmission Demand Revenue Requirements		$ 57,448	$ 67,209	$ 76,804	$ 86,828	$ 97,951	$ 107,877	$ 121,741	$ 135,993	$ 147,294	$ 161,649	$ 173,218	$ 181,062	$ 1,415,075
7.c.	Total Jurisdictional Demand Revenue Requirements		$ 209,532	$ 271,455	$ 341,370	$ 427,511	$ 509,329	$ 583,268	$ 667,465	$ 738,857	$ 811,384	$ 889,353	$ 962,528	$ 1,023,860	$ 7,435,913
			-	-	-	-	-	-	-	-	-	-	-	-	-

Notes:
Jurisdictional Energy and Demand Revenue Requirements are calculated on the detailed 3P tabs.

TAMPA ELECTRIC COMPANY
DOCKET NO. 20200092-EI
EXHIBIT NO. ASL-1
DOCUMENT NO. 1
WITNESS: LEWIS
PAGE 3 OF 14
FILED: 07/24/2020

Tampa Electric Company
Storm Protection Plan Cost Recovery Clause (SPPCRC)
Initial Projection
January 2021 to December 2021

Return on Capital Investments, Depreciation and Taxes
For Program: Distribution Lateral Undergrounding
(in Dollars)

Line	Description	Beginning of Period Amount	2021 January	2021 February	2021 March	2021 April	2021 May	2021 June	2021 July	2021 August	2021 September	2021 October	2021 November	2021 December	2021 TOTAL
1.	Investments														
	a. Expenditures/Additions		$6,782,717	$6,911,282	$6,862,955	$6,781,763	$6,870,733	$6,880,143	$6,912,150	$7,363,423	$7,401,741	$7,649,654	$7,262,243	$6,422,899	$84,101,703
	b. Clearings to Plant		$0	$69,948	$11,539,087	$5,234,144	$3,569,434	$7,873,088	$5,698,957	$4,972,711	$5,587,837	$6,524,407	$4,333,730	$22,962,439	$78,365,783
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2.	Plant-in-Service/Depreciation Base	$1,418,599	1,418,599	1,488,547	13,027,634	18,261,778	21,831,213	29,704,300	35,403,258	40,375,969	45,963,806	52,488,213	56,821,943	79,784,382	
3.	Less: Net Accumulated Depreciation	0	(1,466)	(2,932)	(4,470)	(17,932)	(36,802)	(59,361)	(90,056)	(126,639)	(168,361)	(215,857)	(270,095)	(328,811)	
4.	CWIP - Non-Interest Bearing	7,668,081	14,450,797	21,292,132	16,615,999	18,163,618	21,464,916	20,471,972	21,685,164	24,075,876	25,889,780	27,015,027	29,943,540	13,404,001	
5.	Net Investment (Lines 2 + 3 + 4)	$9,086,680	15,867,931	22,777,747	29,639,164	36,407,464	43,259,327	50,116,911	56,998,367	64,325,207	71,685,226	79,287,384	86,495,389	92,859,572	
6.	Average Net Investment		12,477,305	19,322,839	26,208,455	33,023,314	39,833,395	46,688,119	53,557,639	60,661,787	68,005,216	75,486,305	82,891,386	89,677,480	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (A)		63,874	98,918	134,168	169,055	203,917	239,008	274,175	310,543	348,136	386,433	424,342	459,081	3,111,650
	b. Debt Component Grossed Up For Taxes (B)		18,006	27,884	37,821	47,655	57,483	67,375	77,288	87,540	98,137	108,933	119,619	129,412	877,153
			81,880	126,802	171,989	216,710	261,400	306,383	351,463	398,083	446,273	495,366	543,961	588,493	3,988,803
8.	Investment Expenses														
	a. Depreciation (C)		3,547	3,547	3,721	32,569	45,654	54,578	74,261	88,508	100,940	114,910	131,221	142,055	795,510
	b. Depreciation Savings (D)		(2,081)	(2,081)	(2,183)	(19,107)	(26,784)	(32,019)	(43,566)	(51,925)	(59,218)	(67,414)	(76,983)	(83,339)	(466,699)
	c. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Property Taxes (E)		2,081	2,081	2,081	2,081	2,081	2,081	2,081	2,081	2,081	2,081	2,081	2,076	24,967
	f. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		85,427	130,349	175,608	232,253	282,351	331,023	384,238	436,747	490,076	544,943	600,280	649,285	4,342,580
	a. Recoverable Costs Allocated to Demand		85,427	130,349	175,608	232,253	282,351	331,023	384,238	436,747	490,076	544,943	600,280	649,285	4,342,580
	b. Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Distribution Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Distribution Energy Jurisdictional Factor		0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	
12.	Retail Distribution Demand-Related Recoverable Costs (F)		85,427	130,349	175,608	232,253	282,351	331,023	384,238	436,747	490,076	544,943	600,280	649,285	4,342,580
13.	Retail Distribution Energy-Related Recoverable Costs (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$85,427	$130,349	$175,608	$232,253	$282,351	$331,023	$384,238	$436,747	$490,076	$544,943	$600,280	$649,285	$4,342,580

Notes:
(A) Line 6 x 6.1431% x 1/12 (Jan-Dec). Based on ROE of 10.25% and weighted income tax rate of 24.522% (expansion factor of 1.32830)
(B) Line 6 x 1.7317% x 1/12 (Jan-Dec)
(C) Applicable depreciation group for additions is 367.0 and applicable depreciation rate is 3.0%
(D) Applicable depreciation group for retirements is 364.0 and applicable depreciation savings rate is 4.4%
(E) Ad Valorem Tax Rate is 1.76%
(F) Line 9a x line 10
(G) Line 9b x line 11

TAMPA ELECTRIC COMPANY
DOCKET NO. 20200092-EI
EXHIBIT NO. ASL-1
DOCUMENT NO. 1
WITNESS: LEWIS
PAGE 4 OF 14
FILED: 07/24/2020

Tampa Electric Company
Storm Protection Plan Cost Recovery Clause (SPPCRC)
Initial Projection
January 2021 to December 2021

Return on Capital Investments, Depreciation and Taxes
For Program: Transmission Asset Upgrades
(in Dollars)

Line	Description	Beginning of Period Amount	2021 January	2021 February	2021 March	2021 April	2021 May	2021 June	2021 July	2021 August	2021 September	2021 October	2021 November	2021 December	2021 TOTAL
1.	Investments														
	a. Expenditures/Additions		$1,071,720	$1,077,000	$1,077,000	$1,303,620	$1,209,120	$1,495,320	$1,495,320	$1,495,320	$1,525,020	$1,248,720	$1,077,000	$1,077,000	$15,152,160
	b. Clearings to Plant		$1,333,000	$1,268,500	$1,118,000	$1,350,150	$644,100	$1,775,200	$1,836,380	$627,340	$1,997,100	$1,276,140	$0	$1,653,250	$14,879,160
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2.	Plant-in-Service/Depreciation Base	$5,004,398	6,337,398	7,605,898	8,723,898	10,074,048	10,718,148	12,493,348	14,329,728	14,957,068	16,954,168	18,230,308	18,230,308	19,883,558	
3.	Less: Net Accumulated Depreciation	($39,735)	(53,247)	(70,358)	(90,894)	(114,448)	(141,648)	(170,587)	(204,319)	(243,010)	(283,394)	(329,170)	(378,392)	(427,614)	
4.	CWIP - Non-Interest Bearing	$798,550	537,270	345,770	304,770	258,240	823,260	543,380	202,320	1,070,300	598,220	570,800	1,647,800	1,071,550	
5.	Net Investment (Lines 2 + 3 + 4)	$5,763,213	6,821,421	7,881,310	8,937,774	10,217,839	11,399,760	12,866,141	14,327,728	15,784,358	17,268,994	18,471,938	19,499,716	20,527,494	
6.	Average Net Investment		6,292,317	7,351,365	8,409,542	9,577,807	10,808,799	12,132,950	13,596,934	15,056,043	16,526,676	17,870,466	18,985,827	20,013,605	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (A)		32,212	37,633	43,051	49,031	55,333	62,112	69,606	77,076	84,604	91,483	97,193	102,455	801,789
	b. Debt Component Grossed Up For Taxes (B)		9,080	10,609	12,136	13,822	15,598	17,509	19,622	21,727	23,849	25,789	27,398	28,881	226,020
			41,292	48,242	55,187	62,853	70,931	79,621	89,228	98,803	108,453	117,272	124,591	131,336	1,027,809
8.	Investment Expenses														
	a. Depreciation (C)		15,013	19,012	22,818	26,172	30,222	32,154	37,480	42,989	44,871	50,863	54,691	54,691	430,976
	b. Depreciation Savings (D)		(1,501)	(1,901)	(2,282)	(2,617)	(3,022)	(3,215)	(3,748)	(4,299)	(4,487)	(5,086)	(5,469)	(5,469)	(43,098)
	c. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Property Taxes (E)		7,282	7,282	7,282	7,282	7,282	7,282	7,282	7,282	7,282	7,282	7,282	7,276	87,378
	f. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		62,086	72,635	83,005	93,690	105,413	115,842	130,242	144,775	156,119	170,330	181,095	187,834	1,503,066
	a. Recoverable Costs Allocated to Demand		62,086	72,635	83,005	93,690	105,413	115,842	130,242	144,775	156,119	170,330	181,095	187,834	1,503,066
	b. Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Transmission Demand Jurisdictional Factor		0.9252920	0.9252920	0.9252920	0.9252920	0.9252920	0.9252920	0.9252920	0.9252920	0.9252920	0.9252920	0.9252920	0.9252920	
11.	Transmission Energy Jurisdictional Factor		0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	
12.	Retail Transmission Demand-Related Recoverable Costs (F)		57,448	67,209	76,804	86,691	97,538	107,188	120,512	133,959	144,456	157,605	167,566	173,801	1,390,775
13.	Retail Transmission Energy-Related Recoverable Costs (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$57,448	$67,209	$76,804	$86,691	$97,538	$107,188	$120,512	$133,959	$144,456	$157,605	$167,566	$173,801	$1,390,775

Notes:
(A) Line 6 x 6.1431% x 1/12 (Jan-Dec). Based on ROE of 10.25% and weighted income tax rate of 24.522% (expansion factor of 1.32830)
(B) Line 6 x 1.7317% x 1/12 (Jan-Dec)
(C) Applicable depreciation group for additions is 355.0 and applicable depreciation rate is 3.6%
(D) Applicable depreciation group for retirements is 355.0 and applicable depreciation savings rate is 3.6%
(E) Ad Valorem Tax Rate is 1.76%
(F) Line 9a x line 10
(G) Line 9b x line 11

Tampa Electric Company
Storm Protection Plan Cost Recovery Clause (SPPCRC)
Initial Projection
January 2021 to December 2021

Return on Capital Investments, Depreciation and Taxes
For Program: Substation Extreme Weather Protection
(in Dollars)

Line	Description	Beginning of Period Amount	2021 January	2021 February	2021 March	2021 April	2021 May	2021 June	2021 July	2021 August	2021 September	2021 October	2021 November	2021 December	2021 TOTAL
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2.	Plant-in-Service/Depreciation Base	$0	0	0	0	0	0	0	0	0	0	0	0	0	
3.	Less: Net Accumulated Depreciation	0	0	0	0	0	0	0	0	0	0	0	0	0	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$0	0	0	0	0	0	0	0	0	0	0	0	0	
6.	Average Net Investment		0	0	0	0	0	0	0	0	0	0	0	0	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (A)		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Debt Component Grossed Up For Taxes (B)		0	0	0	0	0	0	0	0	0	0	0	0	0
			0	0	0	0	0	0	0	0	0	0	0	0	0
8.	Investment Expenses														
	a. Depreciation (C)		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Depreciation Savings (D)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Property Taxes (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
	f. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		0	0	0	0	0	0	0	0	0	0	0	0	0
	a. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Distribution Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Distribution Energy Jurisdictional Factor		0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	
12.	Retail Distribution Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
13.	Retail Distribution Energy-Related Recoverable Costs (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

Notes:
(A) Line 6 x 6.1431% x 1/12 (Jan-Dec). Based on ROE of 10.25% and weighted income tax rate of 24.522% (expansion factor of 1.32830)
(B) Line 6 x 1.7317% x 1/12 (Jan-Dec)
(C) Applicable depreciation group for additions is 362.0 and applicable depreciation rate is 2.4%
(D) No retirements are anticipated for this program
(E) Ad Valorem Tax Rate is 1.76%
(F) Line 9a x line 10
(G) Line 9b x line 11

TAMPA ELECTRIC COMPANY
DOCKET NO. 20200092-EI
EXHIBIT NO. ASL-1
DOCUMENT NO. 1
WITNESS: LEWIS
PAGE 5 OF 14
FILED: 07/24/2020

Tampa Electric Company
Storm Protection Plan Cost Recovery Clause (SPPCRC)
Initial Projection
January 2021 to December 2021

Return on Capital Investments, Depreciation and Taxes
For Program: Distribution Overhead Feeder Hardening
(in Dollars)

Line	Description	Beginning of Period Amount	2021 January	2021 February	2021 March	2021 April	2021 May	2021 June	2021 July	2021 August	2021 September	2021 October	2021 November	2021 December	2021 TOTAL
1.	Investments														
	a. Expenditures/Additions		$648,679	$1,585,307	$3,031,556	$2,930,259	$1,761,722	$1,134,861	$719,848	$721,749	$785,625	$864,130	$612,283	$538,441	$15,334,461
	b. Clearings to Plant		$0	$0	$0	$2,412,724	$2,718,756	$5,104,963	$62,734	$1,454,012	$1,638,559	$778,340	$455,826	$367,705	$14,993,619
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2.	Plant-in-Service/Depreciation Base (A)	$6,156,888	6,156,888	6,156,888	6,156,888	8,569,612	11,288,368	16,393,331	16,456,065	17,910,077	19,548,635	20,326,975	20,782,802	21,150,507	
3.	Less: Net Accumulated Depreciation	0	(13,545)	(27,090)	(40,635)	(54,181)	(73,034)	(97,868)	(133,934)	(170,137)	(209,539)	(252,546)	(297,265)	(342,988)	
4.	CWIP - Non-Interest Bearing	242,868	891,547	2,476,855	5,508,411	6,025,946	5,068,912	1,098,810	1,755,925	1,023,661	170,728	256,518	412,975	583,711	
5.	Net Investment (Lines 2 + 3 + 4)	$6,399,756	7,034,890	8,606,653	11,624,663	14,541,378	16,284,246	17,394,273	18,078,056	18,763,601	19,509,824	20,330,947	20,898,511	21,391,230	
6.	Average Net Investment		6,717,323	7,820,771	10,115,658	13,083,020	15,412,812	16,839,260	17,736,164	18,420,828	19,136,713	19,920,386	20,614,729	21,144,870	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (A)		34,388	40,036	51,785	66,975	78,902	86,204	90,796	94,301	97,966	101,977	105,532	108,246	957,108
	b. Debt Component Grossed Up For Taxes (B)		9,694	11,286	14,598	18,880	22,242	24,300	25,595	26,583	27,616	28,747	29,749	30,514	269,804
			44,082	51,322	66,383	85,855	101,144	110,504	116,391	120,884	125,582	130,724	135,281	138,760	1,226,912
8.	Investment Expenses														
	a. Depreciation (C)		22,575	22,575	22,575	22,575	31,422	41,391	60,109	60,339	65,670	71,678	74,532	76,204	571,646
	b. Depreciation Savings (D)		(9,030)	(9,030)	(9,030)	(9,030)	(12,569)	(16,556)	(24,044)	(24,136)	(26,268)	(28,671)	(29,813)	(30,481)	(228,658)
	c. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Property Taxes (E)		9,030	9,030	9,030	9,030	9,030	9,030	9,030	9,030	9,030	9,030	9,030	9,031	108,361
	f. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		66,657	73,897	88,958	108,430	129,027	144,368	161,486	166,117	174,014	182,761	189,030	193,513	1,678,258
	a. Recoverable Costs Allocated to Demand		66,657	73,897	88,958	108,430	129,027	144,368	161,486	166,117	174,014	182,761	189,030	193,513	1,678,258
	b. Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Distribution Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Distribution Energy Jurisdictional Factor		0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	
12.	Retail Distribution Demand-Related Recoverable Costs (F)		66,657	73,897	88,958	108,430	129,027	144,368	161,486	166,117	174,014	182,761	189,030	193,513	1,678,258
13.	Retail Distribution Energy-Related Recoverable Costs (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$66,657	$73,897	$88,958	$108,430	$129,027	$144,368	$161,486	$166,117	$174,014	$182,761	$189,030	$193,513	$1,678,258

Notes:
(A) Line 6 x 6.1431% x 1/12 (Jan-Dec). Based on ROE of 10.25% and weighted income tax rate of 24.522% (expansion factor of 1.32830)
(B) Line 6 x 1.7317% x 1/12 (Jan-Dec)
(C) Applicable depreciation group for additions is 364.0 and applicable depreciation rate is 4.4%
(D) Applicable depreciation group for retirements is 364.0 and applicable depreciation savings rate is 4.4%
(E) Ad Valorem Tax Rate is 1.76%
(F) Line 9a x line 10
(G) Line 9b x line 11

TAMPA ELECTRIC COMPANY
DOCKET NO. 20200092-EI
EXHIBIT NO. ASL-1
DOCUMENT NO. 1
WITNESS: LEWIS
PAGE 6 OF 14
FILED: 07/24/2020

Tampa Electric Company
Storm Protection Plan Cost Recovery Clause (SPPCRC)
Initial Projection
January 2021 to December 2021

Return on Capital Investments, Depreciation and Taxes
For Program: Transmission Access Enhancements
(in Dollars)

Line	Description	Beginning of Period Amount	2021 January	2021 February	2021 March	2021 April	2021 May	2021 June	2021 July	2021 August	2021 September	2021 October	2021 November	2021 December	2021 TOTAL
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$45,385	$45,385	$45,385	$132,508	$132,508	$132,508	$264,819	$264,819	$264,819	$1,328,137
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2.	Plant-in-Service/Depreciation Base	$0	0	0	0	0	0	0	0	0	0	0	0	0	
3.	Less: Net Accumulated Depreciation	0	0	0	0	0	0	0	0	0	0	0	0	0	
4.	CWIP - Non-Interest Bearing	0	0	0	0	45,385	90,770	136,155	268,664	401,172	533,680	798,499	1,063,318	1,328,137	
5.	Net Investment (Lines 2 + 3 + 4)	$0	0	0	0	45,385	90,770	136,155	268,664	401,172	533,680	798,499	1,063,318	1,328,137	
6.	Average Net Investment		0	0	0	22,693	68,078	113,463	202,409	334,918	467,426	666,090	930,908	1,195,727	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (A)		0	0	0	116	349	581	1,036	1,715	2,393	3,410	4,766	6,121	20,487
	b. Debt Component Grossed Up For Taxes (B)		0	0	0	33	98	164	292	483	675	961	1,343	1,726	5,775
			0	0	0	149	447	745	1,328	2,198	3,068	4,371	6,109	7,847	26,262
8.	Investment Expenses														
	a. Depreciation (C)		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Depreciation Savings (D)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Property Taxes (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
	f. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		0	0	0	149	447	745	1,328	2,198	3,068	4,371	6,109	7,847	26,262
	a. Recoverable Costs Allocated to Demand		0	0	0	149	447	745	1,328	2,198	3,068	4,371	6,109	7,847	26,262
	b. Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Transmission Demand Jurisdictional Factor		0.9252920	0.9252920	0.9252920	0.9252920	0.9252920	0.9252920	0.9252920	0.9252920	0.9252920	0.9252920	0.9252920	0.9252920	
11.	Transmission Energy Jurisdictional Factor		0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	
12.	Retail Transmission Demand-Related Recoverable Costs (F)		0	0	0	138	414	689	1,229	2,034	2,839	4,044	5,653	7,261	24,300
13.	Retail Transmission Energy-Related Recoverable Costs (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$0	$0	$0	$138	$414	$689	$1,229	$2,034	$2,839	$4,044	$5,653	$7,261	$24,300

Notes:
(A) Line 6 x 6.1431% x 1/12 (Jan-Dec). Based on ROE of 10.25% and weighted income tax rate of 24.522% (expansion factor of 1.32830)
(B) Line 6 x 1.7317% x 1/12 (Jan-Dec)
(C) Applicable depreciation group for additions is 359.0 and applicable depreciation rate is 1.5%
(D) No retirements are anticipated for this program
(E) Ad Valorem Tax Rate is 1.76%
(F) Line 9a x line 10
(G) Line 9b x line 11

Tampa Electric Company
Storm Protection Plan Cost Recovery Clause
Calculation of Current Period Actual/Estimated Amount
Current Period: January through December 2020

Calculation of Annual Revenue Requirements for O&M Programs
(in Dollars)

Line	O&M Activities	T/D	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimate July	Estimate August	Estimate September	Estimate October	Estimate November	Estimate December	End of Period Total	Method of Classification Demand	Method of Classification Energy
1.	Vegetation Management O&M Programs																
	1. Distribution Vegetation Management - Planned	D	$ -	$ -	$ -	$ -	$ 1,656,458	$ 1,275,346	$ 1,751,901	$ 1,442,978	$ 1,381,183	$ 1,774,090	$ 1,567,316	$ 1,889,280	$ 12,738,553	100%	0%
	2. Transmission Vegetation Management - Planned	T	$ -	$ -	$ -	$ -	$ 96,954	$ 90,527	$ 106,903	$ 72,675	$ 72,675	$ 13,367	$ 45,868	$ 45,868	$ 544,837	100%	0%
	3. Transmission Vegetation Management - ROW	T	$ -	$ -	$ -	$ -	$ 42,700	$ 36,506	$ 43,081	$ 52,159	$ 52,159	$ 64,039	$ 52,159	$ 64,039	$ 406,842	100%	0%
1.a.	Adjustment		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	100%	0%
1.b.	Subtotal of Vegetation Management Programs		$ -	$ -	$ -	$ -	$ 1,796,112	$ 1,402,378	$ 1,901,885	$ 1,567,812	$ 1,506,017	$ 1,851,496	$ 1,665,343	$ 1,999,187	$ 13,690,231	-	
2.	Asset Upgrade O&M Programs		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -			
	1. Transmission Asset Upgrades	T	$ -	$ -	$ -	$ -	$ -	$ -	$ 29,254	$ 29,348	$ 37,593	$ 25,789	$ 25,572	$ 17,564	$ 165,120	100%	0%
2.a.	Adjustment		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	100%	0%
2.b.	Subtotal of Asset Upgrade O&M Programs		$ -	$ -	$ -	$ -	$ -	$ -	$ 29,254	$ 29,348	$ 37,593	$ 25,789	$ 25,572	$ 17,564	$ 165,120		
3.	Substation Protection O&M Programs																
	1. Substation Extreme Weather Protection	D	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	100%	0%
3.a.	Adjustment		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	100%	0%
3.b.	Subtotal of Substation Protection O&M Programs		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		
4.	Overhead Feeder Hardening Programs																
	1. Distribution Overhead Feeder Hardening	D	$ -	$ -	$ -	$ -	$ 289	$ -	$ -	$ 5,546	$ 29,183	$ 50,641	$ 50,044	$ 40,285	$ 175,988	100%	0%
4.a.	Adjustment		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	100%	0%
4.b.	Subtotal of Vegetation Management O&M Programs		$ -	$ -	$ -	$ -	$ 289	$ -	$ -	$ 5,546	$ 29,183	$ 50,641	$ 50,044	$ 40,285	$ 175,988		
5.	Transmission Access O&M Programs																
	1. Transmission Access Enhancement	T	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	100%	0%
5.a.	Adjustment		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	100%	0%
5.b.	Subtotal of Transmission Access O&M Programs		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		
6.	Infrastructure Inspection O&M Programs																
	1. Distribution Infrastructure Inspections	D	$ -	$ -	$ -	$ -	$ 83,786	$ 56,229	$ 250	$ 250	$ 250	$ 250	$ 250	$ 250	$ 141,515	100%	0%
	2. Transmission Infrastructure Inspections	T	$ -	$ -	$ -	$ -	$ 19,387	$ 25,616	$ 67,255	$ 50,150	$ 114,065	$ 73,150	$ 34,250	$ 35,954	$ 419,827	100%	0%
6.a.	Adjustment		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	100%	0%
6.b.	Subtotal of Infrastructure Inspection O&M Programs		$ -	$ -	$ -	$ -	$ 103,173	$ 81,845	$ 67,505	$ 50,400	$ 114,315	$ 73,400	$ 34,500	$ 36,204	$ 561,341		
7.	Common SPP O&M Programs																
	1. Common O&M (A)	D	$ 111,566	$ 14,183	$ 467,638	$ 400,504	$ 79,892	$ 48,317	$ 45,520	$ 55,220	$ 45,220	$ 57,920	$ 45,220	$ 45,220	$ 1,416,419	100%	0%
7.a.	Adjustment		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	100%	0%
7.b.	Subtotal of Common SPP O&M Programs		$ 111,566	$ 14,183	$ 467,638	$ 400,504	$ 79,892	$ 48,317	$ 45,520	$ 55,220	$ 45,220	$ 57,920	$ 45,220	$ 45,220	$ 1,416,419		
8.	Total of O&M Programs		111,566	14,183	467,638	400,504	1,979,466	1,532,540	2,044,165	1,708,326	1,732,328	2,059,246	1,820,679	2,138,460	16,009,101		
	a. Total Distribution O&M Programs		111,566	14,183	467,638	400,504	1,820,425	1,379,892	1,797,672	1,503,994	1,455,836	1,882,901	1,662,830	1,975,035	14,472,476		
	b. Total Transmission O&M Programs		0	0	0	0	159,041	152,648	246,493	204,332	276,492	176,345	157,849	163,425	1,536,625		
9.	Allocation of O&M Costs																
	a. Distribution O&M Allocated to Demand		111,566	14,183	467,638	400,504	1,820,425	1,379,892	1,797,672	1,503,994	1,455,836	1,882,901	1,662,830	1,975,035	14,472,476		
	b. Transmission O&M Allocated to Demand		0	0	0	0	159,041	152,648	246,493	204,332	276,492	176,345	157,849	163,425	1,536,625		
	c. Distribution O&M Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0		
	d. Transmission O&M Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0		
10.	a. Less 2020 Base Revenue O&M Threshold - Distribution		0	0	0	0	(1,203,233)	(998,795)	(1,079,524)	(1,137,196)	(842,053)	(1,144,186)	(1,374,598)	(1,672,961)	(9,452,547)		
	b. Less 2020 Base Revenue O&M Threshold - Transmission		0	0	0	0	(129,437)	(116,604)	(53,257)	(68,968)	(154,522)	(128,682)	(155,325)	(140,659)	(947,453)		
	c. Total Threshold Amount Removed (B)		0	0	0	0	(1,332,670)	(1,115,399)	(1,132,781)	(1,206,164)	(996,575)	(1,272,868)	(1,529,924)	(1,813,620)	(10,400,000)		
															-		
11.	Retail Jurisdictional Factors																
	a. Distribution Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000			
	b. Transmission Demand Jurisdictional Factor		0.9252920	0.9252920	0.9252920	0.9252920	0.9252920	0.9252920	0.9252920	0.9252920	0.9252920	0.9252920	0.9252920	0.9252920			
	c. Distribution Energy Jurisdictional Factor		0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000			
	d. Transmission Energy Jurisdictional Factor		0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000			
12.	Jurisdictional Revenue Requirements																
	a. Jurisdictional Distribution Demand Revenue Requirement		111,566	14,183	467,638	400,504	617,192	381,096.96	718,148	366,798	613,783	738,715	288,232	302,074	5,019,929		
	b. Jurisdictional Transmission Demand Revenue Requirement		-	-	-	-	27,392	33,351.30	178,800	125,251	112,858	44,103	2,335	21,065	545,156		
	c. Jurisdictional Distribution Energy Revenue Requirement		-	-	-	-	-	-	-	-	-	-	-	-	-		
	d. Jurisdictional Transmission Energy Revenue Requirement		-	-	-	-	-	-	-	-	-	-	-	-	-		
13.	Total Jurisdictional O&M Revenue Requirements		111,566	14,183	467,638	400,504	644,584	414,448	896,948	492,050	726,641	782,818	290,567	323,139	5,565,085	-	
							-	-	-	-	-	-	-	-			

Notes:
(A) Included in line 7.1 above, are costs related to the planning and design of the Storm Protection Plan and its associated projects and activities.
(B) As per the Order No. PSC-2020-0224-AS-EI, issued June 30, 2020 - Final Order Approving Settlement Agreement

TAMPA ELECTRIC COMPANY
DOCKET NO. 20200092-EI
EXHIBIT NO. ASL-1
DOCUMENT NO. 1
WITNESS: LEWIS
PAGE 9 OF 14
FILED: 07/24/2020

Form 7E
Page 1 of 1

Tampa Electric Company
Storm Protection Plan Cost Recovery Clause (SPPCRC)
Calculation of the Current Period Actual/Estimated Amount
Current Period: January through December 2020

Summary of Monthly Revenue Requirements for Capital Investment Programs
(in Dollars)

Line	Capital Investment Activities	T/D	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimate July	Estimate August	Estimate September	Estimate October	Estimate November	Estimate December	End of Period Total
1.	Distribution Lateral Undergrounding Program	D	$ -	$ -	$ -	$ -	$ -	$ -	$ 3,452	$ 11,025	$ 19,699	$ 29,787	$ 41,576	$ 53,455	$ 158,994
1.a.	Adjustments	D	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1.b.	Subtotal of Distribution Lateral Undergrounding Program	D	$ -	$ -	$ -	$ -	$ -	$ -	$ 3,452	$ 11,025	$ 19,699	$ 29,787	$ 41,576	$ 53,455	$ 158,994
1.c.	Jurisdictional Demand Revenue Requirements		$ -	$ -	$ -	$ -	$ -	$ -	$ 3,452	$ 11,025	$ 19,699	$ 29,787	$ 41,576	$ 53,455	$ 158,994
1.d.	Jurisdictional Energy Revenue Requirements		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2	Transmission Asset Upgrades Program	T	$ -	$ -	$ -	$ 4	$ 66	$ 977	$ 5,052	$ 14,472	$ 22,724	$ 33,306	$ 41,819	$ 49,175	$ 167,595
2.a.	Adjustments	T	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2.b.	Subtotal of Transmission Asset Upgrades Program	T	$ -	$ -	$ -	$ 4	$ 66	$ 977	$ 5,052	$ 14,472	$ 22,724	$ 33,306	$ 41,819	$ 49,175	$ 167,595
2.c.	Jurisdictional Demand Revenue Requirements		$ -	$ -	$ -	$ 4	$ 61	$ 904	$ 4,675	$ 13,391	$ 21,026	$ 30,818	$ 38,695	$ 45,501	$ 155,074
2.d.	Jurisdictional Energy Revenue Requirements		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3	Substation Extreme Weather Program	D	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3.a.	Adjustments	D	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3.b.	Subtotal of Substation Extreme Weather Program	D	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3.c. b	Jurisdictional Demand Revenue Requirements		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3.d. a	Jurisdictional Energy Revenue Requirements		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4	Distribution Overhead Feeder Hardening Program	D	$ -	$ -	$ -	$ -	$ 44	$ 169	$ 300	$ 1,807	$ 8,060	$ 19,426	$ 30,947	$ 38,750	$ 99,503
4.a.	Adjustments	D	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4.b.	Subtotal of Distribution Overhead Feeder Hardening Program	D	$ -	$ -	$ -	$ -	$ 44	$ 169	$ 300	$ 1,807	$ 8,060	$ 19,426	$ 30,947	$ 38,750	$ 99,503
4.c.	Jurisdictional Demand Revenue Requirements		$ -	$ -	$ -	$ -	$ 44	$ 169	$ 300	$ 1,807	$ 8,060	$ 19,426	$ 30,947	$ 38,750	$ 99,503
4.d.	Jurisdictional Energy Revenue Requirements		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5	Transmission Access Enhancement Program	T	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5.a.	Adjustments	T	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5.b.	Subtotal of Transmission Access Enhancement Program	T	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5.c.	Jurisdictional Demand Revenue Requirements		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5.d.	Jurisdictional Energy Revenue Requirements		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
6	Retail Jurisdictional Factors														
6.a.	Distribution Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
6.b.	Transmission Demand Jurisdictional Factor		0.9252920	0.9252920	0.9252920	0.9252920	0.9252920	0.9252920	0.9252920	0.9252920	0.9252920	0.9252920	0.9252920	0.9252920	
6.c.	Distribution Energy Jurisdictional Factor		0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	
6.d.	Transmission Energy Jurisdictional Factor		0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	
7	Total of Capital Investment Programs		$ -	$ -	$ -	$ 4	$ 110	$ 1,146	$ 8,804	$ 27,304	$ 50,483	$ 82,519	$ 114,342	$ 141,380	$ 426,092
7.a.	Jurisdictional Distribution Demand Revenue Requirements		$ -	$ -	$ -	$ -	$ 44	$ 169	$ 3,752	$ 12,832	$ 27,759	$ 49,213	$ 72,523	$ 92,205	$ 258,497
7.b.	Jurisdictional Transmission Demand Revenue Requirements		$ -	$ -	$ -	$ 4	$ 61	$ 904	$ 4,675	$ 13,391	$ 21,026	$ 30,818	$ 38,695	$ 45,501	$ 155,074
7.c.	Total Jurisdictional Demand Revenue Requirements		$ -	$ -	$ -	$ 4	$ 105	$ 1,073	$ 8,427	$ 26,223	$ 48,785	$ 80,031	$ 111,218	$ 137,706	$ 413,571
			-	-	-	-	-	-	-	-	-	-	-	-	-

Notes:
Jurisdictional Energy and Demand Revenue Requirements are calculated on the detailed 7E tabs.

Tampa Electric Company
Storm Protection Plan Cost Recovery Clause (SPPCRC)
Calculation of the Current Period Actual/Estimated Amount
January 2020 to December 2020

Return on Capital Investments, Depreciation and Taxes
For Program: Distribution Lateral Undergrounding
(in Dollars)

Line	Description	Beginning of Period Amount	2020 January	2020 February	2020 March	2020 April	2020 May	2020 June	2020 July	2020 August	2020 September	2020 October	2020 November	2020 December	2020 TOTAL
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$1,061,948	$1,267,585	$1,400,368	$1,702,714	$1,923,774	$1,730,291	$9,086,680
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1,418,599	$1,418,599
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2.	Plant-in-Service/Depreciation Base	$0	0	0	0	0	0	0	0	0	0	0	0	1,418,599	
3.	Less: Net Accumulated Depreciation	0	0	0	0	0	0	0	0	0	0	0	0	0	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	1,061,948	2,329,533	3,729,901	5,432,615	7,356,389	7,668,081	
5.	Net Investment (Lines 2 + 3 + 4)	$0	0	0	0	0	0	0	1,061,948	2,329,533	3,729,901	5,432,615	7,356,389	9,086,680	
6.	Average Net Investment		0	0	0	0	0	0	530,974	1,695,741	3,029,717	4,581,258	6,394,502	8,221,535	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (A)		0	0	0	0	0	0	2,659	8,492	15,173	22,943	32,024	41,173	122,464
	b. Debt Component Grossed Up For Taxes (B)		0	0	0	0	0	0	793	2,533	4,526	6,844	9,552	12,282	36,530
			0	0	0	0	0	0	3,452	11,025	19,699	29,787	41,576	53,455	158,994
8.	Investment Expenses														
	a. Depreciation (C)		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Depreciation Savings (D)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Property Taxes (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
	f. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		0	0	0	0	0	0	3,452	11,025	19,699	29,787	41,576	53,455	158,994
	a. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	3,452	11,025	19,699	29,787	41,576	53,455	158,994
	b. Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Distribution Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Distribution Energy Jurisdictional Factor		0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	
12.	Retail Distribution Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	3,452	11,025	19,699	29,787	41,576	53,455	158,994
13.	Retail Distribution Energy-Related Recoverable Costs (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$0	$0	$0	$0	$0	$0	$3,452	$11,025	$19,699	$29,787	$41,576	$53,455	$158,994

Notes:
(A) Line 6 x 5.9635% x 1/12 (Jan-Jun) and Line 6 x 6.0096% x 1/12 (Jul-Dec). Based on ROE of 10.25% and weighted income tax rate of 24.522% (expansion factor of 1.32830)
(B) Line 6 x 1.7369% x 1/12 (Jan-Jun) and Line 6 x 1.7926% x 1/12 (Jul-Dec).
(C) Applicable depreciation group for additions is 367.0 and applicable depreciation rate is 3.0%
(D) Applicable depreciation group for retirements is 364.0 and applicable depreciation savings rate is 4.4%
(E) Ad Valorem Tax Rate is 1.76%
(F) Line 9a x line 10
(G) Line 9b x line 11

TAMPA ELECTRIC COMPANY
DOCKET NO. 20200092-EI
EXHIBIT NO. ASL-1
DOCUMENT NO. 1
WITNESS: LEWIS
PAGE 10 OF 14
FILED: 07/24/2020

TAMPA ELECTRIC COMPANY
DOCKET NO. 20200092-EI
EXHIBIT NO. ASL-1
DOCUMENT NO. 1
WITNESS: LEWIS
PAGE 11 OF 14
FILED: 07/24/2020

Tampa Electric Company
Storm Protection Plan Cost Recovery Clause (SPPCRC)
Calculation of the Current Period Actual/Estimated Amount
January 2020 to December 2020

Return on Capital Investments, Depreciation and Taxes
For Program: Transmission Asset Upgrades
(in Dollars)

Line	Description	Beginning of Period Amount	2020 January	2020 February	2020 March	2020 April	2020 May	2020 June	2020 July	2020 August	2020 September	2020 October	2020 November	2020 December	2020 TOTAL
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$1,360	$17,764	$266,399	$982,915	$948,240	$1,241,600	$897,000	$877,920	$569,750	$5,802,948
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$1,167,526	$428,260	$1,359,526	$1,038,369	$1,010,716	$0	$5,004,398
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2.	Plant-in-Service/Depreciation Base	$0	0	0	0	0	0	0	1,167,526	1,595,786	2,955,312	3,993,682	5,004,398	5,004,398	
3.	Less: Net Accumulated Depreciation	0	0	0	0	0	0	0	0	(3,152)	(7,461)	(15,440)	(26,223)	(39,735)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	1,360	19,124	285,523	100,911	620,891	502,966	361,596	228,800	798,550	
5.	Net Investment (Lines 2 + 3 + 4)	$0	0	0	0	1,360	19,124	285,523	1,268,438	2,213,526	3,450,817	4,339,838	5,206,975	5,763,213	
6.	Average Net Investment		0	0	0	680	10,242	152,324	776,981	1,740,982	2,832,171	3,895,327	4,773,406	5,485,094	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (A)		0	0	0	3	51	757	3,891	8,719	14,184	19,508	23,905	27,469	98,487
	b. Debt Component Grossed Up For Taxes (B)		0	0	0	1	15	220	1,161	2,601	4,231	5,819	7,131	8,194	29,373
			0	0	0	4	66	977	5,052	11,320	18,415	25,327	31,036	35,663	127,860
8.	Investment Expenses														
	a. Depreciation (C)		0	0	0	0	0	0	0	3,503	4,787	8,866	11,981	15,013	44,150
	b. Depreciation Savings (D)		0	0	0	0	0	0	0	(350)	(479)	(887)	(1,198)	(1,501)	(4,415)
	c. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Property Taxes (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
	f. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		0	0	0	4	66	977	5,052	14,472	22,724	33,306	41,819	49,175	167,595
	a. Recoverable Costs Allocated to Demand		0	0	0	4	66	977	5,052	14,472	22,724	33,306	41,819	49,175	167,595
	b. Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Transmission Demand Jurisdictional Factor		0.9252920	0.9252920	0.9252920	0.9252920	0.9252920	0.9252920	0.9252920	0.9252920	0.9252920	0.9252920	0.9252920	0.9252920	
11.	Transmission Energy Jurisdictional Factor		0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	
12.	Retail Distribution Demand-Related Recoverable Costs (F)		0	0	0	4	61	904	4,675	13,391	21,026	30,818	38,695	45,501	155,074
13.	Retail Distribution Energy-Related Recoverable Costs (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$0	$0	$0	$4	$61	$904	$4,675	$13,391	$21,026	$30,818	$38,695	$45,501	$155,074

Notes:
(A) Line 6 x 5.9635% x 1/12 (Jan-Jun) and Line 6 x 6.0096% x 1/12 (Jul-Dec). Based on ROE of 10.25% and weighted income tax rate of 24.522% (expansion factor of 1.32830)
(B) Line 6 x 1.7369% x 1/12 (Jan-Jun) and Line 6 x 1.7926% x 1/12 (Jul-Dec).
(C) Applicable depreciation group for additions is 355.0 and applicable depreciation rate is 3.6%
(D) Applicable depreciation group for retirements is 355.0 and applicable depreciation savings rate is 3.6%
(E) Ad Valorem Tax Rate is 1.76%
(F) Line 9a x line 10
(G) Line 9b x line 11

TAMPA ELECTRIC COMPANY
DOCKET NO. 20200092-EI
EXHIBIT NO. ASL-1
DOCUMENT NO. 1
WITNESS: LEWIS
PAGE 12 OF 14
FILED: 07/24/2020

Tampa Electric Company
Storm Protection Plan Cost Recovery Clause (SPPCRC)
Calculation of the Current Period Actual/Estimated Amount
January 2020 to December 2020

Return on Capital Investments, Depreciation and Taxes
For Program: Substation Extreme Weather Protection
(in Dollars)

Line	Description	Beginning of Period Amount	2020 January	2020 February	2020 March	2020 April	2020 May	2020 June	2020 July	2020 August	2020 September	2020 October	2020 November	2020 December	2020 TOTAL
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2.	Plant-in-Service/Depreciation Base	$0	0	0	0	0	0	0	0	0	0	0	0	0	
3.	Less: Net Accumulated Depreciation	0	0	0	0	0	0	0	0	0	0	0	0	0	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$0	0	0	0	0	0	0	0	0	0	0	0	0	
6.	Average Net Investment		0	0	0	0	0	0	0	0	0	0	0	0	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (A)		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Debt Component Grossed Up For Taxes (B)		0	0	0	0	0	0	0	0	0	0	0	0	0
			0	0	0	0	0	0	0	0	0	0	0	0	0
8.	Investment Expenses														
	a. Depreciation (C)		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Depreciation Savings (D)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Property Taxes (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
	f. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		0	0	0	0	0	0	0	0	0	0	0	0	0
	a. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Distribution Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Distribution Energy Jurisdictional Factor		0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	
12.	Retail Distribution Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
13.	Retail Distribution Energy-Related Recoverable Costs (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

Notes:
(A) Line 6 x 5.9635% x 1/12 (Jan-Jun) and Line 6 x 6.0096% x 1/12 (Jul-Dec). Based on ROE of 10.25% and weighted income tax rate of 24.522% (expansion factor of 1.32830)
(B) Line 6 x 1.7369% x 1/12 (Jan-Jun) and Line 6 x 1.7926% x 1/12 (Jul-Dec).
(C) Applicable depreciation group for additions is 362.0 and applicable depreciation rate is 2.4%
(D) No retirements are anticipated for this program
(E) Ad Valorem Tax Rate is 1.76%
(F) Line 9a x line 10
(G) Line 9b x line 11

Tampa Electric Company
Storm Protection Plan Cost Recovery Clause (SPPCRC)
Calculation of the Current Period Actual/Estimated Amount
January 2020 to December 2020

Return on Capital Investments, Depreciation and Taxes
For Program: Distribution Overhead Feeder Hardening
(in Dollars)

Line	Description	Beginning of Period Amount	2020 January	2020 February	2020 March	2020 April	2020 May	2020 June	2020 July	2020 August	2020 September	2020 October	2020 November	2020 December	2020 TOTAL
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$13,653	$25,482	$14,000	$449,802	$1,473,194	$2,023,263	$1,520,662	$879,700	$6,399,756
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$6,156,888	$6,156,888
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2.	Plant-in-Service/Depreciation Base (A)	$0	0	0	0	0	0	0	0	0	0	0	0	6,156,888	
3.	Less: Net Accumulated Depreciation	0	0	0	0	0	0	0	0	0	0	0	0	0	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	13,653	39,135	53,135	502,937	1,976,131	3,999,394	5,520,056	242,868	
5.	Net Investment (Lines 2 + 3 + 4)	$0	0	0	0	0	13,653	39,135	53,135	502,937	1,976,131	3,999,394	5,520,056	6,399,756	
														-	
6.	Average Net Investment		0	0	0	0	6,826	26,394	46,135	278,036	1,239,534	2,987,762	4,759,725	5,959,906	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (A)		0	0	0	0	34	131	231	1,392	6,208	14,963	23,837	29,847	76,643
	b. Debt Component Grossed Up For Taxes (B)		0	0	0	0	10	38	69	415	1,852	4,463	7,110	8,903	22,860
			0	0	0	0	44	169	300	1,807	8,060	19,426	30,947	38,750	99,503
8.	Investment Expenses														
	a. Depreciation (C)		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Depreciation Savings (D)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Property Taxes (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
	f. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
	a. Recoverable Costs Allocated to Demand		0	0	0	0	44	169	300	1,807	8,060	19,426	30,947	38,750	99,503
	b. Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Distribution Demand Jurisdictional Factor		1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	1.0000000	
11.	Distribution Energy Jurisdictional Factor		0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	
12.	Retail Distribution Demand-Related Recoverable Costs (F)		0	0	0	0	44	169	300	1,807	8,060	19,426	30,947	38,750	99,503
13.	Retail Distribution Energy-Related Recoverable Costs (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$0	$0	$0	$0	$44	$169	$300	$1,807	$8,060	$19,426	$30,947	$38,750	$99,503
															-

Notes:
(A) Line 6 x 5.9635% x 1/12 (Jan-Jun) and Line 6 x 6.0096% x 1/12 (Jul-Dec). Based on ROE of 10.25% and weighted income tax rate of 24.522% (expansion factor of 1.32830)
(B) Line 6 x 1.7369% x 1/12 (Jan-Jun) and Line 6 x 1.7926% x 1/12 (Jul-Dec).
(C) Applicable depreciation group for additions is 364.0 and applicable depreciation rate is 4.4%
(D) Applicable depreciation group for retirements is 364.0 and applicable depreciation savings rate is 4.4%
(E) Ad Valorem Tax Rate is 1.76%
(F) Line 9a x line 10
(G) Line 9b x line 11

TAMPA ELECTRIC COMPANY
DOCKET NO. 20200092-EI
EXHIBIT NO. ASL-1
DOCUMENT NO. 1
WITNESS: LEWIS
PAGE 14 OF 14
FILED: 07/24/2020

Tampa Electric Company
Storm Protection Plan Cost Recovery Clause (SPPCRC)
Calculation of the Current Period Actual/Estimated Amount
January 2020 to December 2020

Return on Capital Investments, Depreciation and Taxes
For Program: Transmission Access Enhancements
(in Dollars)

Line	Description	Beginning of Period Amount	2020 January	2020 February	2020 March	2020 April	2020 May	2020 June	2020 July	2020 August	2020 September	2020 October	2020 November	2020 December	2020 TOTAL
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2.	Plant-in-Service/Depreciation Base	$0	0	0	0	0	0	0	0	0	0	0	0	0	
3.	Less: Net Accumulated Depreciation	0	0	0	0	0	0	0	0	0	0	0	0	0	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$0	0	0	0	0	0	0	0	0	0	0	0	0	
6.	Average Net Investment		0	0	0	0	0	0	0	0	0	0	0	0	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (A)		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Debt Component Grossed Up For Taxes (B)		0	0	0	0	0	0	0	0	0	0	0	0	0
			0	0	0	0	0	0	0	0	0	0	0	0	0
8.	Investment Expenses														
	a. Depreciation (C)		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Depreciation Savings (D)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Property Taxes (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
	f. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		0	0	0	0	0	0	0	0	0	0	0	0	0
	a. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Transmission Demand Jurisdictional Factor		0.9252920	0.9252920	0.9252920	0.9252920	0.9252920	0.9252920	0.9252920	0.9252920	0.9252920	0.9252920	0.9252920	0.9252920	
11.	Transmission Energy Jurisdictional Factor		0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	0.0000000	
12.	Retail Distribution Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
13.	Retail Distribution Energy-Related Recoverable Costs (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

Notes:
(A) Line 6 x 5.9635% x 1/12 (Jan-Jun) and Line 6 x 6.0096% x 1/12 (Jul-Dec). Based on ROE of 10.25% and weighted income tax rate of 24.522% (expansion factor of 1.32830)
(B) Line 6 x 1.7369% x 1/12 (Jan-Jun) and Line 6 x 1.7926% x 1/12 (Jul-Dec).
(C) Applicable depreciation group for additions is 359.0 and applicable depreciation rate is 1.5%
(D) No retirements are anticipated for this program
(E) Ad Valorem Tax Rate is 1.76%
(F) Line 9a x line 10
(G) Line 9b x line 11

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition to approve the 2020 settlement agreement by Tampa Electric Company.	DOCKET NO. 20200145-EI
In re: Petition for a limited proceeding to approve fourth SoBRA, by Tampa Electric Company.	DOCKET NO. 20200064-EI
In re: Petition for a limited proceeding to eliminate accumulated amortization reserve surplus for intangible software assets, by Tampa Electric Company.	DOCKET NO. 20200065-EI
In re: Review of 2020-2029 Storm Protection Plan pursuant to Rule 25-6.030, F.A.C., Tampa Electric Company.	DOCKET NO. 20200067-EI
In re: Storm protection plan cost recovery clause.	DOCKET NO. 20200092-EI ORDER NO. PSC-2020-0224-AS-EI ISSUED: June 30, 2020

The following Commissioners participated in the disposition of this matter:

GARY F. CLARK, Chairman
ART GRAHAM
JULIE I. BROWN
DONALD J. POLMANN
ANDREW GILES FAY

APPEARANCES:

JEFFRY WAHLEN, JAMES D. BEASLEY and MALCOLM MEANS, ESQUIRES, Ausley Law Firm, P.O. Box 391, Tallahassee, Florida 32302-0391
On behalf of Tampa Electric Company

J.R. KELLY, PUBLIC COUNSEL, CHARLES REHWINKEL, DEPUTY PUBLIC COUNSEL, and MIREILLE FALL-FRY, ESQUIRES, Office of Public Counsel, c/o The Florida Legislature, 111 W. Madison Street, Room 812, Tallahassee, Florida 32399-1400
On behalf of the Citizen of the State of Florida

JON C. MOYLE, JR. and KAREN A. PUTNAL, ESQUIRES, Moyle Law Firm, P.A., 118 North Gadsden Street, Tallahassee, Florida 32301
On behalf of Florida Industrial Power Users Group

ROBERT SCHEFFEL WRIGHT, ESQUIRE, Gardner, Bist, Bowden, et al., 1300 Thomaswood Drive, Tallahassee, Florida 32308
On behalf of Florida Industrial Power Users Group

THOMAS "DREW" JERNIGAN, AFLOA/JACL-ULFSC, 139 Barnes Drive, Suite 1, Tyndall AFB, Florida 32403
On behalf of Federal Executive Agencies

MARK F. SUNDBACK and WILLIAM M. RAPPOLT, ESQUIRES, 2099 Pennsylvania Ave., Suite 100 Washington DC 20006
On behalf of West Central Florida Hospital Utility Alliance

STEPHANIE EATON, ESQUIRE, Spillman Thomas and Battle, PLLC, 100 Oakwood Drive, Suite 500, Winston-Salem, NC 27103
On behalf of Walmart

BIANCA LHERISSON and SHAW STILLER, ESQUIRES, Florida Public Service Commission General Counsel's Office, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850
On behalf of 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 C. 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 SETTLEMENT AGREEMENT

BY THE COMMISSION:

Background

On May 4, 2020, Tampa Electric Company (TECO) filed a Motion to Approve 2020 Agreement, attaching the 2020 Settlement Agreement (2020 Agreement). The 2020 Agreement, attached hereto, is signed and executed by TECO, the Office of Public Counsel (OPC), the

Florida Industrial Power Users Group (FIPUG), the Florida Retail Federation (FRF), the Federal Executive Agencies (FEA), and the West Central Florida Hospital Utility Alliance (HUA) (collectively, the Signatories). The 2020 Agreement was filed in Docket Nos. 20200064-EI,[1] 20200065-EI,[2] 20200067-EI,[3] and 20200092-EI[4] because it impacts, in part, all of these dockets. Docket No. 20200145-EI was opened to have one central docket in which to address the 2020 Agreement. The Signatories are deemed parties for purposes of our consideration of the 2020 Agreement.

TECO contends that if the 2020 Agreement is approved, it will establish, as to TECO, a series of stipulations that will reduce the issues to be litigated in Docket Nos. 20200067-EI and 20200092-EI, thereby allowing the Signatories and us to focus on the merits of TECO's Storm Protection Plan and the recovery of the costs associated with that Plan in 2020 and 2021 in Docket No. 20200092-EI. TECO states that if the 2020 Agreement is approved, it will resolve all issues currently pending in Docket No. 20200065-EI, and reduce the issues to be litigated in Docket No. 20200064-EI.

The 2020 Agreement also presents a base rate revenue reduction amount and reflects a determination of certain expenses for which TECO plans to seek cost recovery through the Storm Protection Plan Cost Recovery Clause, Docket No. 20200092-EI. TECO contends that approval of the 2020 Agreement promotes regulatory economy and administrative efficiency, and avoids the time and expense associated with litigating the settled issues in the various existing and continuing Commission dockets.

TECO, with the support of the Signatories, requested an administrative hearing for us to consider the 2020 Agreement. TECO stated that the Signatories to the 2020 Agreement believe that approval of the 2020 Agreement is in the best interests of the customers the Signatories represent, and that the 2020 Agreement in its totality is in the public interest. TECO stated that the Signatories agree that if the 2020 Agreement is approved, then the approval of the 2020 Agreement will resolve specified matters in Docket Nos. 20200064-EI, 20200065-EI, 20200067-EI, and 20200092-EI.

We held an administrative hearing on June 9, 2020. In addition to oral argument by the Signatories, we heard testimony from two TECO witnesses and admitted documentary exhibits into the record, all in support that approval of the 2020 Agreement is in the public interest. As part of this hearing, we provided notice that there was an opportunity for members of the public who wished to testify on this matter to do so either telephonically or by submitting written comments. No requests for public testimony were made, and no written comments were filed. At the conclusion of the evidentiary portion of the hearing, the parties indicated that they were

[1] *In re: Petition for a limited proceeding to approve fourth SoBRA, by Tampa Electric Company.*
[2] *In re: Petition for a limited proceeding to eliminate accumulated amortization reserve surplus for intangible software assets, by Tampa Electric Company.*
[3] *In re: Review of 2020-2029 Storm Protection Plan pursuant to Rule 25-6.030, F.A.C., Tampa Electric Company.*
[4] *In re: Storm protection plan cost recovery clause.*

willing to waive the filing of post-hearing briefs, and we approved the 2020 Agreement, as set forth herein, by bench vote.

The 2020 Settlement Agreement

The 2020 Agreement reduces the scope of potentially litigated issues in three dockets and fully resolves all matters in one docket.

Docket No. 20200064-EI: Petition for a Limited Proceeding to Approve Fourth SoBRA

Section I, paragraphs 1-4

In Docket No. 20200064-EI, a potential issue concerns whether TECO's solar projects qualify for treatment under the Solar Base Rate Adjustment (SoBRA) provisions of its 2017 Amended and Restated Stipulation and Settlement Agreement (2017 Agreement).[5] A requirement for eligibility of a 2021 SoBRA is that the calculation of the actual average installed cost value for the First and Second Solar Base Rate Adjustments (SoBRAs) is below a set threshold of $1,475 per KWac. The provisions of Section I of the 2020 Agreement will resolve how this calculation should occur, and the values to be input will be based on the outcome of pending Docket No. 20200144-EI, Petition to True-up First and Second SoBRAs. TECO's petition and prefiled testimony in Docket No. 20200144-EI purportedly will show that its average cost of the SoBRA projects are at or below the threshold value. In this way, the Signatories assert that approval of the 2020 Agreement potentially simplifies the issues that will be litigated in Docket 2020064-EI.

Docket No. 20200065-EI: Petition to Eliminate Accumulated Amortization Reserve Surplus for Intangible Software Assets

Section II, paragraphs 5-9

TECO is required to record a credit of approximately $16.0 million to amortization expense over 12 months beginning retroactively in January 2020. This is the relief TECO has requested in its revised petition filed in Docket No. 20200065-EI. Furthermore, the Signatories agree that granting TECO's revised petition will not violate the 2017 Agreement or require amendments to the 2017 Agreement. Approval of the 2020 Agreement would therefore grant the relief TECO is now requesting and Docket No. 20200065-EI can be closed.

[5] Order No. PSC-2017-0456-S-EI, issued on November 27, 2017, in Docket Nos. 20170210-EI, *In re: Petition for limited proceeding to approve 2017 amended and restated stipulation and settlement agreement, by Tampa Electric Company*, and 20160160-EI, *In re: Petition for approval of energy transaction optimization mechanism, by Tampa Electric Company*, approving the 2017 Amended and Restated Stipulation and Settlement Agreement (2017 Agreement).

Docket No. 20200067-EI: Review of TECO's 2020-2029 Storm Protection Plan pursuant to Rule 25-6.030, F.A.C.

Section III of the 2020 Agreement discusses the Signatories' agreements pertaining to TECO's Storm Protection Plan (SPP) filings in Docket No. 20200067-EI and TECO's anticipated filings in the Storm Protection Plan Cost Recovery Clause (SPPCRC) Docket No. 20200092-EI.

Section III, paragraph 10

The Signatories agree that TECO will provide project-level details in the SPP docket for years 2020 and 2021. Furthermore, the Vegetation Management Program, Infrastructure Inspection Program, and Legacy Storm Hardening Plan Initiatives Program[6] do not have project components. Similarly, the Signatories agree that TECO's Extreme Weather Hardening Study does not have project components during 2020 and 2021.

Section III, paragraph 15(a)

The Signatories agree that nothing in the 2020 Agreement shall be construed to prevent any party from challenging the reasonableness and/or prudence of all or part of any SPP program or project in any future proceeding, nor limit the amount of allowed discovery as specified in the Order Establishing Procedure for Docket Nos. 20200067-EI or 2020092-EI.

Section III, paragraph 15(c)

The Signatories will meet beginning October 1, 2020, and for a period of up to 60 days, to identify a method to modify the analytical framework TECO used in developing its SPP in Docket No. 20200067-EI. The good faith objective is to establish a unanimous and mutually agreed-upon method consistent with applicable statutes and rules that TECO will use thereafter unless the resulting framework is changed by agreement of the Signatories.

Docket No. 20200092-EI: Storm Protection Plan Cost Recovery Clause

Section III of the 2020 Agreement sets forth matters pertaining to TECO in Docket No. 20200092-EI and discusses a one-time reduction in base rates of approximately $15 million.

Section III, paragraph 10

Pursuant to the 2020 Agreement, TECO is required to provide project level details for projects it is planning for 2020 and 2021 when it files its petition for cost recovery.

---

[6] The term "Legacy Storm Hardening Plan Initiatives" refers to seven initiatives contained in TECO's approved storm hardening plan pursuant to Order No. PSC-2019-0302-PAA-EI, issued July 29, 2019, in Docket No. 20180145-EI. The seven initiatives are now grouped as one program with that name.

Section III, paragraph 11

This section and its subparts describe the Signatories' agreement to regulatory methods that allow TECO to recover through the SPPCRC its SPP operations and maintenance (O&M) expenses incurred during 2020 and 2021 that are incremental to its base rates. The O&M expenses are for six activities identified in TECO's SPP: Planned Distribution Vegetation Management, Planned Transmission Vegetation Management, Transmission Vegetation Management-ROW Maintenance, Infrastructure Inspections, Distribution and Transmission Wood Pole Inspections, and Transmission Asset Upgrades.

TECO may seek recovery of its 2020 O&M expenses for the period May through December in excess of the total expenses of approximately $10.3 million shown on Exhibit 3 of the 2020 Agreement. Recovery of all of TECO's 2021 SPP O&M expenses through the SPPCRC is contingent on a one-time base rate reduction of approximately $15 million shown on Exhibit 2 of the 2020 Agreement. The one-time base rate reduction is to be effective contemporaneous with the beginning of cost recovery via the SPPCRC.[7]

Section III, paragraph 12

Concerning capital projects, the Signatories agree that cost recovery shall remain in base rates for projects initiated prior to April 10, 2020. The Signatories define the term "initiated" to mean when, in the normal and ordinary course of business, the first dollar is posted to the project work order as reflected in TECO's accounting system in accordance with its standard procedures.

Project records and fixed asset records for SPP capital projects will be maintained in a manner that clearly distinguishes capital and assets recovered in retail rate base from capital and assets recovered through the SPPCRC. The return on investment and depreciation expense associated with capital projects initiated on or after April 10, 2020, shall be eligible for cost recovery through the SPPCRC, subject to a prudence review in the SPPCRC docket.

For assets being retired and replaced with new assets as part of an SPP program, TECO will not seek to recover the cost of removal net of salvage associated with the related assets to be retired through the SPPCRC. Rather, such net cost of removal will be debited to TECO's accumulated depreciation reserve according to normal regulatory plant accounting procedures. Additionally, any depreciation expense from SPP asset additions will be reduced by the depreciation expense savings that results from the retirement of assets removed from service during the SPP project. Only the net of the two depreciation amounts will be recoverable through the SPPCRC.

[7] Section III, paragraph 15(b) notes that to the extent the base rate adjustment is inconsistent with paragraph 4 of the 2017 Agreement, the Signatories agree that the 2017 Agreement is hereby amended, as necessary to accomplish the base rate adjustment.

TECO retains the option to seek to move prospective cost recovery from the SPPCRC to base rates for costs that have been determined prudently incurred through a final true-up in the SPPCRC. This request would be through a petition pursuant to Sections 366.06 and/or 366.07, Florida Statutes.

Section III, paragraph 13

The Signatories acknowledge that TECO's Distribution Pole Replacement program is a legacy storm hardening activity that is included in TECO's SPP. However, cost recovery for the plant additions and retirements associated with all distribution pole replacements will remain through base rates. This includes O&M expenses from asset transfers related to distribution pole replacements.

Section III, paragraph 14

The Signatories agree that TECO will not aggregate certain SPP capital projects as a means of demonstrating that it has met the threshold for accruing Allowance for Funds Used During Construction in Rule 25-6.0141, Florida Administrative Code. The 2020 Agreement includes guidance on this matter addressing factors such as geographic vicinity, same SPP program, contractor, or project manager.

<u>Decision</u>

The standard for approval of a settlement agreement is whether it is in the public interest.[8] A determination of public interest requires a case-specific analysis based on consideration of the proposed settlement taken as a whole.[9] By approving the 2020 Agreement, the 2020 Agreement promotes regulatory economy and administrative efficiency, and avoids the time and expense associated with litigating the settled issues in the various existing and continuing Commission dockets.

Based upon TECO's motion, our review of the 2020 Agreement, and evidence and testimony on the record, we find that the 2020 Agreement is in the public interest and it is hereby

---

[8] 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-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.*

[9] Order No. PSC-13-0023-S-EI, at p. 7.

approved. The 2020 Agreement resolves all of the issues in Docket Nos. 20200145-EI and 20200065-EI.

Based on the foregoing, it is

ORDERED by the Florida Public Service Commission that the stipulations, findings, and rulings herein are hereby approved. It is further

ORDERED that each utility that was a party to this docket shall abide by the stipulations, findings, and rulings herein which are applicable to it. It is further

ORDERED that the attached 2020 Settlement Agreement is approved. It is further

ORDERED that Docket Nos. 20200145-EI and 20200065-EI shall be closed.

By ORDER of the Florida Public Service Commission this 30th day of June, 2020.

ADAM J. TEITZMAN
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.

BYL

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 for a Limited Proceeding to Approve Fourth SoBRA by Tampa Electric Company	)))	Docket No. 20200064-EI
In re: Petition of Tampa Electric Company To Eliminate Accumulated Amortization Reserve Surplus for Intangible Software Assets	))))	Docket No. 20200065-EI
In re: Review of 2020-2029 Storm Protection Plan pursuant to Rule 25-6.030, F.A.C., Tampa Electric Company	))))	Docket No. 20200067-EI
In re: Storm protection plan cost recovery Clause	)))	Docket No. 20200092-EI

2020 SETTLEMENT AGREEMENT

THIS AGREEMENT is dated this 27th day of April 2020 and is by and between Tampa Electric Company ("Tampa Electric" or the "company") and 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 West Central Florida 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 "2020 Agreement."

Recitals

2017 Agreement

A. Tampa Electric is operating under its 2017 Amended and Restated Stipulation and Settlement Agreement ("2017 Agreement") approved by the Florida Public Service Commission

ATTACHMENT A

("FPSC" or "Commission").[1] Among other things, paragraph 6 of the company's 2017 Agreement contains a provision that authorizes the company to recover the costs of certain qualifying solar generating projects through a solar base rate adjustment mechanism ("SoBRA") based on projected costs and estimated in-service dates, with true-ups for both. It also contains provisions addressing depreciation [paragraph 8], customer rates [paragraph 3(a)], other cost recovery [paragraph 4], storm damage [paragraph 5] and changes in federal and state income tax rates [paragraph 9].

B. The Commission has approved three SoBRAs for Tampa Electric totaling 550 MW of solar capacity. The First SoBRA was approved by Order No. PSC-2018-0288-FOF-EI, issued June 5, 2018, in Docket No. 20170260-EI. The Second SoBRA was approved by Order No. PSC-2018-0571-FOF-EI, issued December 7, 2018, in Docket No. 20180133-EI. The Third SoBRA was approved by Order No. PSC-2019-0477-FOF-EI, issued November 12, 2019, in Docket No. 20190136-EI. The Commission has also approved two base rate reductions for Tampa Electric to reflect changes to federal and state corporate income tax rates (Docket Nos. 20180045-EI and 20190203-EI) and approved cost recovery for four named storms by Tampa Electric without a base rate increase or storm surcharge appearing on customers' bills (Docket No. 20170271-EI) — all pursuant to the 2017 Agreement. The 2017 Agreement has promoted regulatory certainty and efficiency and has proven to be in the public interest.

<u>Fourth SoBRA</u>
<u>and First and Second SoBRA True-Up</u>

C. On February 27, 2020, Tampa Electric filed a notice with the Commission advising the Commission and Consumer Parties to the 2017 Agreement that it has met the requirements to

[1] The Commission approved the 2017 Agreement by Order No. PSC-2017-0456-S-EI, issued on November 27, 2017 in Docket Nos. 20170210-EI and 20160160-EI.

qualify to petition for approval of its Fourth SoBRA totaling 45.7 MW with an effective date of January 1, 2021. The Commission opened Docket No. 20200064-EI for use when the company files its final SoBRA petition.

D. Tampa Electric will soon be filing a petition to true-up its First and Second SoBRAs. The company will request approval of tariff changes that reflect the actual annual revenue requirements for the seven projects in the First and Second SoBRAs and permission to implement those changes effective with the first billing cycle for January 1, 2021, or another date to be decided by the Commission. The company will also request that the FPSC approve the company's proposed revenue true-up — a credit to customers — and to allow the company to apply the credit amount to customers through the Capacity Cost Recovery Clause for 2021. The Office of Public Counsel plans to intervene in that proceeding.

Software Amortization Petition

E. On February 28, 2020, Tampa Electric filed a petition (Docket No. 20200065-EI) seeking FPSC permission to eliminate an approximately $16 million accumulated amortization reserve surplus for intangible software assets through a credit to amortization expense in 2020. OPC filed a notice of intervention in that docket on March 24, 2020. The Commission acknowledged OPC's intervention by Order No. PSC-2020-0091-PCO-EI, issued on March 27, 2020.

Storm Protection Plan and Cost Recovery Clause

F. In 2019, the Florida Legislature enacted section 366.96, Florida Statutes, entitled "Storm protection plan cost recovery." Section 366.96(3) requires Tampa Electric and the other public electric utilities to file a transmission and distribution storm protection plan ("SPP") at least every three years that covers the immediate 10-year planning period, and explain the systematic approach they will follow to achieve the objectives of reducing restoration costs and outage times associated with extreme weather events and enhancing reliability. The Commission must determine whether it is in the public interest to approve, approve with modification, or deny each utility's transmission and distribution storm protection plan no later than 180 days after the utility files a plan that contains all of the elements required by Commission Rule. The new statute also creates a storm protection plan cost recovery clause ("SPPCRC") to promote the timely recovery of costs incurred by a utility pursuant to its Storm Protection Plan. Rules 25-6.030 and 25-6.031, Florida Administrative Code, were adopted by the Commission to implement section 366.96.

G. Rule 25-6.030 requires each utility to file a SPP at least every three years with the Commission, and specifies the required elements of the utility's SPP. Subsection 25-6.030(3)(h) requires a Plan to include "an estimate of rate impacts for each of the first three years of the Storm Protection Plan for the utility's typical residential, commercial, and industrial customers." Pursuant to the Order Establishing Procedure for the SPP Dockets, each public electric utility, including Tampa Electric, must file a SPP by April 10, 2020.

H. Rule 25-6.031 governs the new SPPCRC created by section 366.93, Florida Statutes. Subsection 6(b) of that rule states: "Storm Protection Plan costs recoverable through the clause shall not include costs recovered through the utility's base rates or any other cost recovery mechanism."

I. The FPSC established Docket No. 20200067-EI for the filing and approval of Tampa Electric's SPP. It also opened Docket No. 20200092-EI for the consideration of issues related to SPP costs through the SPPCRC. Tampa Electric anticipates filing its petition for storm protection plan cost recovery in Docket No. 20200092-EI (SPPCRC), as required by the Docket Schedule, in late July 2020.

Overall Regulatory Activity

J. The cumulative total of the regulatory activity described above, together with the other annual clause proceedings and other dockets pending at the FPSC, is greater than normal and led Tampa Electric, OPC, and the other Consumer Parties to discuss ways to resolve some or all of the potentially time-consuming issues in the dockets listed above by agreement or stipulation in a manner that promotes regulatory economy and administrative efficiency and that serves the public interest. This 2020 Agreement is the product of those discussions and is being filed for approval in the above-styled four Dockets to resolve some or all of the issues in those dockets as discussed further below.

K. The Parties have entered into this 2020 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 2020 Agreement, each Party has agreed to concessions to the others with the expectation, intent, and understanding such that all provisions of the 2020 Agreement, upon approval by the Commission, will be enforced by the Commission as to all matters addressed herein with respect to all Parties. The Parties agree that this 2020 Agreement is in the public interest and should be approved.

NOW, THEREFORE, in light of the mutual covenants of the Parties and the benefits accruing to all Parties through this 2020 Agreement, and for good and valuable consideration, the receipt and sufficiency of which is hereby acknowledged, the Parties agree as follows:

Terms

I. **Docket No. 20200064-EI: Petition to Approve Fourth SoBRA**

The Parties agree and stipulate as follows:

1. OPC has taken the position that, for the company to meet the cost cap trigger for the 2021 Tranche specified in paragraph 6 of the 2017 Agreement ("Fourth SoBRA"), a two-part test applies, namely: the average cost of the projects in the First SoBRA must be less than or equal to $1,475 per kWac and, in addition, the average cost of the projects in the Second SoBRA must be less than or equal to $1,475 per kWac.

2. The company believes that for the company to meet the cost cap trigger for the Fourth SoBRA, a one-step test applies, namely: the average cost of the projects in the First and Second SoBRAs, taken together, must be at or below $1,475 per kWac.

3. To the extent the costs of the actual First and Second SoBRA projects as determined in the company's First and Second SoBRA True-Up docket make this difference an issue in Docket No. 20200064-EI, the Parties stipulate that the one-step test as described in paragraph 2 above shall be used to assess eligibility of the Fourth SoBRA for recovery under the SoBRA mechanism.

4. Nothing in this agreement shall limit any party to Docket No. 20200064-EI from taking any position, offering any evidence or advocating as it desires in Docket No. 20200064-EI, except as specified in paragraph 3.

II. **Docket No. 20200065-EI: Intangible Software Amortization Surplus.**

The Parties agree and stipulate as follows:

5. The surplus in the company's accumulated amortization reserve for Intangible Software in Account 303.15 as of December 31, 2019, was $15,971,292.

6. Granting the relief requested by Tampa Electric in Docket No. 20200065-EI ("Software Amortization Petition") will not violate the 2017 Agreement or require the 2017 Amendment to be amended.

7. The relief requested by Tampa Electric in Docket No. 20200065-EI shall be granted.

8. Tampa Electric shall eliminate its approximately $16.0 million accumulated amortization reserve surplus for intangible software assets through a credit to amortization expense in 2020.

9. Tampa Electric shall record the approximately $16.0 million credit to amortization expense ratably over 12 months beginning retroactively in January 2020.

III. <u>Storm Protection Plan, Cost Recovery Clause and Base Rate True-Up</u>

The Parties agree and stipulate as follows:

10. <u>Project-level Detail</u>. Except for the four Programs specified below, Tampa Electric has included project-level detail for all Projects for 2020 in its initial Storm Protection Plan filed on April 10, 2020, for approval by the FPSC. It will provide project-level detail for all Projects it is planning for 2021 to the Consumer Parties on or before April 23, 2020. It will also include project-level detail for Projects it is planning for 2020 and 2021 when it files its petition for cost recovery through the SPPCRC. The Parties agree that the following three Programs do not have project components: (1) Vegetation Management, (2) Infrastructure Inspections and (3) Legacy Storm Hardening Plan Initiatives,[2] so project level detail is not needed or required for these three

[2] The term "Legacy Storm Hardening Plan Initiatives" refers to seven initiatives contained in the company's last approved storm hardening plan that it has included in its SPP as one program with that name. The seven programs are Geographic Information System, Post-Storm Data Collection, Outage Data – Overhead and Underground Systems, Increase Coordination with Local Governments. Collaborative Research, Disaster Preparedness and Recovery Plan and Distribution Pole Replacement, and are described in Section 6.8 of the company's SPP.

Programs for 2020 and 2021. The Parties further agree that the company's Extreme Weather Hardening Study[3] does not have project components for at least 2020 and 2021; therefore, project level detail is not needed or required for this program in 2020 and 2021.

11. Operations and Maintenance Expenses. Tampa Electric will seek recovery of incremental Operations and Maintenance (O&M) expenses related to its proposed SPP programs in the following manner:

(a) Rather than recovering incremental SPP O&M expenses (i.e., SPP O&M costs that are over and above the O&M costs already recovered through base rates) through the SPPCRC, the company will seek to recover all of the O&M expenses associated with activities in its SPP through the SPPCRC (except as otherwise provided herein) and will reduce its base rates on a one-time basis by an agreed-upon amount. The agreed-upon, one-time base rate reduction amount is specified in paragraph 11(c), below, and reflects a good faith determination of the annual O&M expenses associated with six activities ("Six Activities")[4] that were being incurred prior to the filing of the company's SPP[5], are currently being recovered through the company's base rates,

---

[3] As explained in section 6.4 of its SPP, the company's Substation Extreme Weather Hardening Program is designed to harden existing substations to minimize outages, reduce restoration times and enhance emergency response during extreme weather events. Hardening Projects within this Program could involve the installation of extreme weather protection barriers; installation of flood or storm surge prevention barriers; additions, modifications or relocation of substation equipment; modification to the designs of the company's substations; or other approaches identified to protect against extreme weather damage in or around the company's substations.

[4] The six activities are Planned Distribution Vegetation Management, Planned Transmission Vegetation Management, Transmission Vegetation Management – ROW Maintenance, Infrastructure Inspections, Distribution and Transmission Wood Pole Inspections and Transmission Asset Upgrades. The first three are now included the company's proposed Vegetation Management SPP program. The next two have been included the company's proposed SPP Infrastructure Inspection program. Transmission Asset Upgrades is included in the company's proposed SPP in a program by that name.

[5] There are two additional activities (Targeted Critical Facilities/Flood Damage Mitigation and Targeted Distribution Overhead Feeder Hardening) that are included in the company's SPP and shown on Exhibit One; however, the company did not incur O&M expenses for these activities in 2017, 2018 and 2019 and the agreed-to base rate reduction in paragraph 11(c) does not include O&M expenses for these activities. The costs associated with a third category of activity included in the SPP — Joint Use Pole Attachments Audits — are borne by the entities that attach to the company's poles, so the net expense to Tampa Electric for that activity is zero and did not factor into the calculation of the agreed-to base rate reduction.

have been included in the company's proposed SPP and for which the company will seek cost recovery through the SPPCRC. The purpose of the one-time, agreed-upon base reduction is to streamline cost recovery for the expenses associated with the Six Activities, so that all O&M expenses associated with the activities reflected in the SPP will be recoverable (subject to prudency review) via the SPPCRC, except as otherwise provided herein. The intent of this base rate true-up is to promote transparency and to ensure that the O&M expenses the company will recover through the SPPCRC do not include O&M expenses recovered through the utility's existing base rates or any other cost recovery mechanism as required by Rule 25-6.031(6)(b), Florida Administrative Code, in accord with section 366.96(8).

(b) The specified amount of base revenue reduction described above will be accomplished through one-time reductions to base rates using the cost allocation and rate design principles reflected in paragraph 3 of the 2013 Stipulation among the Parties as modified by paragraph 3 of the 2017 Agreement, and those same cost allocation and rate design principles shall be used to develop the cost recovery factors/rates that will be used for SPP cost recovery in the SPPCRC beginning in 2020 and annually thereafter as provided in paragraph 3(g) of the 2017 Agreement. The one-time base rate reductions will become effective contemporaneous with the beginning of cost recovery via the SPPCRC and remain in effect until the next Commission-approved change in the company's general base rates (i.e., in the company's next general base rate case). The company will file the revised tariffs necessary to implement the one-time base rate reduction specified herein for Commission approval in Docket No. 20200092-EI within a reasonable time following approval of this 2020 Agreement and on a schedule such that the necessary customer notices can be given and the proposed base rate reduction can become effective contemporaneous with the effective date of cost recovery by the company under the SPPCRC.

(c) For each category of O&M expense for which cost recovery will be moved from base rates to SPPCRC (i.e., the Six Activities), the specified amount of base revenue reduction should be calculated as the company's average actual O&M expense for the most recent two years and grossed up for the regulatory assessment fee which is not reflected as a separate line-item on customers' bills. Based on the company's current plan to seek cost recovery under the SPPCRC in 2020, the company has calculated, and the Parties agree, that Tampa Electric's 2-year average actual annual O&M expense amounts for the Six Activities for 2018 and 2019 totals $15.0 million per year as shown on Exhibit One and the grossed-up amount of the annual base revenue reduction is $15,010,800. The manner in which this $15.0 million O&M expense amount has been grossed up to reflect the $15,010,800 annual base revenue reduction to be made is set out in Exhibit Two to this agreement.

(d) For purposes of this paragraph 11, the Parties intend that the $15,010,800 agreed-upon base revenue reduction be final and not subject to further true-up, unless any of the Six Activities as a category used to calculate the $15.0 million annual O&M expense amount are not allowed for cost recovery through the SPPCRC, in which case, the $15.0 million amount and related base revenue reduction shall be reduced by the associated amounts shown in Exhibit One multiplied by the Regulatory Assessment Fee Multiplier shown on Exhibit Two Notwithstanding the foregoing, the Parties agree that nothing in this Agreement shall preclude any Consumer Party from challenging the recovery of any specific cost or level of cost proposed for recovery by the company through the SPPCRC.

(e) In its 2020 SPPCRC filing, Tampa Electric may seek to recover 2020 SPP O&M expense for the Six Activities in the period May to December 2020 only to the extent that the May 2020 to December 2020 total expense for those activities exceeds the average of the total expense incurred by the company for those activities in May through December 2018 and May through December 2019 as shown on Exhibit Three (i.e., $10.4 million).

(f) Most of the Vegetation Management Program activities in the company's SPP are planned, meaning that the company develops a scheduled Vegetation Management plan that it intends to follow, i.e., trim specific circuits, etc. The company engages in two other general types of vegetation management activities, namely: (1) Vegetation Management associated with named storms, the costs of which are subject to recovery under paragraph 5 of the 2017 Agreement and the FPSC's storm cost recovery rules and (2) unscheduled or unplanned vegetation management activities necessitated by minor storm damage, identification of danger trees, automobile accidents, routine repair work and the like ("Unplanned Vegetation Management"). Even though the company's SPP includes Unplanned Vegetation Management as part of its overall Vegetation Management program, the company will continue to recover costs associated with Unplanned Vegetation Management activities through base rates and will not seek recovery of costs associated with those activities through the SPPCRC.

12. Rate Base Items. Tampa Electric will seek recovery of return on capital expenditures and assets related to the SPP programs, as well as the incremental depreciation expense for the SPP assets, in the following manner:

(a) Cost recovery for capital projects initiated prior to April 10, 2020, shall remain recovered through base rates. This means that both the return on investment associated with a capital project initiated before April 10, 2020 and the related depreciation expense shall continue to be recovered through base rates and will not be recoverable through the SPPCRC. For purposes of this section, a project shall be considered "initiated" when, in the normal and ordinary course of business, the first dollar is posted to the project work order as reflected in the company's accounting system in accordance with the company's standard accounting procedures. This means that any capital project with an open work order in which costs have been posted before April 10, 2020 shall not be eligible for cost recovery through the SPPCRC.

(b) The return on investment and depreciation expense associated with capital projects initiated on or after April 10, 2020, shall be eligible for cost recovery through the SPPCRC, subject to a prudency review in the SPPCRC docket. For purposes of this section, a project shall be considered "initiated" when, in the normal and ordinary course of business, the first dollar is posted to the project work order as reflected in the company's accounting system in accordance with the company's standard accounting procedures. This means that any capital project with an open work order that did not have any costs charged to it before April 10, 2020, or opened on or after April 10, 2020, may be eligible for cost recovery through the SPPCRC, subject to a prudency review in the SPPCRC docket.

(c) To ensure that there is no double recovery between base revenue and SPPCRC revenue, the company will employ the following protocols for capital items:

(i) For assets being retired and replaced with new assets as part of a program in the company's SPP, the company will not seek to recover the cost of removal net of salvage associated with the related assets to be retired through the SPPCRC. Rather, such net cost of removal will be debited to the company's accumulated depreciation reserve according to normal regulatory plant accounting procedures.

(ii) For SPP capital projects, any depreciation expense from SPP asset additions will be reduced by the depreciation expense savings that results from the retirement of assets removed from service during the SPP project. Only the net of the two depreciation amounts will be recoverable through the SPPCRC.

(iii) Project records and fixed asset records for SPP capital projects will be maintained in a manner that clearly distinguishes capital and assets in retail rate base from capital and assets being recovered through the SPPCRC.

(iv) Whenever the company petitions for a change to its base rates and charges pursuant to sections 366.06 and/or 366.07, Florida Statutes, the assets being recovered that have been determined prudent through a final true-up in the SPPCRC by the Commission as of the end of the historic year presented in the company's minimum filing requirement schedules may, at the Company's option, be simultaneously removed from SPPCRC recovery and included in retail rate base for the applicable test year by appropriate proforma adjustments. Thereafter, new SPP capital and assets related to SPP programs that were not included in the test year used to set base rates may be submitted for recovery through the SPPCRC petition process.

13. Distribution Pole Replacements. Distribution Pole Replacement is a legacy storm hardening activity that is included in the company's SPP in section 6.8.7. Due to the large number of annual pole replacements and the challenges associated with accounting for the associated mass asset additions and retirements, and as a matter of accounting and administrative efficiency, the company will include distribution pole replacements within its SPP; however, cost recovery for the plant additions and retirements associated with all distribution pole replacements (for the avoidance of doubt, this includes like kind replacements, replacements of existing poles with higher class wood poles, and/or concrete or steel for wood distribution poles identified though the company's Infrastructure Inspection Program) will remain through base rates, not through the SPPCRC. The company will also not seek recovery of the O&M expenses from asset transfers related to distribution pole replacements[6] through the SPPCRC.

[6] During a capital project that involves changing out a distribution pole, the costs associated with moving supporting fixtures and conductors and transferring them to new distribution poles, which sometimes involves rearranging and

14. No Bundling. The company will not, as a means of demonstrating that it has met the threshold for accruing Allowance for Funds Used During Construction ("AFUDC") in Rule 25-6.0141, Florida Administrative Code, aggregate SPP capital projects (a) that are not in the same geographic vicinity or (b) that would otherwise only be aggregated solely because the projects or activities: (i) are part of the same SPP program; (ii) will be performed by the same contractor; (iii) are part of the same SPP program budget or (iv) are being managed by the same company project manager.

15. Other SPP items.

(a) Nothing in this Agreement shall be construed to prevent any Party from challenging the reasonableness and/or prudency of all or part of any SPP program or project in any future proceeding, nor limit the amount of allowed discovery as specified in the Order Establishing Procedure for Docket Nos. 20200067-EI or 2020092-EI.

(b) To the extent the base rate adjustment described in paragraph 11 is inconsistent with paragraph 4 of the 2017 Agreement, the Parties agree that the 2017 Agreement is hereby amended, as necessary to accomplish the base rate adjustment.

(c) Beginning October 1, 2020 and for a period of up to 60 days thereafter, Tampa Electric shall meet with the Parties and will work in good faith with them to identify a method acceptable to all of the Parties to modify the analytical framework used in the development of the company's SPP in Docket No. 20200067-EI that: (1) complies with applicable statutes and rules and (2) reasonably recognizes the importance of protecting transmission and distribution facilities serving public safety customers and critical public infrastructure (e.g., hospitals, fire stations,

---

changing the location of plant not retired, are considered an O&M expense pursuant to CFR Title 18. Chapter 1, Subchapter C, Part 101: Operating Expense Instructions, 2. Maintenance, and CFR Title 18. Chapter 1, Subchapter C, Part 101: Account 593.

police stations, military installations, ports, airports, etc.). The company shall use any such unanimously and mutually agreed-upon method consistent with applicable statutes and rules when it prepares and files its next SPP for FPSC approval and thereafter unless the resulting modified framework is changed by agreement of the Parties.

IV. <u>Other Provisions</u>

16. <u>Commission Approval.</u>

(a) The provisions of this 2020 Agreement are contingent on approval of this 2020 Agreement in its entirety by the Commission without modification, regardless of the sequence of the individual above styled Docket decisions; further, any decision by the Commission not to approve any provision of this Agreement shall, per se and as a matter of law, render the Agreement null and void and of no force or effect. The Parties further agree that this 2020 Agreement is in the public interest, that they will support this 2020 Agreement and that they will not request or support any order, relief, outcome, or result in conflict with the terms of this 2020 Agreement in any administrative or judicial proceeding relating to, reviewing, or challenging the establishment, approval, adoption, or implementation of this 2020 Agreement or the subject matter hereof.

(b) No Party will assert in any proceeding before the Commission that this 2020 Agreement or any of the terms in the 2020 Agreement shall have any precedential value. The Parties' agreement to the terms in the 2020 Agreement shall be without prejudice to any Party's ability to advocate a different position in future proceedings not involving this 2020 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 2020 Agreement by virtue of that Party's signature on, or participation in, this

2020 Agreement. It is the intent of the Parties to this 2020 Agreement that the Commission's approval of all the terms and provisions of this 2020 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 2020 Agreement endorses a specific provision, in isolation, of this 2020 Agreement by virtue of that Party's signature on, or participation in, this 2020 Agreement.

(c) The Parties intend, and agree to request, that the Commission's order state that approval of this 2020 Agreement in its entirety will resolve the matters as specified herein in Docket Nos. 20200064-EI, 20200065-EI, 20200067-EI, and 20200092-EI and in accordance with section 120.57(4), Florida Statutes.

(d) No Party shall seek appellate review of any Commission order approving this 2020 Agreement in its entirety.

17. Disputes. To the extent a dispute arises among the Parties about the provisions, interpretation, or application of this 2020 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.

18. Execution. This 2020 Agreement is dated as of April 27, 2020. It may be executed in counterpart originals and a facsimile of an original signature shall be deemed an original.

IN WITNESS WHEREOF, the Parties evidence their acceptance and agreement with the provisions of this 2020 Agreement by their signature(s):

Tampa Electric Company
702 N. Franklin Street
Tampa, FL 33601

By:

E-Signed: 04/27/2020 12:51 PM EDT
Nancy Tower
ntower@tecoenergy.com
IP: 66.35.152.98
Sertifi Electronic Signature
DocID: 20200427113456645

Signature Page to 2020 Agreement

Office of Public Counsel
J. R. Kelly, Esquire
Public Counsel
Charles Rehwinkel, Esquire
Deputy Public Counsel
c/o The Florida Legislature
111 West Madison Street, Room 812
Tallahassee, FL 32399-1400

By: ______________________
J.R. Kelly

Signature Page to 2020 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: ______________________ 4/27/20
Jon C. Moyle, Jr.

Signature Page to 2020 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

Signature Page to 2020 Agreement

Federal Executive Agencies

Thomas Andrew Jernigan, Esquire
AFLOA/JACL-ULFSC
139 Barnes Drive, Suite 1
Tyndall Air Force Base, FL 32403

By: ______________________
Thomas Jernigan

Attachment A

Signature Page to 2020 Agreement

WCF Hospital Utility Alliance
Mark F. Sundback
Sheppard Mullin
2099 Pennsylvania Ave., Suite 100
Washington, D.C. 20006-6801
msundback@sheppardmullin.com

By: Mark F. Sundback - JJW
Mark F. Sundback

Attachment A

TAMPA ELECTRIC'S STORM PROTECTION PLAN O&M EXPENSES ($ Million)

Recovered Through SPP Clause	2018 Actual	2019 Actual	2018-2019 Average
Distribution Vegetation Management - Planned	10.3	13.8	12.0
Transmission Vegetation Management - Planned	0.8	0.8	0.8
Transmission Vegetation Management - ROW Maintenance	0.4	0.5	0.5
Infrastructure Inspections	0.4	0.5	0.4
Distribution & Transmission Wood Pole Inspections	1.2	1.3	1.3
J/U Pole Attachments Audit	-	-	-
Transmission Asset Upgrades	0.1	0.1	0.1
Targeted Critical Fac. / Flood Damage Mitigation	-	-	-
Targeted Distribution Overhead Feeder Hardening	-	-	-
Total SPP Clause	**13.2**	**16.9**	**15.0**

Recovered Through Base Rates	2018 Actual	2019 Actual	2018-2019 Average
Distribution Vegetation Management - Unplanned	1.6	2.2	1.9
Transmission Vegetation Management - Unplanned	-	-	0.0
Distribution Pole Replacement	0.8	0.7	0.8
Disaster Preparedness and Recovery Plan	0.2	0.3	0.2
Geographical Information System	-	-	-
Post Storm Data Collection	-	-	-
Outage Data - Overhead and Underground	-	-	-
Increase Coordination with Local Governments	-	-	-
Collaborative Research	-	-	-
Total Base Rates	**2.6**	**3.2**	**2.9**
Total SPP O&M Expenses	**15.8**	**20.1**	**17.9**

Note: Totals may not sum due to rounding.

Attachment A

TAMPA ELECTRIC'S STORM PROTECTION PLAN BASE RATE REVENUE REQUIREMENT REDUCTION FOR CLAUSE RECOVERY

($)

Revenue Requirement Calculation:	
Agreed Upon SPP O&M Expenses Currently Recovered through Base Rates to be Recovered through the SPP Clause	15,000,000
Agreed Upon SPP Capital Expenses Currently Recovered through Base Rates to be Recovered through the SPP Clause	0
Agreed Upon Expense Amount Related to Base Revenue Reduction	**15,000,000**
Regulatory Assessment Fee Multiplier[7]	1.00072
Revenue Requirement to Be Used for Base Rate Revenue Reduction	**15,010,800**

Proof of Net Impact of Base Rate Revenue Reduction:	
Lower Base Revenue	(15,010,800)
Resulting Lower Regulatory Assessment Fee Expense	10,800
Net Reduction to Pre-Income-Tax Operating Income	**(15,000,000)**

TAMPA ELECTRIC COMPANY
2020 AGREEMENT
EXHIBIT TWO

[7] Each investor-owned electric company shall pay a regulatory assessment fee in the amount of .00072 of gross operating revenues derived from intrastate business, excluding sales for resale between public utilities, municipal electric utilities, and rural electric cooperatives or any combination thereof. *Rule 25-6.0131(1)(a), F.A.C.*

Attachment A

"Exhibit Three"

TAMPA ELECTRIC COMPANY
($ Million)

Actual May – December	2018	2019	2018-2019
STORM PROTECTION PLAN O&M EXPENSES	**ACTUAL**	**ACTUAL**	**AVERAGE**
TO BE RECOVERED THROUGH SPP CLAUSE			
Distribution Vegetation Management - Planned	6.9	10.1	8.5
Transmission Vegetation Management - Planned	0.4	0.3	0.4
Transmission Vegetation Management - ROW Maintenance	0.2	0.4	0.3
Infrastructure Inspections	0.3	0.3	0.3
Distribution & Transmission Wood Pole Inspections	1.2	0.6	0.9
J/U Pole Attachments Audit	-	-	-
Transmission Asset Upgrades	0.0	0.0	0.0
Targeted Critical Fac. / Flood Damage Mitigation	-	-	-
Targeted Distribution Overhead Feeder Hardening	-	-	-
Total - Clause	**9.0**	**11.8**	**10.4**

TAMPA ELECTRIC COMPANY
($ Million)

STORM PROTECTION PLAN O&M EXPENSES	2018 (May - Dec) Actual								
TO BE RECOVERED THROUGH SPP CLAUSE	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Distribution Vegetation Management - Planned	0.8	0.8	0.7	1.0	0.6	0.8	1.0	1.2	6.9
Transmission Vegetation Management - Planned	0.1	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.4
Transmission Vegetation Management - ROW Maintenance	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2
Infrastructure Inspections	0.0	0.0	0.1	(0.0)	0.0	0.0	0.0	0.0	0.3
Distribution & Transmission Wood Pole Inspections	0.0	(0.0)	-	0.1	0.2	0.2	0.4	0.3	1.2
J/U Pole Attachments Audit	-	-	-	-	-	-	-	-	-
Transmission Asset Upgrades	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Targeted Critical Fac. / Flood Damage Mitigation	-	-	-	-	-	-	-	-	-
Targeted Distribution Overhead Feeder Hardening	-	-	-	-	-	-	-	-	-
Total - Clause	**1.0**	**0.9**	**0.9**	**1.2**	**0.9**	**1.1**	**1.5**	**1.6**	**9.0**

Attachment A

TAMPA ELECTRIC COMPANY
($ Million)

STORM PROTECTION PLAN O&M EXPENSES	2019 (May - Dec) Actual								
TO BE RECOVERED THROUGH SPP CLAUSE	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	**Total**
Distribution Vegetation Management - Planned	1.4	1.0	1.3	1.2	0.9	1.3	1.2	1.9	**10.1**
Transmission Vegetation Management - Planned	0.0	0.1	(0.0)	0.0	0.2	0.1	0.0	0.0	**0.3**
Transmission Vegetation Management - ROW Maintenance	0.1	0.1	0.0	0.0	0.0	0.1	0.0	0.1	**0.4**
Infrastructure Inspections	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.0	**0.3**
Distribution & Transmission Wood Pole Inspections	0.1	0.2	0.0	0.0	0.0	0.0	0.3	0.0	**0.6**
J/U Pole Attachments Audit	-	-	-	-	-	-	-	-	-
Transmission Asset Upgrades	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0.0**
Targeted Critical Fac. / Flood Damage Mitigation	-	-	-	-	-	-	-	-	-
Targeted Distribution Overhead Feeder Hardening	-	-	-	-	-	-	-	-	-
Total - Clause	**1.7**	**1.3**	**1.4**	**1.2**	**1.1**	**1.5**	**1.6**	**2.0**	**11.8**

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 20200092-EI

IN RE: STORM PROTECTION PLAN COST RECOVERY CLAUSE

TESTIMONY AND EXHIBIT

OF

WILLIAM R. ASHBURN

FILED: July 24, 2020

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

WILLIAM R. ASHBURN

Q. Please state your name, address, occupation, and employer.

A. My name is William R. Ashburn. My business address is 702 N. Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "company") as Director, Pricing and Financial Analysis.

Q. Please provide a brief outline of your educational background and business experience.

A. I graduated from Creighton University with a Bachelor of Science degree in Business Administration. Upon graduation, I joined Ebasco Business Consulting Company where my consulting assignments included the areas of cost allocation, computer software development, electric system inventory and mapping, cost of service filings and property record development. I joined Tampa Electric in 1983 as a

Senior Cost Consultant in the Rates and Customer Accounting Department. At Tampa Electric I have held a series of positions with responsibility for cost of service studies, rate filings, rate design, implementation of new conservation and marketing programs, customer surveys and various state and federal regulatory filings. In March 2001, I was promoted to my current position of Director, Pricing and Financial Analysis in Tampa Electric's Regulatory Affairs Department. I am a member of the Rate and Regulatory Affairs Committee of the Edison Electric Institute ("EEI").

Q. Have you previously testified before the Florida Public Service Commission ("Commission")?

A. Yes. I have testified or filed testimony before this Commission in several dockets. Most recently, I filed testimony before this Commission in Docket No. 20180045-EI, Consideration of the Tax Impacts Associated with Tax Cuts and Jobs Act of 2017 for Tampa Electric and Docket No. 20180133-EI, petition for limited proceeding to approve second solar base rate adjustment ("SoBRA"), effective January 1, 2019, by Tampa Electric Company. I also testified before this Commission in Docket No.

20170260-EI, petition for limited proceeding to approve first solar base rate adjustment, effective September 1, 2018, by Tampa Electric Company. I testified for Tampa Electric in Docket No. 20170210-EI as a member of a panel of witnesses during the November 6, 2017 hearing on the 2017 Amended and Restated Stipulation and Settlement Agreement ("2017 Agreement"). I also testified on behalf of Tampa Electric in Docket No. 20130040-EI regarding the company's petition for an increase in base rates and miscellaneous service charges and in Docket No. 20080317-EI which was Tampa Electric's previous base rate proceeding. I testified in Docket No. 20020898-EI regarding a self-service wheeling experiment and in Docket No. 20000061-EI regarding the company's Commercial/Industrial service rider. In Docket Nos. 20000824-EI, 20001148-EI, 20010577-EI and 20020898-EI, I testified at different times for Tampa Electric and as a joint witness representing Tampa Electric, Florida Power & Light Company ("FP&L") and Progress Energy Florida, Inc. ("PEF") regarding rate and cost support matters related to the GridFlorida proposals. In addition, I represented Tampa Electric numerous times at workshops and in other proceedings regarding rate, cost of service and related matters. I have also provided testimony and represented Tampa Electric before the

Federal Energy Regulatory Commission (“FERC”) in rate and cost of service matters.

Q. What are the purposes of your prepared direct testimony?

A. My testimony addresses the appropriate revenue allocation and rate design methodologies to develop the resulting Storm Protection Plan Cost Recovery Clause (“SPPCRC”) factors and the impact of the $15 Million transfer of cost recovery for certain SPP programs from base rates to clause rates recovery.

Q. Have you prepared an exhibit to accompany your direct testimony?

A. Yes, Exhibit No. WRA-1 that was prepared under my direction and supervision. Exhibit No. WRA-1 details the revenue allocation and rate design methodologies that were appropriately used to develop the allocation and impact on SPPCRC factors of the $15 Million transfer of cost recovery for certain SPP programs from base rates to clause rates recovery.

METHOD OF DERIVING JURISDICTIONAL REVENUE REQUIREMENTS AND THEN ALLOCATING THOSE COSTS TO DERIVE SPPCRC CHARGES FOR 2020-

2021

Q. Please describe how the SPPCRC related total revenue requirements are being derived for the proposed SPPCRC.

A. As described in the Direct Testimony of A. Sloan Lewis, the revenue requirements associated with the SPP programs were derived on a total cost basis for 2020 and 2021 using cost estimates for each of the SPP programs plus depreciation and return on the associated SPP assets, as outlined in Rule 25-6.031(6), F.A.C., the SPP Cost Recovery Clause Rule. These costs included not only incremental costs for 2021 but, in order to avoid double recovery through both base rates and SPPCRC, included capital expenditures for SPP projects to be initiated after April 10, 2020 and O&M expenditures associated with six existing activities which will be included in the SPPCRC the costs of which are currently recovered through base rates.

Q. How were these total revenue requirements then converted to jurisdictional revenue requirements?

A. For each project, jurisdictional separation factors were applied to derive the jurisdictional revenue requirements. Certain of the projects are transmission related and the others are distribution related. Tampa Electric provided wholesale transmission service to some utilities under its Open Access Transmission Tariff (“OATT”) and to avoid double recovery, a portion of the total transmission related project costs must be jurisdictionally separated before being identified for cost recovery through the SPPCRC. Tampa Electric does not provide any wholesale distribution service and so 100 percent of those project costs can be called jurisdictional and thus totally recovered through the SPPCRC from retail customers.

Part of Exhibit No. WRA-1 shows how this jurisdictional allocation was performed. The jurisdictional separation factors utilized for this purpose are the same as those that are utilized for the 2020 Forecasted Surveillance Report filed with the FPSC in March 2020.

Q. Were there any other adjustments made to the company’s SPP revenue requirements prior to separating these costs jurisdictionally for retail cost recovery?

A. Yes, the revenue requirements were also adjusted downward by $10.4 Million that was approved by the Commission in the company’s 2020 Settlement Agreement. This adjustment in the settlement, which is described in detail in the Testimony of A. Sloan, is a threshold and was not jurisdictionally separated but any expenses above that threshold will be jurisdictionally separated before becoming a jurisdictional revenue requirement to be recovered through the SPPCRC.

Q. Once the revenue requirements have been calculated and then jurisdictionally separated for retail cost recovery, how were those revenue requirements then allocated to rate class for derivation of SPPCRC charges?

A. For each year, the programs were itemized and identified as either substation, transmission, or distribution costs. Each of those functionalized costs was then allocated to rate class using the allocation factors for that function. The allocation factors were from the Tampa Electric 2013 Cost of Service Study prepared in Docket No. 20130040-EI, which was used for the company’s current (non-SoBRA) base rate design. Once the total SPP revenue requirement recovery allocation to the rate classes was derived, the rates were determined in the same manner. For Residential, the charge is a kWh charge. For both Commercial and Industrial, the charge is a kW charge. The charges are derived by dividing the rate class allocated SPP revenue requirements by the 2020 energy billing determinants (for residential) and by the 2020 demand billing determinants (for commercial and industrial). Those charges were then applied to the billing determinants associated with typical bills for each group to calculate the impact on those bills. This methodology is shown both in my Exhibit No. WRA-1 as it applied to the $15 Million transfer from base to clause rates, and also in Exhibit MRR-1 to the total amount to be recovered in the SPPCRC in 2021, which includes the $15 Million transfer amount. Mr. Roche's direct testimony and Exhibit No. MRR-1 will support the final development of the 2021 SPPCRC factors.

Q. How will the company implement this $15 Million one-time base rate reduction required by the 2020 Settlement Agreement?

A. Paragraph 11(b) of the 2020 Settlement Agreement states: "The company will file the revised tariffs necessary to implement the one-time base rate reduction specified herein for Commission approval in Docket No. 20200092-EI..." Accordingly, Tampa Electric will file a Motion to Approve Revised Tariff Sheets with the revised tariffs necessary to implement the one-time base rate reduction in this docket.

Q. Will the rate impacts established through the 2021 SPPCRC differ from those presented in the rate impact calculations that were provided in the company's SPP that was filed on April 10, 2020?

A. Yes, the rate impacts presented in the company's SPP reflected the "all-in" costs of the company's SPP without regard to whether the costs would be recovered through the SPPCRC or through the company's base rates and charges. Since that time, the Commission approved the 2020 Settlement Agreement, which sets out a methodology for separating SPPCRC and base rate recovery and for avoiding double recovery. Additionally, the values utilized in the SPPCRC have been reduced to the retail jurisdictional amount. Furthermore, the company used the then-existing billing determinants to develop the rate estimates in the SPP. The rate estimates presented here are based on more recent billing determinant forecasts for 2021, which are in turn based on the most current load forecast.

Q. In the development of the proposed 2021 SPPCRC factors, did the company use the most recent billing determinants, within the most current load forecast?

A. Yes, the 2021 SPPCRC factors are based upon the company's most current load forecast (load forecast for 2021).

CONCLUSIONS

Q. Please summarize your direct testimony.

A. My testimony and exhibit demonstrate that the methodology utilized to jurisdictionalize and then allocate to rate class the SPPCRC costs is appropriate, just, and reasonable based on the guidance provided in the rule, the 2020 Settlement Agreement and ratemaking principles.

Q. Does this conclude your testimony?

A. Yes.

EXHIBIT

OF

WILLIAM R. ASHBURN

TAMPA ELECTRIC COMPANY
DOCKET NO. 20200092-EI
EXHIBIT NO. WRA-1
WITNESS: ASHBURN
PAGE 1 OF 1
FILED: 07/24/2020

Storm Protection Program	Function	SPPCRC Revenue Requirement	RS (Tier 1, Tier 2, RSVP)	GS & CS	GSD, SBF	GSD Optional	IS	LS1, LS2	LTG-FAC	Total
Capital										
Distribution Lateral Undergrounding	Dist	$0	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	0	$0.00
Transmission Asset Upgrades	Trans Retail	$0	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	0	$0.00
Substation Extreme Weather Protection	Dist	$0	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	0	$0.00
Distribution Overhead Feeder Hardening	Dist	$0	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	0	$0.00
Transmission Access Enhancements	Trans Retail	$92,529	$51,275.42	$5,634.38	$31,628.46	$1,510.17	$2,393.04	$87.74	0	$92,529.20
O&M										
Distribution Vegetation Management - planned	Dist	$12,000,000	$7,102,437.64	$680,513.61	$3,800,509.28	$181,463.42	$64,855.27	$170,220.78	0	$12,000,000.00
Transmission Vegetation Management - planned	Trans Retail	$1,110,350	$615,304.99	$67,612.60	$379,541.51	$18,122.02	$28,716.46	$1,052.82	0	$1,110,350.40
Transmission Asset Upgrades	Trans Retail	$0	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	0	$0.00
Substation Extreme Weather Protection	Dist	$0	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	0	$0.00
Distribution Overhead Feeder Hardening	Dist	$0	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	0	$0.00
Distribution Infrastructure Inspections	Dist	$1,200,000	$710,243.76	$68,051.36	$380,050.93	$18,146.34	$6,485.53	$17,022.08	0	$1,200,000.00
Transmission Infrastructure Inspections	Trans Retail	$462,646	$256,377.08	$28,171.92	$158,142.30	$7,550.84	$11,965.19	$438.68	0	$462,646.00
SPP Planning & Common	Dist	$0	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	0	$0.00
	Total	$14,865,525.60	$8,735,638.89	$849,983.87	$4,749,872.47	$226,792.79	$114,415.48	$188,822.10	$0.00	$14,865,525.60
	Revenue Tax Factor	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	
	Total with Revenue Tax Factor	$14,876,228.78	$8,741,928.55	$850,595.86	$4,753,292.38	$226,956.08	$114,497.86	$188,958.05	$0.00	$14,876,228.78

	RS (Tier 1, Tier 2, RSVP)	GS & CS	GSD, SBF	GSD Optional	IS	LS1, LS2	LTG-FAC
Billing Determinants	9,684,803	902,049	17,528,483	360,212	1,986,004	134,246	0

After Taxes	RS (Tier 1, Tier 2, RSVP)	GS & CS	GSD, SBF	GSD Optional	IS	LS1, LS2	LTG-FAC
Charges (per kWh)	$0.000903	$0.000943		$0.000630		$0.001408	$0.000000
Charges (per kW)			$0.271175		$0.057652		

Clause Charges (per kWh)	RS (Tier 1, Tier 2, RSVP)	GS & CS		GSD Optional		LS1, LS2	LTG-FAC
Secondary	$0.000903	$0.000943		$0.000630		$0.001408	$0.000000
Primary				$0.000624			
Sub-Transmission				$0.000617			

Clause Charges (per kW)			GSD, SBF		IS		
Secondary			$0.271175				
Primary			$0.268464		$0.057076		
Sub-Transmission			$0.265752		$0.056499		