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May 31, 2018

VIA: ELECTRONIC FILING

Ms. Carlotta S. Stauffer
Commission Clerk
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, FL 32399-0850

Re: Consideration of the tax impacts associated with Tax Cuts and Jobs Act of 2017 for Tampa Electric Company; Docket No. 20180045-EI

Dear Ms. Stauffer:

Attached for filing in the above docket on behalf of Tampa Electric Company are the following:

1. Tampa Electric Company's Petition for Limited Proceeding to Reduce Base Rates and Charges to Reflect Impact of the Tax Cuts and Jobs Act of 2017

2. Prepared Direct Testimony and Exhibit (ADF-1) of Alan D. Felsenthal

3. Prepared Direct Testimony and Exhibit (VS-1) of Valerie Strickland

4. Prepared Direct Testimony and Exhibit (JSC-1) of Jeffrey S. Chronister

5. Prepared Direct Testimony and Exhibit (WRA-1) of William R. Ashburn

Thank you for your assistance in connection with this matter.

Sincerely,

James D. Beasley

JDB/pp
Attachment

cc: All Parties of Record (w/attachment)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Consideration of the Tax Impacts Associated with Tax Cuts and Jobs Act of 2017 for Tampa Electric Company	))))	Docket No. 20180045-EI Filed: May 31, 2018

TAMPA ELECTRIC COMPANY'S PETITION FOR LIMITED PROCEEDING TO REDUCE BASE RATES AND CHARGES TO REFLECT IMPACT OF THE TAX CUTS AND JOBS ACT OF 2017

Pursuant to Sections 366.076, 120.57(2) and 366.06(3), Florida Statutes, and Rule 28-106.301, F.A.C., Tampa Electric Company ("Tampa Electric" or "the company") respectfully petitions the Florida Public Service Commission ("FPSC" or "the Commission") for a limited proceeding to reduce base rates and charges effective for the first meter reading cycle in January 2019 to reflect the impact of the Tax Cuts and Jobs Act of 2017, and states:

Background

On September 27, 2017, Tampa Electric, the Office of Public Counsel ("OPC" or "Citizens"), the Florida Industrial Power Users Group ("FIPUG"), the Florida Retail Federation ("FRF"), the Federal Executive Agencies ("FEA"), and the WCF Hospital Utility Alliance ("HUA") (collectively, the "Consumer Parties") entered into the 2017 Amended and Restated Stipulation and Settlement Agreement ("2017 Agreement"). 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. Paragraph 9 of the 2017 Agreement addresses the procedures and principles to be followed should Congress change the rate of taxation of corporate income during the term of the 2017 Agreement.

Tampa Electric filed a Petition for Recovery of Costs Associated with Named Tropical Systems and Replenishment of Storm Reserve in Docket No. 20170271-EI on December 27, 2017. On January 30, 2018, the company filed an Amended Petition for Recovery of Costs

Associated with Named Tropical Systems and Replenishment of Storm Reserve in the same docket ("Amended Storm Petition"). The Amended Storm Petition updated the total estimated storm restoration costs (approximately $102.5 million) from those set forth in the company's original petition and requested approval of revised storm cost recovery factors and tariff sheets to recover the company's proposed total updated storm restoration costs.

The Tax Cuts and Jobs Act of 2017 ("TCJA") was enacted by the United States Congress on December 20, 2017 and was signed into law by the President on December 22, 2017. *See Tax Cuts and Jobs Act of 2017*, Pub. Law 115-97, 131 Stat. 2054 (2017). The TCJA triggered the provisions in paragraph 9 of the 2017 Agreement.[1] In January 2018, the company estimated the impact of the TCJA to result in a reduction in annual revenue requirements of approximately $95 million for 2018 using the methodologies set forth in Paragraphs 9(b) and 9(c) of the 2017 Agreement.

On February 12, 2018, Tampa Electric and the Consumer Parties entered into an Amended Implementation Stipulation, which was approved by the Commission on March 1, 2018. *See Order No. PSC-2018-0125-PCO-EI, issued on March 7, 2018 in Docket Nos. 20170271-EI.* Therein, Tampa Electric and the Consumer Parties agreed that Tampa Electric should effectively use the preliminary estimated annual TCJA tax savings reduction of approximately $95 million per year to avoid the need to charge customers for the estimated $102.5 million of storm damage costs that they would have otherwise been obligated to pay beginning in April 2018. The Parties also recognized that because the estimated amounts of

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[1] On January 9, 2018, OPC petitioned the Commission to establish a generic docket to investigate and adjust rates for all investor-owned utilities related to the reduction in the federal corporate income tax rate as a result of the passage of the TCJA. Thereafter, the Commission opened Docket No. 20180013-PU for consideration of OPC's petition. Since the company has committed to address the impacts of tax reform pursuant to paragraph 9 of the 2017 Agreement, it does not believe that the Commission should address the impacts of tax reform on Tampa Electric in the generic docket and has filed this petition in the stand-alone docket for Tampa Electric established by the Commission.

storm costs and tax savings were approximately the same, there was an opportunity to provide customers full credit for 100 percent of the estimated 2018 tax savings during calendar year 2018 and avoid collection of a surcharge from customers to recover the company's estimated storm damage costs, by essentially "netting" the two amounts in 2018, subject to a determination of the final amounts for each and a true-up in 2019 through the conservation cost recovery clause.

The Commission will address the company's Amended Storm Petition and make a final determination regarding the amount of named storm restoration costs the company may recover from customers in Docket No. 20170271-EI. The final hearing in that docket has been set for October 15-19, 2018. This Petition addresses the impacts of the TCJA on Tampa Electric as provided in the 2017 Agreement (Order No. PSC-2017-0456-S-EI) and the Amended Implementation Stipulation (Order No. PSC-2018-0125-PCO-EI).

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
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 electric utility regulated by the Commission pursuant to Chapter 366, Florida Statutes, and is a wholly-owned subsidiary of Emera, Inc. Tampa Electric's principal place of business is located at 702 North Franklin Street, Tampa, Florida 33602.

4. Tampa Electric serves more than 750,000 retail customers in Hillsborough and portions of Polk, Pinellas and Pasco Counties, Florida.

5. This Petition represents an original pleading and is not in response to any proposed action by the Commission. Accordingly, the Petitioner is not responding to any proposed agency action.

II. The TCJA and Paragraph 9 of the 2017 Agreement

6. As it relates to regulated public utilities like Tampa Electric, the TCJA:

(a) Reduces the federal corporate income tax rate from 35 percent to 21 percent effective January 1, 2018.

(b) Exempts regulated utilities from the new general limits on deductibility of interest expense and from immediate deducting certain capital additions.

(c) Applies the modified accelerated cost recovery system ("MACRS") rules to regulated utility property.

(d) Retains the corporate deduction for state and local taxes.

(e) Includes normalization provisions for public utility property that requires application of the average rate assumption method ("ARAM") for "protected" excess deferred tax reserves.

(f) Leaves unchanged the 2015 renewable credit tax arrangement and the Electric Vehicle tax credit.

(g) Eliminates the Section 199 manufacturing deduction.

7. Paragraph 9 of the 2017 Agreement states:

> (a) Changes in the rate of taxation of corporate income by federal or state taxing authorities ("Tax Reform") could impact the effective tax rate recognized by the company in FPSC adjusted reported net operating income and the measurement of existing and prospective deferred federal income tax assets and liabilities reflected in the FPSC adjusted capital structure. When Congress last reduced the maximum federal corporate income tax rate in the Tax Reform Act of 1986, it included a transition rule that, as an eligibility requirement for using accelerated depreciation with respect to public utility property, provided guidance regarding returning to customers the portion of the resulting excess deferred income taxes attributable to the use of accelerated depreciation. To the extent Tax Reform includes a transition rule applicable to excess deferred federal income tax assets and liabilities ("Excess Deferred Taxes"), defined as those that arise from the re-measurement of those deferred federal income tax assets and liabilities at the new applicable corporate tax rate(s), those Excess Deferred Taxes will be governed by the Tax Reform transition rule, as applied to most promptly and effectively reduce Tampa Electric's rates consistent with the Tax Reform rules and normalization rules.
>
> (b) If Tax Reform is enacted before the company's next general base rate proceeding, the company will quantify the impact of Tax Reform on its Florida retail jurisdictional net operating income thereby neutralizing the FPSC adjusted net operating income of the Tax Reform to a net zero. The company's forecasted earnings surveillance report for the calendar year that includes the period in which Tax Reform is effective will be the basis for determination of the impact of Tax Reform. The company will also adjust any SoBRAs that have not yet gone into effect to specifically account for Tax Reform. The impacts of Tax Reform on base revenue requirements will be flowed back to retail customers within 120 days of when the Tax Reform becomes law, through a one-time adjustment to base rates upon a thorough review of the effects of the Tax Reform on base revenue requirements consistent with Subparagraph 9(a). This adjustment shall be accomplished through a uniform percentage decrease to customer, demand and energy base rate charges for all retail customer classes. Any effects of Tax Reform on retail revenue requirements from the Effective Date through the date of the one-

> time base rate adjustment shall be flowed back to customers through the ECCR Clause on the same basis as used in any base rate adjustment. * * *
>
> (c) All Excess Deferred Taxes shall be deferred to a regulatory asset or liability which shall be included in FPSC adjusted capital structure and flowed back to customers over a term consistent with law. If the same Average Rate Assumption Method used in the Tax Reform Act of 1986 is prescribed, then the regulatory asset or liability will be flowed back to customers over the remaining life of the assets associated with the Excess Deferred Taxes subject to the provisions related to FPSC adjusted operating income impacts of Tax Reform noted above. If the Tax Reform law or act is silent on the flow-back period, and there are no other statutes or rules that govern the flow-back period, then there shall be a rebuttable presumption that the following flow-back period(s) will apply: (1) if the cumulative net regulatory liability is less than $100 million, the flow-back period will be five years; or (2) if the cumulative net regulatory liability is greater than $100 million, the flow-back period will be ten years. * * *

8. Section 366.076(1), Florida Statutes, provides that the Commission may conduct a limited proceeding to consider and act upon any issue within its jurisdiction, including any such issue which, once resolved, requires a public utility to adjust its rates. Approval of the company's proposed reduction to base rates and charges to reflect the impact of TCJA through a limited proceeding under Section 366.076, Florida Statutes, will provide the Commission and substantially affected persons a single proceeding in which all issues related to implementation of paragraph 9 of the 2017 Agreement and tax reform can be resolved. Accordingly, Tampa Electric requests that the Commission open a docket that provides an opportunity for a hearing to address the matters in this Petition.

III. Statement on Disputed Issues of Material Fact

9. Tampa Electric is not aware of any disputed issues of material fact at this time, but anticipates that the Office of Public Counsel and other parties, including some or all of the

Consumer Parties to the 2017 Agreement, may assert disputed issues of material fact during this proceeding.

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

10. The ultimate facts that entitle Tampa Electric to the relief requested herein are:

(a) Paragraph 9(b) of the 2017 Agreement requires that the impacts of Tax Reform on base revenue requirements be flowed back to retail customers within 120 days of when the Tax Reform becomes law. The TCJA became law on December 22, 2017, so the company was required to reflect the TCJA in its rates and charges on or before April 23, 2018 to comply with the 2017 Agreement.

(b) The company complied with the 2017 Agreement by entering into the Amended Implementation Stipulation and foregoing the collection of a storm cost recovery surcharge based on the storm cost recovery factors approved by the Commission in Docket No. 20170271-EI on March 1, 2018.

(c) Paragraph 9(b) of the 2017 Agreement requires the company to quantify the impact of Tax Reform on its Florida retail jurisdictional net operating income thereby neutralizing the FPSC adjusted net operating income of the Tax Reform to a net zero based on the company's forecasted earnings surveillance report for the calendar year that includes the period in which Tax Reform is effective.

(d) The company's forecasted earnings surveillance report for the calendar year that includes the period in which Tax Reform is effective is the 2018 forecasted earnings surveillance report, which was filed on March 16, 2018.

(e) The federal corporate income tax rate is 21 percent, effective January 1, 2018.

(f) In order to avoid a normalization violation, TCJA requires that a taxpayer like Tampa Electric, in computing its cost of service for ratemaking purposes and reflecting operating results in its regulated books of account, may not reduce protected excess deferred tax reserves more rapidly or to a greater extent that such reserve would be reduced under the ARAM. The mechanics and requirements of the ARAM are set forth in TCJA.

(g) Based on the 21 percent corporate tax rate effective January 1, 2018, the amount of protected excess deferred tax reserves as of December 31, 2017 was approximately $347.8 million.

(h) Based on the 21 percent corporate tax rate effective January 1, 2018, the amount of unprotected excess deferred tax reserves as of December 31, 2017 was $133.0 million.

(i) According to paragraph 9(c) of the 2017 Agreement, if the amount of unprotected excess deferred taxes exceeds $100 million, the flow-back period for unprotected excess deferred tax reserves is 10 years.

(j) Based on the company's December 31, 2017 balances for protected and unprotected excess deferred tax reserves specified above, the company's 2018 forecasted earnings surveillance report filed on March 16, 2018, the 21 percent federal corporate income tax rate effective January 1, 2018, and using the ARAM and 10-year flow-back periods for protected and unprotected excess deferred tax reserves, respectively, the annual revenue requirement reduction for 2018 necessary to reflect the effect of tax reform pursuant to the 2017 Agreement is $102,686,671.

(k) The $102.7 million annual revenue requirement reduction calculated pursuant to the 2017 Agreement does not take into consideration factors such as the effect of the TCJA on the company's financial integrity, credit metrics or future operating cash flows. Likewise, it does not reflect a final determination of the company's unprotected excess deferred tax reserves as of December 31, 2017, which will become final when the company files its 2017 federal and state income tax returns in October 2018 and may warrant a true-up.

(l) Paragraph 9(b) of the 2017 Agreement requires that the revenue reduction adjustment specified in the agreement be accomplished through a uniform percentage decrease to customer, demand and energy base rate charges for all retail customer classes. The company's proposed tariff changes applying the $102,686,671 annual revenue requirement reduction to the rates approved as effective with the first billing cycle in September 2018, which reflect the first SoBRA, on a uniform percentage basis in both clean and redline format are attached as Exhibit A.

V. Relief Requested

11. Tampa Electric Company requests that the Commission grant the following relief:

(a) Approve an annual revenue requirement reduction for 2018 necessary to reflect the effect of TCJA of $102,686,671 as specified in the 2017 Agreement.

(b) Approve the company's proposed tax reform tariff changes applying the $102,686,671 reduction on a uniform percentage basis as reflected on Exhibit A.

(c) Make a final determination of the annual revenue requirement reduction for 2018 necessary to reflect the effect of tax reform and approve the related tariff changes to be effective concurrently with meter readings for the first billing cycle in January 2019.

(d) If the Commission has made a final determination of the company's recoverable storm costs in Docket No. 20170271-EI, calculate and determine the amount of the 2017 net tax reform-storm cost true-up as specified in the Amended Implementation Stipulation.

(e) Provide public notice of the proposed tariff changes as shown on Exhibit A as expeditiously as possible, and to approve them or allow them to go into effect concurrently with meter readings for the first billing cycle in January 2019, subject to refund, pending the final determinations in subparagraphs (c) and (d), above.

(f) Grant other such relief as may be required or appropriate.

12. Tampa Electric is entitled to the relief requested pursuant to Chapter 366, Florida Statutes, Chapter 120, Florida Statutes, the 2017 Agreement, the Amended Implementation Stipulation and FPSC Order Nos. PSC-2017-0456-S-EI and PSC-2018-0125-PCO-EU.

VI. Conclusion

For the reasons shown above, Tampa Electric Company respectfully requests that the Commission grant this Petition and the relief requested herein.

DATED this 31st day of May, 2018

Respectfully submitted,

JAMES D. BEASLEY
J. JEFFRY WAHLEN
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 31st day of May, 2018 to the following:

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ATTORNEY

RESIDENTIAL SERVICE

SCHEDULE: RS

AVAILABLE: Entire service area.

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

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

Resale not permitted.

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

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

MONTHLY RATE:

Basic Service Charge:
$15.12

Energy and Demand Charge:

First 1,000 kWh	4.896¢ per kWh
All additional kWh	5.806¢ per kWh

MINIMUM CHARGE: The Basic Service Charge.

FUEL CHARGE: See Sheet Nos. 6.020 and 6.021.

Continued to Sheet No. 6.031

GENERAL SERVICE - NON DEMAND

SCHEDULE: GS

AVAILABLE: Entire service area.

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

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

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

MONTHLY RATE:

Basic Service Charge:

Metered accounts	$18.14
Un-metered accounts	$15.12

Energy and Demand Charge:

5.165¢ per kWh

MINIMUM CHARGE: The Basic Service Charge.

EMERGENCY RELAY POWER SUPPLY CHARGE: The monthly charge for emergency relay power supply service shall be 0.156¢ per kWh of billing energy. This charge is in addition to the compensation the customer must make to the Company as a contribution-in-aid of construction.

Continued to Sheet No. 6.051

GENERAL SERVICE - DEMAND

SCHEDULE: GSD

AVAILABLE: Entire service area.

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

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

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

MONTHLY RATE:

	STANDARD		OPTIONAL
Basic Service Charge:		**Basic Service Charge:**	
Secondary Metering Voltage	$ 30.25	Secondary Metering Voltage	$ 30.25
Primary Metering Voltage	$ 131.06	Primary Metering Voltage	$ 131.06
Subtrans. Metering Voltage	$ 998.05	Subtrans. Metering Voltage	$ 998.05
Demand Charge:		**Demand Charge:**	
$9.74 per kW of billing demand		$0.00 per kW of billing demand	
Energy Charge:		**Energy Charge:**	
1.596¢ per kWh		6.199¢ per kWh	

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

Continued to Sheet No. 6.081

Continued from Sheet No. 6.080

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

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

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

POWER FACTOR: Power factor will be calculated for customers with measured demands of 1,000 kW or more in any one billing period out of twelve (12) consecutive billing periods ending with the current billing period. When the average power factor during the month is less than 85%, the monthly bill will be increased 0.202¢ for each kVARh by which the reactive energy numerically exceeds 0.619744 times the billing energy. When the average power factor during the month is greater than 90%, the monthly bill will be decreased 0.101¢ for each kVARh by which the reactive energy is numerically less than 0.484322 times the billing energy.

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

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

DELIVERY VOLTAGE CREDIT: When a customer under the standard rate takes service at primary voltage, a discount of 79¢ per kW of billing demand will apply. A discount of $2.45 per kW of billing demand will apply when a customer under the standard rate takes service at subtransmission or higher voltage.

Continued to Sheet No. 6.082

Continued from Sheet No. 6.081

When a customer under the optional rate takes service at primary voltage, a discount of 0.209¢ per kWh will apply. A discount of 0.639¢ per kWh will apply when a customer under the optional rate takes service at subtransmission or higher voltage.

EMERGENCY RELAY POWER SUPPLY CHARGE: The monthly charge for emergency relay power supply service shall be 63¢ per kW of billing demand for customers taking service under the standard rate and 0.158¢/kWh for customer taking service under the optional rate. This charge is in addition to the compensation the customer must make to the Company as a contribution-in-aid of construction.

FUEL CHARGE: See Sheet Nos. 6.020 and 6.021.

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

CAPACITY CHARGE: See Sheet Nos. 6.020 and 6.021.

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

FLORIDA GROSS RECEIPTS TAX: See Sheet No. 6.021.

FRANCHISE FEE CHARGE: See Sheet No. 6.021.

PAYMENT OF BILLS: See Sheet No. 6.022.

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

SCHEDULE: IS

AVAILABLE: Entire Service Area.

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

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

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

MONTHLY RATE:

Basic Service Charge:

Primary Metering Voltage	$ 627.06
Subtransmission Metering Voltage	$2,391.29

Demand Charge:

$1.99 per KW of billing demand

Energy Charge:

2.524¢ per KWH

Continued to Sheet No. 6.086

Continued from Sheet No. 6.085

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

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

POWER FACTOR: When the average power factor during the month is less than 85%, the monthly bill will be increased 0.202¢ for each kVARh by which the reactive energy numerically exceeds 0.619744 times the billing energy. When the average power factor during the month is greater than 90%, the monthly bill will be decreased 0.101¢ for each kVARh by which the reactive energy is numerically less than 0.484322 times the billing energy.

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

DELIVERY VOLTAGE CREDIT: When the customer furnishes and installs all subtransmission or higher voltage to utilization voltage substation transformation, a discount of 55¢ per KW of billing demand will apply.

EMERGENCY RELAY POWER SUPPLY CHARGE: The monthly charge for emergency relay power supply service shall be 78¢ per KW of billing demand. This charge is in addition to the compensation the customer must make to the Company as a contribution-in-aid of construction.

Continued to Sheet No. 6.087

CONSTRUCTION SERVICE

SCHEDULE: CS

AVAILABLE: Entire service area.

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

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

MONTHLY RATE:
Basic Service Charge: $18.14

Energy and Demand Charge: 5.165¢ per kWh
.
MINIMUM CHARGE: The Basic Service Charge.

FUEL CHARGE: See Sheet Nos. 6.020 and 6.021.

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

CAPACITY CHARGE: See Sheet Nos. 6.020 and 6.021.

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

FLORIDA GROSS RECEIPTS TAX: Sheet No. 6.021.

FRANCHISE FEE CHARGE: See Sheet No. 6.021.

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

PAYMENT OF BILLS: See Sheet No. 6.022.

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

SCHEDULE: GST

AVAILABLE: Entire service area.

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

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

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

MONTHLY RATE:

Basic Service Charge:
$20.16

Energy and Demand Charge:
13.183¢ per kWh during peak hours
1.406¢ per kWh during off-peak hours

Continued to Sheet No. 6.321

Continued from Sheet No. 6.320

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

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

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

MINIMUM CHARGE: The Basic Service Charge.

BASIC SERVICE CHARGE CREDIT: Any customer who makes a one time contribution in aid of construction of $94.00 (lump-sum meter payment), shall receive a credit of $2.02 per month. This contribution in aid of construction will be subject to a partial refund if the customer terminates service on this optional time-of-day rate.

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

EMERGENCY RELAY POWER SUPPLY CHARGE: The monthly charge for emergency relay power supply service shall be 0.156¢ per kWh of billing energy. This charge is in addition to the compensation the customer must make to the Company as a contribution-in-aid of construction.

FUEL CHARGE: See Sheet Nos. 6.020 and 6.021.

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

Continued to Sheet No. 6.322

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

SCHEDULE: GSDT

AVAILABLE: Entire service area.

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

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

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

MONTHLY RATE:

Basic Service Charge:

Secondary Metering Voltage	$ 30.25
Primary Metering Voltage	$ 131.06
Subtransmission Metering Voltage	$ 998.05

Demand Charge:

$3.28 per kW of billing demand, plus
$6.45per kW of peak billing demand

Energy Charge:

2.922¢ per kWh during peak hours
1.055¢ per kWh during off-peak hours

Continued to Sheet No. 6.331

Continued from Sheet No. 6.331

<u>POWER FACTOR</u>: Power factor will be calculated for customers with measured demands of 1,000 kW in any billing period out of twelve (12) consecutive billing periods ending with the current billing period. When the average power factor during the month is less than 85%, the monthly bill will be increased 0.202¢ for each kVARh by which the reactive energy numerically exceeds 0.619744 times the billing energy. When the average power factor during the month is greater than 90%, the monthly bill will be decreased 0.101¢ for each kVARh by which the reactive energy is numerically less than 0.484322 times the billing energy.

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

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

<u>DELIVERY VOLTAGE CREDIT</u>: When the customer takes service at primary voltage a discount of 79¢ per kW of billing demand will apply. When the customer takes service at subtransmission or higher voltage, a discount of $2.45 per kW of billing demand will apply.

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

<u>FUEL CHARGE</u>: See Sheet Nos. 6.020 and 6.021.

<u>ENERGY CONSERVATION CHARGE</u>: See Sheet Nos. 6.020 and 6.021.

<u>CAPACITY CHARGE</u>: See Sheet Nos. 6.020 and 6.021.

<u>ENVIRONMENTAL COST RECOVERY CHARGE</u>: See Sheet Nos. 6.020 and 6.021.

<u>FLORIDA GROSS RECEIPTS TAX</u>: See Sheet No. 6.021.

<u>FRANCHISE FEE CHARGE</u>: See Sheet No. 6.021.

<u>PAYMENT OF BILLS</u>: See Sheet No. 6.022.

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

SCHEDULE: IST

AVAILABLE: Entire Service Area.

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

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

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

Basic Service Charge:

Primary Metering Voltage	$ 627.06
Subtransmission Metering Voltage	$2,391.29

Demand Charge:
$1.99 per KW of billing demand

Energy Charge:
2.524¢ per KWH

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Continued from Sheet No. 6.340

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

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

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

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

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

POWER FACTOR: When the average power factor during the month is less than 85%, the monthly bill will be increased 0.202¢ for each kVARh by which the reactive energy numerically exceeds 0.619744 times the billing energy. When the average power factor during the month is greater than 90%, the monthly bill will be decreased 0.101¢ for each kVARh by which the reactive energy is numerically less than 0.484322 times the billing energy.

Continued to Sheet No. 6.350

Continued from Sheet No. 6.345

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

DELIVERY VOLTAGE CREDIT: When the customer furnishes and installs all subtransmission or higher voltage to utilization voltage substation transformation, a discount of 55¢ per KW of billing demand will apply.

EMERGENCY RELAY POWER SUPPLY CHARGE: The monthly charge for emergency relay power supply service shall be 78¢ per KW of billing demand. This charge is in addition to the compensation the customer must make to the Company as a contribution-in-aid of construction.

FUEL CHARGE: See Sheet Nos. 6.020 and 6.021.

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

CAPACITY CHARGE: See Sheet Nos. 6.020 and 6.021.

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

FLORIDA GROSS RECEIPTS TAX: See Sheet No. 6.021.

FRANCHISE FEE CHARGE: See Sheet No. 6.021.

PAYMENT OF BILLS: See Sheet No. 6.025.

Continued from Sheet No. 6.560

MONTHLY RATES:
Basic Service Charge: $15.12

Energy and Demand Charges: 5.182¢ per kWh (for all pricing periods)

MINIMUM CHARGE: The Basic Service Charge.

FUEL CHARGE: See Sheet Nos. 6.020 and 6.021.

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

CAPACITY CHARGE: See Sheet Nos. 6.020 and 6.021.

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

FLORIDA GROSS RECEIPTS TAX: See Sheet No. 6.021.

FRANCHISE FEE CHARGE: See Sheet No. 6.021.

PAYMENT OF BILLS: See Sheet No. 6.022.

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

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

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

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

Continued to Sheet No. 6.570

FIRM STANDBY AND SUPPLEMENTAL SERVICE

SCHEDULE: SBF

AVAILABLE: Entire service area.

APPLICABLE: Required for all self-generating Customers whose generating capacity in kilowatts (exclusive of emergency generation equipment) exceeds 20% of their site load in kilowatts and who take firm service from the utility. Also available to self-generating Customers whose generating capacity in kilowatts does not exceed 20% of their site load in kilowatts, but who agree to all the terms and conditions of this rate schedule. Resale not permitted.

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

LIMITATION OF SERVICE: A customer taking service under this tariff must sign a Tariff Agreement for the Purchase of Firm Standby and Supplemental Service. (See Sheet No. 7.600)

MONTHLY RATE:

Basic Service Charge:

Secondary Metering Voltage	$ 55.44
Primary Metering Voltage	$ 156.26
Subtransmission Metering Voltage	$1,023.26

CHARGES FOR STANDBY SERVICE:

Demand Charge:

$ 1.96 per kW-Month of Standby Demand
(Local Facilities Reservation Charge)

plus the greater of:

$ 1.56 per kW-Month of Standby Demand
(Power Supply Reservation Charge) or
$ 0.62 per kW-Day of Actual Standby Billing Demand
(Power Supply Demand Charge)

Energy Charge:

.921¢ per Standby kWh

Continued to Sheet No. 6.601

Continued from Sheet No. 6.600

CHARGES FOR SUPPLEMENTAL SERVICE:

Demand Charge:

$9.74	per kW-Month of Supplemental Billing Demand (Supplemental Billing Demand Charge)

Energy Charge:

1.596¢	per Supplemental kWh

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

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

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

BILLING UNITS:

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

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

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

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

Continued to Sheet No. 6.602

Continued from Sheet No. 6.601

Contract Standby Demand - As established pursuant to the Tariff Agreement for the Purchase of Firm Standby and Supplemental Service. Anytime a customer registers a Standby Demand that is higher than the existing Contract Standby Demand, that Standby Demand will become the new Contract Standby Demand, beginning with the following period.

Standby Demand - The greater of Contract Standby Demand or the amount by which Metered Demand exceeds Supplemental Billing Demand, but no greater than Normal Generation.

Actual Standby Billing Demand - The summation of the daily amounts by which the highest on-peak measured 30-minute interval kW demands served by the Company exceed the monthly Supplemental Billing Demand.

Energy Units: Energy provided by the Company during each 30-minute period up to the Supplemental Demand level shall be billed as Supplemental kWh. The remaining energy shall be billed as Standby kWh.

MINIMUM CHARGE: The Basic Service Charge, Local Facilities Reservation Charge, Power Supply Reservation Charge, and any Minimum Charge associated with optional riders.

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

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

POWER FACTOR: When the average power factor during the month is less than 85%, the monthly bill will be increased 0.202¢ for each kVARh by which the reactive energy numerically exceeds 0.619744 times the billing energy. When the average power factor during the month is greater than 90%, the monthly bill will be decreased 0.101¢ for each kVARh by which the reactive energy is numerically less than 0.484322 times the billing energy.

Continued to Sheet No. 6.603

Continued from Sheet No. 6.602

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

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

DELIVERY VOLTAGE CREDIT: When the customer takes service at primary voltage, a discount of 79¢ per kW of Supplemental Demand and 63¢ per kW of Standby Demand will apply.

When the customer takes service at subtransmission or higher voltage, a discount of $2.45 per kW of Supplemental Demand and $1.97 per kW of Standby Demand will apply.

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

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

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

CAPACITY CHARGE: See Sheet Nos. 6.020 and 6.021.

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

FLORIDA GROSS RECEIPTS TAX: See Sheet No. 6.021.

FRANCHISE FEE CHARGE: See Sheet No. 6.021.

PAYMENT OF BILLS: See Sheet No. 6.022.

TIME-OF-DAY
FIRM STANDBY AND SUPPLEMENTAL SERVICE
(OPTIONAL)

SCHEDULE: SBFT

AVAILABLE: Entire service area.

APPLICABLE: Required for all self-generating Customers whose generating capacity in kilowatts (exclusive of emergency generation equipment) exceeds 20% of their site load in kilowatts and who take firm service from the utility. Also available to self-generating Customers whose generating capacity in kilowatts does not exceed 20% of their site load in kilowatts, but who agree to all the terms and conditions of this rate schedule. Resale not permitted.

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

LIMITATION OF SERVICE: A Customer taking service under this tariff must sign a Tariff Agreement for the Purchase of Firm Standby and Supplemental Service. (See Sheet No. 7.600)

MONTHLY RATE:

Basic Service Charge:

Secondary Metering Voltage	$ 55.44
Primary Metering Voltage	$ 156.26
Subtransmission Metering Voltage	$1,023.26

CHARGES FOR STANDBY SERVICE:

Demand Charge:

$ 1.96 per kW-Month of Standby Demand
(Local Facilities Reservation Charge)

plus the greater of:

$ 1.56 per kW-Month of Standby Demand
(Power Supply Reservation Charge) or

$ 0.62 per kW-Day of Actual Standby Billing Demand
(Power Supply Demand Charge)

Energy Charge:

.921¢ per Standby kWh

Continued to Sheet No. 6.606

Continued from Sheet No. 6.605

CHARGES FOR SUPPLEMENTAL SERVICE

Demand Charge:

$3.28	per kW-Month of Supplemental Demand (Supplemental Billing Demand Charge), plus
$6.45	per kW-Month of Supplemental Peak Demand (Supplemental Peak Billing Demand Charge)

Energy Charge:

2.922¢	per Supplemental kWh during peak hours
1.055¢	per Supplemental kWh during off-peak hours

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

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

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

BILLING UNITS:

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

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

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

Continued to Sheet No. 6.607

Continued from Sheet No. 6.607

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

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

POWER FACTOR: When the average power factor during the month is less than 85%, the monthly bill will be increased 0.202¢ for each kVARh by which the reactive energy numerically exceeds 0.619744 times the billing energy. When the average power factor during the month is greater than 90%, the monthly bill will be decreased 0.101¢ for each kVARh by which the reactive energy is numerically less than 0.484322 times the billing energy.

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

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

DELIVERY VOLTAGE CREDIT: When the customer takes service at primary voltage, a discount of 79¢ per kW of Supplemental Demand and 63¢ per kW of Standby Demand will apply.

When the customer takes service at subtransmission or higher voltage, a discount of $2.45 per kW of Supplemental Demand and $1.97 per kW of Standby Demand will apply.

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

Continued to Sheet No. 6.609

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

SCHEDULE: SBI

AVAILABLE: Entire service area.

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

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

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

MONTHLY RATE:

Basic Service Charge:

Primary Metering Voltage	$652.26
Subtransmission Metering Voltage	$2,416.50

Demand Charge:

$1.99 per KW-Month of Supplemental Demand (Supplemental Demand Charge)
$1.47 per KW-Month of Standby Demand (Local Facilities Reservation Charge)

plus the greater of:
$1.21 per KW-Month of Standby Demand (Power Supply Reservation Charge); or
$0.48 per KW-Day of Actual Standby Billing Demand (Power Supply Demand Charge)

Continued to Sheet No. 6.705

Continued from Sheet No. 6.700

Energy Charge:
2.524¢ per Supplemental KWH
1.015¢ per Standby KWH

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

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

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

BILLING UNITS:

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

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

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

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

Continued to Sheet No. 6.710

Continued from Sheet No. 6.710

POWER FACTOR: When the average power factor during the month is less than 85%, the monthly bill will be increased 0.202¢ for each kVARh by which the reactive energy numerically exceeds 0.619744 times the billing energy. When the average power factor during the month is greater than 90%, the monthly bill will be decreased 0.101¢ for each kVARh by which the reactive energy is numerically less than 0.484322 times the billing energy.

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

DELIVERY VOLTAGE CREDIT: When the customer furnishes and installs all subtransmission or higher voltage to utilization voltage substation transformation, a discount of 55¢ per KW of Supplemental Demand and 34¢ per KW of Standby Demand will apply.

EMERGENCY RELAY POWER SUPPLY CHARGE: The monthly charge for emergency relay power supply service shall be 78¢ per KW of Supplemental Demand and Standby Demand. This charge is in addition to the compensation the customer must make to the Company as a contribution-in-aid of construction.

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

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

CAPACITY CHARGE: See Sheet Nos. 6.020 and 6.021.

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

FLORIDA GROSS RECEIPTS TAX: See Sheet No. 6.021.

FRANCHISE FEE CHARGE: See Sheet No. 6.021.

PAYMENT OF BILLS: See Sheet No. 6.022.

Continued from Sheet No. 6.800

MONTHLY RATE:

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

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

[1] Closed to new business
[2] Lumen output may vary by lamp configuration and age.
[3] Wattage ratings do not include ballast losses.
[4] The Base Energy charges are calculated by multiplying the kWh times the lighting base energy rate of 2.494¢ per kWh for each fixture.

Continued to Sheet No. 6.806

Continued from Sheet No. 6.805

MONTHLY RATE:

Metal Halide Fixture, Maintenance, and Base Energy Charges:

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

[1] Closed to new business
[2] Lumen output may vary by lamp configuration and age.
[3] Wattage ratings do not include ballast losses.
[4] The Base Energy charges are calculated by multiplying the kWh times the lighting base energy rate of 2.494¢ per kWh for each fixture.

Continued to Sheet No. 6.808

Continued from Sheet No. 6.806

MONTHLY RATE:

LED Fixture, Maintenance, and Base Energy Charges:

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

(1) Closed to new business
(2) Average
(3) Average wattage. Actual wattage may vary by up to +/- 5 watts.
(4) The Base Energy charges are calculated by multiplying the kWh times the lighting base energy rate of 2.494¢ per kWh for each fixture.

Continued to Sheet No. 6.810

Continued from Sheet No. 6.808

MONTHLY RATE:

LED Fixture, Maintenance, and Base Energy Charges:

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

(1) Average
(2) Average wattage. Actual wattage may vary by up to +/- 10 %.
(3) The Base Energy charges are calculated by multiplying the kWh times the lighting base energy rate of 2.494¢ per kWh for each fixture.
(4) Enhanced Post Top. Customizable decorative options

Continued to Sheet No. 6.810

Continued from Sheet No. 6.810

Miscellaneous Facilities Charges:

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

NON-STANDARD FACILITIES AND SERVICES:

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

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

MINIMUM CHARGE: The monthly charge.

FUEL CHARGE: See Sheet Nos. 6.020 and 6.021.

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

CAPACITY CHARGE: See Sheet Nos. 6.020 and 6.021

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

FLORIDA GROSS RECEIPTS TAX: See Sheet No. 6.021

FRANCHISE FEE: See Sheet No. 6.021

PAYMENT OF BILLS: See Sheet No. 6.022

SPECIAL CONDITIONS:
On customer-owned public street and highway lighting systems not subject to other rate schedules, the monthly rate for energy served at primary or secondary voltage, at the company's option, shall be 2.494¢ per kWh of metered usage, plus a Basic Service Charge of $10.57 per month and the applicable additional charges as specified on Sheet Nos. 6.020 and 6.021.

Continued to Sheet No. 6.820

Continued from Sheet No. 8.061

CHARGES/CREDITS TO QUALIFYING FACILITY

A. Basic Service Charges

A monthly Basic Service Charge will be rendered for maintaining an account for a Qualifying Facility engaged in either an As-Available Energy or Firm Capacity and Energy transaction and for other applicable administrative costs. Actual charges will depend on how the QF is interconnected to the Company.

QFs not directly interconnected to the Company, will be billed $990 monthly as a Basic Service Charge.

Monthly Basic Service charges, applicable to QFs directly interconnected to the Company, by Rate Schedule are:

Rate Schedule	Basic Service Charge ($)	Rate Schedule	Basic Service Charge ($)
RS	15.12	GST	20.16
GS	18.14	GSDT (secondary)	30.25
GSD (secondary)	30.25	GSDT (primary)	131.06
GSD (primary)	131.06	GSDT (subtrans.)	998.05
GSD (subtrans.)	998.05	SBFT (secondary)	55.44
SBF (secondary)	55.44	SBFT (primary)	156.26
SBF (primary)	156.26	SBFT (subtrans.)	1,023.26
SBF (subtrans.)	1,023.26	IST (primary)	627.06
IS (primary)	627.06	IST (subtrans.)	2,391.29
IS (subtrans.)	2,391.29		
SBI (primary)	652.26		
SBI (subtrans.)	2,416.50		

When appropriate, the Basic Service Charge will be deducted from the Qualifying Facility's monthly payment. A statement of the charges or payments due the Qualifying Facility will be rendered monthly. Payment normally will be made by the twentieth business day following the end of the billing period.

Continued to Sheet No. 8.071

Continued from Sheet No. 8.308

Should the CEP elect a Net Billing Arrangement, the hourly net capacity and energy sales delivered to the purchasing utility shall be purchased at the utility's avoided capacity and energy rates, where applicable, in accordance with FPSC Rules 25-17.0825 and 25-17.0832, F.A.C. Purchases from the interconnecting utility shall be billed at the retail rate schedule, under which the CEP load would receive service as a customer of the utility.

Although a billing option may be changed in accordance with FPSC Rule 25-17.082, F.A.C., the Contracted Capacity may only change through mutual negotiations satisfactory to the CEP and the Company.

Basic Service charges that are directly attributable to the purchase of firm capacity and energy from the CEP are deducted from the CEP's total monthly payment. A statement covering the charges and payments due the CEP is rendered monthly and payment normally is made by the 20th business day following the end of the Monthly Period.

CHARGES/CREDITS TO THE CEP:

1. **Basic Service Charges:** A monthly Basic Service Charge will be rendered for maintaining an account for the CEP engaged in either an As-Available Energy or firm capacity and energy transaction and for other applicable administrative costs. Actual charges will depend on how the CEP is interconnected to the Company.

   CEPs not directly interconnected to the Company, will be billed $990 monthly as a Basic Service Charge.

   Monthly Basic Service charges, applicable to CEPs directly interconnected to the Company, by Rate Schedule are:

RATE SCHEDULE	BASIC SERVICE CHARGE ($)	RATE SCHEDULE	BASIC SERVICE CHARGE ($)
RS	15.12		
GS	18.14	GST	20.16
GSD (secondary)	30.25	GSDT (secondary)	30.25
GSD (primary)	131.06	GSDT (primary)	131.06
GSD (subtrans.)	998.05	GSDT (subtrans.)	998.05
SBF (secondary)	55.44	SBFT (secondary)	55.44
SBF (primary)	156.26	SBFT (primary)	156.26
SBF (subtrans.)	1,023.26	SBFT (subtrans.)	1,023.26
IS (primary)	627.06	IST (primary)	627.06
IS (subtrans.)	2,391.29	IST (subtrans.)	2,391.29
SBI (primary)	652.26		
SBI (subtrans.)	2,416.50		

Continued to Sheet No. 8.314

BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 20180045-EI

IN RE: CONSIDERATION OF THE TAX IMPACTS ASSOCIATED WITH TAX CUTS AND JOBS ACT OF 2017 FOR TAMPA ELECTRIC COMPANY

DIRECT TESTIMONY AND EXHIBIT
OF
ALAN D. FELSENTHAL
ON BEHALF OF
TAMPA ELECTRIC COMPANY

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

ALAN D. FELSENTHAL

ON BEHALF OF TAMPA ELECTRIC COMPANY

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

A. My name is Alan D. Felsenthal. My business address is One North Wacker Drive, Chicago, Illinois 60606. I am a Managing Director at PricewaterhouseCoopers LLP ("PwC").

Q. Please describe your educational background and business experience.

A. I was graduated from the University of Illinois in 1971 and began my career at Arthur Andersen & Co ("Arthur Andersen"), where I was an auditor, and focused on audits of financial statements of regulated entities. In 2002, I joined PricewaterhouseCoopers and became a Managing Director in their Utilities Group and continued performing audits for regulated entities. I was hired by Huron Consulting Group ("Huron") in 2008 and returned to PwC in November of 2010.

At both Arthur Andersen and PwC, I supervised audits of financial statements on which the firms issued audit opinions that were filed with the SEC, the Federal Communications Commission, the Federal Energy Regulatory Commission (“FERC”) and various state commissions. At Arthur Andersen, PwC and Huron, I consulted on a significant number of utility rate cases and helped develop testimony for myself and others on a variety of issues, including construction work in progress in rate base, projected test years, lead-lag studies, cost allocation, several accounting issues (e.g., pension accounting, regulatory accounting, income tax accounting, cost of removal) and compliance with the income tax normalization requirements.

Q. Please describe your duties and responsibilities at PwC.

A. I lead PwC’s regulatory support practice. Throughout my career, my focus has been on the regulated industry sector, primarily electric, gas, telecommunication and water utilities. I have focused on utility accounting, income tax and regulatory issues, primarily as a result of auditing regulated entities. The unique accounting standards applicable to regulated entities embodied in Accounting Standards Codification ("ASC") 980, Regulated Operations (formerly, Statement of Financial Accounting Standards ("SFAS") 71, FAS 90, FAS 92, FAS 101 and various Emerging

Issues Task Force ("EITF") issues, all need to be understood so that auditors can determine whether a company's financial statements are fairly presented in accordance with generally accepted accounting principles. I have witnessed the issuance of these standards and have consulted with utilities as to how they should be applied. At both Arthur Andersen and PwC, I worked with the technical industry, accounting and auditing leadership to communicate and consult on utility accounting and audit matters.

Q. Have you provided training on the application of Generally Accepted Accounting Principles ("GAAP") to regulated entities?

A. Yes. At Arthur Andersen, Huron and PwC, I developed and taught utility accounting seminars focusing on the unique aspects of the regulatory process and the resulting accounting consequences of the application of GAAP, including accounting and ratemaking for income taxes. I have presented seminars, as well as delivered training on an in-house basis. Seminar participants have included utility company and regulatory commission staff accountants, utility rate departments and internal auditors, tax accountants and others. I have also conducted these seminars for the FERC and several state commissions, and I have presented at various Edison Electric Institute and American Gas Association ratemaking and accounting seminars. The income tax training programs I have presented include topics such as the normalization requirements for public utilities in the Internal Revenue Code (“IRC”), protected and unprotected deferred taxes and the mechanics and application of the Average Rate Assumption Method (“ARAM”).

Q. Have you previously testified before the Florida Public Service Commission (“FPSC” or “Commission”)?

A. Yes. I have testified or filed testimony before this Commission in two dockets. The first was in connection with Central Telephone Company’s rate case filing in Docket No. 19891246-TL, in which I testified on the Company’s approach to determining their projected test year. I next testified in Tampa Electric’s Docket No. 20080317-El on the subject of income taxes.

Q. Have you previously testified before other government entities with regulatory authority over regulated telecommunications, electric or gas companies?

A. Yes. I have testified before the Arizona Corporation

Commission, the Illinois Commerce Commission, the Indiana Utility and Regulatory Commission, the Public Utility Commission of Ohio, the Public Utility Commission of Texas and the Washington Utilities and Transportation Commission on various utility ratemaking topics, including accounting and ratemaking for income taxes.

Q. What are the purposes of your direct testimony in this proceeding?

A. The purposes of my direct testimony are to: (1) discuss accounting for income taxes for public utilities like Tampa Electric Company ("company" or "Tampa Electric") and related ratemaking principles, (2) describe the recent changes caused by the Tax Cuts and Jobs Act of 2017 ("TCJA") and their general impact on regulated utilities, (3) explain the ratemaking requirement in the TCJA for "protected excess deferred taxes" and (4) describe the work PwC performed to test the company's calculation of the impact of the TCJA on the company's 2018 income tax expense.

Q. Did you prepare an exhibit in support of your direct testimony?

A. Yes. Exhibit No. ___ (ADF-1) was prepared under my direction and supervision. My exhibit consists of the following two documents:

Document No. 1 Depreciation Timing Difference Example

Document No. 2 ARAM Illustration

Q. As part of your work for Tampa Electric in this docket, have you read the documents referred to as the 2017 Agreement and Amended Implementation Stipulation in the prepared direct testimony of Mr. Jeffrey S. Chronister?

A. Yes, I have. I also read all of Mr. Chronister’s prepared direct testimony and exhibits as well as the prepared direct testimony and exhibits of company witnesses Valerie Strickland and William R. Ashburn.

Q. Please summarize your direct testimony.

A. After providing a framework for the accounting and regulatory treatment of income taxes and the impacts of the TCJA, I discuss how Tampa Electric’s proposal to reflect the effects of the TCJA from an accounting perspective is consistent and accurate and complies with both the 2017 Agreement and Amended Implementation Stipulation as well as the IRC’s normalization requirements applicable to public utility property.

Accounting for Income Taxes
and Related Ratemaking Principles

Q. Can you please describe the accounting for income taxes required under GAAP?

A. Yes. Accounting for income taxes under GAAP is contained in the accounting literature in section ASC 740 (formerly SFAS No. 109, Accounting for Income Taxes) of the accounting codification. There are three major components to the calculation: currently payable income taxes; deferred income taxes, and investment tax credits.

Q. Please describe the first component, currently payable income taxes.

A. Currently payable income tax expense represents the estimated amount of current year income taxes payable based on current year taxable income. Taxable income for the year is determined in accordance with the IRC. For purposes of preparing an income tax return each year, the IRC contains procedures for determining if and when an item is “taxable” or “deductible.” After considering the taxable and deductible amounts in the current year, “taxable income” is determined, which is then multiplied by the applicable statutory tax rate. This subtotal is further adjusted for any available income tax “credits.”

The result of calculating the amounts to be included on the annual tax return using the guidance in the IRC is a journal entry to record current income tax expense and current income tax payable.

Q. Are the IRC rules for determining what is taxable or deductible for completing the tax return the same as the GAAP rules for determining what items constitute revenues, income and expenses for the year?

A. No. The IRC rules for determining what is taxable or deductible often differ from what is reportable as revenue, income or expense under GAAP. For instance, certain expenses recorded on the financial statements under GAAP in one period may be deductible on the tax return in a different period. There are also instances where the amounts shown as deductions on the tax return in one period are not reflected on the financial statements until a later period. As a result, at the end of each reporting period, there will likely be accumulated differences of reported assets and liabilities resulting from different book treatment as opposed to tax return treatment of revenues, income and expenses.

The differences each year between book and tax return recognition are referred to as either “timing/temporary differences” or “permanent differences”, with the vast majority being of a timing/temporary nature.

Q. What is the distinction between a timing/temporary difference and a permanent difference?

A. A timing/temporary difference will enter into the determination of book/financial income (revenue, income or expense) in one period and into the determination of taxable income on the tax return (revenue, income/deduction) in another period. Over time, however, the total amount will ultimately enter into each statement equally. A permanent difference will enter into the determination of either book income or taxable income in one period but will not be included in the other.

Q. Can you further explain what is meant by a timing/temporary difference and provide some examples?

A. Yes. One common timing/temporary difference is depreciation. For book purposes, when a company acquires a fixed asset, GAAP requires that the asset be depreciated over its estimated useful life in a systematic and rational manner. The cost of the fixed asset is "allocated" to the periods in which the fixed asset is being used to provide service. The annual allocation is known as depreciation expense. Most utilities, like Tampa Electric, depreciate their fixed assets for book purposes using the straight-line depreciation method. This method of calculating depreciation is different than the accelerated depreciation approach commonly used for determining the depreciation deduction on an income tax return. For income tax purposes that same asset may be depreciated for determining taxable income on the income tax return using an accelerated depreciation method or a different (generally shorter) estimated useful life permitted under the IRC.

When the annual depreciation charge for book purposes is compared to the annual depreciation for income tax purposes, there will likely be differences. In the early years of an asset’s life, tax depreciation will exceed book depreciation. In the later years, the reverse will be true because given the same capitalized asset cost, over the life of the asset, total depreciation will be the same.

The sum of the annual depreciation differences results in accumulated depreciation differences when comparing the net book value and net tax value of fixed assets. As I will discuss later, it is important to understand that for any fixed asset book-tax depreciation difference there will be a period of time where tax depreciation is greater than book depreciation, and at some point, the reverse will occur and book depreciation will exceed tax depreciation. This pattern exists because the same amount (the fixed asset amount) will eventually be fully depreciated for tax purposes and book purposes.

Q. Can you provide an example of how depreciation book-tax differences arise and reverse?

A. Yes. An example of this is included in Document No. 1 of my exhibit. This example assumes that a utility acquires property, plant and equipment with an estimated useful life of 10 years for $10.0 million cash and, for simplicity, ignores salvage value and cost of removal. It also assumes that the asset qualifies under the IRC for a five-year tax depreciation using the Modified Accelerated Cost Recovery System (“MACRS”).

The entry to record the acquisition of the asset is to debit property, plant and equipment and to credit cash. Using the straight-line method for book depreciation, the company would record $1.0 million of depreciation expense in its financial statements each year of useful life of the asset. Under MACRS for a five-year asset, the tax depreciation deduction is 20 percent the first year, 32 percent in year two, 19.2 percent in year three, 11.52 percent in years four and five and 5.76 percent in year six. Six years are included in the MACRS table as the assumption of one-half year depreciation in the first and last years are considered. The annual depreciation charges for book and tax are shown on Document No. 1 of my exhibit.

At the end of year 1, the net basis of the asset for book purposes would be $9.0 million ($10.0 million gross plant, less $1.0 million of accumulated book depreciation) while its tax basis would be $8.0 million ($10.0 million gross tax basis less $2.0 million of accumulated tax depreciation). Each year's book depreciation expense would reduce the net book basis of the asset and each year's tax depreciation would affect the tax basis of the asset. The difference between the book basis and tax basis of the asset represents a temporary difference under ASC 740.

However, because total depreciation expense/deductions are limited to the gross capitalized cost of the asset, accelerated income tax depreciation claimed in the early years (reducing income tax payments) will reverse in subsequent periods when book depreciation exceeds tax depreciation (increasing income tax payments) so that when the asset is retired, the depreciation temporary difference will have completely reversed. In this example, the reversal begins in year six because, during that year, book depreciation begins to exceed tax depreciation and that result continues until the book life ends.

Q. What are the accounting requirements for timing/temporary differences under ASC 740?

A. Under GAAP, particularly ASC 740, financial statements are required to assign the income tax benefits/expenses to the period in which the associated book income/expense is recorded, and therefore deferred income taxes are recorded on timing/temporary differences. As a result, income tax expense under GAAP includes both a currently payable component (as previously described, based on the tax return) as well as a "deferred" income tax component (based on timing/temporary differences).

To determine current tax expense and taxes currently payable for the year, the company will use the guidance for taxable income and tax deductions in the IRC, arriving at taxable income, applying the current income tax rate to that amount and consider any income tax credits. The result is recorded by the following journal entry:

Current Income Tax Expense	**$XXX,XXX**	
Currently Payable Income Taxes		**$XXX,XXX**

Q. What is the second component of the income tax calculation?

A. The second component of the income tax calculation is deferred income tax. To calculate this component, the revenue, income and deductible items that enter into the determination of taxable income are compared to those same items as shown on the company's income statement. Where an item has reduced taxable income in an amount greater than the book amount, current income taxes are decreased. But when that additional amount shown on the tax return is an originating timing/temporary difference, the company will record a deferred tax expense. In each case, a deferred tax asset or deferred tax liability is recorded to recognize that there will be a future reversal of that timing/temporary difference. The currently enacted income tax rate will be used to measure the deferred income tax of an originating book-tax difference. The entry to record the deferred tax impacts of a timing/temporary differences is:

Deferred Income Tax Expense $XXX,XXX

Accumulated Deferred Income Taxes $XXX,XXX

Q. What do deferred income taxes represent?

A. Deferred income taxes reflect the liability or asset for income taxes payable or receivable in the future stemming from transactions recorded in the financial statements currently. The sum of the annual deferred tax provisions results in a balance sheet liability or asset referred to as Accumulated Deferred Income Taxes ("ADIT"). In other words, to the extent that accelerated tax depreciation is claimed on the income tax return in an amount that exceeds book depreciation reported on the financial statements, a liability for future taxes results. This future tax liability is due to the fact that greater depreciation claimed in early years will "use up" the tax basis of assets at which point book depreciation will exceed tax depreciation resulting in higher taxes in the future.

For regulated entities, such as Tampa Electric, the process of recording deferred income taxes on temporary differences is referred to as "normalization", "deferred tax accounting," or “comprehensive inter-period income tax allocation.”

Q. Can you please explain how current and deferred income taxes would be recorded on the financial statements for the depreciation difference example you discussed previously?

A. Yes. In year 1 of the example, the company would record on its books depreciation expense of $1.0 million in accordance with GAAP. In that same year, they would reduce taxable income on the income tax return by $2.0 million. Assuming a 35 percent income tax rate, by claiming a $2.0 million depreciation deduction, *current* taxes payable and *current* tax expense would be reduced by $700,000 (35 percent income tax rate times the $2.0 million tax depreciation deduction).

However, by claiming an additional $1.0 million of tax depreciation ($2.0 million tax depreciation compared to $1.0 million of book depreciation) the company will also record a *deferred* income tax liability and *deferred* tax expense of $350,000 (35 percent income tax rate times the book-tax difference of $1.0 million). The deferred tax will begin becoming payable when the book depreciation exceeds tax depreciation. In other words, by claiming accelerated depreciation (compared to straight line book depreciation) in years 1-5, the company has incurred a deferred tax obligation that will become payable in years 6-10.

Q. Does claiming deductions for income tax purposes in excess of expenses recorded for book purposes provide incentives to the company that benefit customers?

A. Yes. By claiming tax deductions using accelerated depreciation, the company reduces its current income tax payments, but tax payments will be higher in the future when the temporary differences reverse. As a result, ADIT balances are often referred to as "interest free loans" from the U.S. Treasury. This was the objective Congress intended when it included accelerated depreciation provisions in the IRC. Congress believed that allowing companies to increase their tax depreciation deductions (and thereby reduce current income tax payments), would lower the financing costs of investments in capital assets and, therefore, companies would be incented to make such expenditures.

Q. Can you give an example of a book-tax difference that is permanent?

A. Yes. Certain items of revenue, income and expense are, over time, treated differently for financial reporting purposes than for income tax purposes and are included in only one of either taxable income or financial reporting income.

These are referred to as permanent differences.

An example of a permanent difference is the cost of meals and entertainment. These costs are reported as expenses in the financial statements for a given period, but, based on the IRC, are not completely deductible in determining taxable income on the income tax return. Thus, over time, the financial statement reporting of meals and entertainment expenses will differ from the related amounts on the income tax return.

Deferred income taxes are not required on permanent differences because the difference will never reverse, it is "permanent." In the case of meals and entertainment costs, in the period reported, current income taxes will be adjusted to reflect the non-deductibility of these costs and there will be no deferred income taxes since these amounts, under the current IRC, will never be deducted on the tax return.

Q. Is the distinction between permanent and temporary differences important in the income tax calculation?

A. Yes. Because permanent differences do not require deferred income tax accounting, the income tax effects of such items increase or decrease total income tax expense. With timing differences, each and every item that impacts current income tax expense has an equal and offsetting impact to deferred income tax expense. Because total income tax expense affects net income under GAAP and total income tax expense must be recovered in a rate case, permanent differences need to be separately identified and included in the income tax calculation.

Q. Please explain the third component, tax credits.

A. Tax credits, such as the investment tax credit, are direct offsets against taxes otherwise payable. The investment tax credit is calculated by applying a percentage to investments in property, plant and equipment, effectively reducing the net expenditure on such investment. For expenditures on public utility property, the journal entry to record the investment tax credit when claimed is:

Currently Payable Income Taxes	**$XXX,XXX**		
		Unamortized Investment Tax Credits	**$XXX,XXX**

The unamortized investment tax credit is then amortized over the book lives of the property giving rise to the investment tax credit:

Unamortized Investment Tax Credits	**$XX,XXX**
Income Tax Expense	**$XX,XXX**

In this manner, the investment tax credit is deferred on the balance sheet when realized and allocated to the income statement as the property is being depreciated. The accounting and ratemaking treatment of the investment tax credit was not directly impacted by the TCJA.

Ratemaking Treatment of Income Taxes

Q. Is deferred income tax accounting appropriate for ratemaking purposes?

A. Yes. Income tax expense in a given year is the result of that year's economic activity. In determining the revenue requirement, it is important for regulatory commissions to consider the recovery of all appropriate costs of providing service, including the associated income tax effects of the costs.

During the ratemaking process, regulators consider all items of revenues, income and expenses and makes a finding as to whether the individual revenues, income and expenses should be allowed in the determination of revenue requirements. Once regulators determine the allowable costs excluding income taxes, the income tax consequences, both current and deferred, can be calculated. This is because income taxes do not exist independently. They are dependent on and result from a determination of income and expenses. The revenue, income and expenses are generally determined on an accrual basis and the tax consequences of income and expenses must be determined on that same accrual basis (both current and deferred income taxes).

As I discussed earlier, the accelerated depreciation (the major component of deferred taxes for capital intensive entities such as Tampa Electric) of assets was meant to lower the cost of financing assets by providing the company an interest free loan. The ADIT balance (the interest free loan from the U.S. Treasury) is a zero-cost source of capital in the cost of capital computation thereby giving the benefit of reduced financing costs to ratepayers.

Q. Has the FERC taken a position on the appropriateness of deferred income tax accounting?

A. Yes. The FERC requires comprehensive inter-period income tax allocation for all book-tax timing/temporary differences. Orders 144 and 144A provide guidance in this area. This has been the FERC methodology since the early 1980's. The FERC Uniform System of Accounts ("FERC USOA") and many FERC rate orders require normalization.

Q. Has the FPSC taken a position on the appropriateness of deferred income tax accounting?

A. Yes. The FPSC has long acknowledged that normalization is appropriate for revenues, income and expenses that are recognized at different times for book and tax purposes.

Q. Does the IRC contain requirements addressing deferred income tax accounting?

A. Yes. The IRC contains specific requirements that are applicable to the use of accelerated depreciation on public utility property. These requirements, called the “normalization requirements,” mandate that in order for a public utility to be eligible to claim accelerated depreciation for income tax purposes, the regulator must permit recovery of deferred income taxes on the difference resulting from using accelerated depreciation for income tax purposes and straight-line depreciation for book purposes.

The penalty for violating the normalization requirements is the loss of the ability to claim accelerated depreciation for income tax purposes on all assets as of the violation date and on subsequent additions. It is a severe penalty.

Q. How do the terms "protected" and "unprotected" deferred income taxes relate to the normalization requirements for public utility property under the IRC?

A. The income tax normalization requirements in the IRC pertain to accelerated depreciation on public utility property, excess ADIT and investment tax credits. Certain contributions in aid of construction must also be normalized. Book-tax differences that require the provision of deferred taxes, as well as appropriate treatment of the resulting ADIT, are known as "protected" accumulated deferred taxes. Book-tax differences where deferred tax expense is not required to be applied in the ratemaking process are called "unprotected."

Q. Document No. 4 in Exhibit No. ___ (VS-1) of Tampa Electric witness Valerie Strickland includes a presentation of the company's income tax calculation in the format required for Minimum Filing Requirement Schedule C-22. Referring to that document, can you identify which book-tax differences are protected and which are unprotected?

A. Yes. Witness Strickland's Document No. 4 in Exhibit No. ___ (VS-1) lists the individual book-tax differences which gave rise to the ADIT balances recorded as of December 31, 2017. The protected ADIT's relate to accelerated depreciation and are described as:

- o ADIT related to differences caused by using straight-line depreciation for determining book depreciation and an accelerated depreciation method for determining tax depreciation (method difference).
- o ADIT related to differences caused by using shorter depreciation lives for determining tax depreciation than for determining book depreciation (life difference).
- o ADIT related to contributions in aid of construction (CIAC) which are included as taxable income when received with the contribution providing a depreciable basis and future tax depreciation deductions.

In short, depreciation related method and life differences are considered "protected." All other temporary book-tax differences are considered "unprotected."

Q. Does the distinction between protected and unprotected ADIT matter under the Tax Cuts and Jobs Act of 2017?

A. Yes. The distinction between protected ADIT and unprotected ADIT is critical. The Tax Cuts and Jobs Act of 2017 (the "TCJA") contains specific language on how excess ADIT relating to protected ADIT is to be treated in order to avoid a normalization violation. Similar guidance does not exist for excess unprotected ADIT. I will discuss these provisions later in my direct testimony.

Tax Cuts and Jobs Act of 2017

Q. Please generally describe the Tax Cuts and Jobs Act of 2017.

A. The TCJA was enacted by the United States Congress on December 20, 2017 and was signed into law by the President on December 22, 2017. *See Tax Cuts and Jobs Act of 2017*, Pub. Law 115-97, 131 Stat. 2054 (2017). The TCJA amends the IRC and is the most significant set of changes to the federal income tax laws since the Tax Reform Act of 1986. The TCJA makes major changes in many areas of our nation's tax laws, some of which directly affect regulated utilities like Tampa Electric.

Q. What are the most significant parts of the TCJA for regulated utilities?

A. Although there may be other portions of the TCJA that may have some effect on regulated utilities, the most significant changes in the TCJA to regulated utilities and their ratepayers can be summarized as follows:

(a) The TCJA reduces the federal corporate income tax rate from 35 percent to 21 percent effective January 1, 2018.

(b) The TCJA exempts regulated utilities from the immediate expensing of certain capital additions and applies the MACRS rules to regulated utility property additions, without a provision for “bonus” (accelerated) tax depreciation.

(c) The TCJA exempts regulated utilities from an interest deductibility limitation.

(d) The TCJA retains the corporate deduction for state and local taxes.

(e) The TCJA includes normalization provisions for public utility property that requires application of the ARAM to the flowback of “protected” excess deferred income taxes.

(f) The TCJA leaves unchanged the 2015 renewable credit tax arrangement and the Electric Vehicle tax credit.

(g) The TCJA eliminates the Alternative Minimum Tax.

(h) The TCJA eliminates the Section 199 manufacturing deduction.

Q. Please describe the provisions of the TCJA that will have the greatest impact on regulated utilities like Tampa Electric and their customers.

A. The TCJA will have significant, though varying impacts on most utilities in terms of reported tax expenses charged against the company’s operations, cash flows and the calculation of revenue requirements and cost of service.

The most significant provision of the TCJA for regulated utilities, including Tampa Electric, is the reduction of the Federal Income Tax Rate from 35 percent to 21 percent, which will reduce current income tax expense and originating deferred tax expense. As a result of the lower 21 percent income tax rate becoming effective under the TCJA, all companies, including public utilities, were required under ASC 740 to “remeasure,” as of December 31, 2017, the amounts of ADIT in their financial statements. Regulated utilities reclassified the reduction in ADIT to a regulatory liability representing the excess ADIT that will be used to reduce future revenue requirements.

The loss of bonus tax depreciation on plant additions going forward will also have a significant impact with regulated utilities now limited to MACRS, with no bonus tax depreciation, reducing the amount of available ADIT.

Some of the TCJA effects will occur immediately while others will occur over time. However, in each of these cases, cash flow decreases.

Q. Can you explain how the reduction in the federal corporate income tax rate will affect Tampa Electric’s current and deferred income taxes, including excess ADIT?

A. Yes. The Federal corporate tax rate is reduced from 35 percent to 21 percent for tax years beginning after January 1, 2018. At a 35 percent tax rate, revenue of $1.5385 was required to provide $1.00 of after-tax income. A corporate tax rate of 21 percent requires $1.2685 of revenue to generate $1.00 of after tax income. This reduction in the cash outflow from the company to the U.S. Treasury to pay currently payable income taxes is offset by reduced cash flows (revenue requirements) from ratepayers.

With respect to deferred Federal income taxes, those related to originating book-tax differences will be provided and collected at 21 percent rather than at 35 percent. Therefore, there will be reduced cash inflow because, at a 21 percent tax rate, for every $100 of accelerated depreciation or other book-tax difference, a utility will now have an interest-free loan from the U.S. Treasury of $21 compared to $35 under the previous income tax rate. However, initially there is no corresponding reduction in cash outflow from the company.

With respect to reversing book-tax differences, there will be no change in cash flow because the effects of reversing book-tax differences will continue to be computed and passed onto ratepayers at the tax rate used when the book-tax difference originated (generally 35 percent).

The effect of this reduced cash inflow will be an increase in outside financing requirements. The substitution of investor supplied capital having a financing cost of more than zero for interest-free ADIT will likely increase the company's overall cost of capital.

The TCJA continues the normalization requirements that deferred income taxes must be provided on depreciation timing/temporary differences between the financial statements and the tax return. The Federal ADIT on the company's books as of December 31, 2017 were, in most cases, stated at 35 percent of the related timing/temporary difference. For regulatory or ratemaking purposes, the reversals of the ADIT are credited to income as the related timing/temporary difference reverse, and that credit to income is computed as 35 percent of the reversing timing/temporary difference. The amount credited to income in future years with respect to all Federal ADIT at December 31, 2017 will not change as a result of the TCJA. In fact, the TCJA affirms the existing accounting for timing/temporary difference reversals as to ADIT related to protected book-tax differences (depreciation method and life timing differences, CIAC) by requiring that these ADIT be flowed back in rates and on the books using the ARAM.

Q. How is the ARAM computed?

A. The ARAM requires the development of an average rate which is determined by dividing the aggregate normalized protected timing/temporary differences into the ADIT that have been provided on such timing/temporary differences. The average rate so calculated is applied to reversing timing differences to derive the deferred taxes that are credited to income tax expense. Under this approach, protected ADIT are reduced over the remaining lives of the property which gave rise to the ADIT as the timing/temporary differences reverse. Public utilities must take care to properly apply the ARAM to protected ADIT because a normalization violation could occur if the amount of protected excess ADIT is reduced more rapidly or to a greater extent than under the ARAM.

The normalization violation would result in an increase in current income taxes payable for the amount of the more rapid reduction plus, more importantly, accelerated depreciation methods could not be used for income tax purposes going forward. Rather, book depreciation would have to be used for income tax purposes.

Q. What are "excess" ADIT and how are they calculated?

A. Excess ADIT means the ADIT balance existing immediately prior to the reduction in the corporate tax rate less the amount that would have been in the ADIT balance had that balance been determined using the revised lower corporate income tax rate.

Q. Can you summarize the net impacts of the tax rate reduction on utility revenue requirements?

A. The net effect of the tax rate change on taxes currently payable is to decrease tax expense. The net effect of the tax rate change on deferred taxes is that the provision on originating book-tax differences would be reduced, the reversals of previously provided deferred income taxes would not be changed (continue to reverse such existing ADIT at the average rate they had been provided) and the amount of ADIT at the time of enactment would decline. The decline in this zero-cost source of capital will likely cause the weighted cost of capital to increase compared to the cost if the TCJA had not been enacted.

Q. Other than the reduction in tax rates which will have an effect on current and deferred income taxes, what is another impact of the TCJA for utilities such as Tampa Electric?

A. For capital intensive industries, the use of accelerated depreciation to determine the tax liability is significant. The TCJA allows many companies to deduct, for income tax purposes, significant portions (in some cases, all) of their capital expenditures. However, the utility industry is specifically excluded from being able to apply this provision. Instead, public utility property continues to be subject to the MACRS without a provision for bonus tax depreciation. Prior to the TCJA, the utility industry had been permitted to apply for bonus tax depreciation.

As a result of losing bonus tax depreciation, all else being equal, aggregate cash flow will decrease as taxes currently payable will be higher and the deferred provision and resulting ADIT will be lower. Since ADIT will be lower, the weighted cost of capital will be higher reflecting the replacement of zero-cost capital with investor funds containing a cost greater than zero.

Protected Excess Deferred Income Taxes

Q. Please provide more detail on how the TCJA prescribes the ratemaking treatment for "protected" excess deferred income taxes.

A. The TCJA requires that excess ADIT be reversed, over the lives of the related property as temporary/timing differences reverse using the ARAM, or, if the records needed to compute the ARAM are unavailable, through an alternative procedure known as the Reverse South Georgia Method ("RSGM"). The ARAM is required for excess ADIT for those "protected" book-tax differences subject to the aforementioned normalization rules. Tampa Electric has the records to apply the ARAM and, as discussed in the direct testimony of Valerie Strickland, has done so in this case.

Q. Does the TCJA prescribe a method for excess ADIT on "unprotected" excess ADIT?

A. No. Prior to the TCJA, the ADIT provided on all book-tax differences typically reversed at the tax rate used to record the deferred tax expense when the book-tax difference originated; however, the TCJA does not contain such a requirement on the excess ADIT on unprotected book-tax differences. The balance of unprotected ADIT is thus up to a decision by the company and the regulator. I understand that Tampa Electric has agreed to a 10-year amortization of the unprotected excess ADIT existing at December 31, 2017 if the amount of unprotected excess ADIT is greater than $100 million.

Q. Have you prepared an exhibit that demonstrates how the ARAM is to be calculated?

A. Yes, Document No. 2 of my exhibit shows the originating and reversing book-tax differences and the required ADIT each year. The example in Document No. 2 is based on the assumptions used in my previous example describing depreciation book-tax differences and how such differences originate and reverse. However, in this example I begin with an income tax rate of 35 percent in the early years that is reduced to 21 percent before the asset is fully depreciated. The example again assumes a $1 million asset placed in service in 2016 with a 10-year book life and a five-year MACRS life, with no bonus tax depreciation. The MACRS rate is shown in Column B and each year's tax depreciation is shown in Column C. Book depreciation is $100,000 each year and Column F contains the difference between tax and book depreciation each year. Column G contains the income tax rates, beginning with 35 percent in 2016 and 2017, reducing that rate to 21 percent at the beginning of 2018.

Columns H and I show each year's deferred tax expense, with Column H showing the deferred tax expense on originating book-tax differences and Column I showing the deferred tax expense on reversing book-tax differences. Column K shows the ADIT balance, increasing and decreasing the previous year's balance by the deferred tax expense.

Q. Can you walk through the determination of excess ADIT and how the ARAM is used to reverse the ADIT for the tax rate change?

A. Yes. When the tax rate changed at the end of 2017, the balance of ADIT was $112,000 (Column K). This balance was derived by applying the 35 percent tax rate to the 2016 and 2017 originating book-tax differences in Column F ($100,000 + $220,000 = $320,000). The excess ADIT is calculated by applying the new 21 percent tax rate to those cumulative book-tax differences at the time of the rate change ($320,000 x 21 percent = $67,200) and comparing that amount to the then existing ADIT balance with the difference representing the excess ADIT ($112,000 - $67,200 = $44,800).

Under the ARAM, this excess ADIT balance does not begin reversing until 2021 when the book-tax difference begins to reverse. In 2018 through 2020, book-tax differences continue to originate, now at the lower 21 percent income tax rate with no reversal permitted for excess ADIT.

At the end of 2020 the ADIT balance is $137,704 (Column K) and the cumulative book-tax difference is $442,400 (the 2016 through 2020 differences in Column F). The average rate at which the $137,704 ADIT balance was accumulated is thus 31.1266 percent ($137,704 / $442,400). This is the average rate that must be applied to the book-tax differences reversing in each year beginning in 2021

(Column F) producing the reversal of the deferred tax expense each year (Column I).

At the end of its useful life, the originating and reversing deferred tax expense equal one another and the ADIT balance is 0.

Q. If a rate higher than 31.1266 percent were used to reduce the reversing ADIT or if any of the excess ADIT were reversed prior to 2020 what would happen?

A. Flowing back protected ADIT more rapidly than permitted under the ARAM will result in a violation of the normalization rules. The TCJA specifies the penalty for violating the normalization rules is severe and two-fold: (1) currently payable income tax is increased by the amount by which the utility reduced its excess tax reserve more rapidly than permitted under the ARAM or the RSGM, and (2) the utility will be unable to claim accelerated depreciation for income tax purposes.

Q. Once the excess ADIT related to protected differences are identified, is it fair to characterize the remaining excess ADIT as relating to unprotected book-tax differences?

A. Yes.

Q. Are any of the unprotected book-tax differences related to property, plant and equipment?

A. Yes. The more significant unprotected book-tax differences with some elements of property, plant and equipment accounting are book-tax differences for the treatment of repairs (deducted currently for tax, capitalized and depreciated for books), different amounts capitalized into the book and tax bases of depreciable property, plant and equipment (overheads) and cost of removal.

Q. Please describe the cost of removal book-tax difference.

A. For most commercial and industrial companies, when computing book depreciation, the concept of "salvage value" is taken into consideration when determining the book basis to be depreciated. When a fixed asset is placed in service, the book basis subject to book depreciation is the amount incurred in rendering that asset ready for service less any expected salvage value that will be received when that asset is retired. So for instance, if an asset placed in service cost $1,000, with a five-year life and $50 of salvage is expected to be received upon retirement, the book basis to be depreciated is $950. Annual book depreciation charges will be $190 ($950 / 5 = $190).

Most regulated entities, including Tampa Electric, do not receive a net salvage upon the retirement of property, plant and equipment. Instead, they incur the opposite, a “cost of removal” upon retirement, meaning there are additional expenditures required to remove such property, plant and equipment. The costs to remove, dispose or otherwise permanently retire an asset from service including the costs of dismantling, tearing down or demolishing, meet the cost of removal definition. When depreciation rates are established for regulated entities, such rates are increased to reflect the estimated cost of removal. If, when expending the removal cost, there is some salvage received, the salvage is netted against the cost of removal to produce a net cost of removal or “negative net salvage.” For book purposes, this treatment charges the customers who benefit from using the property, plant and equipment, with the cost to remove that asset at the end of its depreciable life.

For instance, if the cost of property, plant and equipment is $1,000 and there is a $50 estimated cost associated with removing that asset when it is retired, the annual book depreciation charge is $210 ($1,050 / 5 = $210). In the utility's depreciation study, depreciation rate for this asset would be 21 percent--20 percent to recover the incurred cost of $1,000 over five years and 1 percent to recover the estimated cost of removal in years 1 to 5 (1 percent x $1,000 each year = $10 per year). In this manner, year 5 to cover the actual removal cost incurred upon retirement.

Q. How is cost of removal treated for income tax purposes?

A. For income tax purposes, cost of removal is deducted when the actual removal costs are expended. Because book depreciation includes an estimated component to recover cost of removal, but for tax purposes the cost is not deductible until expended, a book-tax difference results.

Q. Please explain the deferred income tax consequences of cost of removal.

A. As explained above, the impact to deferred tax of cost of removal is the opposite of, for example, the impact of accelerated depreciation because the book expense (the cost of removal component of book depreciation expense) is deducted for income tax purposes in later years when the cost of removal is expended. The effect is to create an ADIT asset (rather than liability) when book depreciation initially exceeds tax depreciation by the amount of the cost of removal component of book depreciation. The ADIT for cost of removal is reversed when the tax depreciation deduction for cost of removal is expended and subsequently deducted.

Q. Is the cost of removal a protected or unprotected book-tax difference?

A. Cost of removal is an unprotected book-tax difference. Cost of removal, or negative salvage value, is not a depreciation method or life difference. Unlike accelerated versus straight-line depreciation differences which are required to be normalized in order to permit the utility to enjoy the benefits of the interest free loan by accelerating recovery of depreciation tax deductions, cost of removal does not provide an up-front tax deduction. This view is shared by the Edison Electric Institute and my Firm. I am not aware of any applicable guidance from the Internal Revenue Service to the contrary covering the specific issue of cost of removal when the net cost of removal produces a net cost. Private letter rulings in this area, if applicable, are confusing or not on point.

Q. What is Tampa Electric proposing for reducing revenues and customer bills for the excess ADIT related to unprotected book-tax differences resulting from the TCJA?

A. As mentioned previously, there is no requirement in the IRC for excess ADIT which applies to unprotected book-tax differences. While one approach is to use an ARAM-type approach to unprotected excess ADIT reversing the excess ADIT as the related book-tax difference reverses, Tampa Electric has entered into the 2017 Agreement and Amended Implementation Stipulation which have been approved by the FPSC and, due to the dollar amount of excess unprotected excess ADIT, will amortize the unprotected excess ADIT balance over 10 years.

The calculation of the amortization is straightforward. The company’s unprotected ADIT balance as of December 31, 2017 was divided by 10 and this amount was used to reduce income tax expense and revenue requirements beginning January 1, 2019.

Q. You have stated that the effects of the tax rate reduction and the loss of the ability to claim bonus tax depreciation will have a negative effect on cash flows because there will be less ADIT. What is the significance of a decrease in cash flows?

A. A decrease in cash flow, all else being equal, is often considered a negative factor by investors when they evaluate the quality of a security. There will be a negative factor in this instance, because there will be a reduction in zero-cost capital due to a lower amount of ADIT which must be replaced by investor funds which typically have a cost greater than zero.

In addition, other effects of the TCJA which would likely be considered negatively by investors include a reduction in pretax coverage ratios and an increase in the invested capital per dollar of property, plant and equipment. In addition, because of the reduction in the tax rates, the company's shareholders will now share losses and declines in earnings with the US Treasury in the ratio of 79 percent to 21 percent rather than 65 percent to 35 percent. The existence of these negative factors will likely be recognized in the cost of capital.

PWC Procedures

Q. What procedures did PWC perform with respect to Tampa Electric's 2018 income tax expense calculations in this docket?

A. The following procedures were performed by me or under my direction and supervision:

1. We read Document Nos. 1 through 4 included as the exhibit to Valerie Strickland’s direct testimony.
2. We analyzed the roll-forward of the company’s ADIT from December 31, 2017 noting that adjustments to such balances primarily reflected minimal differences as a result of adjusting balances to agree with amounts to be included in the 2017 income tax return filing as well as reclassifying the cost of removal and CIAC ADIT from the accelerated depreciation ADIT line item to separate line items.
3. We obtained management’s schedule identifying which of the company’s book-tax differences and related excess ADIT were identified as protected or unprotected differences based on their descriptions. We obtained documentation supporting these conclusions and agreed with management’s classification.
4. We obtained management’s calculation of amounts determined to represent reversal of protected excess ADIT or amortization of unprotected excess ADIT. We tested the schedule for mathematical accuracy and agreed management’s schedule to standard system

reports.

5. On a sample basis, we tested the ARAM by examining book depreciation by vintage by asset compared to tax depreciation by vintage by asset noting the reversal in 2018 and that the appropriate tax rate was applied. The detail support is maintained in the company's Power Plan property and income tax software systems.

6. We recalculated the company's break out and allocation of the cost of removal excess ADIT from the book-tax depreciation ADIT line item by tax vintage.

Q. As a result of applying the above procedures and your understanding of ADIT and the TCJA, do you agree with Tampa Electric's calculations of excess ADIT, the flowback of protected excess ADIT using the ARAM and the amortization of unprotected excess ADIT in the 2018 tax calculations prepared by Ms. Strickland?

A. Yes.

Q. Does this conclude your prepared direct testimony?

A. Yes, it does.

EXHIBIT

OF

ALAN D. FELSENTHAL

ON BEHALF OF TAMPA ELECTRIC COMPANY

Table of Contents

Depreciation Timing Difference Example

Year	Book Depreciation	Tax Depreciation	Difference	Cumulative Difference
1	1,000,000	2,000,000	1,000,000	1,000,000
2	1,000,000	3,200,000	2,200,000	3,200,000
3	1,000,000	1,920,000	920,000	4,120,000
4	1,000,000	1,152,000	152,000	4,272,000
5	1,000,000	1,152,000	152,000	4,424,000
6	1,000,000	576,000	(424,000)	4,000,000
7	1,000,000		(1,000,000)	3,000,000
8	1,000,000		(1,000,000)	2,000,000
9	1,000,000		(1,000,000)	1,000,000
10	1,000,000		(1,000,000)	0
Total	10,000,000	10,000,000	0	

ARAM Illustration

		(A)	(B)	(A x B = C)	(A x D = E)	(C-E=F)	(G)	(F x G = H)	(F x J = I)	(J)	(K)
Line No.	**Year**	**Asset Cost**	**5-year MACRS Tax Rate**	**Tax Depreciation**	**Book Depreciation 10 years S/L**	**Tax over Book Difference**	**Tax Rate**	**Originating Deferred**	**Reversing Deferred**	**Average Rate**	**ADIT**
1	2016	1,000,000.00	20.000%	200,000.00	100,000.00	100,000.00	35%	35,000.00			35,000.00
2	2017		32.000%	320,000.00	100,000.00	220,000.00	35%	77,000.00			112,000.00
3	2018		19.200%	192,000.00	100,000.00	92,000.00	21%	19,320.00			131,320.00
4	2019		11.520%	115,200.00	100,000.00	15,200.00	21%	3,192.00			134,512.00
5	2020		11.520%	115,200.00	100,000.00	15,200.00	21%	3,192.00			137,704.00
6	2021		5.760%	57,600.00	100,000.00	(42,400.00)	21%		(13,197.67)	31.1266%	124,506.33
7	2022		0.000%	-	100,000.00	(100,000.00)	21%		(31,126.58)	31.1266%	93,379.75
8	2023		0.000%	-	100,000.00	(100,000.00)	21%		(31,126.58)	31.1266%	62,253.16
9	2024		0.000%	-	100,000.00	(100,000.00)	21%		(31,126.58)	31.1266%	31,126.58
10	2025		0.000%	-	100,000.00	(100,000.00)	21%		(31,126.58)	31.1266%	-
				1,000,000.00	1,000,000.00	-		137,704.00	(137,704.00)		

$1,000,000 asset placed in service on January 1, 2016

Book depreciation using straight-line method, 10-year life, no half-year convention

Tax Depreciation using MACRS, five-year life

Average rate (Column J) computed when the book/tax difference reverses (2021). Computation is based on dividing the ADIT balance ($137,704 in Column K) by the cumulative book-tax differences at the beginning of the year ($442,400, total increases in Column F)

BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 20180045-EI

IN RE: CONSIDERATION OF THE TAX IMPACTS ASSOCIATED WITH TAX CUTS AND JOBS ACT OF 2017 FOR TAMPA ELECTRIC COMPANY

DIRECT TESTIMONY AND EXHIBIT
OF
VALERIE STRICKLAND

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

VALERIE STRICKLAND

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

A. My name is Valerie Strickland. My business address is 702 North Franklin Street, Tampa, Florida 33602. I am employed by TECO Services, Inc. ("TSI") as the Director of Corporate Taxes.

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

A. I am responsible for managing TSI's Tax Department, which provides tax services to Tampa Electric Company ("Tampa Electric" or "company". My responsibilities include the preparation and filing of tax returns, tax accounting for internal and external purposes, and tax planning, as well as managing federal and state tax audits. The only taxes I do not oversee are payroll taxes, which are the responsibility of TSI's Payroll Department.

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

A. I was educated in Europe where I received a Master’s degree in Accounting & Finance from the “Institut de l’Administration and Gestion” in Paris, France. Upon graduation in 1992, I joined Coopers & Lybrand LLC, an independent accounting firm, as a tax professional. In 1998, Coopers & Lybrand LLC merged with Price Waterhouse LLP and became PricewaterhouseCoopers LLP (“PwC”). I continued to work for PwC as a Tax Manager until I joined the TECO Energy Tax Department in 2000. I am also an active participant of the Edison Electric Institute (“EEI”) Taxation Committee.

Q. What are the purposes of your direct testimony in this proceeding?

A. The purposes of my direct testimony are to explain how the company is accounting for the impacts of the Tax Cuts and Jobs Act of 2017 (“TCJA”) and to sponsor the company’s calculation of forecasted income tax expense for 2018 based on its 2018 Forecasted Earnings Surveillance Report (filed March 15, 2018) as adjusted to reflect the impact of the TCJA.

Q. Did you prepare an exhibit in support of your direct testimony?

A. Yes. Exhibit No. ___ (VS-1) was prepared under my direction and supervision. My exhibit consists of four documents, as described below.

Document No. 1	Estimated Excess ADIT as of December 31, 2017
Document No. 2	Revised Estimate of Excess ADIT
Document No. 3	2018 Tax Expense under the TCJA
Document No. 4	MFR C-22 With and Without Tax Reform

Q. As part of your work for Tampa Electric in this docket, have you read the documents referred to as the "2017 Agreement" and "Amended Implementation Stipulation" (and related FPSC Orders) in the prepared direct testimony of Tampa Electric witness Jeffrey S. Chronister?

A. Yes, I have.

Q. What does the 2017 Agreement require with respect to protected and unprotected excess deferred taxes?

A. With respect to "protected" excess deferred income taxes, paragraph 9(a) of the 2017 Agreement states: “[t]o the extent Tax Reform includes a transition rule applicable to excess deferred federal income tax assets and liabilities (“Excess Deferred Taxes”), defined as those that arise from the re-measurement of those deferred federal income tax assets and liabilities at the new applicable corporate tax rate(s), those Excess Deferred Taxes will be governed by the Tax Reform transition rule, as applied to most promptly and effectively reduce Tampa Electric’s rates consistent with the Tax Reform rules and normalization rules.” The TCJA prescribes the Average Rate Assumption Method (“ARAM”) as the transition rule for a category of excess deferred taxes known as “protected excess deferred taxes.”

With respect to “unprotected” excess deferred taxes, paragraph 9(c) of the 2017 Agreement states “there shall be a rebuttable presumption that the following flow-back period(s) will apply: (1) if the cumulative net regulatory liability is less than $100 million, the flow-back period will be five years; or (2) if the cumulative net regulatory liability is greater than $100 million, the flow-back period will be ten years.”

Accounting for the Impact of the TCJA

Q. What changes to the Internal Revenue Code ("IRC") in the TCJA have made the biggest impact on Tampa Electric?

A. Although the TCJA includes other changes that impact the way Tampa Electric calculates income tax expense, the decrease in the federal income tax rate from 35 percent to 21 percent and the flowback of protected and unprotected excess deferred taxes have the greatest impact on Tampa Electric.

Q. What steps has the company taken to properly account for the impact of the TCJA?

A. Tampa Electric became aware that tax reform had become a priority of the federal government in 2017 and began participating in internal and external discussions – with PwC and EEI - to better understand the potential impacts of tax reform.

Tampa Electric made the change in the federal tax rate in accordance with FASB Accounting Standards Codification ("ASC") Topics 740 (Accounting for Income Taxes) and 980 (Accounting for Regulated Operations) and Rule 25-14.013

(10), Florida Administrative Code.

The company reviewed the book-tax differences that factor into the calculation of income tax expense to determine whether and the extent to which the TCJA would impact the differences. These differences are reflected in Document No. 4 of my exhibit, which presents the company’s 2018 income tax expense calculation in the format required by Minimum Filing Requirement (“MFR”) Schedule C-22.

The company separately identified and evaluated tax credits to ensure that they would be properly accounted for in the calculation of income tax and the valuation of deferred tax balances.

Tampa Electric then re-measured its non-tax credit related accumulated deferred income tax (“ADIT”) balances and calculated the related excess ADIT balances. Excess ADIT arise from the re-measurement of the company’s deferred federal income tax assets and liabilities at the new applicable corporate tax rate.

As I previously mentioned, the TCJA prescribes the Average Rate Assumption Method (“ARAM”) as the transition rule for treatment of “protected” excess deferred taxes, and the

2017 Settlement provides that the treatment of excess deferred taxes will be governed by the tax reform transition rule. The 2017 Agreement provides that “unprotected” excess deferred taxes be amortized over 10 years if the amount is greater than $100 million, and over five years if the total is less than $100 million.

Since Tampa Electric uses the PowerPlan Provision module from a software company called PowerPlan to calculate its current and deferred tax expense, the company has worked with PowerPlan consultants to configure the system to estimate its deferred taxes and generate the required journal entries in accordance with ASC Topics 740 and 980. As of December 31, 2017, the company’s excess deferred income taxes liability was $484.5 million. This is shown in Document No. 1 of my exhibit.

In early 2018, the company engaged PowerPlan to assist with the implementation of ARAM for protected timing differences. The company analyzed its records to segregate protected versus unprotected timing differences in order to derive the correct amount of protected for ARAM flowback as well as flowback of unprotected differences under the “2017 Agreement”.

Witness Felsenthal describes the ARAM in greater detail in his prepared direct testimony. I will discuss the amounts and treatment of the protected versus unprotected excess deferred taxes in more detail later in my testimony.

In May 2018, the TSI Tax Department completed Tampa Electric's 2017 federal corporate income tax return for plant related book-tax differences to derive the best possible estimate of the company's excess deferred income taxes. As a result of this activity, the company revised its estimate of excess ADIT as of December 31, 2017 to $480.7 million, which is $3.8 million lower than the original amount recorded in the company's December 31, 2017 Audited Financial Statements. This revision is reflected in Document No. 2 of my exhibit.

Q. What are "protected" excess deferred taxes?

A. Protected excess deferred taxes are excess ADIT associated with the use of accelerated tax depreciation under IRC section 167 and 168. Book-tax differences related to depreciation occur when the method and life used to compute depreciation are different for tax and book purposes. Additionally, in accordance with Internal Revenue Service ("IRS") Notice 87-82 "Regulated Public Utilities-

Contribution In Aid of Construction After Tax Reform", when a regulated company does not calculate a gross up for Contribution In Aid of Construction ("CIAC"), the timing difference related to CIAC is then required to be normalized under IRC section 167 and 168, and therefore becomes protected under the normalization rules as a method-life timing difference.

The normalization provisions of the TCJA specify that protected excess ADIT may not be used to reduce protected excess tax reserves more rapidly or to a greater extent than the reserve would be reduced using the ARAM. Under the ARAM, excess ADIT are reduced and flowed back into the calculation of income tax expense as the timing difference giving rise to the deferred taxes reverse. Under ARAM, the calculation of the average tax rate is made as of the beginning of the year in which temporary differences in the vintage account begin to reverse, namely, in the first year in which the book depreciation exceeds tax depreciation. Any method that results in the flowback of a taxpayer's excess deferred tax reserve more rapidly than the ARAM is a violation of the depreciation normalization requirements.

As of December 31, 2017, the company estimated its protected excess deferred taxes to be $313.5 million as shown on

Document No. 1 of my exhibit.

In May 2018, Tampa Electric completed a detailed analysis to refine the amounts of its deferred tax balances related to method and life book-tax differences. This information was not readily available in the existing records. For example, the book depreciation amount contains reversal amounts of book depreciation related to unprotected ADIT such as cost of removal, basis adjustments (excluding CIAC), and tax repairs. The company therefore identified and reclassified the book depreciation related to these timing differences to the unprotected category. As shown in Document No. 2 of my exhibit, the company reclassified $34.2 million of excess ADIT from the original estimate developed as of December 31, 2017, resulting in a revised total protected excess ADIT amount of $347.8 million.

Q. What are “unprotected” excess deferred taxes?

A. Any book-tax differences other than method and life depreciation differences are not “protected” by the normalization rules. The original estimated amount of unprotected deferred taxes is $171.0 million as shown on Document No. 1 of my exhibit. However, as mentioned in my previous answer, the company went through a detailed analysis to determine the proper categorization of book depreciation reversal amounts that belong in the unprotected category. The company identified the need to reclassify deferred tax assets in the amount of $38.0 million, and the revised unprotected deferred taxes estimate is $133.0 million, as shown on Document No. 2 of my exhibit.

Q. What is the amount associated with “tax repairs” and why is that amount considered unprotected?

A. The company uses the tax repairs module within PowerPlan to optimize the tax repairs deduction allowed under IRC section 162. The company is currently maximizing its tax deduction by expensing qualifying capital costs for Generation and Transmission and Distribution repairs for tax purposes. For book purposes, however, these costs are capitalized and depreciated over the life of the asset. Therefore, tax repairs deductions generate significant deferred tax liability every year. Even though the book-tax timing difference is directly related to plant, it is not considered protected since it is not related to method or life differences. The amount of excess ADIT associated with the tax repairs book-tax difference is $173.3 million, as shown on Document No. 2 of my exhibit.

Q. What are the amounts associated with cost of removal?

A. The total excess ADIT deficiency related to cost of removal is $27.8 million as shown on Document No. 2 of my exhibit.

Q. Why does the company consider ADIT related to cost of removal to be unprotected?

A. The company believes that excess ADIT related to cost of removal are unprotected. A timing difference is protected if there is tax depreciation on an asset that falls within IRC section 168. Cost of removal generates no tax depreciation, rather it generates a tax deduction when payments occur at the end of the asset's life. For book purposes, depreciation expense includes a factor for this estimated cost of removal. The book depreciation in excess of the future tax deduction related to that asset creates a deferred tax asset which was embedded in accumulated book depreciation. Therefore, Tampa Electric reclassified cost of removal amounts to the unprotected excess ADIT category. Witness Felsenthal's testimony describes how cost of removal originates and reverses in greater detail. The amount of Tampa Electric's reclassification for cost of removal is a $95.8 million deferred tax asset as shown on Document No. 2 of my exhibit.

Q. Has the company complied with the requirements of the 2017 Agreement related to protected and unprotected excess deferred income taxes?

A. Yes. As I previously described, I believe Tampa Electric implemented the new corporate income tax rate and other provisions of the TCJA, including calculating the flowback of its excess deferred tax amounts using the prescribed ARAM transition rule for protected excess deferred taxes and following the method stated in the 2017 Agreement for unprotected excess deferred taxes.

Calculation of 2018 Income Tax Expense

Q. Have you prepared calculations showing the impact of the TCJA on the company's 2018 financial forecast?

A. Yes. Document No. 3 of my exhibit shows the calculation of the company's forecasted 2018 income tax expense with and without the impact of the TCJA. The amount of tax expense I identified in this document, without the impact of the TCJA, was included in the company's 2018 forecasted earnings surveillance report filed with this Commission on March 16, 2018 and included in witness Chronister's prepared direct testimony as Document No. 3 of Exhibit No.

___ (JSC-1).

Document No. 3 of my exhibit also provides the calculation of the company's revised forecasted 2018 income tax expense based on the TCJA. This amount of tax expense, with the impact of the TCJA, is included in the company's updated 2018 forecasted earnings surveillance report that reflects the impact of the TCJA and in witness Chronister's exhibit as Document No. 4.

In an effort to be transparent, I have also provided our calculation of the company's 2018 projected income tax expense, with and without the effects of the TCJA, in the format normally seen in a base rate proceeding as MFR Schedule C-22. This presentation shows each of the temporary and permanent book-tax differences that impact the calculation of current and deferred income tax expense and is included as Document No. 4 of my exhibit.

Q. Please explain how the calculation of tax expense under the current tax law is different than the calculation under the former tax laws.

A. The tax expense under the TCJA was calculated using the rules in effect as of January 1, 2018, with major changes including the decrease of the Federal Income Tax Rate from 35 percent to 21 percent, the repeal of IRC section 199 deduction, transition rules with respect to the former bonus depreciation provision, new 100 percent asset expensing exemption for regulated utilities, and the calculation of the flowback of excess deferred taxes. As provided in Document No. 3, the total 2018 tax expense without tax reform is $168.1 million, and the total 2018 tax expense with tax reform is $85.9 million. The change in the total 2018 tax expense between the current law and the former law is an annual decrease of $82.1 million.

Q. How did the company reflect the “flowback” of excess deferred income taxes in its calculation of income tax expense under the TCJA?

A. The flowback of protected excess deferred taxes for 2018 was calculated using the ARAM as required by the TCJA and the 2017 Agreement, and it reduces 2018 income tax expense by $10.2 million.

The flowback of unprotected excess deferred taxes was accomplished by reflecting one-tenth of the balance of unprotected excess deferred taxes as of January 1, 2018 as a $13.3 million reduction to 2018 deferred income tax expense. This treatment is consistent with the 2017 Agreement, which states that the flowback of unprotected excess deferred taxes in amounts that exceed $100 million will occur over a 10-year period.

In his direct testimony, witness Felsenthal describes the work PwC performed to test and verify the company's calculation of the impact of the TCJA on the company's 2018 forecasted income tax expense.

Q. Are the amounts you have identified in calculating the company's 2018 income tax expense under the TCJA subject to change?

A. Yes, although I have provided the company's best estimates at this time, it is possible that there may be a need to true-up the calculated amounts. Once Tampa Electric has filed its 2017 federal and state income tax returns in October 2018, the company will provide revised unprotected excess deferred tax amounts if a true-up is needed. In addition, if the IRS issues clarification rules with respect to the treatment of cost of removal or application of the previous bonus depreciation rules, and these rulings are different than the company's proposed treatment of these items, then Tampa Electric will true-up those amounts.

Summary

Q. Please summarize your direct testimony.

A. The key drivers of the impact of the TCJA as reflected in the 2018 Forecasted Earnings Surveillance Report are changes in the Federal Income Tax Rate, IRC section 199 deduction, bonus depreciation, and the flowback of excess ADIT generated by the rate change. I have quantified Tampa Electric’s total excess ADIT resulting from the TCJA, as well as quantified the protected and unprotected amounts related to those excess deferred taxes and their respective flowback amounts under IRS rules and the 2017 Agreement.

Q. Does this conclude your prepared direct testimony?

A. Yes.

EXHIBIT

OF

VALERIE STRICKLAND

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Estimated Excess ADIT as of December 31, 2017

Tampa Electric	Beginning Balance	True-Up Activity	Gross Timing Difference	DIT Beginning Balance	Current Activity	True up/ Reclass Activity	Adjustment Activity	After Tax Deferred Tax Liability	Rate	Normalization	Excess DTL
401K - PERFORMANCE MATCH	1,413,314	0	1,413,314	545,186	(147,821)	0	(39,161)	358,204	0.25	**Unprotected**	(186,981)
ACC DEF ITC 10% - 1975 - GT	(8)	0	(8)	(5)	0	0	2	(2)	0.28	**Unprotected**	2
ACC DEF ITC 10% - 1980	11,972	0	11,972	6,822	109	0	(3,563)	3,368	0.28	**Unprotected**	(3,454)
ACC DEF ITC 10% - 1981 - NU	351	0	351	200	5	0	(106)	99	0.28	**Unprotected**	(101)
ACC DEF ITC 10% - 1982	232,512	0	232,512	132,485	3,197	0	(70,279)	65,404	0.28	**Unprotected**	(67,081)
ACC DEF ITC 10% - 1982 - NU	739	0	739	421	10	0	(223)	208	0.28	**Unprotected**	(213)
ACC DEF ITC 10% - 1984	148,416	0	148,416	84,568	1,905	0	(44,724)	41,749	0.28	**Unprotected**	(42,819)
ACC DEF ITC 10% - 1984 - GT	17,832	0	17,832	10,161	229	0	(5,374)	5,016	0.28	**Unprotected**	(5,145)
ACC DEF ITC 10% - 1985 - GT	5,014	0	5,014	2,857	62	0	(1,508)	1,410	0.28	**Unprotected**	(1,447)
ACC DEF ITC 10% - 1986	299,660	0	299,660	170,746	3,558	0	(90,011)	84,293	0.28	**Unprotected**	(86,454)
ACC DEF ITC 10% - 1986 - GT	397	0	397	226	5	0	(119)	112	0.28	**Unprotected**	(115)
ACC DEF ITC 10% - 1987	125,422	0	125,422	71,466	1,433	0	(37,618)	35,281	0.28	**Unprotected**	(36,185)
ACC DEF ITC 10% - 1988	119,055	0	119,055	67,838	1,310	0	(35,659)	33,489	0.28	**Unprotected**	(34,348)
ACC DEF ITC 10% - 1989	21,364	0	21,364	12,173	227	0	(6,391)	6,010	0.28	**Unprotected**	(6,164)
ACC DEF ITC 10% - 1990	2,097	0	2,097	1,195	22	0	(627)	590	0.28	**Unprotected**	(605)
ACC DEF ITC 30% - 2015 - SOLAR	(122,411)	0	(122,411)	(69,750)	17,298	0	18,019	(34,434)	0.28	**Unprotected**	35,316
ACC DEF ITC 30% - 2016 - SOLAR	(47,755)	0	(47,755)	(27,211)	13,228	0	550	(13,433)	0.28	**Unprotected**	13,778
ACC DEF ITC 30% - 2017- SOLAR	(327,750)	0	(327,750)	(186,752)	94,558	0	0	(92,194)	0.28	**Unprotected**	94,558
ACC DEF ITC 8% - 1983	129,680	0	129,680	73,892	1,729	0	(39,142)	36,478	0.28	**Unprotected**	(37,413)
ACC DEF ITC 8% - 1983 - GT	2,283	0	2,283	1,301	30	0	(689)	642	0.28	**Unprotected**	(659)
ACC DEF ITC 8% - 1984	1,105,595	0	1,105,595	629,969	14,193	0	(333,164)	310,997	0.28	**Unprotected**	(318,971)
ACC DEF ITC 8% - 1985	703,159	0	703,159	400,661	8,681	0	(211,547)	197,794	0.28	**Unprotected**	(202,866)
ACC DEF ITC BB4 10% - 1981	168,851	0	168,851	96,211	2,084	0	(50,799)	47,497	0.28	**Unprotected**	(48,715)
ACC DEF ITC BB4 10% - 1982	1,286,920	0	1,286,920	733,288	15,888	0	(387,173)	362,003	0.28	**Unprotected**	(371,285)
ACC DEF ITC BB4 10% - 1984	737,253	0	737,253	420,087	9,102	0	(221,804)	207,385	0.28	**Unprotected**	(212,702)
ACC DEF ITC BB4 10% - 1986	28,182	0	28,182	16,058	334	0	(8,465)	7,927	0.28	**Unprotected**	(8,131)
ACC DEF ITC BB4 10% - 1987	26,419	0	26,419	15,053	302	0	(7,924)	7,431	0.28	**Unprotected**	(7,622)
ACC DEF ITC BB4 8% - 1983	2,009,195	0	2,009,195	1,144,840	24,805	0	(604,471)	565,174	0.28	**Unprotected**	(579,666)
ACC DEF ITC BB4 8% - 1984	539,795	0	539,795	307,576	6,664	0	(162,399)	151,841	0.28	**Unprotected**	(155,735)
ACC DEF ITC BB4 8% - 1985	260,112	0	260,112	148,212	3,211	0	(78,255)	73,168	0.28	**Unprotected**	(75,044)
ACCRUED BONUS	13,766,654	0	13,766,654	5,310,487	(252,250)	0	(1,569,079)	3,489,158	0.25	**Unprotected**	(1,821,328)
AFUDC EQUITY	(189,962,004)	0	(189,962,004)	(73,277,843)	208,610	0	24,923,363	(48,145,870)	0.25	**Unprotected**	25,131,973
AFUDC EQUITY - DEPR	65,695,049	0	65,695,049	25,341,865	(955,393)	0	(7,736,062)	16,650,410	0.25	**Unprotected**	(8,691,455)
AMORT - BOND DISCOUNT	(584,472)	0	(584,472)	(225,460)	(15,998)	0	93,324	(148,134)	0.25	**Unprotected**	77,326
AMORT - BOND ISSUE COSTS	(578,156)	0	(578,156)	(223,024)	(21,995)	0	98,485	(146,534)	0.25	**Unprotected**	76,490
AMORT - BOND PREMIUM	(1,008,977)	0	(1,008,977)	(389,213)	(30,592)	0	164,079	(255,725)	0.25	**Unprotected**	133,488
AMORTIZATION FED	(169,004,894)	0	(169,004,894)	(59,151,713)	(641,938)	0	24,302,623	(35,491,028)	0.21	**Unprotected**	23,660,685
AMORTIZATION STATE	(169,004,894)	0	(169,004,894)	(6,041,925)	35,307	0	(1,336,644)	(7,343,263)	0.04	**Unprotected**	(1,301,338)
BAD DEBT	762,123	0	762,123	293,989	8,611	0	(109,440)	193,160	0.25	**Unprotected**	(100,829)
CIAC	151,141,690	0	151,141,690	58,302,907	(1,648,608)	0	(18,347,438)	38,306,861	0.25	**Unprotected**	(19,996,046)

Estimated Excess ADIT as of December 31, 2017

Tampa Electric	Beginning Balance	True-Up Activity	Gross Timing Difference	DIT Beginning Balance	Current Activity	True up/ Reclass Activity	Adjustment Activity	After Tax Deferred Tax Liability	Rate	Normalization	Excess DTL
COST OF REMOVAL	(514,365,658)	0	(514,365,658)	(198,416,552)	6,804,612	0	61,245,965	(130,365,976)	0.25	**Unprotected**	68,050,577
CURRENCY ADJ - UNREAL G/L	6,196	0	6,196	2,390	(880)	0	60	1,570	0.25	**Unprotected**	(820)
DEF SEP CO - EMERA FED NOL	0	0	0	0	(19,783,342)	0	19,783,342	0	0.00	**Unprotected**	-
DEF SEP CO - EMERA FED NOL-PROTECTED	141,309,588	0	141,309,588	49,458,356	0	0	(19,783,342)	29,675,013	0.21	**Protected**	(19,783,342)
DEF SEP CO - FED NOL - UNPROTECTED	194,143,570	0	194,143,570	67,950,250	0	0	(27,180,100)	40,770,150	0.21	**Unprotected**	(27,180,100)
DEF SEP CO - FL NOL	0	0	0	0	0	0	(0)	0	0.00	**Unprotected**	(0)
DEF SEP CO - FL NOL - UNPROTECTED	268,538,363	0	268,538,363	9,600,246	0	0	2,067,745	11,667,992	0.04	**Unprotected**	2,067,745
DEFERRED COMP	248,190	0	248,190	95,739	(32,835)	0	(0)	62,904	0.25	**Unprotected**	(32,836)
DEFERRED FUEL	(5,364,387)	0	(5,364,387)	(2,069,312)	(373,436)	0	1,083,145	(1,359,604)	0.25	**Unprotected**	709,708
DEFERRED INTEREST - BONDS	(11,393,068)	0	(11,393,068)	(4,394,876)	(460,634)	0	1,967,937	(2,887,573)	0.25	**Unprotected**	1,507,303
DEFERRED LEASE - NC	678,521	0	678,521	261,739	(7,928)	0	(81,840)	171,971	0.25	**Unprotected**	(89,768)
DEPRECIATION - BOOK	(12,596,149)	0	(12,596,149)	(4,858,965)	(24,400)	0	1,690,871	(3,192,494)	0.25	**Protected**	1,666,471
DEPRECIATION - BOOK TAX DIFF FED	(2,467,663,268)	0	(2,467,663,268)	(863,682,144)	50,072,377	0	295,400,480	(518,209,286)	0.21	**Protected**	345,472,858
DEPRECIATION - BOOK TAX DIFF STATE	(1,793,631,218)	0	(1,793,631,218)	(64,122,316)	(798,173)	0	(13,012,787)	(77,933,276)	0.04	**Protected**	(13,810,960)
DISMANTLEMENT COSTS	125,943,563	0	125,943,563	48,582,730	(156,920)	0	(16,505,413)	31,920,396	0.25	**Unprotected**	(16,662,333)
DREDGING	(2,183,942)	0	(2,183,942)	(842,456)	38,832	0	250,103	(553,520)	0.25	**Unprotected**	288,935
FAS 106 - NC	81,591,563	0	81,591,563	31,473,946	756,480	0	(11,551,043)	20,679,382	0.25	**Unprotected**	(10,794,564)
FAS 106 FAS 158	3,119,528	0	3,119,528	1,203,358	0	0	(412,714)	790,644	0.25	**Unprotected**	(412,714)
FAS 106 FAS 158 - C	9,640,008	0	9,640,008	3,718,633	(121,385)	0	(1,153,988)	2,443,260	0.25	**Unprotected**	(1,275,373)
FAS 106 FAS 158 - C 283	(9,640,008)	0	(9,640,008)	(3,718,633)	121,385	0	1,153,988	(2,443,260)	0.25	**Unprotected**	1,275,373
FAS 106 FAS 158 - NC	46,775,125	0	46,775,125	18,043,504	(2,465,563)	0	(3,722,786)	11,855,155	0.25	**Unprotected**	(6,188,349)
FAS 106 FAS 158 - NC 283	(46,775,125)	0	(46,775,125)	(18,043,504)	2,465,563	0	3,722,786	(11,855,155)	0.25	**Unprotected**	6,188,349
FAS 112	13,977,835	0	13,977,835	5,391,950	212,172	0	(2,061,440)	3,542,682	0.25	**Unprotected**	(1,849,268)
FIBER OPTIC	383,750	0	383,750	148,032	11,693	0	(62,463)	97,261	0.25	**Unprotected**	(50,770)
G/L - SALE OF ASSETS	79,543	0	79,543	30,684	1,958	0	(12,481)	20,160	0.25	**Unprotected**	(10,524)
GENERAL BUSINESS CREDIT	(22,320,526)	0	(22,320,526)	22,320,526	0	0	0	22,320,526	(1.00)	**Unprotected**	-
INSURANCE RESERVE - C	0	0	0	0	(428,224)	0	428,224	0	0.00	**Unprotected**	-
INSURANCE RESERVE - NC	(27,328,771)	0	(27,328,771)	(10,542,073)	13,057,664	0	(9,442,067)	(6,926,477)	0.25	**Unprotected**	3,615,596
ITC 30% - SOLAR	14,407,398	0	14,407,398	8,209,344	(3,241,948)	0	(914,682)	4,052,714	0.28	**Unprotected**	(4,156,630)
LEGAL EXPENSES	404,157	0	404,157	155,904	(49,674)	0	(3,796)	102,434	0.25	**Unprotected**	(53,470)
LONG TERM INCENTIVE	6,046,168	0	6,046,168	2,332,309	(619,196)	0	(180,712)	1,532,401	0.25	**Unprotected**	(799,908)
LOSS FROM GRANTOR TRUST	272,075	0	272,075	104,953	0	0	(35,996)	68,957	0.25	**Unprotected**	(35,996)
OCI FAS 133 - C	933,935	0	933,935	360,265	1,640,513	0	(1,764,073)	236,706	0.25	**Unprotected**	(123,560)
OCI FAS 133 - C 283	(933,935)	0	(933,935)	(360,265)	(1,640,513)	0	1,764,073	(236,706)	0.25	**Unprotected**	123,560
OCI FAS 133 - NC	0	0	0	0	162,435	0	(162,435)	0	0.00	**Unprotected**	-
OCI FAS 133 - NC 283	0	0	0	0	(162,435)	0	162,435	0	0.00	**Unprotected**	-

Estimated Excess ADIT as of December 31, 2017

Tampa Electric	Beginning Balance	True-Up Activity	Gross Timing Difference	DIT Beginning Balance	Current Activity	True up/ Reclass Activity	Adjustment Activity	After Tax Deferred Tax Liability	Rate	Normalization	Excess DTL
OCI FAS 133 INTEREST - NC	2,309,241	0	2,309,241	890,790	117,265	0	(422,778)	585,277	0.25	**Unprotected**	(305,513)
PENSION - NC	(176,830,203)	0	(176,830,203)	(68,212,251)	(66,382)	0	23,461,018	(44,817,615)	0.25	**Unprotected**	23,394,636
PENSION FAS 158	1,523,058	0	1,523,058	587,520	0	0	(201,501)	386,019	0.25	**Unprotected**	(201,501)
PENSION FAS 158 - NC	189,213,304	0	189,213,304	72,989,032	1,653,391	0	(26,686,311)	47,956,112	0.25	**Unprotected**	(25,032,920)
PENSION FAS 158 - NC 283	(189,213,304)	0	(189,213,304)	(72,989,032)	(1,653,391)	0	26,686,311	(47,956,112)	0.25	**Unprotected**	25,032,920
RATE CASE EXPENSE - NC	(1)	0	(1)	(0)	(62,609)	0	62,609	(0)	0.25	**Unprotected**	0
REPAIRS CAPITALIZED ON BOOKS	(1,213,986,281)	0	(1,213,986,281)	(468,295,208)	16,769,407	0	143,840,978	(307,684,823)	0.25	**Unprotected**	160,610,385
RESTORATION PLAN	202,436	0	202,436	78,090	(7,699)	0	(19,083)	51,307	0.25	**Unprotected**	(26,782)
RESTORATION PLAN FAS 158 - NC	381,200	0	381,200	147,048	57,750	0	(108,183)	96,615	0.25	**Unprotected**	(50,433)
RESTORATION PLAN FAS 158 - NC 283	(381,200)	0	(381,200)	(147,048)	(57,750)	0	108,183	(96,615)	0.25	**Unprotected**	50,433
SEC 263A INDIRECT COSTS/BASIS ADJ	41,418,357	0	41,418,357	15,977,131	(497,543)	0	(4,982,106)	10,497,483	0.25	**Unprotected**	(5,479,649)
SEC 263A INTEREST CAP	216,688,306	0	216,688,306	83,587,514	(91,793)	0	(28,576,070)	54,919,651	0.25	**Unprotected**	(28,667,863)
SERP - NC	8,069,213	0	8,069,213	3,112,699	(113,746)	0	(953,811)	2,045,142	0.25	**Unprotected**	(1,067,557)
SERP FAS 158	163,086	0	163,086	62,910	0	0	(21,576)	41,334	0.25	**Unprotected**	(21,576)
SERP FAS 158 - C	6,335,831	0	6,335,831	2,444,047	(810,181)	0	(28,049)	1,605,816	0.25	**Unprotected**	(838,230)
SERP FAS 158 - C 283	(6,335,831)	0	(6,335,831)	(2,444,047)	810,181	0	28,049	(1,605,816)	0.25	**Unprotected**	838,230
SERP FAS 158 - NC	(2,920,464)	0	(2,920,464)	(1,126,569)	928,212	0	(541,834)	(740,192)	0.25	**Unprotected**	386,377
SERP FAS 158 - NC 283	2,920,464	0	2,920,464	1,126,569	(928,212)	0	541,834	740,192	0.25	**Unprotected**	(386,377)
SOLAR ITC	258,917	0	258,917	90,621	(31,435)	0	(4,813)	54,373	0.21	**Unprotected**	(36,248)
UNBILLED CONSERVATION REV	1,868,924	0	1,868,924	720,937	(74,849)	0	(172,410)	473,679	0.25	**Unprotected**	(247,259)
UNBILLED ENVIRONMENTAL REV	3,643,458	0	3,643,458	1,405,464	(39,133)	0	(442,897)	923,434	0.25	**Unprotected**	(482,030)
UNBILLED REVENUE/FUEL	28,071,616	0	28,071,616	10,828,626	171,023	0	(3,884,898)	7,114,751	0.25	**Unprotected**	(3,713,875)
VACATION ACCRUAL	12,887,665	0	12,887,665	4,971,417	(35,401)	0	(1,669,637)	3,266,379	0.25	**Unprotected**	(1,705,038)
Total For Tampa Electric:	(5,369,289,404)	0	(5,369,289,404)	(1,361,050,138)	57,777,414	0	426,750,610	(876,522,114)			484,528,023

Summary

Row Labels	**Original**
Protected	313,545,025.49
Unprotected	170,982,997.98
Grand Total	484,528,023.47

	Current Law	**Proposed Rate**	
offset	-0.01925	-0.01155	0.0077
state	0.055	0.055	0
fed	0.33075	0.19845	-0.1323
st + offset	0.03575	0.04345	**0.0077**
fed stat.	0.35	0.21	-0.14
Net Fed & State	0.38575	0.25345	**-0.1323**
Norm Gross Up	0.62800	0.339495	**-0.288506618**

TAMPA ELECTRIC COMPANY
DOCKET NO. 20180045-EI
EXHIBIT NO. ___ (VS-1)
WITNESS: STRICKLAND
DOCUMENT NO. 2
PAGE 1 OF 2
FILED: 05/31/2018

Revised Estimate of Excess ADIT

M Item	Beginning Balance	True-Up Activity	Gross Timing Difference	DIT Beginning Balance	Current Activity	True up / Reclass Activity	Adjustment Activity	After Tax Deferred Tax Liability	Rate	Normalization	Excess DTL
401K - PERFORMANCE MATCH	1,413,314.26	0.00	1,413,314.26	545,185.97	-147,820.67	0.00	-39,160.81	358,204.49	0.25	Unprotected	-186,981.48
ACC DEF ITC 10% - 1975 - GT	-8.00	0.00	-8.00	-4.56	0.00	0.00	2.32	-2.24	0.28	Unprotected	2.32
ACC DEF ITC 10% - 1980	11,972.36	0.00	11,972.36	6,821.86	108.69	0.00	-3,562.79	3,367.76	0.28	Unprotected	-3,454.10
ACC DEF ITC 10% - 1981 - NU	351.10	0.00	351.10	200.06	5.00	0.00	-106.30	98.76	0.28	Unprotected	-101.30
ACC DEF ITC 10% - 1982	232,511.59	0.00	232,511.59	132,485.24	3,197.40	0.00	-70,278.54	65,404.10	0.28	Unprotected	-67,081.14
ACC DEF ITC 10% - 1982 - NU	739.16	0.00	739.16	421.17	10.10	0.00	-223.35	207.92	0.28	Unprotected	-213.25
ACC DEF ITC 10% - 1984	148,416.04	0.00	148,416.04	84,567.53	1,905.32	0.00	-44,724.32	41,748.53	0.28	Unprotected	-42,819.00
ACC DEF ITC 10% - 1984 - GT	17,832.46	0.00	17,832.46	10,160.94	228.79	0.00	-5,373.57	5,016.16	0.28	Unprotected	-5,144.78
ACC DEF ITC 10% - 1985 - GT	5,014.01	0.00	5,014.01	2,856.98	61.75	0.00	-1,508.32	1,410.41	0.28	Unprotected	-1,446.57
ACC DEF ITC 10% - 1986	299,659.84	0.00	299,659.84	170,746.34	3,557.59	0.00	-90,011.42	84,292.51	0.28	Unprotected	-86,453.83
ACC DEF ITC 10% - 1986 - GT	397.09	0.00	397.09	226.25	4.93	0.00	-119.48	111.70	0.28	Unprotected	-114.55
ACC DEF ITC 10% - 1987	125,422.32	0.00	125,422.32	71,465.71	1,433.30	0.00	-37,618.47	35,280.54	0.28	Unprotected	-36,185.17
ACC DEF ITC 10% - 1988	119,054.97	0.00	119,054.97	67,837.60	1,310.40	0.00	-35,658.56	33,489.44	0.28	Unprotected	-34,348.16
ACC DEF ITC 10% - 1989	21,364.42	0.00	21,364.42	12,173.46	226.76	0.00	-6,390.54	6,009.68	0.28	Unprotected	-6,163.78
ACC DEF ITC 10% - 1990	2,097.23	0.00	2,097.23	1,195.01	21.57	0.00	-626.63	589.95	0.28	Unprotected	-605.06
ACC DEF ITC 30% - 2015 - SOLAR	-122,411.12	0.00	-122,411.12	-69,749.92	17,297.73	0.00	18,018.68	-34,433.51	0.28	Unprotected	35,316.41
ACC DEF ITC 30% - 2016 - SOLAR	-47,754.96	0.00	-47,754.96	-27,210.80	13,227.93	0.00	549.69	-13,433.18	0.28	Unprotected	13,777.62
ACC DEF ITC 30% - 2017- SOLAR	-327,749.51	0.00	-327,749.51	-186,751.86	94,557.90	0.00	0.00	-92,193.96	0.28	Unprotected	94,557.90
ACC DEF ITC 8% - 1983	129,679.79	0.00	129,679.79	73,891.63	1,728.72	0.00	-39,142.20	36,478.15	0.28	Unprotected	-37,413.48
ACC DEF ITC 8% - 1983 - GT	2,283.15	0.00	2,283.15	1,300.94	30.30	0.00	-689.01	642.23	0.28	Unprotected	-658.71
ACC DEF ITC 8% - 1984	1,105,595.05	0.00	1,105,595.05	629,968.69	14,192.80	0.00	-333,164.29	310,997.20	0.28	Unprotected	-318,971.49
ACC DEF ITC 8% - 1985	703,159.24	0.00	703,159.24	400,660.53	8,680.88	0.00	-211,546.98	197,794.43	0.28	Unprotected	-202,866.10
ACC DEF ITC BB4 10% - 1981	168,850.53	0.00	168,850.53	96,211.13	2,084.47	0.00	-50,798.98	47,496.62	0.28	Unprotected	-48,714.51
ACC DEF ITC BB4 10% - 1982	1,286,919.57	0.00	1,286,919.57	733,287.51	15,888.05	0.00	-387,172.86	362,002.70	0.28	Unprotected	-371,284.81
ACC DEF ITC BB4 10% - 1984	737,252.64	0.00	737,252.64	420,086.97	9,102.10	0.00	-221,804.36	207,384.71	0.28	Unprotected	-212,702.26
ACC DEF ITC BB4 10% - 1986	28,182.23	0.00	28,182.23	16,058.25	334.40	0.00	-8,465.16	7,927.49	0.28	Unprotected	-8,130.76
ACC DEF ITC BB4 10% - 1987	26,418.77	0.00	26,418.77	15,053.43	301.78	0.00	-7,923.77	7,431.44	0.28	Unprotected	-7,621.99
ACC DEF ITC BB4 8% - 1983	2,009,194.50	0.00	2,009,194.50	1,144,840.18	24,804.93	0.00	-604,470.85	565,174.26	0.28	Unprotected	-579,665.92
ACC DEF ITC BB4 8% - 1984	539,795.27	0.00	539,795.27	307,575.65	6,664.21	0.00	-162,398.72	151,841.14	0.28	Unprotected	-155,734.51
ACC DEF ITC BB4 8% - 1985	260,111.54	0.00	260,111.54	148,211.70	3,211.36	0.00	-78,255.26	73,167.80	0.28	Unprotected	-75,043.90
ACCRUED BONUS	13,766,654.12	0.00	13,766,654.12	5,310,486.83	-252,249.82	0.00	-1,569,078.52	3,489,158.49	0.25	Unprotected	-1,821,328.34
AFUDC EQUITY	-189,962,004.49	0.00	-189,962,004.49	-73,277,843.23	208,610.15	0.00	24,923,363.04	-48,145,870.04	0.25	Unprotected	25,131,973.19
AFUDC EQUITY - DEPR	65,695,048.88	1,801,640.12	67,496,689.00	25,341,865.11	-955,393.33	-238,356.99	-7,736,061.64	16,412,053.15	0.25	Unprotected	-8,929,811.96
AMORT - BOND DISCOUNT	-584,472.08	0.00	-584,472.08	-225,460.10	-15,998.39	0.00	93,324.04	-148,134.45	0.25	Unprotected	77,325.65
AMORT - BOND ISSUE COSTS	-578,156.28	0.00	-578,156.28	-223,023.79	-21,995.40	0.00	98,485.48	-146,533.71	0.25	Unprotected	76,490.08
AMORT - BOND PREMIUM	-1,008,976.78	0.00	-1,008,976.78	-389,212.79	-30,591.86	0.00	164,079.49	-255,725.16	0.25	Unprotected	133,487.63
AMORTIZATION FED	-169,004,894.06	-1,232,001.94	-170,236,896.00	-59,151,712.92	-641,937.94	172,480.27	24,302,623.11	-35,318,547.48	0.21	Unprotected	23,833,165.44
AMORTIZATION STATE	-169,004,894.06	-1,232,001.94	-170,236,896.00	-6,041,924.96	35,306.58	-9,486.41	-1,336,644.26	-7,352,749.05	0.04	Unprotected	-1,310,824.09
BAD DEBT	762,122.54	0.00	762,122.54	293,988.77	8,611.27	0.00	-109,440.09	193,159.95	0.25	Unprotected	-100,828.82
CIAC	151,141,690.06	-69,660,837.06	81,480,853.00	58,302,906.94	-1,648,607.57	9,216,128.74	-18,347,438.03	47,522,990.08	0.25	Protected	-10,779,916.86
COST OF REMOVAL	-514,365,657.67	724,188,117.67	209,822,460.00	-198,416,552.44	6,804,611.67	-95,810,087.97	61,245,964.84	-226,176,063.90	0.25	Unprotected	-27,759,511.46
CURRENCY ADJ - UNREAL G/L	6,196.45	0.00	6,196.45	2,390.28	-880.07	0.00	60.27	1,570.48	0.25	Unprotected	-819.80
DEF SEP CO - EMERA FED NOL	0.00	0.00	0.00	0.00	-19,783,342.28	0.00	19,783,342.28	0.00	0.00	Unprotected	0.00
DEF SEP CO - EMERA FED NOL-PROTECTED	141,309,587.74	0.00	141,309,587.74	49,458,355.71	0.00	0.00	-19,783,342.28	29,675,013.43	0.21	Protected	-19,783,342.28
DEF SEP CO - FED NOL - UNPROTECTED	194,143,570.00	0.00	194,143,570.00	67,950,249.50	0.00	0.00	-27,180,099.80	40,770,149.70	0.21	Unprotected	-27,180,099.80
DEF SEP CO - FL NOL	0.00	0.00	0.00	0.01	0.00	0.00	-0.01	0.00	0.00	Unprotected	-0.01
DEF SEP CO - FL NOL - UNPROTECTED	268,538,363.00	0.00	268,538,363.00	9,600,246.47	0.00	0.00	2,067,745.41	11,667,991.88	0.04	Unprotected	2,067,745.41
DEFERRED COMP	248,190.04	0.00	248,190.04	95,739.30	-32,835.36	0.00	-0.17	62,903.77	0.25	Unprotected	-32,835.53
DEFERRED FUEL	-5,364,387.37	0.00	-5,364,387.37	-2,069,312.43	-373,436.07	0.00	1,083,144.51	-1,359,603.99	0.25	Unprotected	709,708.44
DEFERRED INTEREST - BONDS	-11,393,068.41	0.00	-11,393,068.41	-4,394,876.13	-460,633.82	0.00	1,967,936.76	-2,887,573.19	0.25	Unprotected	1,507,302.94
DEFERRED LEASE - NC	678,520.98	0.00	678,520.98	261,739.46	-7,927.90	0.00	-81,840.42	171,971.14	0.25	Unprotected	-89,768.32
DEPRECIATION - BOOK	-12,596,149.34	12,596,149.34	0.00	-4,858,964.61	-24,400.38	-1,666,470.56	1,690,870.94	-4,858,964.61	0.25	Protected	0.00
DEPRECIATION - BOOK TAX DIFF FED	-2,467,663,268.46	-355,107,918.54	-2,822,771,187.00	-863,682,143.96	50,072,377.41	49,715,108.60	295,400,480.17	-468,494,177.78	0.21	Protected	395,187,966.18
DEPRECIATION - BOOK TAX DIFF STATE	-1,793,631,217.86	-397,264,729.14	-2,190,895,947.00	-64,122,316.04	-798,172.94	-3,058,938.41	-13,012,787.43	-80,992,214.82	0.04	Protected	-16,869,898.78
DISMANTLEMENT COSTS	125,943,563.24	0.00	125,943,563.24	48,582,729.52	-156,920.24	0.00	-16,505,413.18	31,920,396.10	0.25	Unprotected	-16,662,333.42
DREDGING	-2,183,941.70	0.00	-2,183,941.70	-842,455.51	38,832.31	0.00	250,103.18	-553,520.02	0.25	Unprotected	288,935.49
FAS 106 - NC	81,591,563.31	0.00	81,591,563.31	31,473,945.55	756,479.63	0.00	-11,551,043.46	20,679,381.72	0.25	Unprotected	-10,794,563.83
FAS 106 FAS 158	3,119,528.00	0.00	3,119,528.00	1,203,357.93	0.00	0.00	-412,713.56	790,644.37	0.25	Unprotected	-412,713.56
FAS 106 FAS 158 - C	9,640,008.00	0.00	9,640,008.00	3,718,633.09	-121,384.59	0.00	-1,153,988.47	2,443,260.03	0.25	Unprotected	-1,275,373.06

M Item	Beginning Balance	True-Up Activity	Gross Timing Difference	DIT Beginning Balance	Current Activity	True up / Reclass Activity	Adjustment Activity	After Tax Deferred Tax Liability	Rate	Normalization	Excess DTL
FAS 106 FAS 158 - C 283	-9,640,008.00	0.00	-9,640,008.00	-3,718,633.09	121,384.59	0.00	1,153,988.47	-2,443,260.03	0.25	**Unprotected**	1,275,373.06
FAS 106 FAS 158 - NC	46,775,125.00	0.00	46,775,125.00	18,043,504.47	-2,465,563.43	0.00	-3,722,785.60	11,855,155.44	0.25	**Unprotected**	-6,188,349.03
FAS 106 FAS 158 - NC 283	-46,775,125.00	0.00	-46,775,125.00	-18,043,504.47	2,465,563.43	0.00	3,722,785.60	-11,855,155.44	0.25	**Unprotected**	6,188,349.03
FAS 112	13,977,835.00	0.00	13,977,835.00	5,391,949.86	212,172.01	0.00	-2,061,439.58	3,542,682.29	0.25	**Unprotected**	-1,849,267.57
FIBER OPTIC	383,749.84	0.00	383,749.84	148,031.50	11,693.21	0.00	-62,463.31	97,261.40	0.25	**Unprotected**	-50,770.10
G/L - SALE OF ASSETS	79,543.13	-79,543.13	0.00	30,683.76	1,957.65	10,523.56	-12,481.20	30,683.77	0.25	**Unprotected**	0.01
GENERAL BUSINESS CREDIT	-22,320,525.66	0.00	-22,320,525.66	22,320,525.66	0.00	0.00	0.00	22,320,525.66	0.00	**Unprotected**	0.00
INSURANCE RESERVE - C	0.00	0.00	0.00	0.00	-428,223.74	0.00	428,223.74	0.00	0.00	**Unprotected**	0.00
INSURANCE RESERVE - NC	-27,328,771.17	0.00	-27,328,771.17	-10,542,073.47	13,057,663.53	0.00	-9,442,067.11	-6,926,477.05	0.25	**Unprotected**	3,615,596.42
ITC 30% - SOLAR	14,407,398.00	0.00	14,407,398.00	8,209,343.60	-3,241,948.01	0.00	-914,681.67	4,052,713.92	0.28	**Unprotected**	-4,156,629.68
LEGAL EXPENSES	404,156.98	0.00	404,156.98	155,903.55	-49,674.23	0.00	-3,795.73	102,433.59	0.25	**Unprotected**	-53,469.96
LONG TERM INCENTIVE	6,046,167.72	0.00	6,046,167.72	2,332,309.19	-619,195.98	0.00	-180,712.01	1,532,401.20	0.25	**Unprotected**	-799,907.99
LOSS FROM GRANTOR TRUST	272,075.00	0.00	272,075.00	104,952.94	0.00	0.00	-35,995.53	68,957.41	0.25	**Unprotected**	-35,995.53
OCI FAS 133 - C	933,935.00	0.00	933,935.00	360,265.43	1,640,513.38	0.00	-1,764,072.98	236,705.83	0.25	**Unprotected**	-123,559.60
OCI FAS 133 - C 283	-933,935.00	0.00	-933,935.00	-360,265.43	-1,640,513.38	0.00	1,764,072.98	-236,705.83	0.25	**Unprotected**	123,559.60
OCI FAS 133 - NC	0.00	0.00	0.00	0.00	162,434.64	0.00	-162,434.64	0.00	0.00	**Unprotected**	0.00
OCI FAS 133 - NC 283	0.00	0.00	0.00	0.00	-162,434.64	0.00	162,434.64	0.00	0.00	**Unprotected**	0.00
OCI FAS 133 INTEREST - NC	2,309,241.18	0.00	2,309,241.18	890,789.78	117,265.04	0.00	-422,777.65	585,277.17	0.25	**Unprotected**	-305,512.61
PENSION - NC	-176,830,202.82	0.00	-176,830,202.82	-68,212,250.75	-66,382.18	0.00	23,461,018.02	-44,817,614.91	0.25	**Unprotected**	23,394,635.84
PENSION FAS 158	1,523,058.00	0.00	1,523,058.00	587,519.62	0.00	0.00	-201,500.57	386,019.05	0.25	**Unprotected**	-201,500.57
PENSION FAS 158 - NC	189,213,304.00	0.00	189,213,304.00	72,989,032.02	1,653,390.67	0.00	-26,686,310.79	47,956,111.90	0.25	**Unprotected**	-25,032,920.12
PENSION FAS 158 - NC 283	-189,213,304.00	0.00	-189,213,304.00	-72,989,032.02	-1,653,390.67	0.00	26,686,310.79	-47,956,111.90	0.25	**Unprotected**	25,032,920.12
RATE CASE EXPENSE - NC	-0.68	0.00	-0.68	-0.27	-62,609.18	0.00	62,609.28	-0.17	0.25	**Unprotected**	0.10
REPAIRS CAPITALIZED ON BOOKS	-1,213,986,281.49	-95,619,433.51	-1,309,605,715.00	-468,295,208.08	16,769,407.33	12,650,451.05	143,840,977.71	-295,034,371.99	0.25	**Unprotected**	173,260,836.09
RESTORATION PLAN	202,435.79	0.00	202,435.79	78,089.61	-7,698.94	0.00	-19,083.31	51,307.36	0.25	**Unprotected**	-26,782.25
RESTORATION PLAN FAS 158 - NC	381,200.00	0.00	381,200.00	147,047.90	57,749.89	0.00	-108,182.65	96,615.14	0.25	**Unprotected**	-50,432.76
RESTORATION PLAN FAS 158 - NC 283	-381,200.00	0.00	-381,200.00	-147,047.90	-57,749.89	0.00	108,182.65	-96,615.14	0.25	**Unprotected**	50,432.76
SEC 263A INDIRECT COSTS/BASIS ADJ	41,418,356.67	-34,484,150.67	14,192,517.49	15,977,131.08	-497,543.07	4,562,253.13	-4,982,105.51	15,059,735.63	0.25	**Unprotected**	-917,395.45
SEC 263A INTEREST CAP	216,688,306.18	-156,033,952.18	60,654,354.00	83,587,514.11	-91,793.06	20,643,291.87	-28,576,069.85	75,562,943.07	0.25	**Unprotected**	-8,024,571.04
SERP - NC	8,069,212.70	0.00	8,069,212.70	3,112,698.81	-113,746.13	0.00	-953,810.72	2,045,141.96	0.25	**Unprotected**	-1,067,556.85
SERP FAS 158	163,086.00	0.00	163,086.00	62,910.42	0.00	0.00	-21,576.27	41,334.15	0.25	**Unprotected**	-21,576.27
SERP FAS 158 - C	6,335,831.00	0.00	6,335,831.00	2,444,046.81	-810,181.26	0.00	-28,049.18	1,605,816.37	0.25	**Unprotected**	-838,230.44
SERP FAS 158 - C 283	-6,335,831.00	0.00	-6,335,831.00	-2,444,046.81	810,181.26	0.00	28,049.18	-1,605,816.37	0.25	**Unprotected**	838,230.44
SERP FAS 158 - NC	-2,920,464.00	0.00	-2,920,464.00	-1,126,568.99	928,211.51	0.00	-541,834.12	-740,191.60	0.25	**Unprotected**	386,377.39
SERP FAS 158 - NC 283	2,920,464.00	0.00	2,920,464.00	1,126,568.99	-928,211.51	0.00	541,834.12	740,191.60	0.25	**Unprotected**	-386,377.39
SOLAR ITC	258,917.49	0.00	258,917.49	90,621.12	-31,435.04	0.00	-4,813.41	54,372.67	0.21	**Unprotected**	-36,248.45
UNBILLED CONSERVATION REV	1,868,924.03	0.00	1,868,924.03	720,937.44	-74,848.84	0.00	-172,409.80	473,678.80	0.25	**Unprotected**	-247,258.64
UNBILLED ENVIRONMENTAL REV	3,643,458.18	0.00	3,643,458.18	1,405,463.99	-39,132.62	0.00	-442,896.89	923,434.48	0.25	**Unprotected**	-482,029.51
UNBILLED REVENUE/FUEL	28,071,615.89	0.00	28,071,615.89	10,828,625.82	171,023.03	0.00	-3,884,897.80	7,114,751.05	0.25	**Unprotected**	-3,713,874.77
VACATION ACCRUAL	12,887,665.10	0.00	12,887,665.10	4,971,416.82	-35,401.20	0.00	-1,669,636.90	3,266,378.72	0.25	**Unprotected**	-1,705,038.10
Total For Tampa Electric:	-5,369,289,403.60	-372,128,660.98	-5,734,159,753.09	-1,361,050,137.83	57,777,413.72	-3,813,103.12	426,750,609.75	-880,335,217.48			480,714,920.35

Summary

Row Labels	Original	reclass	Revised
Protected	313,545,025.49	34,209,782.77	347,754,808.26
Unprotected	170,982,997.98	(38,022,885.88)	132,960,112.10
Grand Total	484,528,023.47	-3,813,103.12	**480,714,920.35**

	Current Law	Proposed Rate	
offset	-0.01925	-0.01155	0.0077
state	0.055	0.055	0
fed	0.33075	0.19845	-0.1323
st + offset	0.03575	0.04345	**0.0077**
fed stat.	0.35	0.21	-0.14
Net Fed & State	0.38575	0.25345	**-0.1323**
Norm Gross Up	0.62800	0.339495	**-0.288506618**

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2018 Tax Expense Under the TCJA
Original Forecast of Total Income Tax Expense

	With Tax Reform	Without Tax Reform	Difference
==			
Book Income Before Tax	$ 459,420,220	$ 459,784,863	$ (364,643)
==			
Permanent Differences			
P100 MEALS & ENTERTAINMENT 50%	134,686	134,686	-
P130 CLUB DUES	26,576	26,576	-
P220 LOBBYING	96,800	96,800	-
P400 PENALTIES	75,000	75,000	-
P500 PRODUCTION DEDUCTION	-	(4,764,864)	4,764,864
T505 AFUDC EQUITY	(10,322,514)	(10,322,514)	-
T510 AFUDC EQUITY - DEPR	7,946,458	7,946,458	-
T511 SOLAR ITC	-	-	-
Total Permanent Differences	(2,042,994)	(6,807,858)	4,764,864
==			
Taxable Income	457,377,226	452,977,005	4,400,221
Statutory Tax Rate	0	0	
	115,922,258	174,735,880	(58,813,622)
Solar ITC Basis	125,919	209,865	(83,946)
Excess ADIT	(23,484,852)	(198,486)	(23,286,366)
Medicare Part D amortization	303,252	303,252	-
ITC Amortization	(1,453,868)	(1,453,868)	-
R&D Tax Credit	(5,308,968)	(5,308,968)	-
Total Income Tax	$ 86,103,740	$ 168,287,674	$ (82,183,934)

2018 Tax Expense Under the TCJA
Revised Forecast of Income Tax Expense

	With Tax Reform	Without Tax Reform	Difference
==			
Book Income Before Tax	$ 458,942,222	$ 459,334,263	$ (392,041)
==			
Permanent Differences			
P100 MEALS & ENTERTAINMENT 50%	134,686	134,686	-
P130 CLUB DUES	26,576	26,576	-
P400 PENALTIES	75,000	75,000	-
P500 PRODUCTION DEDUCTION	-	(4,764,864)	4,764,864
T505 AFUDC EQUITY	(10,322,514)	(10,322,514)	-
T510 AFUDC EQUITY - DEPR	7,946,458	7,946,458	-
T511 SOLAR ITC- basis difference	-	-	-
Total Permanent Differences	(2,139,794)	(6,904,658)	4,764,864
==			
Taxable Income	456,802,428	452,429,605	4,372,823
Statutory Tax Rate	0	0	
	115,776,575	174,524,720	(58,748,145)
Solar ITC Basis	125,919	209,865	(83,946)
Excess ADIT	(23,502,489)	(216,378)	(23,286,111)
Medicare Part D	303,252	303,252	-
ITC Amortization	(1,453,868)	(1,453,816)	(52)
R&D Tax Credit	(5,308,968)	(5,308,968)	-
Total Income Tax	$ 85,940,421	$ 168,058,675	$ (82,118,254)

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FLORIDA PUBLIC SERVICE COMMISSION

EXPLANATION: Provide the calculation of state and federal income taxes for the historical base year and the projected test year.

Type of data shown:
XX TAX YEAR 2018 WITH TAX REFORM
TAX YEAR 2018 WITHOUT TAX REFORM
Witness: V. Strickland

COMPANY: TAMPA ELECTRIC COMPANY

DOCKET NO. 20180045-EI

(Dollars in 000's)

Line		CURRENT TAX			DEFERRED TAX		
No.	DESCRIPTION	STATE	FEDERAL	TOTAL	STATE	FEDERAL	TOTAL
1							
2	INCOME PER BOOKS	$ 458,942	$ 458,942				
3							
4							
5	TEMPORARY ADJUSTMENTS TO TAXABLE INCOME (LIST)						
6	ADD: BOOK DEPRECIATION	316,474	316,474				
7	LESS: TAX DEPRECIATION	(460,733)	(441,330)				
8	TAX OVER BOOK DEPRECIATION	(144,259)	(124,856)		7,934	24,554	
9	BONUS ACCRUAL	3,460	3,460		(190)	(687)	
10	DEFERRED COMPENSATION	171	171		(9)	(34)	
11	MEDICAL & LIFE BENEFITS-FAS 106	(3,314)	(3,314)		182	658	
12	LONG TERM MEDICAL - FAS 112	(625)	(625)		34	124	
13	LONG TERM INCENTIVE	6,774	6,774		(373)	(1,344)	
14	PENSION	(19,633)	(19,633)		1,080	3,896	
15	RESTORATION PLAN	108	108		(6)	(21)	
16	SUPPLEMENTAL EXECUTIVE RETIREMENT PLAN	912	912		(50)	(181)	
17	VACATION	720	720		(40)	(143)	
18	BOND REFINANCING	3,507	3,507		(193)	(696)	
19	BAD DEBT	(42)	(42)		2	8	
20	DEFERRED FUEL	(14,236)	(14,236)		783	2,825	
21	DEFERRED LEASE - UTILITY	(20)	(20)		1	4	
22	DREDGING	936	936		(51)	(186)	
23	FIBER OPTIC	4	4		(0)	(1)	
24	INSURANCE RESERVE	(899)	(899)		49	178	
25	UNBILLED REVENUE	(3,820)	(3,820)		210	758	
26	AMORTIZATION	8,015	8,015		(441)	(1,591)	
27	CIAC	12,000	12,000		(660)	(2,381)	
28	COST OF REMOVAL	(30,432)	(30,432)		1,674	6,039	
29	DISMANTLEMENT COSTS	1,186	1,186		(65)	(235)	
30	GAIN/LOSS ON SALE OF ASSETS	(20)	(20)		1	4	
31	REPAIRS	(114,311)	(114,311)		6,287	22,685	
32	TAX INTEREST CAPITALIZED	9,889	9,889		(544)	(1,962)	
33	INDIRECT COSTS	10,323	10,323		(568)	(2,049)	
34	TOTAL TEMPORARY DIFFERENCES	(273,606)	(254,203)		15,048	50,222	
35							
36							
37							
38							
39	Total may not foot due to rounding.						

SCHEDULE C-22 — STATE AND FEDERAL INCOME TAX CALCULATION —

FLORIDA PUBLIC SERVICE COMMISSION

EXPLANATION: Provide the calculation of state and federal income taxes for the historical base year and the projected test year.

Type of data shown:
XX TAX YEAR 2018 WITH TAX REFORM
TAX YEAR 2018 WITHOUT TAX REFORM
Witness: V. Strickland

COMPANY: TAMPA ELECTRIC COMPANY

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(Dollars in 000's)

Line No.	DESCRIPTION	CURRENT TAX STATE	CURRENT TAX FEDERAL	CURRENT TAX TOTAL	DEFERRED TAX STATE	DEFERRED TAX FEDERAL	DEFERRED TAX TOTAL
1							
2	PERMANENT ADJUSTMENTS TO TAXABLE INCOME (LIST)						
3	50% MEALS	135	135				
4	CLUB DUES	27	27				
5	PENALTIES	75	75				
6	AFUDC EQUITY	(10,323)	(10,323)				
7	DEPR-AFUDC EQUITY	7,946	7,946				
8	SOLAR ITC		600				
9	TOTAL PERMANENT ADJUSTMENTS	(2,140)	(1,540)				
10							
11	STATE TAXABLE INCOME (L2+L34+L10)	183,196					
12	STATE INCOME TAX (5.5%)	10,076					
13	ADJUSTMENTS TO STATE INCOME TAX (LIST)						
14	OUT OF PERIOD ADJUSTMENTS						
15	TOTAL ADJUSTMENTS TO STATE INCOME TAX	-					
16							
17	MEDICARE PART D SUBSIDY AMORTIZATION				43		
18							
19	STATE INCOME TAX	$ 10,076			$ 15,091		
20							
21							
22							
23							
24							
25							
26							
27							
28							
29							
30							
31							
32							
33							
34							
35							
36							
37							
38							
39	Total may not foot due to rounding.						

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EXPLANATION: Provide the calculation of state and federal income taxes for the historical base year and the projected test year.

Type of data shown:
XX TAX YEAR 2018 WITH TAX REFORM
TAX YEAR 2018 WITHOUT TAX REFORM
Witness: V. Strickland

COMPANY: TAMPA ELECTRIC COMPANY

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(Dollars in 000's)

Line No.	DESCRIPTION	CURRENT TAX STATE	CURRENT TAX FEDERAL	CURRENT TAX TOTAL	DEFERRED TAX STATE	DEFERRED TAX FEDERAL	DEFERRED TAX TOTAL
1							
2	FEDERAL TAXABLE INCOME (L2+L34+L10-L13state)		193,123				
3	FEDERAL INCOME TAX (21%)		40,556				
4							
5	ADJUSTMENTS TO FEDERAL INCOME TAX						
6	OUT OF PERIOD ADJUSTMENTS						
7	TOTAL ADJUSTMENTS TO FEDERAL INCOME TAX		-				
8							
9	MEDICARE PART D SUBSIDY AMORTIZATION					260	
10							
11							
12	FEDERAL INCOME TAX		$ 40,556			$ 50,482	116,205
13							
14	ITC AMORTIZATION						(1,454)
15							
16	GENERAL BUSINESS CREDIT						(5,309)
17							
18	WRITE-OFF OF EXCESS DEFERRED TAXES BEFORE TAX REFORM						(216)
19	WRITE-OFF OF EXCESS DEFERRED TAXES RELATED TO TAX REFORM						(23,286)
20							
21	TOTAL INCOME TAXES						$ 85,940
22							
23							
24							
25							
26							
27							
28	SUMMARY OF INCOME TAX EXPENSE:						

Line No.		FEDERAL	STATE	TOTAL
29				
30	CURRENT TAX EXPENSE	$ 40,556	$ 10,076	$ 50,632
31	DEFERRED INCOME TAXES	50,482	15,091	65,574
32	INVESTMENT TAX CREDITS, NET	(1,454)		(1,454)
33	GENERAL BUSINESS CREDIT	(5,309)		(5,309)
34	WRITE-OFF OF EXCESS DEFERRED TAXES BEFORE TAX REFORM	(216)		(216)
35	WRITE-OFF OF EXCESS DEFERRED TAXES RELATED TO TAX REFORM	(23,286)		(23,286)
36	TOTAL INCOME TAX PROVISION	$ 60,773	$ 25,167	$ 85,940
37				
38				

39 Total may not foot due to rounding.

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EXPLANATION: Provide the calculation of state and federal income taxes for the historical base year and the projected test year.

Type of data shown:
TAX YEAR 2018 WITH TAX REFORM
XX TAX YEAR 2018 WITHOUT TAX REFORM
Witness: V. Strickland

COMPANY: TAMPA ELECTRIC COMPANY

DOCKET NO. 20180045-EI

(Dollars in 000's)

Line No.	DESCRIPTION	CURRENT TAX STATE	CURRENT TAX FEDERAL	CURRENT TAX TOTAL	DEFERRED TAX STATE	DEFERRED TAX FEDERAL	DEFERRED TAX TOTAL
1							
2	INCOME PER BOOKS	$ 459,334	$ 459,334				
3							
4							
5	TEMPORARY ADJUSTMENTS TO TAXABLE INCOME (LIST)						
6	ADD: BOOK DEPRECIATION	316,474	316,474				
7	LESS: TAX DEPRECIATION	(464,452)	(498,906)				
8	TAX OVER BOOK DEPRECIATION	(147,978)	(182,432)		8,139	61,004	
9	BONUS ACCRUAL	3,460	3,460		(190)	(1,144)	
10	DEFERRED COMPENSATION	171	171		(9)	(57)	
11	MEDICAL & LIFE BENEFITS-FAS 106	(3,314)	(3,314)		182	1,096	
12	LONG TERM MEDICAL - FAS 112	(625)	(625)		34	207	
13	LONG TERM INCENTIVE	6,774	6,774		(373)	(2,241)	
14	PENSION	(19,633)	(19,633)		1,080	6,494	
15	RESTORATION PLAN	108	108		(6)	(36)	
16	SUPPLEMENTAL EXECUTIVE RETIREMENT PLAN	912	912		(50)	(302)	
17	VACATION	720	720		(40)	(238)	
18	BOND REFINANCING	3,507	3,507		(193)	(1,159)	
19	BAD DEBT	(42)	(42)		2	14	
20	DEFERRED FUEL	(14,236)	(14,236)		783	4,709	
21	DEFERRED LEASE - UTILITY	(20)	(20)		1	7	
22	DREDGING	936	936		(51)	(310)	
23	FIBER OPTIC	4	4		(0)	(1)	
24	INSURANCE RESERVE	(899)	(899)		49	297	
25	UNBILLED REVENUE	(3,820)	(3,820)		210	1,263	
26	AMORTIZATION	8,015	8,015		(441)	(2,651)	
27	CIAC	12,000	12,000		(660)	(3,969)	
28	COST OF REMOVAL	(30,432)	(30,432)		1,674	10,065	
29	DISMANTLEMENT COSTS	1,186	1,186		(65)	(392)	
30	GAIN/LOSS ON SALE OF ASSETS	(20)	(20)		1	7	
31	REPAIRS	(114,311)	(114,311)		6,287	37,808	
32	TAX INTEREST CAPITALIZED	9,889	9,889		(544)	(3,271)	
33	INDIRECT COSTS	10,323	10,323		(568)	(3,414)	
34	TOTAL TEMPORARY DIFFERENCES	(277,325)	(311,779)		15,253	103,786	
35							
36							
37							
38							
39	Total may not foot due to rounding.						

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Type of data shown:
TAX YEAR 2018 WITH TAX REFORM
XX TAX YEAR 2018 WITHOUT TAX REFORM
Witness: V. Strickland

COMPANY: TAMPA ELECTRIC COMPANY

DOCKET NO. 20180045-EI

(Dollars in 000's)

Line		CURRENT TAX			DEFERRED TAX		
No.	DESCRIPTION	STATE	FEDERAL	TOTAL	STATE	FEDERAL	TOTAL
1							
2	PERMANENT ADJUSTMENTS TO TAXABLE INCOME (LIST)						
3	50% MEALS	135	135				
4	CLUB DUES	27	27				
5	PENALTIES	75	75				
6	PRODUCTION DEDUCTION	(4,765)	(4,765)				
7	AFUDC EQUITY	(10,323)	(10,323)				
8	DEPR-AFUDC EQUITY	7,946	7,946				
9	SOLAR ITC		600				
10	TOTAL PERMANENT ADJUSTMENTS	(6,905)	(6,305)				
11							
12	STATE TAXABLE INCOME (L2+L34+L10)	175,104					
13	STATE INCOME TAX (5.5%)	9,631					
14	ADJUSTMENTS TO STATE INCOME TAX (LIST)						
15	OUT OF PERIOD ADJUSTMENTS						
16	TOTAL ADJUSTMENTS TO STATE INCOME TAX	-					
17							
18	MEDICARE PART D SUBSIDY AMORTIZATION				43		
19							
20	STATE INCOME TAX	$ 9,631			$ 15,296		
21							
22							
23							
24							
25							
26							
27							
28							
29							
30							
31							
32							
33							
34							
35							
36							
37							
38							
39	Total may not foot due to rounding.						

FLORIDA PUBLIC SERVICE COMMISSION

EXPLANATION: Provide the calculation of state and federal income taxes for the historical base year and the projected test year.

Type of data shown:
TAX YEAR 2018 WITH TAX REFORM
XX TAX YEAR 2018 WITHOUT TAX REFORM
Witness: V. Strickland

COMPANY: TAMPA ELECTRIC COMPANY

DOCKET NO. 20180045-EI

(Dollars in 000's)

Line No.	DESCRIPTION	CURRENT TAX STATE	CURRENT TAX FEDERAL	CURRENT TAX TOTAL	DEFERRED TAX STATE	DEFERRED TAX FEDERAL	DEFERRED TAX TOTAL
1							
2	FEDERAL TAXABLE INCOME (L2+L34+L10-L13state)		131,619				
3	FEDERAL INCOME TAX (35%)		46,066				
4							
5	ADJUSTMENTS TO FEDERAL INCOME TAX						
6	OUT OF PERIOD ADJUSTMENTS						
7	TOTAL ADJUSTMENTS TO FEDERAL INCOME TAX		-				
8							
9	MEDICARE PART D SUBSIDY AMORTIZATION					260	
10							
11	FEDERAL INCOME TAX		$ 46,066			$ 104,046	175,038
12							
13	ITC AMORTIZATION						(1,454)
14							
15	GENERAL BUSINESS CREDIT						(5,309)
16							
17	WRITE-OFF OF EXCESS DEFERRED TAXES BEFORE TAX REFORM						(216)
18							
19							
20	TOTAL INCOME TAXES						$ 168,059
21							
22							
23							
24							
25							
26							
27							

Line No.	DESCRIPTION	FEDERAL	STATE	TOTAL
28	SUMMARY OF INCOME TAX EXPENSE:			
29		FEDERAL	STATE	TOTAL
30	CURRENT TAX EXPENSE	$ 46,066	$ 9,631	$ 55,696
31	DEFERRED INCOME TAXES	104,046	15,296	119,342
32	INVESTMENT TAX CREDITS, NET	(1,454)		(1,454)
33	GENERAL BUSINESS CREDIT	(5,309)		(5,309)
34	WRITE-OFF OF EXCESS DEFERRED TAXES BEFORE TAX REFORM	(216)		(216)
35	TOTAL INCOME TAX PROVISION	$ 143,133	$ 24,927	$ 168,059
36				
37				
38				
39	Total may not foot due to rounding.			

TAMPA ELECTRIC COMPANY
DOCKET NO. 20180045-EI
EXHIBIT NO. ___ (VS-1)
WITNESS: STRICKLAND
DOCUMENT NO. 4
PAGE 6 OF 6
FILED: 05/31/2018

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 20180045-EI

IN RE: CONSIDERATION OF THE TAX IMPACTS ASSOCIATED WITH TAX CUTS AND JOBS ACT OF 2017 FOR TAMPA ELECTRIC COMPANY

DIRECT TESTIMONY AND EXHIBIT

OF

JEFFREY S. CHRONISTER

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

JEFFREY S. CHRONISTER

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

A. My name is Jeffrey S Chronister. My business address is 702 North Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "the company") as Controller, Tampa Electric.

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

A. I am responsible for maintaining the financial books and records of the company and for the determination and implementation of accounting policies and practices for Tampa Electric. I am also responsible for budgeting activities within the company.

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

A. I graduated from Stetson University in 1982 with a

Bachelor of Business Administration degree in Accounting. Upon graduation I joined Coopers & Lybrand, an independent public accounting firm, where I worked for four years before joining Tampa Electric in 1986. I started in Tampa Electric's Accounting department, moved to TECO Energy's Internal Audit department in 1987, and returned to the company's Accounting department in 1991. I am a Certified Public Accountant in the State of Florida, and I am a member of both the American Institute of Certified Public Accountants ("AICPA") and the Florida Institute of Certified Public Accountants ("FICPA"). I have served in my current position as Controller of Tampa Electric since July 2009.

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

A. Yes, I have testified or filed testimony before this Commission in several dockets. Most recently, I filed testimony for Tampa Electric in Docket No. 20130040-EI, which was Tampa Electric's last base rate proceeding, on the same topics I testify to in this case. I testified in Docket No. 20080317-EI regarding Tampa Electric's petition for an increase in base rates and miscellaneous service charges. I filed testimony in Docket No. 19960007-EI, Tampa

Electric's environmental cost recovery clause, Docket No. 19960688-EI in support of Tampa Electric's petition for approval of certain environmental compliance activities for purposes of cost recovery, and most recently Docket No. 20170271-EI in support of Tampa Electric's petition for recovery of costs associated with named tropical systems during the 2015, 2016, and 2017 hurricane seasons and replenishment of storm reserve subject to final true-up.

Q. What are the purposes of your direct testimony in this proceeding?

A. The purposes of my direct testimony are to: (1) provide background information relevant to the calculation of the revenue requirement reduction required to reflect the recent changes in the Internal Revenue Code ("IRC"), including information about the company's 2017 Amended and Restated Stipulation and Settlement Agreement ("2017 Agreement") and Amended Implementation Stipulation, (2) sponsor the calculation of the annual revenue requirement reduction required by the 2017 Agreement, and (3) present information about how the recent federal income tax law changes will impact the company's financial condition in the future.

Q. How does your prepared direct testimony relate to the prepared direct testimonies of Tampa Electric witnesses Alan Felsenthal, Valerie Strickland, and William Ashburn?

A. Mr. Felsenthal's direct testimony discusses accounting for income taxes and related ratemaking principles, the recent changes caused by the Tax Cuts and Jobs Act of 2017 ("TCJA") and their general impact on regulated utilities, the ratemaking requirement in the TCJA for "protected excess deferred taxes" and the work his firm performed to test and verify the company's calculation of the impact of the TCJA on the company's 2018 forecasted income tax expense.

Ms. Strickland sponsors the company's calculation of the company's forecasted income tax expense for 2018, as originally presented in the company's approved 2018 operating budget and submitted in the company's earnings surveillance report in March 2018, and as adjusted to reflect the impact of the TCJA.

The calculation of the revenue requirement reduction required by the 2017 Agreement in my direct testimony uses Ms. Strickland's calculations of income tax expense before and after the TCJA as verified by Mr. Felsenthal.

Mr. Ashburn uses the calculation of the annual revenue requirement reduction required by the 2017 Agreement in my direct testimony to calculate the required customer rate reductions and provides related tariff sheets using the rate design and cost of service principles specified in the 2017 Agreement.

Q. Did you prepare an exhibit in support of your direct testimony?

A. Yes. Exhibit No. ___ (JSC-1) was prepared under my direction and supervision. My exhibit consists of the following six documents:

Document No. 1	2017 Agreement
Document No. 2	Amended Implementation Stipulation
Document No. 3	2018 Forecasted Earnings Surveillance Report as Filed on March 16, 2018
Document No. 4	2018 Forecasted Earnings Surveillance Report Updated for Effect of TCJA
Document No. 5	Calculation of Annual Revenue Requirement Reduction Required by the 2017 Agreement
Document No. 6	Calculation of the Adjustment to the Annual Revenue Requirement Reduction

Due to the First SoBRA Budget Difference and Tax Reform Adjustment

Background Information

Q. Has the Commission approved any agreements that address the impact of federal income tax reform on the company’s revenue requirement and customer rates?

A. Yes. There are two such agreements. The first is the 2017 Agreement. The second is a document we refer to as the “Amended Implementation Stipulation.”

Q. Please describe the 2017 Agreement.

A. On September 27, 2017, Tampa Electric, the Office of Public Counsel (“OPC” or “Citizens”), the Florida Industrial Power Users Group (“FIPUG”), the Florida Retail Federation (“FRF”), the Federal Executive Agencies (“FEA”), and the WCF Hospital Utility Alliance (“HUA”) (collectively, the “Consumer Parties”) entered into the 2017 Amended and Restated Stipulation and Settlement Agreement (“2017 Agreement”). Among other things, the 2017 Agreement amended and restated the stipulation that resolved the company’s 2013 rate case (“2013 Agreement”), extended the general base rate freeze included in the 2013 Agreement, limited fuel hedging and investments in natural gas reserves, and replaced the Generation Base Rate Adjustment ("GBRA") mechanism in the 2013 Agreement with a Solar Base Rate Adjustment ("SoBRA") mechanism. 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.

As it relates to this docket, Paragraph 9 of the 2017 Agreement addresses the procedures and principles to be followed should Congress change the rate of taxation of corporate income during the term of the 2017 Agreement. A copy of the 2017 Agreement is included as Document No. 1 in my exhibit.

Q. Did Congress change the rate of taxation of corporate income during the term of the 2017 Agreement?

A. Yes. The TCJA was enacted by the United States Congress on December 20, 2017 and was signed into law by the President on December 22, 2017. *See Tax Cuts and Jobs Act of 2017*, Pub. Law 115-97, 131 Stat. 2054 (2017). The TCJA triggered the provisions in paragraph 9 of the 2017 Agreement. In his prepared direct testimony, witness Felsenthal describes the changes in the TCJA applicable to public utilities like Tampa Electric, including the required ratemaking treatment for a category of deferred income taxes known as “protected excess deferred taxes.”

Q. Did the company prepare a preliminary estimate of the impact of the TCJA based on the principles and procedures in the 2017 Agreement?

A. Yes. In January 2018, the company estimated the impact of the TCJA to result in a reduction in annual revenue requirements of approximately $95 million for 2018 using the methodologies set forth in Paragraphs 9(b) and 9(c) of the 2017 Agreement.

Q. Please describe the Amended Implementation Stipulation.

A. The Amended Implementation Stipulation is a stipulation between the Consumer Parties and the company. It arose from discussions between the company and Consumer Parties regarding how to implement the storm cost recovery and tax reform provisions in paragraphs 5 and 9 of the 2017 Agreement, respectively. A copy of the Amended Implementation Stipulation is included as Document No. 2 of my exhibit.

Pursuant to paragraph 5 of the 2017 Agreement, Tampa Electric filed a Petition for Recovery of Costs Associated with Named Tropical Systems and Replenishment of Storm Reserve in Docket No. 20170271-EI on December 27, 2017. On January 30, 2018, the company filed an Amended Petition for Recovery of Costs Associated with Named Tropical Systems and Replenishment of Storm Reserve in the same docket ("Amended Storm Petition"). The Amended Storm Petition updated the total estimated storm restoration costs (approximately $102.5 million) from those set forth in the company's original petition and requested approval of revised storm cost recovery factors and tariff sheets to recover the company's proposed total updated storm restoration costs.

Recognizing that the company's estimate of the revenue requirement reduction to reflect tax reform was close to the company's estimate of storm costs to be recovered, Tampa Electric and the Consumer Parties entered into an Amended Implementation Stipulation, which was approved by the Commission on March 1, 2018. See Order No. PSC-2018-125-PCO-EI, issued on March 7, 2018 in Docket Nos. 20170271-EI and 20180013-PU.

Therein, Tampa Electric and the Consumer Parties agreed that Tampa Electric should effectively use the preliminary estimated annual TCJA tax savings reduction of approximately $95 million per year to avoid the need to charge customers for the estimated $102.5 million of storm damage costs that they would have otherwise been obligated to pay beginning in April 2018.

The Parties also recognized that because the estimated amounts of storm costs and tax savings were approximately the same, there was an opportunity to provide customers full credit for 100 percent of the estimated 2018 tax savings during calendar year 2018 and avoid collection of a surcharge from customers to recover the company's estimated storm damage costs by essentially "netting" the two amounts in 2018, subject to a determination of the final amounts for each and a true-up in 2019 through the conservation cost recovery clause.

The Amended Implementation Stipulation also states that the required one-time reduction to base rates to reflect the impact of the TCJA should occur in conjunction with the first billing cycle in January 2019.

Q. Will this docket be used to determine the final dollar amount of storm costs the company can recover under paragraph 5 of the 2017 Agreement?

A. No. That issue will be decided in Docket No. 20170271-EI. Once the final amount of recoverable storm costs is determined in Docket No. 20170271-EI, those storm costs can be "netted" against the revenue requirement reduction required by the 2017 Agreement as determined in this docket, and any true-up will be addressed in 2019 through the conservation cost recovery clause as contemplated in the 2017 Agreement.

Tax Reform Annual Revenue Requirement Reduction

Q. What procedures and principles were included in the 2017 Agreement to guide the company in the event Congress changed the rate of taxation of corporate income during the term of the 2017 Agreement?

A. The required procedures and principles to be followed are contained in paragraph 9 of the 2017 Agreement. Five key provisions are listed below.

First, according to paragraph 9(a), "[t]o the extent Tax Reform includes a transition rule applicable to excess deferred federal income tax assets and liabilities ("Excess

Deferred Taxes"), defined as those that arise from the re-measurement of those deferred federal income tax assets and liabilities at the new applicable corporate tax rate(s), those Excess Deferred Taxes will be governed by the Tax Reform transition rule, as applied to most promptly and effectively reduce Tampa Electric's rates consistent with the Tax Reform rules and normalization rules."

As explained in the testimony of witness Felsenthal, the TCJA prescribes the Average Rate Assumption Method ("ARAM") as the transition rule for a category of excess deferred taxes known as "protected excess deferred taxes." As discussed in the prepared direct testimony of witness Strickland, the company had protected excess deferred taxes in the amount of $347.8 million as of December 31, 2017 and has used the ARAM to calculate the "flowback" of protected excess deferred taxes in its calculation of the revenue requirement reduction for tax reform required by the 2017 Agreement.

Second, according to paragraph 9(b), "[i]f Tax Reform is enacted before the company's next general base rate proceeding, the company will quantify the impact of Tax Reform on its Florida retail jurisdictional net operating income thereby neutralizing the FPSC adjusted net operating income of the Tax Reform to a net zero [and] [t]he company's forecasted earnings surveillance report for the calendar year that includes the period in which Tax Reform is effective will be the basis for determination of the impact of Tax Reform."

The provisions of the TCJA became effective January 1, 2018, so the company used its forecasted earnings surveillance report for 2018, which is provided as Document No. 4 of my exhibit, to compute the impact of the TCJA on the company's revenue requirement and customer rates. I describe these calculations later in my testimony.

Third, paragraph 9(b) also states that the company will make a one-time reduction to base rates, which shall be accomplished through "a uniform percentage decrease to customer, demand and energy base rate charges for all retail customer classes." The application of this provision is addressed in the testimony of witness Ashburn.

Fourth, pursuant to paragraph 9(c), "[a]ll Excess Deferred Taxes shall be deferred to a regulatory asset or liability which shall be included in FPSC adjusted capital structure and flowed back to customers over a term consistent with law."

As explained in the prepared direct testimony of witness Strickland, the company estimated its excess Accumulated Deferred Income Taxes ("ADIT") which were recorded in its accounting books and records as of December 31, 2017 in the amount of $484.5 million in accordance with this provision of the agreement. In May 2018, the company revised its estimated excess ADIT to $480.7 million based on the completion of Tampa Electric's 2017 federal income tax return for plant related book-tax differences, for a reduction of $3.8 million from the original amount.

Fifth, with respect to excess deferred taxes not governed by a transition rule ("unprotected excess deferred taxes"), paragraph 9(c) states "there shall be a rebuttable presumption that the following flow-back period(s) will apply: (1) if the cumulative net regulatory liability is less than $100 million, the flow-back period will be five years; or (2) if the cumulative net regulatory liability is greater than $100 million, the flow-back period will be ten years."

As explained in the testimony of witness Strickland, the company had unprotected excess deferred taxes in the amount of $133.0 million as of December 31, 2017, so the company has used a 10-year flow-back period in its calculation of the annual revenue requirement reduction for tax reform required by the 2017 Agreement.

Q. Based on these principles and procedures, what is the annual revenue requirement reduction necessary to account for the effects of TCJA in accordance with the 2017 Agreement?

A. The annual revenue requirement reduction necessary to account for the effects of TCJA in accordance with the 2017 Agreement, prior to applying an adjustment to reflect the difference between budgeted and actual SoBRA revenue requirements and avoid double-counting the effects of tax reform for the company's SoBRA which is effective beginning in September 2018 ("First SoBRA"), is $104,805,004. A document summarizing the calculation of this amount is included as Document No. 5 of my exhibit. I explain the First SoBRA adjustment later in my testimony.

Q. How was this revenue requirement reduction amount calculated?

A. The annual revenue requirement reduction was calculated by comparing the net operating income ("NOI") in two forecasted earnings surveillance reports – one without the effects of tax reform and one with the effects of tax reform.

Q. How were the two forecasted earnings surveillance reports prepared?

A. The preparation began with the creation of the 2018 budget using the company’s normal budgeting process. To deal with the issue of tax reform appropriately, the board-approved budget was updated to reflect December 2017 actual general ledger account balances, which reflected the necessary 2017 postings related to the TCJA. This 2018 budget was used as the basis of both the company’s 2018 forecasted earnings surveillance report (“ESR”), filed with the Commission on March 16, 2018 without the impact of tax reform and the 2018 forecasted ESR updated for the effects of the TCJA.

Q. Please provide additional detail on how the annual revenue requirement reduction was calculated.

A. The calculation began with the company’s 2018 forecasted ESR, filed with the Commission on March 16, 2018. This ESR was prepared based on the company’s 2018 operating budget, which was approved by company management in March 2018, and reflects income tax expense calculated on a pre-TCJA basis. The company’s forecasted FPSC adjusted 13-month average net operating income per the March 16, 2018 forecasted ESR is $360,092,378, a number I will refer to as the "Benchmark NOI."

The next step was to adjust the company's forecasted 2018 ESR to reflect the impact of the TCJA. Document No. 4 of my exhibit contains the company's forecasted 2018 ESR adjusted for the impact of the TCJA and includes the post-TCJA tax expense amount calculated by Ms. Strickland. The company's forecasted FPSC adjusted 13-month average net operating income per 2018 forecasted ESR as adjusted for tax reform is $438,334,554, a number I will refer to as the "Post-TCJA NOI."

The third step in the calculation was to compare the Post-TCJA NOI amount in Document No. 4 of my exhibit to the Benchmark NOI amount in Document No. 3 of my exhibit and to calculate the annual revenue requirement reduction necessary to make the company's NOI for 2018 adjusted for the impact of TCJA equal to the Benchmark NOI. This calculation is shown in Document No. 5 of my exhibit.

The final step was to adjust the annual revenue requirement calculated in the third step to reflect the revision the company made to its proposed First SoBRA, to reflect the impact of the TCJA as well as adjust for differences between actual and budgeted SoBRA revenue requirements.

Q. Please explain the First SoBRA adjustment.

A. On December 14, 2017, the company filed a petition for a limited proceeding to approve its First SoBRA in Docket No. 20170260-EI. Therein, the company requested approval to increase base rates in an amount sufficient to recover the $26,493,000 annual revenue requirement associated with its Payne Creek and Balm solar projects, which are expected to be in service on September 1, 2018. The $26,493,000 in annual revenue requirements was $4,107,000 less than the $30,600,000 (or $10,200,000 for four months) reflected in the 2017 Agreement and included in the budgeted surveillance report. The tariffs filed by the company for the First SoBRA reflect this $26,493,000 annual revenue requirement amount, but because the tariffs will not become effective until the first billing cycle in September 2018, the amount of First SoBRA revenue to be collected in 2018 (four months) was estimated to be $8,831,000 or $1,369,000 less than what was included for budget purposes. This revenue from the First SoBRA was calculated before the TCJA was enacted or became effective and was included in the company's 2018 operating budget, which serves as the basis of the company’s 2018 forecasted ESR as presented in Document No. 3 of my exhibit.

Paragraph 9(b) of the 2017 Agreement requires that Tampa Electric adjust any SoBRA not yet in effect to “specifically account for Tax Reform.” Consequently, on February 14, 2018, the company filed an Amendment to its petition in Docket No. 20170271-EI to adjust the proposed rates associated with the First SoBRA to reflect the impact of the TCJA. The effects of the TCJA required a downward adjustment to the projected annual revenue requirement for the two First SoBRA projects from $26,493,000 to $24,245,000 and a corresponding downward adjustment to the 2018 four-month recovery amounts from $8,831,000 to $8,081,667, or a difference of $749,333. Since the annual revenue requirement reduction calculated in Step 3 was based on all of the company’s budgeted revenues or $30,600,000 (including four months recovery of the pre-TCJA First SoBRA), and the company has revised the First SoBRA to reflect tax reform, the number calculated in step 3 must be reduced by $2,118,333, which includes $749,333 for the impact associated with the TCJA to avoid double-counting the tax savings associated with the First SoBRA plus the $1,369,000 difference between budgeted and actual revenue requirements included for the First SoBRA. This calculation is shown in Document No. 6 of my exhibit.

Q. So, with that explanation, what is the one-time annual revenue requirement reduction, as required in the 2017 Agreement, to account for the impact of the TCJA?

A. The one-time annual revenue requirement reduction to account for the impact of the TCJA is $102,686,671. This calculation is shown in Document No. 5 of my exhibit. The customer rate and tariff changes necessary to implement this reduction are presented and explained in the prepared direct testimony of witness Ashburn.

Future Impacts of TCJA

Q. In his prepared direct testimony, Mr. Felsenthal describes the general effects the TCJA will have on regulated utilities like Tampa Electric. Has the company looked beyond 2018 to assess the impacts the TCJA will have on its financial condition?

A. Yes. It is important for the company and the Commission to consider the impacts of the TCJA beyond 2018, because it will impact the company’s financial integrity in three ways: (1) the TCJA decreases operating cash flows, (2) the

TCJA increases required equity support in the capital structure due to the reduction in ADIT balances, and (3) the TCJA increases the overall weighted cost of capital.

Q. How does the TCJA decrease operating cash flows?

A. The decrease in operating cash flows results from the flowback of excess deferred taxes plus the elimination of bonus depreciation for regulated utilities. As discussed in the prepared direct testimony of Ms. Strickland, the TCJA exempted regulated utilities from the new 100 percent asset expensing provision. The TCJA phase out of bonus depreciation and the exemption from 100 percent asset expensing will result in reduced deferred taxes and greater current taxes payable, which reduces operating cash flows. This will adversely impact Tampa Electric's credit metrics, specifically Funds From Operations to Debt.

Q. Please explain why the company's deferred tax balances will change as a result of the TCJA.

A. Starting in the year 2002, the IRS established bonus depreciation as an income tax deduction. Bonus depreciation allowed companies like Tampa Electric to deduct a large percentage (50 percent in most years) of an asset's cost as tax depreciation in the first year of service. Bonus depreciation deductions substantially reduced taxable income, reduced current taxes payable and increased ADIT. Tampa Electric used bonus depreciation in its tax calculations since 2002. Doing so, together with the normalization requirement, generated large amounts of deferred taxes and caused a substantial increase in the company's ADIT balances.

As noted by witnesses Felsenthal and Strickland, however, the TCJA eliminated the use of bonus depreciation for regulated utilities, and substituted the Modified Accelerated Cost Recovery System ("MACRS") in its place. Although the MACRS is a form of accelerated cost recovery and will still generate deferred taxes in the early years of an asset's life, the elimination of bonus depreciation over time will substantially reduce the relative dollar value of ADIT on the company's balance sheet.

Furthermore, as witnesses Felsenthal and Strickland have explained in detail, the company has revalued its ADIT balances as of December 31, 2017 to reflect the tax rate reduction in the TCJA and identified "excess deferred taxes" that must be flowed back to customers as a reduction of income tax expense in accordance with the IRC and the

2017 Agreement. Over time, the flowback of excess ADIT will further reduce the amount of ADIT in the company's capital structure.

Q. How do the changes in Tampa Electric's deferred tax balances affect the elements of the company's capital structure?

A. As noted by witness Felsenthal, ADIT are often considered a no interest loan and, in Florida, are considered a zero-cost source of capital in a public utility's capital structure. Since the company's rate base and capital structure are synchronized in the ratemaking process, a relative reduction in the amount of zero-cost ADIT must be made up with relatively higher amounts of debt and equity, both of which have a cost. The financial equity ratio can remain constant, but the relative reduction in the dollar amount of ADIT drives a need for debt and equity dollar support to be higher. Because both debt and equity have a cost and ADIT does not, tax reform and the relative reduction of ADIT will cause the overall weighted average cost of capital ("WACC") to increase. Since the WACC is an important part of the revenue requirement calculation, the portions of the TCJA that reduce ADIT actually put upward pressure on the revenue requirement of a public utility like Tampa Electric.

Q. How are the changes in equity support of rate base likely to impact the company's ability to earn a reasonable rate of return on equity with pre-TCJA NOI levels?

A. As mentioned above, the required equity dollar support of rate base will increase in future years. With an increasing equity denominator, unchanging projected NOI levels will produce a lower Return on Equity ("ROE") percentage in the future. Thus, the relative reduction of ADIT and the corresponding increase in equity support caused by the TCJA will cause earned ROE to be lower than it would otherwise be without the TCJA.

Q. Has the company modeled this ADIT decrease and the corresponding earned ROE reductions?

A. Yes. Our financial models indicate that ADIT balances will be lower than pre-TCJA projections by almost $200 million by the end of 2019, by almost $250 million by the end of 2021, and by almost $350 million by the end of 2023. This could potentially reduce earned ROE in each year in amounts from 50 to 130 basis points.

Summary

Q. Please provide a summary of your direct testimony.

A. My testimony provides background information relevant to the calculation of the revenue requirement reduction required to reflect the TCJA and the guidelines reflected in the company’s 2017 Agreement and Amended Implementation Stipulation. My testimony demonstrates how the annual revenue requirement reduction was calculated. Finally, my testimony discusses how the TCJA will adversely impact the company’s financial condition in the future.

Q. Does this conclude your prepared direct testimony?

A. Yes, it does.

EXHIBIT

OF

JEFFREY S. CHRONISTER

TAMPA ELECTRIC COMPANY
DOCKET NO. 20180045-EI
EXHIBIT NO. ____ (JSC-1)
WITNESS: CHRONISTER

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BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition by Tampa Electric Company for a limited proceeding to approve 2017 Amended and Restated Stipulation and Settlement Agreement	)))	DOCKET NO. 2017 _____-EI
In re: Tampa Electric Company's Petition for Approval of Energy Transaction Optimization Mechanism	))))	DOCKET NO. 20160160-EI FILED: September 27, 2017

2017 AMENDED AND RESTATED STIPULATION AND SETTLEMENT AGREEMENT

THIS AGREEMENT is dated this 27th day of September, 2017 and is by and between Tampa Electric Company ("Tampa Electric" or the "company"), the Office of Public Counsel ("OPC" or "Citizens"), the Florida Industrial Power Users Group ("FIPUG"), the Florida Retail Federation ("FRF"), the Federal Executive Agencies ("FEA"), and the WCF Hospital Utility Alliance ("HUA"). Collectively, Tampa Electric, OPC, FIPUG, FRF, FEA, and HUA shall be referred to herein as the "Parties" and the term "Party" shall be the singular form of the term "Parties." OPC, FIPUG, FRF, FEA, and HUA will be referred to herein as the "Consumer Parties." This document shall be referred to as the "2017 Agreement."

Background

On September 8, 2013, Tampa Electric and the Consumer Parties filed a Stipulation and Settlement Agreement ("2013 Stipulation") that resolved all the issues in Tampa Electric's 2013 base rate case (Docket No. 20130040-EI). Therein, among other things, Tampa Electric agreed that the general base rates provided for in the 2013 Stipulation would remain in effect through December 31, 2017, and thereafter, until the company's next general base rate case. The 2013

Stipulation also specified that Tampa Electric would forego seeking future general base rate increases with an effective date prior to January 1, 2018, except in limited circumstances. The Florida Public Service Commission ("FPSC" or "Commission") approved the 2013 Stipulation and memorialized its decision in Order No. PSC-2013-0443-FOF-EI, issued September 30, 2013 ("2013 Stipulation Order").

In late 2016, recognizing that the period in which Tampa Electric agreed to refrain from seeking general base rate increases would expire at the end of 2017, Tampa Electric and the Consumer Parties began discussing whether the company would be willing and able to (a) refrain from seeking a general base rate increase beyond December 31, 2017 and (b) extend the terms of the 2013 Stipulation for an additional period of time. The Parties also discussed the company's desire to build 600 MW of solar photovoltaic generation with cost recovery via a solar base rate adjustment mechanism ("SoBRA").

The Parties have entered into this 2017 Agreement in compromise of positions taken in accord with their rights and interests under Chapters 350, 366 and 120, Florida Statutes, as applicable, and as part of a negotiated exchange of consideration among the Parties to this 2017 Agreement, each Party has agreed to concessions to the others with the expectation, intent, and understanding such that all provisions of the 2017 Agreement, upon approval by the Commission, will be enforced by the Commission as to all matters addressed herein with respect to all Parties.

NOW, THEREFORE, in light of the mutual covenants of the Parties and the benefits accruing to all Parties through this 2017 Agreement, and for good and valuable consideration, the receipt and sufficiency of which is hereby acknowledged, the Parties agree as follows:

1. Term.

This 2017 Agreement will become effective upon the date of the Commission's vote approving it (the "Effective Date") and continue through and including December 31, 2021, such that, except as specified in this 2017 Agreement, no base rates, charges, or credits (including the credits that are specifically the subject of this 2017 Agreement) or rate design methodologies will be changed before January 1, 2022. The period from the Effective Date through December 31, 2021 (subject to Paragraph 7(c)) shall be referred to herein as the "Term". The Parties reserve all rights, unless such rights are expressly waived or released, under the terms of this 2017 Agreement.

2. Return on Equity and Equity Ratio.

(a) Subject to the adjustment Trigger provisions in Subparagraph 2(b), Tampa Electric's authorized return on common equity ("ROE") shall be within a range of 9.25% to 11.25%, with a mid-point of 10.25%, except under the conditions specifically provided in this 2017 Agreement in Paragraphs 2(b) and 7. Tampa Electric's authorized ROE range and mid-point shall be used for all regulatory purposes during the Term, together with an equity ratio as follows: (a) a 54% equity ratio for the SoBRA revenue requirement calculations, (b) the company's actual equity ratio for earnings surveillance reporting, and (c) the actual equity ratio up to a cap of 54% for purposes of setting cost recovery clause rates, triggering an exit from this 2017 Agreement pursuant to paragraph 7, or calculating interim rates.

(b) ROE Trigger Mechanism. The purpose of the provisions in this Subparagraph 2(b) is to provide Tampa Electric with rate relief in the event that market capital costs, as indicated by the interest rate on U.S. Treasury bonds, rise above the level specified herein; these provisions are generically referred to as the "Trigger" mechanism or the "Trigger provisions," or simply as the "Trigger." If at any time during the Term, the average 30-year United States Treasury Bond yield rate for any period of six (6) consecutive months is at least 4.6039% (the "Trigger Point")[1], Tampa Electric's authorized ROE shall be increased by 25 basis points to be within a range of 9.50% to 11.50%, with a mid-point of 10.50% ("Revised Authorized ROE") from the Trigger Effective Date defined below for and through the remainder of the Term, and thereafter until the Commission resets the Company's rates and its authorized ROE. The Trigger Criterion Value ("Trigger Value") shall be calculated by summing the reported 30-year U.S. Treasury Bond rates for each day over a consecutive six-month period for which rates are reported, and dividing the resulting sum by the number of reporting days in such period. The effective date of the Revised Authorized ROE ("Trigger Effective Date") shall be the first day of the month following the day in which the Trigger Value reaches the Trigger Point. If the Trigger Point is reached and the Revised Authorized ROE becomes effective, Tampa Electric's Revised Authorized ROE range and mid-point shall be used for the remainder of the Term for all regulatory purposes, and thereafter until changed by a final non-appealable order ("Final Order") of the Commission.

(c) The ROE in effect at the expiration of the Term of this 2017 Agreement shall continue in effect until the company's ROE is next reset by a Final Order of the Commission whether by operation of Paragraph 7 or otherwise.

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[1] This value was derived as provided for in the 2013 Stipulation and reflected in Late Filed Hearing Exhibit 246, in Docket No. 130040-EI as follows: "The Trigger shall be calculated by summing the reported 30-year U.S. Treasury Bond rates for each day over any six-month period, e.g. January 1, 2014 through July 1, 2014, or March 17, 2014 through September 17, 2014, for which rates are reported, and dividing the resulting sum by the number of reporting days in such period."

3. Customer Rates.

(a) Except as specified in this 2017 Agreement, the company's general base rates, charges, credits, and rate design methodologies, for retail electric service in effect on December 31, 2017, shall remain in effect for service rendered and charges imposed through and including December 31, 2021, and thereafter until revised by a future unanimous agreement of the Parties approved by a Final Order of the Commission or a Final Order of the Commission issued as the result of a future general base rate proceeding.

(b) Except as specified in this 2017 Agreement, the company may not petition to change any of its general base rates, charges, credits, or rate design methodologies for retail electric service with an effective date for the new rates, charges, credits, or rate design methodologies earlier than January 1, 2022.

(c) Notwithstanding Subparagraphs 3(a) and 3(b), the company shall be authorized to change its base rates as set forth in Paragraphs 6 and 9, below, in accordance with procedures identified for the SoBRA mechanism and to reduce rates in accordance with Federal Income Tax Reform that may occur during the Term of this 2017 Agreement.

(d) The current lock period for the Contracted Credit Value ("CCV") shall remain 72 months (6 years).

(e) The company's standby generator credit shall be increased from $4.75/kW/month to $5.35/kW/month, concurrent with meter reads for the first billing cycle of January 2018. The CCV credit shall be increased from $9.98/kW/month to $10.23/kW/month for secondary, $9.88/kW/month to $10.13/kW/month for primary, and $9.78/kW/month to $10.03/kW/month for sub-transmission voltage customers, concurrently with meter readings for the first billing cycle of January 2018. To the extent that implementation of these revised credits results in an under-recovery or over-recovery of revenues that are subject to the Energy Conservation Cost Recovery ("ECCR") clause, the company shall be authorized to make an adjustment to remedy any such under-recovery or over-recovery in its ECCR charges for 2019 and thereafter. The level of these credits will not change during the Term and will remain in effect after the expiration of the Term until changed, if at all, by a future unanimous agreement of the Parties approved by a Final Order of the Commission or a Final Order of the Commission issued as a result of a future general base rate proceeding. The credit modifications addressed in this Subparagraph 3(e) are reflected in the revised tariff sheets set forth in Exhibit A to this 2017 Agreement, the approval of which shall constitute approval of the revised tariff sheets.

(f) The company's Economic Development Rider, which is set forth in Rate Schedule ECONOMIC DEVELOPMENT RATE – EDR of the company's retail tariff, shall remain in effect during the Term and thereafter until modified or terminated by order of the Commission. The Parties intend that the Commission's approval of this 2017 Agreement shall constitute continuing approval of the Economic Development Rider and that such approval shall satisfy the requirements of Rule 25-6.0426(3) - (6), F.A.C., and accordingly, the reductions afforded in Rate Schedule EDR shall be included as a cost in the company's cost of service for all ratemaking purposes and surveillance reporting. The rates in the Economic Development Rider shall be open for new customers and for new applications by existing customers through December 31, 2021, unless the maximum amount of economic development expenditures as specified in Rule 25-6.0426, F.A.C., is met, at which time the Economic Development Rider will be closed to new customers and to new applications by existing customers until the amount again falls below the maximum allowed.

(g) The provisions of this Paragraph 3 shall remain in effect during the Term except as otherwise permitted or provided for in this 2017 Agreement and shall continue in effect until changed by unanimous agreement of the Parties approved by a Final Order of the Commission or a Final Order of the Commission issued as a result of a future general base rate proceeding.

4. Other Cost Recovery. Nothing in this 2017 Agreement shall preclude the company from requesting the Commission to approve the recovery of costs that are: (a) of a type which traditionally or historically would be, have been, or are presently recovered through cost recovery clauses or surcharges, or (b) incremental costs not currently recovered in base rates which the Legislature expressly requires shall be clause recoverable subsequent to the approval of this 2017 Agreement. It is the intent of the Parties that, in conjunction with the provisions of Subparagraph 3(a), the company shall not seek to recover, nor shall the company be allowed to recover, through any cost recovery clause or charge, or through the functional equivalent of such cost recovery clauses and charges, costs of any type or category that have historically or traditionally been recovered in base rates, unless such costs are: (i) the direct and unavoidable result of new governmental impositions or requirements; or (ii) new or atypical costs that were unforeseeable and could not have been contemplated by the Parties resulting from significantly changed industry-wide circumstances directly affecting the company's operations. As a part of the base rate freeze agreed to herein, the company will not seek Commission approval to defer for later recovery in rates, any costs incurred or reasonably expected to be incurred from the Effective Date through and including December 31, 2021, which are of the type which historically or traditionally have been or would be recovered in base rates, unless such deferral and subsequent recovery is expressly authorized herein or otherwise agreed to by each of the Parties. The Parties are not precluded from participating in any proceedings pursuant to this

Paragraph 4, nor is any Party precluded from raising any issues pertinent to any such proceedings.

5. Storm Damage.

(a) Nothing in this 2017 Agreement shall preclude Tampa Electric from petitioning the Commission to seek recovery of costs associated with any tropical systems named by the National Hurricane Center or its successor without the application of any form of earnings test or measure and irrespective of previous or current base rate earnings. Consistent with the rate design methods approved in this 2017 Agreement, the Parties agree that recovery of storm costs from customers will begin, on an interim basis (subject to refund following a hearing or a full opportunity for a formal proceeding), sixty days following the filing of a cost recovery petition and tariff with the Commission and will be based on a 12-month recovery period if the storm costs do not exceed $4.00/1,000 kWh on monthly residential customer bills. In the event the company's reasonable and prudent storm costs exceed that level, any additional costs in excess of $4.00/1,000 kWh shall be recovered in a subsequent year or years as determined by the Commission, after hearing or after the opportunity for a formal proceeding has been afforded to all substantially affected persons or parties. All storm related costs shall be calculated and disposed of pursuant to Rule 25-6.0143, F.A.C., and shall be limited to (i) costs resulting from a tropical system named by the National Hurricane Center or its successor, (ii) the estimate of incremental storm restoration costs above the level of storm reserve prior to the storm, and (iii) the replenishment of the storm reserve to $55,860,642. The Parties to this 2017 Agreement are not precluded from participating in any such proceedings and opposing the amount of Tampa Electric's claimed costs (for example, and without limitation, on grounds that such claimed costs were not reasonable or were not prudently incurred) or whether the proposed recovery is consistent with this Paragraph 5, but not the mechanism agreed to herein.

(b) The Parties agree that the $4.00/1,000 kWh cap in this Paragraph 5 shall apply in aggregate for a calendar year; provided, however, that Tampa Electric may petition the Commission to allow Tampa Electric to increase the initial 12 month recovery at rates greater than $4.00/1,000 kWh or for a period longer than 12 months if Tampa Electric incurs in excess of $100 million of storm recovery costs that qualify for recovery in a given calendar year, inclusive of the amount needed to replenish the storm reserve to $55,860,642. All Consumer Parties reserve their right to oppose such a petition.

(c) The Parties expressly agree that any proceeding to recover costs associated with any storm shall not be a vehicle for a "rate case" type inquiry concerning the expenses, investment, or financial results of operations of Tampa Electric and shall not apply any form of earnings test or measure or consider previous or current base rate earnings. Such issues may be fully addressed in any subsequent Tampa Electric base rate case.

(d) The provisions of this Paragraph 5 shall remain in effect during the Term except as otherwise permitted or provided for in this 2017 Agreement and shall continue in effect until the company's base rates are next reset by the Commission. For clarity, this means that if this 2017 Agreement is terminated pursuant to Paragraph 7 hereof, the company's rights regarding storm cost recovery under this 2017 Agreement are terminated at the same time, except that any Commission-approved surcharge then in effect shall remain in effect until the costs subject to that surcharge are fully recovered. A storm surcharge in effect without approval of the Commission shall be terminated at the time this 2017 Agreement is terminated pursuant to Paragraph 7 hereof.

6. Solar Base Rate Adjustment Mechanism ("SoBRA").

(a) Notwithstanding the general base rate freeze specified in Paragraph 2, the company shall be allowed to recover the cost of its investment in, and operation of, certain new solar generation facilities and to make solar base rate adjustments consistent with this Paragraph 6. If the applicable federal or state income tax rate for the Company changes before any of the increases provided for in in this Paragraph 6, the Company will adjust the amount of the base rate increase to reflect the new tax rate before the implementation of such increase, pursuant to the applicable methodology in Exhibit C.

(b) Subject to the conditions in Subparagraph 6(c), the planned capacity amounts, earliest in-service and rate adjustment dates, and associated maximum annual revenue requirements (calculated at the Installed Cost Cap specified herein) are as follows:

Year	Earliest Rate Change And In-Service Date	Maximum Incremental SoBRA MW	Maximum Incremental Annualized SoBRA Revenue Requirements (millions)	Maximum Cumulative SoBRA MW	Maximum Cumulative Annualized SoBRA Revenue Requirements (millions)
2018	September 1	150	$30.6[2]	150	$30.6
2019	January 1	250	$50.9	400	$81.5
2020	January 1	150	$30.6	550	$112.1
2021	January 1	50	$10.2	600	$122.3[3]

(c) The company will seek approval of and cost recovery for specific solar generation projects in SoBRA Tranches up to the amounts as specified in this Paragraph 6. Nothing in this 2017 Agreement requires Tampa Electric to build the full amount of solar generating capacity

[2] The annual revenue requirement is approximately $30.6 million, however, since the first 150 MW Tranche is scheduled to come online September 1, 2018, the revenue requirements collected would be four months of the annual revenue requirements, or $10.2 million.
[3] The 2021 Tranche can be included in and its costs recovered under the SoBRA mechanism only if the projects constituting the 2018 and 2019 Tranches in this table are in-service and operating per design specifications as of December 31, 2019, and were constructed at an average capital cost of no more than $1475 per kW_{ac}.

allowed by this 2017 Agreement for any year or in total over the Term of this 2017 Agreement. Commission action may occur before or after expiration of the Term, but to qualify for cost recovery pursuant to these SoBRA provisions, any Tranche must be fully operational and providing service no later than December 31, 2022. A SoBRA Tranche may consist of a single project or may include multiple individual solar projects, which may be located throughout the company's retail service territory. Tampa Electric will construct and bring into full commercial operation, the full Maximum Incremental SoBRA MW for each year's Tranche by the dates shown in the table above. The Rate Change and In-Service Dates specified in the chart in Subparagraph 6(b) are "no sooner than" dates, and the SoBRA rate changes for each Tranche will be implemented effective on the earliest In-Service Date for that Tranche identified in such chart and subsequently trued up to reflect and correct for (1) any delay in the actual In-Service Dates of any of the projects in a particular Tranche beyond the applicable In-Service date for that Tranche and (2) the extent to which the actual installed costs of any project or projects vary from the projected costs used to set the SoBRA rate change but may not exceed the Maximum Incremental Annualized SoBRA Revenue Requirements or Maximum Cumulative Annualized SoBRA Revenue Requirements set forth in Subparagraph 6(b) or the Installed Cost Cap set forth in Subparagraph 6(d). Each SoBRA revenue increase shall be calculated based on the projected In-Service date, operating capacity, and estimated cost of the solar projects to which it corresponds, subject to being trued up as described in this Subparagraph 6(c). The 2021 SoBRA will only be available to the company if (i) for all projects in the 2018 and 2019 Tranches (totaling 400MW subject to the two percent (2%) variance allowance described in the following sentence), the actual average installed cost necessary to make such projects fully operational is less than or equal to \$1,475 per kW_{ac} and (ii) the 2018 and 2019 Tranches in the amount of 400

MW (subject to the 2% variance) are installed and operating at design specifications as of December 31, 2019. The SoBRA Tranches of solar generation capacity and the associated revenue requirements shown in Subparagraph 6(b) are "up to" or maximum amounts; however, the amount of revenues and MW in the 2019 SoBRA Tranche or Tranches may vary by up to 2 percent of the 2019 total (5 MW variance, either greater than or less than the specified maximum for 2019) to accommodate efficient planning and construction of the associated individual solar projects, and the 2019 Tranche or Tranches remain subject to the cost cap contained herein. Tampa Electric shall make a filing with the Commission by February 28, 2020, reflecting whether it has met the requirements to qualify for the 2021 SoBRA Tranche.

(d) For the solar projects that are approved by the Commission for cost recovery pursuant to this Paragraph 6, Tampa Electric's base rates will be increased by the incremental annualized base revenue requirement in steps, one step for each SoBRA Tranche. Each such base rate adjustment will be referred to as a SoBRA, and shall be authorized for solar projects for which Tampa Electric files for Commission approval pursuant to this Paragraph 6. Each project qualifying for SoBRA treatment must consist of either single axis tracking or other solar electric generating equipment or tracking technology that yields greater efficiency or higher capacity value, or both, for the benefit of customers all within the cost caps stated in this Paragraph 6. The types of costs of solar projects that traditionally have been allowed in rate base (including Engineering, Procurement and Construction ("EPC") costs; development costs including third party development fees, if any; permitting fees and costs; actual land costs and land acquisition costs; taxes; utility costs to support or complete development; transmission interconnection costs; installation labor and equipment costs; costs associated with electrical balance of system, structural balance of system, inverters, and modules; AFUDC at the weighted average cost of capital from Exhibit B of this 2017 Agreement; and other traditionally allowed rate base costs) shall be eligible for SoBRA cost recovery. The total installed capital cost of a project eligible for cost recovery through a SoBRA shall not exceed \$1,500 per kW_{ac} (the "Installed Cost Cap"). This Installed Cost Cap shall apply on a per project basis, and includes all costs required to make each of the projects in a Tranche fully operational. Each SoBRA will be based on a 10.25% ROE, except under the conditions specifically provided in this 2017 Agreement in Subparagraph 2(b), a 54% equity ratio (based on investor sources of capital), and the incremental capital structure components of long-term debt, short-term debt (if any), common equity, and tax credits, adjusted to reflect the inclusion of investment tax credits on a normalized basis. The debt rate utilized to calculate the revenue requirements associated with the SoBRA projects will be updated to reflect the incremental costs of prospective long-term debt issuances during the first 12 months of operation of each project. The SoBRA Installed Cost Cap is an amount agreed to by and between the Parties that reflects their negotiations regarding all relevant factors affecting or determining the installed cost of each project, including but not limited to capital costs, costs of capital, capital structure, and the other costs and expenses associated with the project.

(e) The Installed Cost Cap is not a "safe harbor" or a "build to" number for the company. The company will use reasonable efforts to design and build solar projects at installed costs below the cap. The Installed Cost Cap will limit the cost recovery of projects under a SoBRA, so if a project costs more than \$1,500 per kW_{ac}, the company can recover through a SoBRA only the installed cost up to the Installed Cost Cap, but may use the actual installed cost for purposes of preparing its periodic earnings surveillance reports; however, during the company's next general base rate proceeding, the depreciated net book value of any SoBRA project included in rate base for the test year may not exceed the Installed Cost Cap.

(f) The individual solar generation projects contemplated in this 2017 Agreement are not subject to the Florida Electrical Power Plant Siting Act, because each project will be smaller than 75 MW, and accordingly, the projects contemplated herein will be subject to the process and FPSC approval as specified herein. For each SoBRA and associated SoBRA Tranche, Tampa Electric will file a petition for approval of each SoBRA, provided that the SoBRA rate change for each Tranche shall not take effect before the dates specified in the aforementioned chart. Each petition for approval of a SoBRA or SoBRAs shall be filed in a separate stand-alone docket. The petition for approval of the first SoBRA (September 1, 2018) shall be made as soon as reasonably possible after the Commission vote to approve this 2017 Agreement. The petition for approval of each of the remaining SoBRAs shall be made in a separate stand-alone docket; the company may file the petitions for each Tranche for the following year at the time of the company's projection filings in the 2018, 2019 and 2020 Fuel and Purchased Power Cost Recovery Clause dockets ("Fuel Docket(s)") for the 2019, 2020 and 2021 factors, respectively, or the company may file each SoBRA petition at a convenient time throughout each year. The Parties contemplate that there will be a final true-up for the 2021 SoBRA, if needed. The Parties agree to request that, to the extent practicable, the deadlines and schedules in the Fuel Dockets apply to the petitions for approval of SoBRAs, so that the amount of solar generation approved for recovery through a SoBRA and related fuel cost savings can be synchronized with the Fuel Dockets.

(g) The issues for determination in each proceeding for approval of a SoBRA shall be limited to: (1) the cost effectiveness of the solar projects in the Tranche, (2) whether the installed cost of each project in the Tranche is projected to be under the Installed Cost Cap, (3) the amount of revenue requirements and appropriate increase in base rates needed to collect the estimated annual revenue requirement for the projects in a Tranche, (4) a true-up of previously approved SoBRAs for the actual cost of the previously approved projects, subject to the sharing provisions in Subparagraph 6(m), and (5) a true-up through the Capacity Cost Recovery Clause ("CCR") of previously approved SoBRAs to reflect the actual in service dates and actual installed cost for each of the previously-approved projects. The cost effectiveness for the projects in a Tranche shall be evaluated in total by considering only whether the projects in the Tranche will lower the company's projected system cumulative present value revenue requirement ("CPVRR") as compared to such CPVRR without the solar projects.

(h) The Parties expect and intend that the first SoBRA will be effective as of September 1, 2018, based on the Parties' expectation and the company's intent that all projects in the 2018 Tranche will be fully operational and providing service as of September 1, 2018. To accommodate efficient planning and construction by the company, the Consumer Parties agree that Tampa Electric may request the Commission to consider approval of the 2018 Tranche as soon as practicable following approval of this 2017 Agreement. The Parties further intend that Commission action on the remaining SoBRAs will be resolved, to the extent practicable, on a schedule that is contemporaneous with the annual, regularly scheduled Fuel and Purchased Power Cost Recovery Docket hearings, provided, however, that the Commission on its own initiative or upon good cause shown by any Party to this 2017 Agreement or any other entity satisfying the standing requirements of Florida law may set Tampa Electric's request for approval of any SoBRA or SoBRA Tranche for a separate hearing to be held at any convenient time to permit timely resolution before the company's projected In-Service date for the SoBRA Tranche that is the subject of such petition and hearing.

(i) The SoBRA increases approved pursuant to this 2017 Agreement shall be calculated based upon Tampa Electric's billing determinants used in the company's then-most-current ECCR Clause filings with the Commission for the twelve months following the effective date of any respective SoBRA. To the extent necessary, this will include projections of such billing determinants into a subsequent calendar year so as to cover the same 12 months as the first 12 months of each Tranche of solar projects' operations. The exception to this will be the first Tranche of SoBRA, which is to go into effect on September 1, 2018. In the case of this Tranche, the billing determinants used will be from the 2017 ECCR Clause filing for the 12 months of 2018 and the base rate adjustment derived on an annual basis but only applied to bills for the four months from September 2018 through December 2018 and then for the 12 months of 2019. The revenue requirement for each SoBRA Tranche shall be allocated to the rate classes using the 12 CP and $1/13^{th}$ method of allocating production plant and shall be applied to existing base rates, charges and credits using the following principles:

(i) 40% of the revenue requirements that would otherwise be allocated to the lighting class under the 12 CP and $1/13^{th}$ methodology shall be allocated to the lighting class for recovery through an increase in the lighting base energy rate and the remaining 60% shall be allocated ratably to the other customer classes.

(ii) The revenue requirement associated with a SoBRA will be recovered through increases to demand charges where demand charges are part of a rate schedule, and through energy charges where no demand charge is used in a rate schedule.

(iii) Within the GSD and IS rate classes, recovery of SoBRA revenue requirements allocated to those rate classes will be borne by non-standby demand charges only within a rate class, which methodology will not impact RS and GS rate classes.

(j) The solar capacity amounts specified in Subparagraphs 6(b) and 6(c) shall limit the maximum amount of solar capacity for which the company may recover costs through a SoBRA during each year of the Term, which may include recovery during 2022 for any SoBRA that satisfies the capacity and cost caps provided herein; provided, however, if Tampa Electric receives approval for SoBRA recovery for capacity amounts below the capacity amounts specified in Subparagraphs 6(b) and 6(c) in any year, the company can seek recovery of the unused capacity in a future petition for approval up to the Maximum Cumulative SoBRA for the applicable year as set forth in Subparagraph 6(b), provided such request is filed with the Commission during the Term of this 2017 Agreement. A SoBRA may become effective at any time during the Term or within one year after expiration of the Term, as limited by Subparagraph 6(d) and subject to the termination of the company's rights to seek SoBRA recovery if this 2017 Agreement is terminated pursuant to Paragraph 7 hereof.

(k) For each of the SoBRAs specified in Subparagraphs 6(b) and 6(c), the increased base rates shall be reflected on Tampa Electric's customer bills as specified herein. Tampa Electric will begin applying the increased base rate charges for each SoBRA concurrently with meter readings for the first billing cycle of September 2018 for the first SoBRA, subject to true-up as provided in Subparagraph 6(c). Tampa Electric will begin applying each subsequent SoBRA concurrently with meter readings for the first billing cycle of the month the Tranche is projected to go in service, subject to true-up as provided in Subparagraph 6(c). The Parties contemplate and intend that the final true-up for the 2021

SoBRA, if any, would be made to the CCR as soon as practicable following implementation of the 2021 SoBRA, if any.

(l) Subject to the revenue requirement limits in Subparagraph 6(b), the SoBRA for a Tranche will be calculated using the company's projected installed cost per kW_{ac} for each project (subject to the Installed Cost Cap); reasonable estimates for depreciation expense (based on an initial average service life of 30 years for depreciable plant), property taxes and fixed O&M expenses; an incremental capital structure reflecting the then current midpoint ROE and a 54% equity ratio adjusted to reflect the inclusion of investment tax credits on a normalized basis.

(m) If Tampa Electric's actual installed cost for a project is less than the Installed Cost Cap, the company's customers and the company will share in the beneficial difference with 75% of the difference inuring to the benefit of customers and 25% serving as an incentive to the company to seek such cost savings over the life of this 2017 Agreement. By way of illustration, if the actual installed cost of a solar project is $1,400 per kW_{ac}, the final cost to be used for purposes of computing cost recovery under this 2017 Agreement and the true-up of the initial SoBRA shall be $1,425 per kW_{ac} [0.25 times ($1,500 - $1,400) + $1,400].

(n) In order to determine the amount of each annual cost true-up, a revised SoBRA will be computed using the same data and methodology incorporated in the initial SoBRA, with the exception that the actual capital expenditures after sharing and the actual in-service date will be used in lieu of the capital expenditures on which the annualized revenue requirement was based. The difference between the cumulative base revenues since the implementation of the initial SoBRA factor and the cumulative base revenues that would have resulted if the revised SoBRA factor (for cost and In-Service date true-ups) had been in place during the same time period will be trued up with interest at the AFUDC rate shown in Exhibit B used for the projects, and will be made through a one-time, twelve-month adjustment through the CCR clause. On a going forward basis, the base rates will be adjusted to reflect the revised SoBRA factors.

(o) Tampa Electric agrees to file monthly reports that will provide the same information as that filed with the Commission in Docket No. 20170007-EI by another utility for its solar projects, in order to reflect the performance of the solar projects after they have been placed in service.

(p) Tampa Electric's base rate and credit levels applied to customer bills, including the effects of the SoBRAs implemented pursuant to this 2017 Agreement, shall continue in effect until next reset by future unanimous agreement of the Parties approved by a Final Order of the Commission or a Final Order of the Commission issued as a result of a future general base rate proceeding. Any incentive attributed to the company during the term of this 2017 Agreement under Subparagraph 6(m) above will not be included in rate base in the company's next general base rate proceeding, meaning that when a solar asset plant balance is moved to base rates in the company's next general base rate case, only the actual cost -- not any incentive -- will be included.

(q) For all new solar generation assets that Tampa Electric places in service during the Term, the lowest total installed cost per-kW solar energy resources up to the capacity amounts associated with the SoBRA mechanism will be attributed to the SoBRA mechanism in the event the company constructs more solar generation capacity than is subject to the SoBRA mechanism.

(r) Nothing in this 2017 Agreement shall preclude any Party to this 2017 Agreement or any other lawful party from participating, consistent with the full rights of an intervenor, in any proceeding that addresses any matter or issue concerning the SoBRA provisions of this 2017 Agreement.

7. Earnings.

(a) Notwithstanding Paragraph 2 and subject to the Trigger provisions in Subparagraph 2(b) above, if Tampa Electric's earned return on common equity falls below 9.25% during the Term on a monthly earnings surveillance report stated on an actual Commission thirteen-month average adjusted basis, Tampa Electric may petition the Commission to amend its base rates either through a general rate proceeding under Sections 366.06 and 366.07, Florida Statutes, or through a limited proceeding under Section 366.076, Florida Statutes. Nothing in this 2017 Agreement shall be construed as an agreement by the Consumer Parties that a limited proceeding would be appropriate, and Tampa Electric acknowledges and agrees that the Parties reserve and retain all rights to challenge the propriety of any limited proceeding or to assert that any request for base rate changes should properly be addressed through a general base rate case, as well as to challenge any substantive proposals to change the company's rates in any such future proceeding. This floor of 9.25% shall be subject to adjustment in accordance with the Trigger provision in Subparagraph 2(b). For purposes of this 2017 Agreement, "Commission actual adjusted basis" and "actual adjusted earned return" shall mean results reflecting all adjustments to Tampa Electric's books required by the Commission by rule or order, but excluding pro forma adjustments. No Consumer Parties shall be precluded from participating in any proceeding initiated by Tampa Electric to increase base rates pursuant to this Paragraph 7, and no Consumer Party is precluded from opposing Tampa Electric's request.

(b) Notwithstanding Paragraph 2 and subject to the Trigger in Subparagraph 2(b) above, if Tampa Electric's earned return on common equity exceeds 11.25% during the Term on a monthly earnings surveillance report stated on an actual Commission thirteen-month average adjusted basis, no Consumer Party shall be precluded from petitioning the Commission for a review of Tampa Electric's base rates. In any case initiated by Tampa Electric or any other Party pursuant to Paragraph 7, all Parties will retain full rights conferred by law. The ceiling of 11.25% set forth in this Subparagraph shall be subject to adjustment in accordance with the Trigger provision in Subparagraph 2(b).

(c) Notwithstanding Paragraph 2 and subject to the Trigger provisions in Subparagraph 2(b) above, this 2017 Agreement shall terminate upon the effective date of any Final Order of the Commission issued in any proceeding pursuant to Paragraph 7 that changes Tampa Electric's base rates prior to the last billing cycle of December 2021.

(d) This Paragraph 7 shall not: (i) be construed to bar Tampa Electric from requesting any recovery of costs otherwise contemplated by this 2017 Agreement; (ii) apply to any request to change Tampa Electric's base rates that would become effective after the expiration of the Term of this 2017 Agreement; (iii) limit any Party's rights in proceedings concerning changes to base rates that would become effective subsequent to the Term of this 2017 Agreement to argue that Tampa Electric's authorized ROE range should be different than as set forth in this 2017 Agreement; or (iv) affect the provisions of Subparagraphs 3(d) and 3(e) of this 2017 Agreement.

(e) Notwithstanding any other provision of this 2017 Agreement, the Parties fully and completely reserve all rights available to them under the law to challenge the level or rate structure (or the cost of service methodologies underlying them) of Tampa Electric's base rates, charges, credits, and rate design methodologies effective as of January 1, 2022 or thereafter. It is specifically understood and agreed that this 2017 Agreement does not preclude any Consumer Party from filing before January 1, 2022, an action to challenge the level or rate structure (or the cost of service methodologies underlying them) of Tampa Electric's base rates, charges and credits effective as of January 1, 2022 or thereafter.

8. Depreciation.

(a) The Parties agree and intend that, notwithstanding any requirements of Rules 25-6.0436 and 25-6.04364, F.A.C., the company shall not be required during the Term of this 2017 Agreement to file any depreciation study or dismantlement study. The depreciation and amortization accrual rates approved by the FPSC and currently in effect as of the Effective Date of this 2017 Agreement shall remain in effect during the Term or the company's next depreciation study, whichever is later. The Parties further agree that the provisions of Rules 25-6.0436 and 25-6.04364, F.A.C., which otherwise require depreciation and dismantlement studies to be filed at least every four years, will not apply to the company during the Term, and that the Commission's approval of this 2017 Agreement shall excuse the company from compliance with the filing requirement of these rules during the Term.

(b) Notwithstanding the non-deferral language in Paragraph 4, unless the company proposes a special capital recovery schedule and the Commission approves it, if coal-fired generating assets or other assets are retired or planned for retirement of a magnitude that would ordinarily or otherwise require a special capital recovery schedule, such assets will continue to be depreciated using their then existing depreciation rates and special capital recovery issues will be addressed in conjunction with the company's next depreciation study. If the company installs Automated Meter Infrastructure ("AMI") meters and retires Automated Meter Reading ("AMR") meters during the Term, such assets will continue to be depreciated using their then existing depreciation rates and special capital recovery issues will be addressed in conjunction with the company's next depreciation study.

(c) Notwithstanding the provisions of Subparagraph 8(a) above, the company shall file a depreciation and dismantlement study or studies no more than one year nor less than 90 days before the filing of its next general rate proceeding under Sections 366.06 and 366.07, Florida Statutes, such that there is a reasonable opportunity for the Consumer Parties to review, analyze and potentially rebut depreciation rates or other aspects of such depreciation and dismantlement studies contemporaneously with the company's next general rate proceeding. The depreciation and dismantlement study period shall match the test year in the company's MFRs, with all supporting data in electronic format with links, cells and formulae intact and functional, and shall be served upon all Consumer Parties and all intervenors in such subsequent rate case.

9. Federal Income Tax Reform.

(a) Changes in the rate of taxation of corporate income by federal or state taxing authorities ("Tax Reform") could impact the effective tax rate recognized by the company in FPSC adjusted reported net operating income and the measurement of existing and prospective deferred federal income tax assets and liabilities reflected in the FPSC adjusted capital structure.

When Congress last reduced the maximum federal corporate income tax rate in the Tax Reform Act of 1986, it included a transition rule that, as an eligibility requirement for using accelerated depreciation with respect to public utility property, provided guidance regarding returning to customers the portion of the resulting excess deferred income taxes attributable to the use of accelerated depreciation. To the extent Tax Reform includes a transition rule applicable to excess deferred federal income tax assets and liabilities ("Excess Deferred Taxes"), defined as those that arise from the re-measurement of those deferred federal income tax assets and liabilities at the new applicable corporate tax rate(s), those Excess Deferred Taxes will be governed by the Tax Reform transition rule, as applied to most promptly and effectively reduce Tampa Electric's rates consistent with the Tax Reform rules and normalization rules.

(b) If Tax Reform is enacted before the company's next general base rate proceeding, the company will quantify the impact of Tax Reform on its Florida retail jurisdictional net operating income thereby neutralizing the FPSC adjusted net operating income of the Tax Reform to a net zero. The company's forecasted earnings surveillance report for the calendar year that includes the period in which Tax Reform is effective will be the basis for determination of the impact of Tax Reform. The company will also adjust any SoBRAs that have not yet gone into effect to specifically account for Tax Reform. The impacts of Tax Reform on base revenue requirements will be flowed back to retail customers within 120 days of when the Tax Reform becomes law, through a one-time adjustment to base rates upon a thorough review of the effects of the Tax Reform on base revenue requirements consistent with Subparagraph 9(a). This adjustment shall be accomplished through a uniform percentage decrease to customer, demand and energy base rate charges for all retail customer classes. Any effects of Tax Reform on retail revenue requirements from the Effective Date through the date of the one-time base rate adjustment shall be flowed back to customers through the ECCR Clause on the same basis as used in any base rate adjustment. An illustration is included as Exhibit C. If Tax Reform results in an increase in base revenue requirements, the company will utilize deferral accounting as permitted by the Commission, thereby neutralizing the FPSC adjusted net operating income impact of the Tax Reform to a net zero, through the Term. In this situation, the company shall defer the revenue requirement impacts to a regulatory asset to be considered for prospective recovery in a change to base rates to be addressed in the company's next base rate proceeding or in a limited scope proceeding before the Commission no sooner than the end of the Term.

(c) All Excess Deferred Taxes shall be deferred to a regulatory asset or liability which shall be included in FPSC adjusted capital structure and flowed back to customers over a term consistent with law. If the same Average Rate Assumption Method used in the Tax Reform Act of 1986 is prescribed, then the regulatory asset or liability will be flowed back to customers over the remaining life of the assets associated with the Excess Deferred Taxes subject to the provisions related to FPSC adjusted operating income impacts of Tax Reform noted above. If the Tax Reform law or act is silent on the flow-back period, and there are no other statutes or rules that govern the flow-back period, then there shall be a rebuttable presumption that the following flow-back period(s) will apply: (1) if the cumulative net regulatory liability is less than \$100 million, the flow-back period will be five years; or (2) if the cumulative net regulatory liability is greater than \$100 million, the flow-back period will be ten years. The company reserves the right to demonstrate by clear and convincing evidence that such five or ten-year maximum period (as applicable) is not in the best interest of the company's customers and should be increased to no greater than 50 percent of the remaining life of the assets associated with the Excess Deferred Taxes ("50 Percent Period"). The relevant factors to support the company's demonstration include, but are not limited to, the impact the flow-back period would have on the company's cash flow and credit metrics or the optimal capitalization of the company's jurisdictional operations in Florida. If the company can demonstrate, by clear and convincing evidence, that limiting the flow-back period to the 50 Percent Period, in conjunction with the other Tax Reform provisions related to deferred taxes within this 2017 Agreement, will be the sole basis for causing a full notch credit downgrade by each of the major rating agencies (i.e. Standard & Poor's and Moody's), as expressly reflected in a publicly available report of the agencies, it may file to seek a longer flow-back period.

10. Incentive Plan. The Parties consent to the FPSC's approval of and request that the Commission approve the company's Asset Optimization/Incentive Program as set forth in its Petition in Docket No. 160160-EI, dated June 30, 2016, for a four-year period beginning January 1, 2018, but with the following sharing thresholds: (a) up to $4.5MM/year, 100% gain to customers; (b) greater than $4.5MM/year and less than $8.0MM/year, 60% to shareholders and 40% to customers; and (c) greater than $8.0MM/year, 50% to shareholders and 50% customers.

11. Other.

(a) Except as specified in this 2017 Agreement, the company will enter into no new natural gas financial hedging contracts for fuel through December 31, 2022.

(b) The company agrees that it will not seek to recover any costs from its customers related to investments in oil and/or natural gas exploration, reserves, acreage and/or production, including but not limited to investments in gas or oil exploration or production projects that utilize "fracking" (hydraulic fracturing) or similar technology, for a period of no less than five years after the Effective Date.

(c) The company may not make separated/stratified sales from energy generated by solar assets being recovered through a SoBRA during the Term.

(d) For any non-separated or non-stratified wholesale energy sales during the Term, the company will credit its fuel clause for an amount equal to the company's incremental cost of generating or purchasing the amount of energy sold during the hours that any such sale was made.

(e) The full benefits of solar renewable energy credits ("RECs") (including any and all rights attaching to environmental attributes) associated with the solar projects subject to this 2017 Agreement, if any, will be retained for, and flowed through to, retail customers through the Environmental Cost Recovery Clause.

(f) All dollar values, asset determinations, rate impact values and revenue requirements in this 2017 Agreement are intended by the Parties to be retail jurisdictional in amount or formulation basis, unless otherwise specified.

12. New Tariffs. Nothing in this 2017 Agreement shall prelude Tampa Electric from filing and the Commission from approving any new or revised tariff provisions or rate schedules requested by Tampa Electric, provided that any such tariff request does not increase any existing base rate component of a tariff or rate schedule, or any other charge imposed on customers during the Term unless the application of such new or revised tariff, rate schedule, or charge is optional to Tampa Electric's customers.

13. Application of 2017 Agreement. No Party to this 2017 Agreement will request, support, or seek to impose a change to any term or provision of this 2017 Agreement. Except as provided in Paragraph 7, no Party to this 2017 Agreement will either seek or support any reduction in Tampa Electric's base rates, charges, or credits, including limited, limited-scope,

interim, or any other rate decreases, or changes to rate design methodologies, that would take effect prior to the first billing cycle for January 2022, except for any such reduction in base rates or charges (but not credits) requested by Tampa Electric or as otherwise provided for in this 2017 Agreement. Tampa Electric shall not seek interim, limited, or general base rate relief during the Term except as provided for in Paragraphs 6 or 7 of this 2017 Agreement. Tampa Electric is not precluded from seeking interim, limited or general base rate relief that would be effective during or after the first billing cycle in January 2022, nor are the Consumer Parties precluded from opposing such relief. Such interim relief may be based on time periods before January 1, 2022, consistent with Section 366.071, Florida Statutes, and calculated without regard to the provisions of this 2017 Agreement. Tampa Electric will not seek to adjust either the standby generator credit or the CCV credit either during the Term of this 2017 Agreement or thereafter, except by unanimous Agreement of the Parties approved by a Final Order of the Commission or a Final Order of the Commission issued as a result of a future general base rate proceeding.

14. Commission Approval.

(a) The provisions of this 2017 Agreement are contingent on approval of this 2017 Agreement in its entirety by the Commission without modification. The Parties further agree that this 2017 Agreement is in the public interest, that they will support this 2017 Agreement and that they will not request or support any order, relief, outcome, or result in conflict with the terms of this 2017 Agreement in any administrative or judicial proceeding relating to, reviewing, or challenging the establishment, approval, adoption, or implementation of this 2017 Agreement or the subject matter hereof.

(b) No Party will assert in any proceeding before the Commission that this 2017 Agreement or any of the terms in the 2017 Agreement shall have any precedential value. The

Parties' agreement to the terms in the 2017 Agreement shall be without prejudice to any Party's ability to advocate a different position in future proceedings not involving this 2017 Agreement. The Parties further expressly agree that no individual provision, by itself, necessarily represents a position of any Party in any future proceeding, and the Parties further agree that no Party shall assert or represent in any future proceeding in any forum that another Party endorses any specific provision of this 2017 Agreement by virtue of that Party's signature on, or participation in, this 2017 Agreement. It is the intent of the Parties to this 2017 Agreement that the Commission's approval of all the terms and provisions of this 2017 Agreement is an express recognition that no individual term or provision, by itself, necessarily represents a position, in isolation, of any Party or that a Party to this 2017 Agreement endorses a specific provision, in isolation, of this 2017 Agreement by virtue of that Party's signature on, or participation in, this 2017 Agreement.

(c) The Parties intend, and agree to request that the Commission's order state that approval of this 2017 Agreement in its entirety will resolve all matters in Docket No. 20160160-EI pursuant to and in accordance with Section 120.57(4), Florida Statutes, and that Docket No. 20160160-EI will be closed effective on the date the Commission's order approving this 2017 Agreement becomes final. The Parties further agree to request that Docket No. 20170057-EI be closed upon approval of this 2017 Agreement or as soon thereafter as is reasonably practical.

(d) No Party shall seek appellate review of any Commission order approving this 2017 Agreement.

15. Disputes. To the extent a dispute arises among the Parties about the provisions, interpretation, or application of this 2017 Agreement, the Parties agree to meet and confer in an effort to resolve the dispute. To the extent that the Parties cannot resolve any dispute, the matter may be submitted to the Commission for resolution.

16. Execution. This 2017 Agreement is dated as of September 27, 2017. It may be executed in counterpart originals and a facsimile of an original signature shall be deemed an original.

[Remainder of page intentionally left blank]

IN WITNESS WHEREOF, the Parties evidence their acceptance and agreement with the provisions of this 2017 Agreement by their signature(s):

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

By ______________________
Gordon L. Gillette, President

Signature Page to 2017 Agreement

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

By: ______________________
J.R. Kelly

Signature Page to 2017 Agreement

The Florida Industrial Power Users Group
Jon C. Moyle, Jr., Esquire
Moyle Law Firm
The Perkins House
118 North Gadsden Street
Tallahassee, FL 32301

By: ______________________________ Sept. 27, 2017
Jon C. Moyle, Jr

Signature Page to 2017 Agreement

WCF Hospital Utility Alliance
Mark F. Sundback, Esquire
Kenneth L. Wiseman, Esquire
Andrews Kurth, LLP
1350 I Street, N.W., Suite 1100
Washington, D.C. 20005

Kenneth L. Wiseman

Signature Page to 2017 Agreement

Federal Executive Agencies
Lanny L. Zieman, Capt, USAF, Esquire
AFLOA/JACL-ULFSC
139 Barnes Drive, Suite 1
Tyndall Air Force Base, FL 32403

By: ______________________
Lanny L. Zieman

Signature Page to 2017 Agreement

Florida Retail Federation
Robert Scheffel Wright
Gardner, Bist, Bowden, Bush, Dee, LaVia & Wright, P.A.
1300 Thomaswood Drive
Tallahassee, FL 32308

By: Robert Scheffel Wright
Robert Scheffel Wright

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition of Tampa Electric Company for Recovery of Costs Associated with Named Tropical Systems and Replenishment of Storm Reserve	)	Docket No. 20170271-EI
In Re: Petition the Commission to establish a generic docket to investigate and adjust rates for all investor owned utilities related to the reduction in the federal corporate income tax rate as a result of the passage of the Tax Cuts and Jobs Act	)	Docket No. 20180013-PU Filed: February 13, 2018

Amended Implementation Stipulation

THIS AMENDED IMPLEMENTATION STIPULATION is dated this 13th day of February, 2018 and is by and between Tampa Electric Company ("Tampa Electric" or the "company"), the Office of Public Counsel ("OPC" or "Citizens"), the Florida Industrial Power Users Group ("FIPUG"), the Florida Retail Federation ("FRF"), the Federal Executive Agencies ("FEA"), and the WCF Hospital Utility Alliance ("HUA"). Collectively, Tampa Electric, OPC, FIPUG, FRF, FEA, and HUA shall be referred to herein as the "Parties" (or "signatories") 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 "Amended Implementation Stipulation."

Background

The Florida Public Service Commission ("FPSC" or "Commission") approved the 2017 Amended and Restated Stipulation and Settlement Agreement between and among the Parties ("2017 Agreement") by Order No. PSC-2017-0456-S-EI, issued on November 27, 2017 in

Docket Nos. 20170210-EI and 20160160-EI. Paragraphs 5 and 9 of the 2017 Agreement address Storm Damage and Federal Income Tax Reform, respectively.

Tampa Electric filed a Petition for Recovery of Costs Associated with Named Tropical Systems and Replenishment of Storm Reserve in Docket No. 20170271-EI on December 27, 2017. On January 30, 2018, the company filed an Amended Petition for Recovery of Costs Associated with Named Tropical Systems and Replenishment of Storm Reserve in the same docket ("Amended Storm Petition"). The Amended Storm Petition updates the total estimated storm restoration costs from those set forth in the company's original petition and seeks approval of revised tariff sheets containing updated Interim Storm Cost Recovery Factors designed to recover the company's proposed total updated storm restoration costs.

The Tax Cuts and Jobs Act of 2017 ("TCJA") was enacted by the United States Congress on December 20, 2017 and was signed into law by the President on December 22, 2017. *See Tax Cuts and Jobs Act of 2017*, Pub. Law 115-97, 131 Stat. 2054 (2017). The TCJA amends a variety of the provisions in the Internal Revenue Code and reduces the federal corporate income tax rate from 35% to 21% effective January 1, 2018. On January 9, 2018, OPC petitioned the Commission to establish a generic docket to investigate and adjust rates for all investor owned utilities related to the reduction in the federal corporate income tax rate as a result of the passage of the TCJA. Thereafter, the Commission opened Docket No. 20180013-PU for consideration of OPC's petition.

On January 30, 2018, Tampa Electric filed an Unopposed Motion to Approve Implementation Stipulation, with the Implementation Stipulation attached to the Motion. The purpose of the Implementation Stipulation was to memorialize the understanding and agreement of the Parties regarding the manner in which Tampa Electric will implement paragraphs 5 and 9 of the 2017 Agreement. Since that filing the Parties have discussed and agreed on certain modifications to the manner in which Tampa Electric will implement paragraphs 5 and 9 of the 2017 Agreement.

This Amended Implementation Stipulation differs from the Implementation Stipulation attached to the Unopposed Motion primarily in connection with the process to be followed with respect to the approval of interim cost recovery factors and the disposition of the tariffs referenced in the amended storm petition. Those changes are reflected in paragraph 4 of this Amended Implementation Stipulation. In all other material respects this Amended Implementation Stipulation is the same as the Implementation Stipulation filed on January 30, 2018.

<u>Stipulated Implementation Provisions</u>

1. Paragraph 5 of the 2017 Agreement grants Tampa Electric the right to recover, on an interim basis, storm damage costs beginning sixty days after filing a petition with the Commission. Pursuant to this paragraph, on January 30, 2018, Tampa Electric filed its Amended Storm Petition seeking recovery of approximately $102.5 million estimated for storm damage costs associated with Tropical Storms Erika and Colin and Hurricanes Hermine, Matthew and Irma and replenishment of Tampa Electric's retail storm damage reserve. Therein, the company proposed to recover this amount over a nine (9) month period effective concurrently with meter readings for the first billing cycle in April, 2018.

2. Paragraph 9 of the 2017 Agreement provides a mechanism for calculating and implementing the impact of tax reform on Tampa Electric's base rates and charges that will inure to the benefit of customers on the effective date of tax reform changes. Tampa Electric, using the methodologies set forth in Paragraphs 9(b) and 9(c) of the 2017 Agreement, has preliminarily

estimated the impact of the TCJA to result in a reduction in annual revenue requirements of approximately $95 million for 2018. Tampa Electric and the other signatories to the 2017 Agreement recognize that the $95 million estimated annual TCJA impact is based on preliminary data and is subject to final true-up. Per the 2017 Agreement, Tampa Electric is obligated to request permission of the Commission to reduce customer base rates within 120 days of the December 22, 2017 enactment date, or by April 23, 2018, upon a thorough review of the effects of the TCJA on base revenue requirements to account for the impacts of the TCJA. Reducing base rates and charges effective concurrently with meter readings for the first billing cycle in May 2018 would allow the company to return approximately eight (8) months of its estimated tax savings to customers in 2018. The remaining four months of annual savings, reflecting the final determination of the annual tax savings amount, would be returned to customers over twelve (12) months in 2019 through the ECCR Clause.

3. Per the 2017 Agreement, the company's storm damage costs are to be allocated to customer rate classes in the same manner as base rates consistent with the rate design methods in the 2017 Agreement. Therefore, absent this Implementation Stipulation and given the 60 day period in paragraph 5(a) of the 2017 Agreement, Tampa Electric would be authorized to increase rates by approximately $102.5 million concurrently with meter readings for the first billing cycle in April 2018, and a month later, pursuant to paragraph 9 of the 2017 Agreement, reduce those same rates by approximately $95 million per year to reflect tax savings from the TCJA. To avoid this volatility in customer rates, and recognizing that the amount of storm damage costs and tax savings are currently estimates, with the final values to be determined by the FPSC after separate opportunities for hearing, the signatories to the 2017 Agreement agree that Tampa Electric should effectively use the estimated annual TCJA tax savings reduction of

approximately $95 million per year to avoid the need to charge customers for the estimated $102.5 million of storm damage costs that they would have otherwise been obligated to pay beginning in April 2018. The parties also recognize that because the estimated amounts of storm costs and tax savings are approximately the same, there is an opportunity to provide customers full credit for 100 percent of the estimated 2018 tax savings during calendar year 2018, and at the same time avoid having to collect a surcharge from customers to recover the company's estimated storm damage costs, by treating both amounts in the manner proposed in this Implementation Stipulation.

4. To accomplish these goals, the Parties agree and request that the Commission approve the interim cost recovery factors referenced in the Amended Storm Petition, Upon approval of the interim cost recovery factors and approval of this Amended Implementation Stipulation, Tampa Electric Company will withdraw the tariffs associated with the interim cost recovery factors approved pursuant to the Amended Storm Petition. The Parties agree and request that the Commission authorize the company to make the appropriate accounting adjustments on its regulated books and records such that the entire estimated amount of storm costs that would have been recovered from customers ratably over a nine (9) month period in 2018 is paid for or recovered ratably from the company's estimated annual tax savings over the same nine (9) month period.

5. The Parties further agree and request that the Commission approve the following additional provisions of this Amended Implementation Stipulation:

(a) The final amount of the company's storm costs authorized to be recovered will be determined by the Commission in Docket No. 20170271-EI.

(b) A final determination of the impact of tax reform on Tampa Electric's base rates and charges pursuant to the 2017 Agreement will be determined by the Commission in Docket No. 20180013-PU or a separate docket established for that purpose and dedicated to Tampa Electric.

(c) After the final determinations of the impact of tax reform and recoverable storm cost amounts have been determined, any difference will be trued up and recovered (or returned) to customers through the ECCR Clause in 2019, as contemplated in the 2017 Agreement.

(d) After its impact is finally determined by the Commission, the company will reflect the full impact of tax reform on Tampa Electric's base rates and charges through tariff changes to be effective concurrently with meter readings for the first billing cycle in January 2019, provided that the Commission's determinations are final before that date.

(e) All signatories maintain and do not waive their rights to raise any argument that is allowed under the 2017 Agreement with respect to the level of storm damage costs and the calculation of the TCJA impacts.

(f) It is the intent of the parties, and a condition of this Amended Implementation Stipulation, that the two distinct proceedings contemplated in Paragraphs 5 and 9 of the 2017 Agreement shall be conducted as if this stipulation did not exist and that final determinations of actual storm costs and tax savings be made independently and separately.

6. The parties intend that the storm damage costs be transparent and ascertainable on a stand-alone basis and that the benefits of the TCJA impacts be transparent and ascertainable on a stand-alone basis. Upon approval of this Amended Implementation Stipulation, the company shall file a monthly storm cost overview which accounts and reports on the recovery of storm

damage costs, the costs remaining to be recovered, and the amount of TCJA benefits applied to storm damage costs.

7. The Parties have entered into this Amended Implementation Stipulation for the purpose of clarifying the appropriate means of implementing the referenced provisions of the 2017 Agreement and not to modify or otherwise impact the 2017 Agreement, which shall remain in full force and effect in accordance with its terms.

8. This Amended Implementation Stipulation is dated as of February 13 , 2018. It may be executed in counterpart originals and a facsimile of an original signature shall be deemed an original.

[Remainder of page intentionally left blank]

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

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

By ______________________
Nancy Tower, President

Signature Page to Implementation Stipulation

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

By: ______________________
J.R. Kelly

Signature Page to Implementation Stipulation

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: ______________________ Feb. 13, 2018
Jon C. Moyle, Jr.

Signature Page to Implementation Stipulation

WCF Hospital Utility Alliance
Mark F. Sundback, Esquire
Kenneth L. Wiseman, Esquire
Andrews Kurth, LLP
1350 I Street, N.W., Suite 1100
Washington, D.C. 20005

By: ______________________

Signature Page to Implementation Stipulation

Federal Executive Agencies
LANNY L. ZIEMAN, Capt, USAF
Utility Litigation Attorney
Utility Law Field Support Center
Tyndall Air Force Base, Florida
Comm: 850-282-8863
DSN: 742-8863

By: ______________________
Capt Lanny L. Zieman

Signature Page to Implementation Stipulation

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

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

March 16, 2018

Mr. Andrew L. Maurey, Director
Division of Accounting and Finance
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, Florida 32399-0850

Dear Mr. Maurey,

Enclosed are copies of Tampa Electric Company's Forecasted Earnings Surveillance Report for the year 2018. These computations have been made for the purposes of complying with Order No. PSC-94-1600-FOF-PU.

This report was calculated using updated jurisdictional separation factors. Tampa Electric Company's forecasted jurisdictional separation study for the year 2018 is based on forecasted levels of wholesale commitments, system rate base and operating expense items.

Please let me know if you have any questions.

Respectfully,

Jeffrey S. Chronister
Controller

Tampa Electric Company
P. O. Box 111 Tampa, Fl 33601-0111 (813) 228-4111 tampaelectric.com

SCHEDULE 1

TAMPA ELECTRIC COMPANY
EARNINGS SURVEILLANCE REPORT SUMMARY
2018 BUDGET
2018 BUDGET

I. Average Rate of Return (Jurisdictional)		(1) Actual Per Books		(2) FPSC Adjustments		(3) FPSC Adjusted	(4) Pro Forma Adjustments		(5) Pro Forma Adjusted
Net Operating Income	$	397,555,236	(a)	(37,462,858)	(b)	360,092,378	0	$	360,092,378
Average Rate Base		6,457,000,791		(646,478,062)		5,810,522,729	0		5,810,522,729
Average Rate of Return		6.16%				6.20%			6.20%

II. Year End Rate of Return (Jurisdictional)		(1)		(2)		(3)	(4)		(5)
Net Operating Income	$	397,555,236	(a)	(35,993,446)	(b)	361,561,790	0	$	361,561,790
Year End Rate Base		6,839,040,071		(797,864,592)		6,041,175,479	0		6,041,175,479
Year End Rate of Return		5.81%				5.98%			5.98%

(a) Includes AFUDC debt of $4,925,532 and AFUDC equity of $10,262,561
(b) Includes reversal of AFUDC earnings.

III. Required Rate of Return
Average Capital Structure
(FPSC Adjusted Basis)

Low	5.62	%
Midpoint	6.05	%
High	6.48	%

IV. Financial Integrity Indicators

A. TIE With AFUDC	5.30		(System per books basis)		
B. TIE Without AFUDC	5.16		(System per books basis)		
C. AFUDC To Net Income	4.59	%	(System per books basis)		
D. Internally Generated Funds	77.11	%	(System per books basis)		
E. LTD To Total Investor Funds	39.31	%	(FPSC adjusted basis)		
F. STD To Total Investor Funds	5.38	%	(FPSC adjusted basis)		
G. Return On Common Equity (Avg)	10.60	%	(FPSC adjusted basis)	Year End	9.84%
H. Return On Common Equity (Avg)	10.60	%	(Pro Forma adjusted basis)	Year End	9.84%

The calculations on this schedule were made in direct response to and according to methodology prescribed in Order No. PSC-93-0165-FOF-EI, Order No. PSC-09-0283-FOF-EI, and decisions made at the July 14, 2009, agenda conference under Docket No. 080317-EI by the Florida Public Service Commission and for that reason only. Tampa Electric Company takes the position that certain portions of these prescribed calculations may not present fairly the Company's current financial status and that they should not be used for that purpose.

I am aware that Section 837.06, Florida Statutes, provides:

Whoever knowingly makes a false statement in writing with the intent to mislead a public servant in the performance of his official duty shall be guilty of a misdemeanor of the second degree, punishable as provided in s. 775.082, s. 775.083, or s. 775.084.

Jeffrey S. Chronister - Controller

3/15/18
Date

Surveillance Backup

TAMPA ELECTRIC COMPANY
AVERAGE RATE OF RETURN
RATE BASE
2018 BUDGET

	(1) Plant In Service	(2) Accumulated Depreciation & Amortization	(3) Net Plant In Service	(4) Property Held For Future Use	(5) Construction Work In Progress	(6) Nuclear Fuel (Net)	(7) Net Utility Plant	(8) Working Capital	(9) Total Rate Base
System Per Books	$ 8,725,169,523	$ (2,895,611,000)	$ 5,829,558,523	$ 52,829,462	$ 443,321,362	$ 0	$ 6,325,709,347	$ 192,154,382	$ 6,517,863,729
Jurisdictional Per Books	8,653,737,016	(2,879,366,247)	5,774,370,769	50,883,576	440,747,137	0	6,266,001,482	190,999,309	6,457,000,791
FPSC Adjustments									
Fuel and ECCR	(36,750,936)	28,552,706	(8,198,230)				(8,198,230)	(5,971,287)	(14,169,517)
Other								(13,820,058)	(13,820,058)
ECRC	(552,757,472)	209,865,618	(342,891,854)				(342,891,854)	0	(342,891,854)
Fuel Inventory								(9,515,246)	(9,515,246)
CWIP					(440,747,137)		(440,747,137)		(440,747,137)
CWIP in Rate Base					176,708,990		176,708,990		176,708,990
Acquisition Book Values	(1,621,727)		(1,621,727)				(1,621,727)		(1,621,727)
Acquisition Accumulated Amortizations		1,687,257	1,687,257				1,687,257		1,687,257
Acquisition Adjustments	(7,423,545)	5,314,775	(2,108,770)				(2,108,770)		(2,108,770)
Total FPSC Adjustments	(598,553,680)	245,420,356	(353,133,324)	0	(264,038,147)	0	(617,171,471)	(29,306,591)	(646,478,062)
FPSC Adjusted	8,055,183,336	(2,633,945,891)	5,421,237,445	50,883,576	176,708,990	0	5,648,830,011	161,692,718	5,810,522,729
Pro Forma Revenue Increase and Annualization Adjustments:									
SoBRA			0				0		0
Total Pro Forma Adjustments	0	0	0	0	0	0	0	0	0
Pro Forma Adjusted	$ 8,055,183,336	$ (2,633,945,891)	$ 5,421,237,445	$ 50,883,576	$ 176,708,990	$ 0	$ 5,648,830,011	$ 161,692,718	$ 5,810,522,729

The calculations on this schedule were made in direct response to and according to methodology prescribed in Order No. PSC-93-0165-FOF-EI, Order No. PSC-09-0283-FOF-EI, and decisions made at the July 14, 2009, agenda conference under Docket No. 080317-EI by the Florida Public Service Commission and for that reason only. Tampa Electric Company takes the position that certain portions of these prescribed calculations may not present fairly the company's current financial status and that they should not be used for that purpose.

TAMPA ELECTRIC COMPANY
AVERAGE RATE OF RETURN
INCOME STATEMENT
2018 BUDGET

SCHEDULE 2
PAGE 2 OF 3

	(1) Operating Revenues	(2) O & M Fuel & Net Interchange	(3) O & M Other	(4) Depreciation & Amortization	(5) Taxes Other Than Income	(6) Income Taxes Current	(7) Deferred Income Taxes (Net)	(8) Investment Tax Credit (Net)	(9) Gain/Loss On Disposition	(10) Total Operating Expenses	(11) Net Operating Income
System Per Books	$ 2,033,252,700	$ 602,780,380	$ 399,233,520	$ 312,090,000	$ 167,549,000	$ 55,659,810	$ 57,224,884	$ 55,163,300	$ (20,400)	$ 1,649,680,494	$ 383,572,206
Jurisdictional Per Books	2,025,300,072	602,780,380	397,521,350	309,977,691	166,972,871	54,689,774	56,523,710	54,487,386	(20,233)	1,642,932,929	382,367,143 (a)
FPSC Adjustments											
Recoverable Fuel	(602,638,504)	(595,740,539)	(660,000)	(5,797,420)	(440,543)	26,048				(602,612,454)	(26,050)
Recoverable Fuel - ROI	(731,756)				(527)	(282,072)				(282,599)	(449,157)
GPIF Revenues/Penalties	(47,423)				(31)	(18,281)				(18,312)	(29,111)
Recoverable ECCR	(40,449,261)		(40,418,747)		(30,515)	2,995				(40,446,267)	(2,994)
Recoverable ECCR - ROI	(238,270)				(169)	(91,847)				(92,016)	(146,254)
Recoverable ECRC	(36,958,769)	(9,151)	(17,114,364)	(19,809,702)	(25,552)	43,059				(36,915,710)	(43,059)
Recoverable ECRC - ROI	(31,030,453)				(22,477)	(11,961,327)				(11,983,804)	(19,046,649)
Industry Association Dues			(15,845)			6,112				(9,733)	9,733
Solaris and Waterfall			(4,023)			1,552				(2,471)	2,471
Stockholder Relations			0			0				0	0
Civic Club Meals			0			0				0	0
Promotional Advertising			0			0				0	0
Franchise Fee Revenue and Expense	(45,571,793)				(45,538,000)	(13,035)				(45,551,035)	(20,758)
Gross Receipts Tax	(47,001,208)				(47,002,000)	306				(47,001,694)	487
Income Tax True-up						2,161,513				2,161,513	(2,161,513)
Opt Prov Revenue and Third Party Purchase	0	0				0				0	0
Economic Development			(12,279)			4,737				(7,542)	7,542
Acquisition Amortizations				(242,942)	(105,114)	134,262				(213,793)	213,793
Incentive Compensation Plan			(1,050,475)			405,221				(645,254)	645,254
Asset Optimization/Incentive Program	(2,000,000)					(771,500)				(771,500)	(1,228,500)
Total FPSC Adjustments	(806,667,436)	(595,749,690)	(59,275,732)	(25,850,063)	(93,164,928)	(10,352,258)	0	0	0	(784,392,671)	(22,274,765)
FPSC Adjusted	1,218,632,636	7,030,690	338,245,618	284,127,628	73,807,943	44,337,516	56,523,710	54,487,386	(20,233)	858,540,258	360,092,378
Pro Forma Revenue Increase and Annualization Adjustments:											
SoBRA	0			0		0				0	0
Total Pro Forma Adjustments	0	0	0	0	0	0	0	0	0	0	0
Pro Forma Adjusted	$ 1,218,632,636	$ 7,030,690	$ 338,245,618	$ 284,127,628	$ 73,807,943	$ 44,337,516	$ 56,523,710	$ 54,487,386	$ (20,233)	$ 858,540,258	$ 360,092,378

(a) The addition of earnings from AFUDC would increase the System NOI by $5,368,200 and Jurisdictional NOI by $15,186,093

Current Month Amount:
System Per Books
Jurisdictional Per Books

The calculations on this schedule were made in direct response to and according to methodology prescribed in Order No. PSC-93-0165-FOF-EI, Order No. PSC-09-0283-FOF-EI, and decisions made at the July 14, 2009, agenda conference under Docket No. 080317-EI by the Florida Public Service Commission and for that reason only. Tampa Electric Company takes the position that certain portions of these prescribed calculations may not present fairly the company's current financial status and that they should not be used for that purpose.

TAMPA ELECTRIC COMPANY
AVERAGE RATE OF RETURN
SYSTEM ADJUSTMENTS
2018 BUDGET

Working Capital Adjustments	System	Retail
Fuel and ECCR	$ (6,009,292)	$ (5,971,287)
Other:		
Other Return Provided	(3,919,377)	(3,894,589)
Non-utility	(9,988,641)	(9,925,469)
Investor Funds	0	0
Unamortized Rate Case Expense	0	0
	$ (13,908,018)	$ (13,820,058)
Fuel Inventory	$ (9,515,246)	$ (9,515,246)
Job Order Receivables	$ 0	$ 0
ECRC	$ 0	$ 0
Total Adjustments	$ (29,432,556)	$ (29,306,591)

Net Utility Plant Adjustments	System	Retail
ECRC - Plant In Service	$ (557,320,224)	$ (552,757,472)
ECRC - Acc Deprec & Amortization	211,049,634	209,865,618
Fuel PK1 Conversion - Plant In Service	(37,054,298)	(36,750,936)
Fuel PK1 Conversion - Acc Deprec & Amortiz	28,713,794	28,552,706
CWIP	(443,321,362)	(440,747,137)
CWIP in Rate Base	177,741,075	176,708,990
OUC Acquisition Book Value	(1,635,114)	(1,621,727)
OUC Acquisition Accumulated Amortization	1,696,776	1,687,257
Acquisition Adjustment - Plant	(7,484,823)	(7,423,545)
Acquisition Adjustment - Acc Amortiz	5,344,760	5,314,775
Total Adjustments	$ (622,269,781)	$ (617,171,471)

Income Statement Adjustments

FPSC Adjustments	System: Operating Revenue	System: O & M Fuel & Net Interchange	System: O & M Other	System: Depreciation & Amortization	System: Taxes Other Than Income	System: Income Taxes Current	Retail: Operating Revenue	Retail: O & M Fuel & Net Interchange	Retail: O & M Other	Retail: Depreciation & Amortization	Retail: Taxes Other Than Income	Retail: Income Taxes Current
Recoverable Fuel	(602,638,504)	(595,740,539)	(660,000)	(5,797,420)	(440,543)	26,048	(602,638,504)	(595,740,539)	(660,000)	(5,797,420)	(440,543)	26,048
Recoverable Fuel - ROI	(731,756)				(527)	(282,072)	(731,756)				(527)	(282,072)
GPIF Revenues/Penalties	(47,423)				(31)	(18,281)	(47,423)				(31)	(18,281)
Recoverable ECCR	(40,449,261)		(40,418,747)		(30,515)	2,995	(40,449,261)		(40,418,747)		(30,515)	2,995
Recoverable ECCR - ROI	(238,270)				(169)	(91,847)	(238,270)				(169)	(91,847)
Recoverable ECRC	(36,958,769)	(9,151)	(17,114,364)	(19,809,702)	(25,552)	43,059	(36,958,769)	(9,151)	(17,114,364)	(19,809,702)	(25,552)	43,059
Recoverable ECRC - ROI	(31,030,453)				(22,477)	(11,961,327)	(31,030,453)				(22,477)	(11,961,327)
Industry Association Dues			(15,913)			6,138			(15,845)			6,112
Solaris and Waterfall			(4,040)			1,558			(4,023)			1,552
Stockholder Relations			0			0			0			0
Civic Club Meals			0			0			0			0
Promotional Advertising			0			0			0			0
Franchise Fee Revenue and Expense	(45,571,793)				(45,538,000)	(13,035)	(45,571,793)				(45,538,000)	(13,035)
Gross Receipts Tax	(47,001,208)				(47,002,000)	306	(47,001,208)				(47,002,000)	306
Income Tax True-up						2,182,211						2,161,513
Opt Prov Revenue and 3rd Party Purchase	0	0				0	0	0				0
Economic Development			(12,332)			4,757			(12,279)			4,737
Acquisition Amortizations				(244,597)	(105,830)	135,177				(242,942)	(105,114)	134,262
Incentive Compensation Plan			(1,055,000)			406,966			(1,050,475)			405,221
Asset Optimization/Incentive Program	(2,000,000)					(771,500)	(2,000,000)					(771,500)
Total FPSC Adjustments	$ (806,667,436)	$ (595,749,690)	$ (59,280,396)	$ (25,851,719)	$ (93,165,644)	$ (10,328,848)	$ (806,667,436)	$ (595,749,690)	$ (59,275,732)	$ (25,850,063)	$ (93,164,928)	$ (10,352,258)
Pro Forma Revenue Increase and Annualization Adjustments:												
SoBRA												
Total Pro Forma Adjustments	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0

The calculations on this schedule were made in direct response to and according to methodology prescribed in Order No. PSC-93-0165-FOF-EI, Order No. PSC-09-0283-FOF-EI, and Order No. PSC-09-0571-FOF-EI by the Florida Public Service Commission and for that reason only. Tampa Electric Company takes the position that certain portions of these prescribed calculations may not present fairly the company's current financial status and that they should not be used for that purpose.

TAMPA ELECTRIC COMPANY
DOCKET NO. 20180045-EI
EXHIBIT NO. ___ (JSC-1)
WITNESS: CHRONISTER
DOCUMENT NO. 3
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TAMPA ELECTRIC COMPANY
YEAR END RATE OF RETURN
RATE BASE
2018 BUDGET

	(1) Plant In Service	(2) Accumulated Depreciation & Amortization	(3) Net Plant In Service	(4) Property Held For Future Use	(5) Construction Work In Progress	(6) Nuclear Fuel (Net)	(7) Net Utility Plant	(8) Working Capital	(9) Total Rate Base
System Per Books	$ 9,053,341,700	$ (2,997,568,300)	$ 6,055,773,400	$ 57,965,400	$ 597,207,300	$ 0	$ 6,710,946,100	$ 192,154,382	$ 6,903,100,482
Jurisdictional Per Books	8,979,222,465	(2,980,751,553)	5,998,470,912	55,830,341	593,739,509	0	6,648,040,762	190,999,309	6,839,040,071
FPSC Adjustments									
Fuel and ECCR	(36,750,936)	31,064,472	(5,686,464)				(5,686,464)	(5,971,287)	(11,657,751)
Other								(13,820,058)	(13,820,058)
ECRC	(557,873,526)	219,716,842	(338,156,684)				(338,156,684)	0	(338,156,684)
Fuel Inventory								(9,515,246)	(9,515,246)
CWIP					(593,739,509)		(593,739,509)		(593,739,509)
CWIP in Rate Base					171,038,637		171,038,637		171,038,637
Acquisition Book Values	(1,621,727)		(1,621,727)				(1,621,727)		(1,621,727)
Acquisition Accumulated Amortizations		1,716,516	1,716,516				1,716,516		1,716,516
Acquisition Adjustments	(7,423,545)	5,314,775	(2,108,770)				(2,108,770)		(2,108,770)
Total FPSC Adjustments	(603,669,734)	257,812,605	(345,857,129)	0	(422,700,872)	0	(768,558,001)	(29,306,591)	(797,864,592)
FPSC Adjusted	8,375,552,731	(2,722,938,948)	5,652,613,783	55,830,341	171,038,637	0	5,879,482,761	161,692,718	6,041,175,479
Pro Forma Revenue Increase and Annualization Adjustments:									
Total Pro Forma Adjustments	0	0	0	0	0	0	0	0	0
Pro Forma Adjusted	$ 8,375,552,731	$ (2,722,938,948)	$ 5,652,613,783	$ 55,830,341	$ 171,038,637	$ 0	$ 5,879,482,761	$ 161,692,718	$ 6,041,175,479

The calculations on this schedule were made in direct response to and according to methodology prescribed in Order No. PSC-93-0165-FOF-EI, Order No. PSC-09-0283-FOF-EI, and decisions made at the July 14, 2009, agenda conference under Docket No. 080317-EI by the Florida Public Service Commission and for that reason only. Tampa Electric Company takes the position that certain portions of these prescribed calculations may not present fairly the company's current financial status and that they should not be used for that purpose.

TAMPA ELECTRIC COMPANY
DOCKET NO. 20180045-EI
EXHIBIT NO. ___ (JSC-1)
WITNESS: CHRONISTER
DOCUMENT NO. 3
PAGE 6 OF 10
FILED: 05/31/2018

TAMPA ELECTRIC COMPANY
YEAR END RATE OF RETURN
INCOME STATEMENT
2018 BUDGET

	(1) Operating Revenues	(2) O & M Fuel & Net Interchange	(3) O & M Other	(4) Depreciation & Amortization	(5) Taxes Other Than Income	(6) Income Taxes Current	(7) Deferred Income Taxes (Net)	(8) Investment Tax Credit (Net)	(9) Gain/Loss On Disposition	(10) Total Operating Expenses	(11) Net Operating Income
System Per Books	$ 2,033,252,700	$ 602,780,380	$ 399,233,520	$ 312,090,000	$ 167,549,000	$ 55,659,810	$ 57,224,884	$ 55,163,300	$ (20,400)	$ 1,649,680,494	$ 383,572,206
Jurisdictional Per Books	2,025,300,072	602,780,380	397,521,350	309,977,691	166,972,871	54,689,774	56,523,710	54,487,386	(20,233)	1,642,932,929	382,367,143 (a)
FPSC Adjustments											
Recoverable Fuel	(602,638,504)	(595,740,539)	(660,000)	(5,797,420)	(440,543)	26,048				(602,612,454)	(26,050)
Recoverable Fuel - ROI	(731,756)				(527)	(282,072)				(282,599)	(449,157)
GPIF Revenues/Penalties	(47,423)				(31)	(18,281)				(18,312)	(29,111)
Recoverable ECCR	(40,449,261)		(40,418,747)		(30,515)	2,995				(40,446,267)	(2,994)
Recoverable ECCR - ROI	(238,270)				(169)	(91,847)				(92,016)	(146,254)
Recoverable ECRC	(36,958,769)	(9,151)	(17,114,364)	(19,809,702)	(25,552)	43,059				(36,915,710)	(43,059)
Recoverable ECRC - ROI	(31,030,453)				(22,477)	(11,961,327)				(11,983,804)	(19,046,649)
Industry Association Dues			(15,845)			6,112				(9,733)	9,733
Solaris and Waterfall			(4,023)			1,552				(2,471)	2,471
Stockholder Relations			0			0				0	0
Civic Club Meals			0			0				0	0
Promotional Advertising			0			0				0	0
Franchise Fee Revenue and Expense	(45,571,793)				(45,538,000)	(13,035)				(45,551,035)	(20,758)
Gross Receipts Tax	(47,001,208)				(47,002,000)	306				(47,001,694)	487
Income Tax True-up						692,101				692,101	(692,101)
Opt Prov Revenue and Third Party Purchase	0	0				0				0	0
Economic Development			(12,279)			4,737				(7,542)	7,542
Acquisition Amortizations				(242,942)	(105,114)	134,262				(213,793)	213,793
Incentive Compensation Plan			(1,050,475)			405,221				(645,254)	645,254
Asset Optimization/Incentive Program	(2,000,000)					(771,500)				(771,500)	(1,228,500)
Total FPSC Adjustments	(806,667,436)	(595,749,690)	(59,275,732)	(25,850,063)	(93,164,928)	(11,821,670)	0	0	0	(785,862,083)	(20,805,353)
FPSC Adjusted	1,218,632,636	7,030,690	338,245,618	284,127,628	73,807,943	42,868,104	56,523,710	54,487,386	(20,233)	857,070,846	361,561,790
Pro Forma Revenue Increase and Annualization Adjustments:											
Pro Forma R&D Tax Credit	0					0				0	0
Total Pro Forma Adjustments	0	0	0	0	0	0	0	0	0	0	0
Pro Forma Adjusted	$ 1,218,632,636	$ 7,030,690	$ 338,245,618	$ 284,127,628	$ 73,807,943	$ 42,868,104	$ 56,523,710	$ 54,487,386	$ (20,233)	$ 857,070,846	$ 361,561,790

(a) The addition of earnings from AFUDC would increase the System NOI by $5,368,200 and Jurisdictional NOI by $15,188,093

The calculations on this schedule were made in direct response to and according to methodology prescribed in Order No. PSC-93-0165-FOF-EI, Order No. PSC-09-0283-FOF-EI, and decisions made at the July 14, 2009, agenda conference under Docket No. 080317-EI by the Florida Public Service Commission and for that reason only. Tampa Electric Company takes the position that certain portions of these

TAMPA ELECTRIC COMPANY
YEAR END RATE OF RETURN
SYSTEM ADJUSTMENTS
2018 BUDGET

Working Capital Adjustments		System		Retail
Fuel and ECCR	$	(6,009,292)	$	(5,971,287)
Other:				
Other Return Provided		(3,919,377)		(3,894,589)
Non-utility		(9,988,641)		(9,925,469)
Investor Funds		0		0
Unamortized Rate Case Expense		0		0
	$	(13,908,018)	$	(13,820,058)
Fuel Inventory	$	(9,515,246)	$	(9,515,246)
Job Order Receivables	$	0	$	0
ECRC	$	0	$	0
Total Adjustments	$	(29,432,556)	$	(29,306,591)

Net Utility Plant Adjustments		System		Retail
ECRC - Plant In Service	$	(562,478,508)	$	(557,873,526)
ECRC - Acc Deprec & Amortization		220,956,436		219,716,842
Fuel PK1 Conversion - Plant In Service		(37,054,298)	$	(36,750,936)
Fuel PK1 Conversion - Acc Deprec & Amortiz		31,239,731		31,064,472
CWIP		(597,207,300)		(593,739,509)
CWIP in Rate Base		172,037,604		171,038,637
Acquisition Book Value		(1,635,114)		(1,621,727)
Acquisition Accumulated Amortization		1,726,200		1,716,516
Acquisition Adjustment - Plant		(7,484,823)		(7,423,545)
Acquisition Adjustment - Acc Amortiz		5,463,114		5,314,775
Total Adjustments	$	(774,436,958)	$	(768,558,001)

Income Statement Adjustments

FPSC Adjustments	System Operating Revenue	System O & M Fuel & Net Interchange	System O & M Other	System Depreciation & Amortization	System Taxes Other Than Income	System Income Taxes Current	Retail Operating Revenue	Retail O & M Fuel & Net Interchange	Retail O & M Other	Retail Depreciation & Amortization	Retail Taxes Other Than Income	Retail Income Taxes Current
-												
Recoverable Fuel	(602,638,504)	(595,740,539)	(660,000)	(5,797,420)	(440,543)	26,048	(602,638,504)	(595,740,539)	(660,000)	(5,797,420)	(440,543)	26,048
Recoverable Fuel - ROI	(731,756)				(527)	(282,072)	(731,756)				(527)	(282,072)
GPIF Revenues/Penalties	(47,423)				(31)	(18,281)	(47,423)				(31)	(18,281)
Recoverable ECCR	(40,449,261)		(40,418,747)		(30,515)	2,995	(40,449,261)		(40,418,747)		(30,515)	2,995
Recoverable ECCR - ROI	(238,270)				(169)	(91,847)	(238,270)				(169)	(91,847)
Recoverable ECRC	(36,958,769)	(9,151)	(17,114,364)	(19,809,702)	(25,552)	43,059	(36,958,769)	(9,151)	(17,114,364)	(19,809,702)	(25,552)	43,059
Recoverable ECRC - ROI	(31,030,453)				(22,477)	(11,961,327)	(31,030,453)				(22,477)	(11,961,327)
Industry Association Dues			(15,913)			6,138			(15,845)			6,112
Solaris and Waterfall			(4,040)			1,558			(4,023)			1,552
Stockholder Relations			0			0			0			0
Civic Club Meals			0			0			0			0
Promotional Advertising			0			0			0			0
Franchise Fee Revenue and Expense	(45,571,793)				(45,538,000)	(13,035)	(45,571,793)				(45,538,000)	(13,035)
Gross Receipts Tax	(47,001,208)				(47,002,000)	306	(47,001,208)				(47,002,000)	306
Income Tax True-up						698,752						692,101
Opt Prov Revenue and 3rd Party Purchase	0	0				0	0	0				0
Economic Development			(12,332)			4,757			(12,279)			4,737
Acquisition Amortizations				(244,597)	(105,830)	135,177				(242,942)	(105,114)	134,262
Incentive Compensation Plan			(1,055,000)			406,966			(1,050,475)			405,221
Asset Optimization/Incentive Program	(2,000,000)					(771,500)	(2,000,000)					(771,500)
Total FPSC Adjustments	$ (806,667,436)	$ (595,749,690)	$ (59,280,396)	$ (25,851,719)	$ (93,165,644)	$ (11,812,307)	$ (806,667,436)	$ (595,749,690)	$ (59,275,732)	$ (25,850,063)	$ (93,164,928)	$ (11,821,670)
Pro Forma Revenue Increase and Annualization Adjustments:												
-												
Total Pro Forma Adjustments	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	0	0	0

The calculations on this schedule were made in direct response to and according to methodology prescribed in Order No. PSC-93-0165-FOF-EI, Order No. PSC-09-0283-FOF-EI, and Order No. PSC-09-0571-FOF-EI by the Florida Public Service Commission and for that reason only. Tampa Electric Company takes the position that certain portions of these prescribed calculations may not present fairly the company's current financial status and that they should not be used for that purpose.

TAMPA ELECTRIC COMPANY
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SCHEDULE 4

TAMPA ELECTRIC COMPANY
CAPITAL STRUCTURE
FPSC ADJUSTED BASIS
2018 BUDGET

					with DR	55.32	Low Point		Mid Point		High Point	
					w/o DR	55.32						
AVERAGE	System Per Books	Retail Per Books	Adjustments Specific	Pro Rata	Adjusted Retail	Ratio (%)	Cost Rate (%)	Weighted Cost (%)	Cost Rate (%)	Weighted Cost (%)	Cost Rate (%)	Weighted Cost (%)
Long Term Debt	$ 1,969,509,085	$ 1,969,509,085	$ (668)	$ (213,025,417)	$ 1,756,483,000	30.23	4.93	1.49	4.93	1.49	4.93	1.49
Short Term Debt	271,533,385	271,533,385	(2,157,973)	(29,136,107)	240,239,305	4.13	2.96	0.12	2.96	0.12	2.96	0.12
Customer Deposits	94,222,077	94,222,077	-	(10,191,254)	84,030,823	1.45	2.41	0.03	2.41	0.03	2.41	0.03
Common Equity	2,771,731,334	2,771,731,334	(940)	(299,795,126)	2,471,935,268	42.54	9.25	3.94	10.25	4.36	11.25	4.79
Deferred Income Taxes	1,372,109,578	1,372,109,578	(479,002)	(148,358,387)	1,223,272,189	21.05	-	-	-	-	-	-
Tax Credits - Weighted Cost	38,754,908	38,754,908	(1,069)	(4,191,695)	34,562,144	0.59	7.22	0.04	7.77	0.05	8.32	0.05
Total	$ 6,517,860,366	$ 6,517,860,366	$ (2,639,652)	$ (704,697,986)	$ 5,810,522,728	100.00		5.62		6.05		6.48
					(1)							

							Low Point		Mid Point		High Point	
YEAR END	System Per Books	Retail Per Books	Specific	Pro Rata	Adjusted Retail	Ratio (%)	Cost Rate (%)	Weighted Cost (%)	Cost Rate (%)	Weighted Cost (%)	Cost Rate (%)	Weighted Cost (%)
Long Term Debt	$ 2,312,798,700	$ 2,312,798,700	$ 44	$ (271,084,269)	$ 2,041,714,475	33.80	4.69	1.59	4.69	1.59	4.69	1.59
Short Term Debt	25,891,000	25,891,000	(2,157,881)	(2,781,770)	20,951,349	0.35	2.96	0.01	2.96	0	2.96	0
Customer Deposits	86,265,300	86,265,300	-	(10,111,196)	76,154,104	1.26	2.41	0.03	2.41	0.03	2.41	0.03
Common Equity	2,962,129,480	2,962,129,480	56	(347,192,648)	2,614,936,888	43.29	9.25	4.00	10.25	4.44	11.25	4.87
Deferred Income Taxes	1,381,789,251	1,381,789,251	(492,564)	(161,902,432)	1,219,394,255	20.18	-	-	-	-	-	-
Tax Credits - Weighted Cost	77,055,200	77,055,200	1,000	(9,031,793)	68,024,407	1.13	7.23	0.08	7.79	0.09	8.35	0.09
Total	$ 6,845,928,931	$ 6,845,928,931	$ (2,649,345)	$ (802,104,109)	$ 6,041,175,478	100.00		5.71		6.16		6.59
					(1)							

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The calculations on this schedule were made in direct response to and according to methodology prescribed in Order No. PSC-09-0283-FOF-EI and decisions made at the July 14, 2009, agenda conference under Docket No. 080317-EI by the Florida Public Service Commission and for that reason only. Tampa Electric Company takes the position that certain portions of these prescribed calculations may not present fairly the company's current financial status and that they should not be used for that purpose.

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SCHEDULE 5

TAMPA ELECTRIC COMPANY
FINANCIAL INTEGRITY INDICATORS
2018 BUDGET

A. Times Interest Earned With AFUDC*

Earnings Before Interest	393,634,736
AFUDC - Debt	4,954,300
Income Taxes	168,287,564
Total	566,876,600
Interest Charges (Before Deducting AFUDC - Debt)	106,918,623
Tie With AFUDC	5.30

B. Times Interest Earned Without AFUDC*

Earnings Before Interest	393,634,736
AFUDC - Equity	(10,322,500)
Income Taxes	168,287,564
Total	551,599,800
Interest Charges (Before Deducting AFUDC - Debt)	106,918,623
Tie Without AFUDC	5.16

C. Percent AFUDC to Net Income Available For Common Stockholders*

AFUDC - Debt	4,954,300
x (Income Tax Rate of 38.575%)	(1,911,121)
Subtotal	3,043,179
AFUDC - Other	10,322,500
Total	13,365,679
Net Income Available For Common Stockholders	291,497,613
Percent AFUDC to Available Net Income	4.59%

* Tampa Electric Company calculates AFUDC using the rate last authorized by the Florida Public Service Commission. On the company's books, AFUDC is allocated between debt and equity using the modified methodology in FERC Order No. 561. The information shown on Schedule 5 Parts A, B and C is stated as if AFUDC had been allocated using the FPSC methodology.

D. Percent Internally Generated Funds

Net Income	291,497,613
Common Dividends	84,476,000
AFUDC (Debt & Other)	(15,276,800)
Depreciation & Amortization	312,090,000
Deferred Income Taxes	57,224,884
Investment Tax Credits	55,163,500
Deferred Clause Revenues (Expenses)	(17,873,200)
Other	0
Total	767,301,997
Construction Expenditures (Excluding AFUDC Other & Debt)	995,065,382
Percent Internally Generated Funds	77.11%

E. Long Term Debt as Percent of Total Capital

F. Short Term Debt as Percent of Total Capital

Reconciled Average Retail Amounts	
Long Term Debt	1,756,483,000
Short Term Debt	240,239,305
Common Equity	2,471,935,268
Total	4,468,657,573
% Long Term Debt to Total	39.31%
% Short Term Debt to Total	5.38%

G. FPSC Adjusted Average Jurisdictional Return On Common Equity

FPSC Adjusted Average Earned Rate Of Return	6.20
Less: Reconciled Average Retail Weighted Cost Rates For:	
Long Term Debt	1.49
Short Term Debt	0.12
Customer Deposits	0.03
Tax Credits-Weighted Cost (Midpoint)	0.05
Subtotal	1.69
Total	4.51
Divided By Common Equity Ratio	42.54
Jurisdictional Return On Common Equity	10.60%

The calculations on this schedule were made in direct response to and according to methodology prescribed in Order No. PSC-93-0165-FOF-EI, Order No. PSC-09-0283-FOF-EI, and decisions made at the July 14, 2009, agenda conference under Docket No. 080317-EI by the Florida Public Service Commission and for that reason only.
Tampa Electric Company takes the position that certain portions of these prescribed calculations may not present fairly the Company's current financial status and that they should not be used for that purpose.

Whoever knowingly makes a false statement in writing with the intent to mislead a public servant in the performance of his official duty shall be guilty of a misdemeanor of the second degree, punishable as provided in s. 775.082, s. 775083, or s. 775.084.

Surveillance Backup

TAMPA ELECTRIC COMPANY
EARNINGS SURVEILLANCE REPORT SUMMARY
2018 BUDGET WITH TR
2018 BUDGET WITH TR

SCHEDULE 1

I. Average Rate of Return (Jurisdictional)	(1) Actual Per Books	(2) FPSC Adjustments	(3) FPSC Adjusted	(4) Pro Forma Adjustments	(5) Pro Forma Adjusted
Net Operating Income	$ 479,323,777 (a)	(40,989,223) (b)	438,334,554	0	$ 438,334,554
Average Rate Base	6,449,819,266	(646,813,972)	5,803,005,294	0	5,803,005,294
Average Rate of Return	7.43%		7.55%		7.55%
II. Year End Rate of Return (Jurisdictional)					
Net Operating Income	$ 479,323,777 (a)	(39,865,004) (b)	439,458,773	0	$ 439,458,773
Year End Rate Base	6,831,858,546	(798,200,502)	6,033,658,044	0	6,033,658,044
Year End Rate of Return	7.02%		7.28%		7.28%

(a) Includes AFUDC debt of $4,925,532 and AFUDC equity of $10,262,561
(b) Includes reversal of AFUDC earnings.

III. Required Rate of Return Average Capital Structure (FPSC Adjusted Basis)	
Low	5.65 %
Midpoint	6.09 %
High	6.52 %

IV. Financial Integrity Indicators				
A. TIE With AFUDC	5.28	(System per books basis)		
B. TIE Without AFUDC	5.14	(System per books basis)		
C. AFUDC To Net Income	3.76 %	(System per books basis)		
D. Internally Generated Funds	71.22 %	(System per books basis)		
E. LTD To Total Investor Funds	39.06 %	(FPSC adjusted basis)		
F. STD To Total Investor Funds	5.62 %	(FPSC adjusted basis)		
G. Return On Common Equity (Avg)	13.65 %	(FPSC adjusted basis)	Year End	12.71%
H. Return On Common Equity (Avg)	13.65 %	(Pro Forma adjusted basis)	Year End	12.71%

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I am aware that Section 837.06, Florida Statutes, provides:

Whoever knowingly makes a false statement in writing with the intent to mislead a public servant in the performance of his official duty shall be guilty of a misdemeanor of the second degree, punishable as provided in s. 775.082, s. 775.083, or s. 775.084.

Jeffrey S. Chronister - Controller

Date

TAMPA ELECTRIC COMPANY
AVERAGE RATE OF RETURN
RATE BASE
2018 BUDGET WITH TR

	(1) Plant In Service	(2) Accumulated Depreciation & Amortization	(3) Net Plant In Service	(4) Property Held For Future Use	(5) Construction Work In Progress	(6) Nuclear Fuel (Net)	(7) Net Utility Plant	(8) Working Capital	(9) Total Rate Base
System Per Books	$ 8,725,169,523	$ (2,895,611,000)	$ 5,829,558,523	$ 52,829,462	$ 443,321,362	$ 0	$ 6,325,709,347	$ 184,927,149	$ 6,510,636,496
Jurisdictional Per Books	8,653,737,016	(2,879,366,247)	5,774,370,769	50,883,576	440,747,137	0	6,266,001,482	183,817,784	6,449,819,266
FPSC Adjustments									
Fuel and ECCR	(36,750,936)	28,552,706	(8,198,230)				(8,198,230)	(5,971,287)	(14,169,517)
Other								(14,155,968)	(14,155,968)
ECRC	(552,757,472)	209,865,618	(342,891,854)				(342,891,854)	0	(342,891,854)
Fuel Inventory								(9,515,246)	(9,515,246)
CWIP					(440,747,137)		(440,747,137)		(440,747,137)
CWIP in Rate Base					176,708,990		176,708,990		176,708,990
Acquisition Book Values	(1,621,727)		(1,621,727)				(1,621,727)		(1,621,727)
Acquisition Accumulated Amortizations		1,687,257	1,687,257				1,687,257		1,687,257
Acquisition Adjustments	(7,423,545)	5,314,775	(2,108,770)				(2,108,770)		(2,108,770)
Total FPSC Adjustments	(598,553,680)	245,420,356	(353,133,324)	0	(264,038,147)	0	(617,171,471)	(29,642,501)	(646,813,972)
FPSC Adjusted	8,055,183,336	(2,633,945,891)	5,421,237,445	50,883,576	176,708,990	0	5,648,830,011	154,175,283	5,803,005,294
Pro Forma Revenue Increase and Annualization Adjustments:									
SoBRA			0				0		0
Total Pro Forma Adjustments	0	0	0	0	0	0	0	0	0
Pro Forma Adjusted	$ 8,055,183,336	$ (2,633,945,891)	$ 5,421,237,445	$ 50,883,576	$ 176,708,990	$ 0	$ 5,648,830,011	$ 154,175,283	$ 5,803,005,294

The calculations on this schedule were made in direct response to and according to methodology prescribed in Order No. PSC-93-0165-FOF-EI, Order No. PSC-09-0283-FOF-EI, and decisions made at the July 14, 2009, agenda conference under Docket No. 080317-EI by the Florida Public Service Commission and for that reason only. Tampa Electric Company takes the position that certain portions of these prescribed calculations may not present fairly the company's current financial status and that they should not be used for that purpose.

TAMPA ELECTRIC COMPANY
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TAMPA ELECTRIC COMPANY
AVERAGE RATE OF RETURN
INCOME STATEMENT
2018 BUDGET WITH TR

	(1) Operating Revenues	(2) O & M Fuel & Net Interchange	(3) O & M Other	(4) Depreciation & Amortization	(5) Taxes Other Than Income	(6) Income Taxes Current	(7) Deferred Income Taxes (Net)	(8) Investment Tax Credit (Net)	(9) Gain/Loss On Disposition	(10) Total Operating Expenses	(11) Net Operating Income
System Per Books	$ 2,033,252,700	$ 602,780,380	$ 399,233,520	$ 312,090,000	$ 167,549,000	$ 50,604,912	$ (19,831,098)	$ 55,163,300	$ (20,400)	$ 1,567,569,614	$ 465,683,086
Jurisdictional Per Books	2,025,300,072	602,780,380	397,521,350	309,977,691	166,972,871	49,033,051	(19,588,108)	54,487,386	(20,233)	1,561,164,388	464,135,684 (a)
FPSC Adjustments											
Recoverable Fuel	(602,638,504)	(595,740,539)	(660,000)	(5,797,420)	(440,543)	17,114				(602,621,388)	(17,116)
Recoverable Fuel - ROI	(731,756)				(527)	(185,330)				(185,857)	(545,899)
GPIF Revenues/Penalties	(47,423)				(31)	(12,012)				(12,043)	(35,380)
Recoverable ECCR	(40,449,261)		(40,418,747)		(30,515)	1,968				(40,447,294)	(1,967)
Recoverable ECCR - ROI	(238,270)				(169)	(60,347)				(60,516)	(177,754)
Recoverable ECRC	(36,958,769)	(9,151)	(17,114,364)	(19,809,702)	(25,552)	28,291				(36,930,478)	(28,291)
Recoverable ECRC - ROI	(31,030,453)				(22,477)	(7,858,972)				(7,881,449)	(23,149,004)
Industry Association Dues			(15,845)			4,016				(11,829)	11,829
Solaris and Waterfall			(4,023)			1,020				(3,003)	3,003
Stockholder Relations			0			0				0	0
Civic Club Meals			0			0				0	0
Promotional Advertising			0			0				0	0
Franchise Fee Revenue and Expense	(45,571,793)				(45,538,000)	(8,565)				(45,546,565)	(25,228)
Gross Receipts Tax	(47,001,208)				(47,002,000)	201				(47,001,799)	592
Income Tax True-up						1,396,054				1,396,054	(1,396,054)
Opt Prov Revenue and Third Party Purchase	0	0				0				0	0
Economic Development			(12,279)			3,112				(9,167)	9,167
Acquisition Amortizations				(242,942)	(105,114)	88,215				(259,840)	259,840
Incentive Compensation Plan			(1,050,475)			266,243				(784,232)	784,232
Asset Optimization/Incentive Program	(2,000,000)					(506,900)				(506,900)	(1,493,100)
Total FPSC Adjustments	(806,667,436)	(595,749,690)	(59,275,732)	(25,850,063)	(93,164,928)	(6,825,892)	0	0	0	(780,866,306)	(25,801,130)
FPSC Adjusted	1,218,632,636	7,030,690	338,245,618	284,127,628	73,807,943	42,207,159	(19,588,108)	54,487,386	(20,233)	780,298,082	438,334,554
Pro Forma Revenue Increase and Annualization Adjustments:											
SoBRA	0			0		0				0	0
Total Pro Forma Adjustments	0	0	0	0	0	0	0	0	0	0	0
Pro Forma Adjusted	$ 1,218,632,636	$ 7,030,690	$ 338,245,618	$ 284,127,628	$ 73,807,943	$ 42,207,159	$ (19,588,108)	$ 54,487,386	$ (20,233)	$ 780,298,082	$ 438,334,554

(a) The addition of earnings from AFUDC would increase the System NOI by $5,368,200 and Jurisdictional NOI by $15,188,093

Current Month Amount: System Per Books											
Jurisdictional Per Books											

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TAMPA ELECTRIC COMPANY
AVERAGE RATE OF RETURN
SYSTEM ADJUSTMENTS
2018 BUDGET WITH TR

Working Capital Adjustments	System	Retail
Fuel and ECCR	$ (6,009,292)	$ (5,971,287)
Other:		
Other Return Provided	(3,381,531)	(3,360,145)
Non-utility	(10,864,534)	(10,795,823)
Investor Funds	0	0
Unamortized Rate Case Expense	0	0
	$ (14,246,065)	$ (14,155,968)
Fuel Inventory	$ (9,515,246)	$ (9,515,246)
Job Order Receivables	$ 0	$ 0
ECRC	$ 0	$ 0
Total Adjustments	$ (29,770,603)	$ (29,642,501)

Net Utility Plant Adjustments	System	Retail
ECRC - Plant In Service	$ (557,320,224)	$ (552,757,472)
ECRC - Acc Deprec & Amortization	211,049,634	209,865,618
Fuel PK1 Conversion - Plant In Service	(37,054,298)	(36,750,936)
Fuel PK1 Conversion - Acc Deprec & Amortiz	28,713,794	28,552,706
CWIP	(443,321,362)	(440,747,137)
CWIP in Rate Base	177,741,075	176,708,990
OUC Acquisition Book Value	(1,635,114)	(1,621,727)
OUC Acquisition Accumulated Amortization	1,696,776	1,687,257
Acquisition Adjustment - Plant	(7,484,823)	(7,423,545)
Acquisition Adjustment - Acc Amortiz	5,344,760	5,314,775
Total Adjustments	$ (622,269,781)	$ (617,171,471)

Income Statement Adjustments

	System						Retail				
FPSC Adjustments	Operating Revenue	O & M Fuel & Net Interchange	O & M Other	Depreciation & Amortization	Taxes Other Than Income	Income Taxes Current	Operating Revenue	O & M Fuel & Net Interchange	O & M Other	Depreciation & Amortization	Taxes Other Than Income	Income Taxes Current
-											
Recoverable Fuel	(602,638,504)	(595,740,539)	(660,000)	(5,797,420)	(440,543)	17,114	(602,638,504)	(595,740,539)	(660,000)	(5,797,420)	(440,543)	17,114
Recoverable Fuel - ROI	(731,756)				(527)	(185,330)	(731,756)				(527)	(185,330)
GPIF Revenues/Penalties	(47,423)				(31)	(12,012)	(47,423)				(31)	(12,012)
Recoverable ECCR	(40,449,261)		(40,418,747)		(30,515)	1,968	(40,449,261)		(40,418,747)		(30,515)	1,968
Recoverable ECCR - ROI	(238,270)				(169)	(60,347)	(238,270)				(169)	(60,347)
Recoverable ECRC	(36,958,769)	(9,151)	(17,114,364)	(19,809,702)	(25,552)	28,291	(36,958,769)	(9,151)	(17,114,364)	(19,809,702)	(25,552)	28,291
Recoverable ECRC - ROI	(31,030,453)				(22,477)	(7,858,972)	(31,030,453)				(22,477)	(7,858,972)
Industry Association Dues			(15,913)			4,033			(15,845)			4,016
Solaris and Waterfall			(4,040)			1,024			(4,023)			1,020
Stockholder Relations			0			0			0			0
Civic Club Meals			0			0			0			0
Promotional Advertising			0			0			0			0
Franchise Fee Revenue and Expense	(45,571,793)				(45,538,000)	(8,565)	(45,571,793)				(45,538,000)	(8,565)
Gross Receipts Tax	(47,001,208)				(47,002,000)	201	(47,001,208)				(47,002,000)	201
Income Tax True-up						1,409,429						1,396,054
Opt Prov Revenue and 3rd Party Purchase	0	0				0	0	0				0
Economic Development			(12,332)			3,126			(12,279)			3,112
Acquisition Amortizations				(244,597)	(105,830)	88,816				(242,942)	(105,114)	88,215
Incentive Compensation Plan			(1,055,000)			267,390			(1,050,475)			266,243
Asset Optimization/Incentive Program	(2,000,000)					(506,900)	(2,000,000)					(506,900)
Total FPSC Adjustments	$ (806,667,436)	$ (595,749,690)	$ (59,280,396)	$ (25,851,719)	$ (93,165,644)	$ (6,810,734)	$ (806,667,436)	$ (595,749,690)	$ (59,275,732)	$ (25,850,063)	$ (93,164,928)	$ (6,825,892)
Pro Forma Revenue Increase and Annualization Adjustments:												
-												
SoBRA												-
Total Pro Forma Adjustments	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0

The calculations on this schedule were made in direct response to and according to methodology prescribed in Order No. PSC-93-0165-FOF-EI, Order No. PSC-09-0283-FOF-EI, and Order No. PSC-09-0571-FOF-EI by the Florida Public Service Commission and for that reason only. Tampa Electric Company takes the position that certain portions of these prescribed calculations may not present fairly the company's current financial status and that they should not be used for that purpose.

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SCHEDULE 3
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TAMPA ELECTRIC COMPANY
YEAR END RATE OF RETURN
RATE BASE
2018 BUDGET WITH TR

	(1) Plant In Service	(2) Accumulated Depreciation & Amortization	(3) Net Plant In Service	(4) Property Held For Future Use	(5) Construction Work In Progress	(6) Nuclear Fuel (Net)	(7) Net Utility Plant	(8) Working Capital	(9) Total Rate Base
System Per Books	$ 9,053,341,700	$ (2,997,568,300)	$ 6,055,773,400	$ 57,965,400	$ 597,207,300	$ 0	$ 6,710,946,100	$ 184,927,149	$ 6,895,873,249
Jurisdictional Per Books	8,979,222,465	(2,980,751,553)	5,998,470,912	55,830,341	593,739,509	0	6,648,040,762	183,817,784	6,831,858,546
FPSC Adjustments									
Fuel and ECCR	(36,750,936)	31,064,472	(5,686,464)				(5,686,464)	(5,971,287)	(11,657,751)
Other								(14,155,968)	(14,155,968)
ECRC	(557,873,526)	219,716,842	(338,156,684)				(338,156,684)	0	(338,156,684)
Fuel Inventory								(9,515,246)	(9,515,246)
CWIP					(593,739,509)		(593,739,509)		(593,739,509)
CWIP in Rate Base					171,038,637		171,038,637		171,038,637
Acquisition Book Values	(1,621,727)		(1,621,727)				(1,621,727)		(1,621,727)
Acquisition Accumulated Amortizations		1,716,516	1,716,516				1,716,516		1,716,516
Acquisition Adjustments	(7,423,545)	5,314,775	(2,108,770)				(2,108,770)		(2,108,770)
Total FPSC Adjustments	(603,669,734)	257,812,605	(345,857,129)	0	(422,700,872)	0	(768,558,001)	(29,642,501)	(798,200,502)
FPSC Adjusted	8,375,552,731	(2,722,938,948)	5,652,613,783	55,830,341	171,038,637	0	5,879,482,761	154,175,283	6,033,658,044
Pro Forma Revenue Increase and Annualization Adjustments:									
Total Pro Forma Adjustments	0	0	0	0	0	0	0	0	0
Pro Forma Adjusted	$ 8,375,552,731	$ (2,722,938,948)	$ 5,652,613,783	$ 55,830,341	$ 171,038,637	$ 0	$ 5,879,482,761	$ 154,175,283	$ 6,033,658,044

The calculations on this schedule were made in direct response to and according to methodology prescribed in Order No. PSC-93-0165-FOF-EI, Order No. PSC-09-0283-FOF-EI, and decisions made at the July 14, 2009, agenda conference under Docket No. 080317-EI by the Florida Public Service Commission and for that reason only. Tampa Electric Company takes the position that certain portions of these prescribed calculations may not present fairly the company's current financial status and that they should not be used for that purpose.

Surveillance Backup

TAMPA ELECTRIC COMPANY
YEAR END RATE OF RETURN
INCOME STATEMENT
2018 BUDGET WITH TR

	(1) Operating Revenues	(2) O & M Fuel & Net Interchange	(3) O & M Other	(4) Depreciation & Amortization	(5) Taxes Other Than Income	(6) Income Taxes Current	(7) Deferred Income Taxes (Net)	(8) Investment Tax Credit (Net)	(9) Gain/Loss On Disposition	(10) Total Operating Expenses	(11) Net Operating Income
System Per Books	$ 2,033,252,700	$ 602,780,380	$ 399,233,520	$ 312,090,000	$ 167,549,000	$ 50,604,912	$ (19,831,098)	$ 55,163,300	$ (20,400)	$ 1,567,569,614	$ 465,683,086
Jurisdictional Per Books	2,025,300,072	602,780,380	397,521,350	309,977,691	166,972,871	49,033,051	(19,588,108)	54,487,386	(20,233)	1,561,164,388	464,135,684 (a)
FPSC Adjustments											
Recoverable Fuel	(602,638,504)	(595,740,539)	(660,000)	(5,797,420)	(440,543)	17,114				(602,621,388)	(17,116)
Recoverable Fuel - ROI	(731,756)				(527)	(185,330)				(185,857)	(545,899)
GPIF Revenues/Penalties	(47,423)				(31)	(12,012)				(12,043)	(35,380)
Recoverable ECCR	(40,449,261)		(40,418,747)		(30,515)	1,968				(40,447,294)	(1,967)
Recoverable ECCR - ROI	(238,270)				(169)	(60,347)				(60,516)	(177,754)
Recoverable ECRC	(36,958,769)	(9,151)	(17,114,364)	(19,809,702)	(25,552)	28,291				(36,930,478)	(28,291)
Recoverable ECRC - ROI	(31,030,453)				(22,477)	(7,858,972)				(7,881,449)	(23,149,004)
Industry Association Dues			(15,845)			4,016				(11,829)	11,829
Solaris and Waterfall			(4,023)			1,020				(3,003)	3,003
Stockholder Relations			0			0				0	0
Civic Club Meals			0			0				0	0
Promotional Advertising			0			0				0	0
Franchise Fee Revenue and Expense	(45,571,793)				(45,538,000)	(8,565)				(45,546,565)	(25,228)
Gross Receipts Tax	(47,001,208)				(47,002,000)	201				(47,001,799)	592
Income Tax True-up						271,835				271,835	(271,835)
Opt Prov Revenue and Third Party Purchase	0	0				0				0	0
Economic Development			(12,279)			3,112				(9,167)	9,167
Acquisition Amortizations				(242,942)	(105,114)	88,215				(259,840)	259,840
Incentive Compensation Plan			(1,050,475)			266,243				(784,232)	784,232
Cost Optimization/Incentive Program	(2,000,000)					(506,900)				(506,900)	(1,493,100)
Total FPSC Adjustments	(806,667,436)	(595,749,690)	(59,275,732)	(25,850,063)	(93,164,928)	(7,950,111)	0	0	0	(781,990,525)	(24,676,911)
FPSC Adjusted	1,218,632,636	7,030,690	338,245,618	284,127,628	73,807,943	41,082,940	(19,588,108)	54,487,386	(20,233)	779,173,863	439,458,773
Pro Forma Revenue Increase and Annualization Adjustments:											
Pro Forma R&D Tax Credit	0					0				0	0
Total Pro Forma Adjustments	0	0	0	0	0	0	0	0	0	0	0
Pro Forma Adjusted	$ 1,218,632,636	$ 7,030,690	$ 338,245,618	$ 284,127,628	$ 73,807,943	$ 41,082,940	$ (19,588,108)	$ 54,487,386	$ (20,233)	$ 779,173,863	$ 439,458,773

(a) The addition of earnings from AFUDC would increase the System NOI by $5,368,200 and Jurisdictional NOI by $15,188,093

The calculations on this schedule were made in direct response to and according to methodology prescribed in Order No. PSC-93-0165-FOF-EI, Order No. PSC-09-0283-FOF-EI, and decisions made at the July 14, 2009, agenda conference under Docket No. 080317-EI by the Florida Public Service Commission and for that reason only. Tampa Electric Company takes the position that certain portions of these

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TAMPA ELECTRIC COMPANY
DOCKET NO. 20180045-EI
EXHIBIT NO. ___ (JSC-1)
WITNESS: CHRONISTER
DOCUMENT NO. 4
PAGE 7 OF 9
FILED: 05/31/2018

TAMPA ELECTRIC COMPANY
YEAR END RATE OF RETURN
SYSTEM ADJUSTMENTS
2018 BUDGET WITH TR

Working Capital Adjustments		System	Retail
Fuel and ECCR	$	(6,009,292) $	(5,971,287)
Other:			
Other Return Provided		(3,381,531)	(3,360,145)
Non-utility		(10,864,534)	(10,795,823)
Investor Funds		0	0
Unamortized Rate Case Expense		0	0
	$	(14,246,065) $	(14,155,968)
Fuel Inventory	$	(9,515,246) $	(9,515,246)
Job Order Receivables	$	0 $	0
ECRC	$	0 $	0
Total Adjustments	$	(29,770,603) $	(29,642,501)

Net Utility Plant Adjustments		System	Retail
ECRC - Plant In Service	$	(562,478,508) $	(557,873,526)
ECRC - Acc Deprec & Amortization		220,956,436	219,716,842
Fuel PK1 Conversion - Plant In Service		(37,054,298) $	(36,750,936)
Fuel PK1 Conversion - Acc Deprec & Amortiz		31,239,731	31,064,472
CWIP		(597,207,300)	(593,739,509)
CWIP in Rate Base		172,037,604	171,038,637
Acquisition Book Value		(1,635,114)	(1,621,727)
Acquisition Accumulated Amortization		1,726,200	1,716,516
Acquisition Adjustment - Plant		(7,484,823)	(7,423,545)
Acquisition Adjustment - Acc Amortiz		5,463,114	5,314,775
Total Adjustments	$	(774,436,958) $	(768,558,001)

Income Statement Adjustments

FPSC Adjustments		System Operating Revenue	System O & M Fuel & Net Interchange	System O & M Other	System Depreciation & Amortization	System Taxes Other Than Income	System Income Taxes Current	Retail Operating Revenue	Retail O & M Fuel & Net Interchange	Retail O & M Other	Retail Depreciation & Amortization	Retail Taxes Other Than Income	Retail Income Taxes Current
-													
Recoverable Fuel		(602,638,504)	(595,740,539)	(660,000)	(5,797,420)	(440,543)	17,114	(602,638,504)	(595,740,539)	(660,000)	(5,797,420)	(440,543)	17,114
Recoverable Fuel - ROI		(731,756)				(527)	(185,330)	(731,756)				(527)	(185,330)
GPIF Revenues/Penalties		(47,423)				(31)	(12,012)	(47,423)				(31)	(12,012)
Recoverable ECCR		(40,449,261)		(40,418,747)		(30,515)	1,968	(40,449,261)		(40,418,747)		(30,515)	1,968
Recoverable ECCR - ROI		(238,270)				(169)	(60,347)	(238,270)				(169)	(60,347)
Recoverable ECRC		(36,958,769)	(9,151)	(17,114,364)	(19,809,702)	(25,552)	28,291	(36,958,769)	(9,151)	(17,114,364)	(19,809,702)	(25,552)	28,291
Recoverable ECRC - ROI		(31,030,453)				(22,477)	(7,858,972)	(31,030,453)				(22,477)	(7,858,972)
Industry Association Dues				(15,913)			4,033			(15,845)			4,016
Solaris and Waterfall				(4,040)			1,024			(4,023)			1,020
Stockholder Relations				0			0			0			0
Civic Club Meals				0			0			0			0
Promotional Advertising				0			0			0			0
Franchise Fee Revenue and Expense		(45,571,793)				(45,538,000)	(8,565)	(45,571,793)				(45,538,000)	(8,565)
Gross Receipts Tax		(47,001,208)				(47,002,000)	201	(47,001,208)				(47,002,000)	201
Income Tax True-up							274,449						271,835
Opt Prov Revenue and 3rd Party Purchase		0	0				0	0	0				0
Economic Development				(12,332)			3,126			(12,279)			3,112
Acquisition Amortizations					(244,597)	(105,830)	88,816				(242,942)	(105,114)	88,215
Incentive Compensation Plan				(1,055,000)			267,390			(1,050,475)			266,243
Asset Optimization/Incentive Program		(2,000,000)					(506,900)	(2,000,000)					(506,900)
Total FPSC Adjustments	$	(806,667,436) $	(595,749,690) $	(59,280,396) $	(25,851,719) $	(93,165,644) $	(7,945,714) $	(806,667,436) $	(595,749,690) $	(59,275,732) $	(25,850,063) $	(93,164,928) $	(7,950,111)
Pro Forma Revenue Increase and Annualization Adjustments:													
-													
Total Pro Forma Adjustments	$	0 $	0 $	0 $	0 $	0 $	0 $	0 $	0 $	0 $	0	0	0

The calculations on this schedule were made in direct response to and according to methodology prescribed in Order No. PSC-93-0165-FOF-EI, Order No. PSC-09-0283-FOF-EI, and Order No. PSC-09-0571-FOF-EI by the Florida Public Service Commission and for that reason only. Tampa Electric Company takes the position that certain portions of these prescribed calculations may not present fairly the company's current financial status and that they should not be used for that purpose.

SCHEDULE 4

TAMPA ELECTRIC COMPANY
CAPITAL STRUCTURE
FPSC ADJUSTED BASIS
2018 BUDGET WITH TR

AVERAGE		System Per Books		Retail Per Books		Adjustments Specific		Pro Rata		Adjusted Retail (with DR / w/o DR)	Ratio (%) (55.32 / 55.32)	Low Point Cost Rate (%)	Low Point Weighted Cost (%)	Mid Point Cost Rate (%)	Mid Point Weighted Cost (%)	High Point Cost Rate (%)	High Point Weighted Cost (%)
Long Term Debt	$	1,969,509,085	$	1,969,509,085	$	(664)	$	(213,252,887)	$	1,756,255,533	30.26	4.93	1.49	4.93	1.49	4.93	1.49
Short Term Debt		285,980,538		285,980,538		(2,622,751)		(30,681,192)		252,676,596	4.35	2.94	0.13	2.94	0.13	2.94	0.13
Customer Deposits		94,222,077		94,222,077		-		(10,202,136)		84,019,941	1.45	2.41	0.03	2.41	0.03	2.41	0.03
Common Equity		2,789,156,183		2,789,156,183		(940)		(302,001,963)		2,487,153,280	42.86	9.25	3.96	10.25	4.39	11.25	4.82
Deferred Income Taxes		1,333,012,038		1,333,012,038		(375,096)		(144,294,666)		1,188,342,276	20.48	-	-	-	-	-	-
Tax Credits - Weighted Cost		38,754,908		38,754,908		(1,069)		(4,196,171)		34,557,668	0.60	7.22	0.04	7.77	0.05	8.32	0.05
Total	$	6,510,634,829	$	6,510,634,829	$	(3,000,521)	$	(704,629,015)	$	5,803,005,294	100.00		5.65		6.09		6.52
										(0)							

YEAR END		System Per Books		Retail Per Books		Specific		Pro Rata		Adjusted Retail	Ratio (%)	Low Point Cost Rate (%)	Low Point Weighted Cost (%)	Mid Point Cost Rate (%)	Mid Point Weighted Cost (%)	High Point Cost Rate (%)	High Point Weighted Cost (%)
Long Term Debt	$	2,312,798,700	$	2,312,798,700	$	43	$	(271,811,787)	$	2,040,986,956	33.83	4.69	1.59	4.69	1.59	4.69	1.59
Short Term Debt		77,119,000		77,119,000		(2,622,654)		(8,755,186)		65,741,160	1.09	2.94	0.03	2.94	0	2.94	0
Customer Deposits		86,265,300		86,265,300		-		(10,138,332)		76,126,968	1.26	2.41	0.03	2.41	0.03	2.41	0.03
Common Equity		2,980,611,946		2,980,611,946		56		(350,296,574)		2,630,315,427	43.59	9.25	4.03	10.25	4.47	11.25	4.90
Deferred Income Taxes		1,306,358,700		1,306,358,700		(386,966)		(153,484,369)		1,152,487,366	19.10	-	-	-	-	-	-
Tax Credits - Weighted Cost		77,055,200		77,055,200		1,000		(9,056,032)		68,000,168	1.13	7.20	0.08	7.75	0.09	8.31	0.09
Total	$	6,840,208,846	$	6,840,208,846	$	(3,008,521)	$	(803,542,281)	$	6,033,658,044	100.00		5.76		6.21		6.64
										(0)							

The calculations on this schedule were made in direct response to and according to methodology prescribed in Order No. PSC-09-0283-FOF-EI and decisions made at the July 14, 2009, agenda conference under Docket No. 080317-EI by the Florida Public Service Commission and for that reason only. Tampa Electric Company takes the position that certain portions of these prescribed calculations may not present fairly the company's current financial status and that they should not be used for that purpose.

TAMPA ELECTRIC COMPANY
FINANCIAL INTEGRITY INDICATORS
2018 BUDGET WITH TR

SCHEDULE 5

A. Times Interest Earned With AFUDC*

Earnings Before Interest	475,818,779
AFUDC - Debt	4,954,300
Income Taxes	86,103,521
Total	566,876,600
Interest Charges (Before Deducting AFUDC - Debt)	107,283,571
Tie With AFUDC	5.28

B. Times Interest Earned Without AFUDC*

Earnings Before Interest	475,818,779
AFUDC - Equity	(10,322,500)
Income Taxes	86,103,521
Total	551,599,800
Interest Charges (Before Deducting AFUDC - Debt)	107,283,571
Tie Without AFUDC	5.14

C. Percent AFUDC to Net Income Available For Common Stockholders*

AFUDC - Debt	4,954,300
x (Income Tax Rate of 25.345%)	(1,255,667)
Subtotal	3,698,633
AFUDC - Other	10,322,500
Total	14,021,133
Net Income Available For Common Stockholders	373,316,708
Percent AFUDC to Available Net Income	3.76%

* Tampa Electric Company calculates AFUDC using the rate last authorized by the Florida Public Service Commission. On the company's books, AFUDC is allocated between debt and equity using the modified methodology in FERC Order No. 561. The information shown on Schedule 5 Parts A, B and C is stated as if AFUDC had been allocated using the FPSC methodology.

D. Percent Internally Generated Funds

Net Income	373,316,708
Common Dividends	21,139,000
AFUDC (Debt & Other)	(15,276,800)
Depreciation & Amortization	312,090,000
Deferred Income Taxes	(19,831,098)
Investment Tax Credits	55,163,500
Deferred Clause Revenues (Expenses)	(17,873,200)
Other	0
Total	708,728,110
Construction Expenditures (Excluding AFUDC Other & Debt)	995,065,382
Percent Internally Generated Funds	71.22%

E. Long Term Debt as Percent of Total Capital

F. Short Term Debt as Percent of Total Capital

Reconciled Average Retail Amounts	
Long Term Debt	1,756,255,533
Short Term Debt	252,676,596
Common Equity	2,487,153,280
Total	4,496,085,409
% Long Term Debt to Total	39.06%
% Short Term Debt to Total	5.62%

G. FPSC Adjusted Average Jurisdictional Return On Common Equity

FPSC Adjusted Average Earned Rate Of Return	7.55
Less: Reconciled Average Retail Weighted Cost Rates For:	
Long Term Debt	1.49
Short Term Debt	0.13
Customer Deposits	0.03
Tax Credits-Weighted Cost (Midpoint)	0.05
Subtotal	1.70
Total	5.85
Divided By Common Equity Ratio	42.86
Jurisdictional Return On Common Equity	13.65%

The calculations on this schedule were made in direct response to and according to methodology prescribed in Order No. PSC-93-0165-FOF-EI, Order No. PSC-09-0283-FOF-EI, and decisions made at the July 14, 2009, agenda conference under Docket No. 080317-EI by the Florida Public Service Commission and for that reason only. Tampa Electric Company takes the position that certain portions of these prescribed calculations may not present fairly the Company's current financial status and that they should not be used for that purpose.

Whoever knowingly makes a false statement in writing with the intent to mislead a public servant in the performance of his official duty shall be guilty of a misdemeanor of the second degree, punishable as provided in s. 775.082, s. 775083, or s. 775.084.

Calculation of Annual Revenue Requirement Reduction Required by the 2017 Agreement

	Without Tax Reform	With Tax Reform	Impact of Tax Reform
Net Operating Income (Retail Jurisdictional)	360,092,378	438,334,554	78,242,176
Effective tax rate gross-up factor			0.74655
Revenue Requirement Change			104,805,004
Adjustment for First SoBRA			(2,118,333)
One-Time Base Rate Revenue Requirement Change			**$ 102,686,671**

Calculation of the Adjustment to the Annual Revenue Requirement Reduction Due to the First SoBRA Budget Difference and Tax Reform Adjustment

	Annual Revenue Requirement	Difference	Four-Month Revenue Requirement	Difference
Maximum Revenue Requirement Specified in 2017 Agreement and Included in Company Budget	$30,600,000		$10,200,000	
First SoBRA Revenue Requirement Requested Before Tax Reform	26,493,000	($4,107,000)	8,831,000	($1,369,000)
Revised First SoBRA Revenue Requirement Requested After Tax Reform	24,245,000	(2,248,000)	8,081,667	(749,333)
				($2,118,333)
Change to Tax Reform Adjustment to Reflect First SoBRA Tax Reform Adjustment Already Included in Docket No. 20170260-EI:				**($2,118,333)**

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 20180045-EI

IN RE: CONSIDERATION OF THE TAX IMPACTS ASSOCIATED WITH TAX CUTS AND JOBS ACT OF 2017 FOR TAMPA ELECTRIC COMPANY

DIRECT TESTIMONY AND EXHIBIT

OF

WILLIAM R. ASHBURN

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 North Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "the company") as Director, Pricing and Financial Analysis in the Regulatory Affairs Department.

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

A. I direct departmental activities in non-clause related pricing, financial regulatory matters, and general regulatory issues management. I direct the coordination and filing of all Tampa Electric, Peoples Gas and TECO Energy filings with federal and state regulatory agencies. I direct the design and analysis of a wide variety of pricing issues including the pricing of: electric bulk power supply contracts and tariffs, electric transmission tariffs and the development of special contracts for retail electric service. I direct the preparation of cost of service studies, jurisdictional separation studies and other cost support analyses.

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 testified for Tampa Electric in Docket No. 20170260-EI regarding the design of the base rate adjustment for the First SoBRA to go into effect in September 2018 as a result of the 2017 Amended and Restated Stipulation and Settlement Agreement ("2017 Agreement"). I also testified in Docket No. 20170210-EI as a member of a panel of witnesses during the November 6, 2017 hearing on the 2017 Agreement. I 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 is the purpose of your direct testimony in this proceeding?

A. The purpose of my direct testimony is to support the customer rate changes and tariffs necessary to implement the one-time base rate reduction for tax reform prescribed in the Company's 2017 Agreement and as agreed to in the Amended Implementation Stipulation. I use the one-time annual revenue requirement reduction contained in the prepared direct testimony of Tampa Electric witness Jeffrey S. Chronister, apply the cost of service and rate design principles specified in the 2017 Agreement, and present the resulting customer rates and tariffs to be approved and implemented for the first billing cycle in January 2019.

Q. Did you prepare an exhibit in support of your direct testimony?

A. Yes. Exhibit No. ___ (WRA-1) was prepared under my direction and supervision. My Exhibit consists of the following five documents:

Document No. 1	Base Revenue by Rate Schedule
Document No. 2	Rollup Base Revenue by Rate Class
Document No. 3	Typical Bills Reflecting Tax Reform Base Rate Decrease
Document No. 4	Redline Tariffs Reflecting Tax Reform Base Rate Decrease
Document No. 5	Clean Tariffs Reflecting Tax Reform Base Rate Decrease

Q. What is the 2017 Agreement?

A. On September 27, 2017, Tampa Electric, the Office of Public Counsel ("OPC" or "Citizens"), the Florida Industrial Power Users Group ("FIPUG"), the Florida Retail Federation ("FRF"), the Federal Executive Agencies ("FEA"), and the WCF Hospital Utility Alliance ("HUA") (collectively, the "Consumer Parties") entered into the 2017 Amended and Restated Stipulation and Settlement Agreement ("2017 Agreement"). 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. It amends and restates the company's previous rate case settlement, entered into in Docket No. 20130040-EI. Paragraph 9 of the 2017 Agreement addresses the procedures and principles to be followed should Congress change the rate of taxation of corporate income during the term of the 2017 Agreement.

Q. What is the Amended Implementation Stipulation?

A. The Amended Implementation Stipulation is described more fully in the prepared direct testimony of Mr. Chronister, but generally it is a document that memorializes the agreement of Tampa Electric and the Consumer Parties regarding how the storm cost recovery and tax reform provisions in the 2017 Agreement are to be implemented. It was approved by the Commission on March 1, 2018. See Order No. PSC-2018-125-PCO-EI, issued on March 7, 2018 in Docket Nos. 20170271-EI and 20180013-PU.

Q. What do the 2017 Agreement and Amended Implementation Stipulation say about customer rate changes as a result of federal income tax reform?

A. As they relate to this docket and the subject matter of my direct testimony, the two documents provide that the company should make a one-time reduction to certain prescribed base rates to reflect the impact of tax reform to be implemented concurrent with the first billing cycle in January 2019. Paragraph 9 of the 2017 Agreement provides that the one-time rate reduction should be accomplished through "a uniform percentage decrease to customer, demand and energy base rate charges for all retail customer classes."

Q. Have you calculated the customer rate decrease to be effective with the first billing cycle of January 2019 as contemplated in the 2017 Agreement and the Amended Implementation Stipulation?

A. Yes. A schedule showing the required customer rate decreases and the new customer rates to be effective with the first billing cycle of 2019, by rate schedule, is included in my Exhibit as Document No. 1. I have also included a rollup schedule showing the required customer rate decreases by customer class as Document No. 2 of my Exhibit. A schedule showing the impact on typical bills is included as Document No. 3 of my Exhibit. Redline tariff sheets that reflect these new rates are included in Document No. 4 of my Exhibit, and clean tariff sheets that reflect these new rates are included in my Exhibit as Document No. 5.

Q. Please describe how you calculated the required one-time base rate decreases reflected in Document No. 1 of your Exhibit.

A. As required by the 2017 Agreement, I utilized the billing determinants for 2019. I began with the recently approved base rates including the adjustment for the company’s First Solar Base Rate Adjustment (“SoBRA”), effective September 1, 2018. Then I reduced the base rates (i.e., customer, demand and energy rates) by a uniform percentage to reduce revenues by the revenue requirements amount provided by witness Chronister.

Q. Do your calculations take into account any Solar Base Rate Adjustments proposed by the company?

A. Yes, as I previously stated, the rate impacts shown in the exhibits to my testimony already include the company’s First SoBRA. They do not reflect Tampa Electric’s expected base rate increase for the Second SoBRA, which is expected to take effect in January 2019. The company is preparing its Second SoBRA petition and testimony and expects to file the documents in June 2018.

Both the rate changes resulting from the Second SoBRA (an increase to base rates) and from this proposed adjustment to account for tax reform (a decrease to base rates) will be implemented at the same time with the first billing cycle of January 2019. For purposes of preparing the tariff sheets and typical bill comparisons for this filing, I used the base rates including the company’s First SoBRA that are to be put into effect with the first billing cycle of September 2018, which were approved by the Commission by their May 8, 2018 vote in Docket No. 20170260-EI, as my starting point since these are the rates that will be in effect at the time of the tax reform rate change. At this time, I request Commission approval of the base rate changes for tax reform which are listed in my Exhibit.

When the company’s Second SoBRA and this tax reform adjustment have been approved, Tampa Electric requests that the Commission give the FPSC Staff administrative authority to approve the final rates reflecting both base rate changes--the Second SoBRA and the reduction for tax reform—together since they are to take effect at the same time, with the first billing cycle of January 2019.

Q. How does Tampa Electric propose to notify customers of the rate decrease for tax reform approved in this docket?

A. The rate change reflecting the permanent tax reduction impact to rates would be made at the same time that the rate changes occur for cost recovery clauses. Customers will be notified of all rate changes effective in January 2019 at the same time (at least 30 days prior to the change) and in the same manner as they are notified of the annual cost recovery clause rate changes.

Q. Please summarize your direct testimony.

A. My direct testimony supports the customer rate changes and tariffs necessary to implement the one-time base rate reduction for tax reform prescribed in the company's 2017 Agreement and as agreed to in the Amended Implementation Stipulation. I use the one-time annual revenue requirement reduction contained in the prepared direct testimony of Tampa Electric witness Jeffrey S. Chronister, apply the cost of service and rate design principles specified in the 2017 Agreement, and present the resulting customer rates and tariffs to be approved and implemented for the first billing cycle in January 2019. I also explain the interrelationship of the proposed base rate reductions reflecting tax reform to be implemented in January 2018 and the proposed base rate increases proposed for the second tranche of SoBRA which are also to be implemented in January

2018, and the need for a unified tariff reflecting those changes into one new set of base rates to be implemented at that same time with a request that the Commission Staff be granted administrative authority to approve those rates after both dockets have received a final order.

Q. Does this conclude your direct testimony?

A. Yes, it does.

EXHIBIT

OF

WILLIAM R. ASHBURN

Table of Contents

Base Revenue by Rate Schedule

TAMPA ELECTRIC COMPANY
DOCKET NO. 20180045-EI
EXHIBIT NO. ___ (WRA-1)
WITNESS: ASHBURN
DOCUMENT NO. 1
PAGE 1 OF 17
FILED: 05/31/2018

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: TAMPA ELECTRIC COMPANY

DOCKET NO. 20180045-EI

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

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

Type of data shown:
XX Projected Test year Ended 12/31/2019

Line No.		
1		
2		
3		
4	Page No.	Rate Schedule
5		
6	2	RS, RSVP-1
7	3	GS, GST
8	4	CS
9	5	GSD, GSDT
10	6	GSD Optional
11	9	SBF, SBFT
12	10	IS, IST
13	14	SBI
14	16	LS-1 (Energy Service)
15		
16		
17		
18		
19		
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Supporting Schedules:

Recap Schedules: E-13a

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Type of data shown:
XX Projected Test year Ended 12/31/2019

Rate Schedule RS, RSVP-1

Line No.	Type of Charges	Present Revenue Calculation: Units		Charge/Unit	$ Revenue	Proposed Revenue Calculation: Units		Charge/Unit	$ Revenue	Percent Decrease
1										
2	Basic Service Charge:									
3	Standard	8,124,336	Bills	$ 16.62	135,026,464	8,124,336	Bills	$ 15.12	122,867,323	
4	RSVP-1	54,683	Bills	$ 16.62	908,831	54,683	Bills	$ 15.12	826,991	
5	Total	8,179,019	Bills		135,935,296	8,179,019	Bills		123,694,314	-9.0%
6										
7										
8										
9	Energy Charge:									
10	Standard									
11	First 1,000 kWh	6,383,752	MWH	$ 53.81	343,477,776	6,383,752	MWH	$ 48.96	312,547,604	
12	All additional kWh	2,915,954	MWH	$ 63.81	186,052,445	2,915,954	MWH	$ 58.06	169,298,423	
13	RSVP-1	82,913	MWH	$ 56.95	4,721,481	82,913	MWH	$ 51.82	4,296,311	
14	Total	9,382,619	MWH		534,251,702	9,382,619	MWH		486,142,338	-9.0%
15										
16										
17										
18	Total Base Revenue:				670,186,998				609,836,652	-9.0%
19										
20										
21										
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Type of data shown:
XX Projected Test year Ended 12/31/2019

Rate Schedule GS, GST

Line No.	Type of Charges	Present Revenue Calculation Units		Charge/Unit	$ Revenue	Proposed Revenue Calculation Units		Charge/Unit	$ Revenue	Percent Decrease
1										
2	Basic Service Charge:									
3	Standard Metered	766,940	Bills	$ 19.94	15,292,784	766,940	Bills	$ 18.14	13,915,667	
4	Standard Unmetered	1,188	Bills	$ 16.62	19,745	1,188	Bills	$ 15.12	17,967	
5	T-O-D	28,994	Bills	$ 22.16	642,507	28,994	Bills	$ 20.16	584,649	
6	T-O-D (Meter CIAC paid)	24	Bills	$ 19.94	479	24	Bills	$ 18.14	435	
7	Total	797,146	Bills		15,955,514	797,146	Bills		14,518,719	-9.0%
8										
9	Energy Charge:									
10	Standard	910,450	MWH	$ 56.76	51,679,418	910,450	MWH	$ 51.65	47,025,683	
11	Standard Unmetered	1,295	MWH	$ 56.76	73,507	1,295	MWH	$ 51.65	66,888	
12	T-O-D On-Peak	8,582	MWH	$ 144.88	1,243,360	8,582	MWH	$ 131.83	1,131,396	
13	T-O-D Off-Peak	24,929	MWH	$ 15.45	385,153	24,929	MWH	$ 14.06	350,470	
14	Total	945,256	MWH		53,381,439	945,256	MWH		48,574,437	-9.0%
15										
16	Emergency Relay Charge:									
17	Standard	2,041	MWH	$ 1.71	3,498	2,041	MWH	$ 1.56	3,183	
18	T-O-D	-	MWH	$ 1.71	-	-	MWH	$ 1.56	-	
19	Total	2,041	MWH		3,498	2,041	MWH		3,183	-9.0%
20										
21										
22										
23	Total Base Revenue:				69,340,450				63,096,339	-9.0%
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Supporting Schedules: Recap Schedules: E-13a

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: TAMPA ELECTRIC COMPANY

DOCKET NO. 20180045-EI

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Type of data shown:
XX Projected Test year Ended 12/31/2019

Rate Schedule CS

Line No.	Type of Charges	Present Revenue Calculation Units		Charge/Unit	$ Revenue	Proposed Revenue Calculation Units		Charge/Unit	$ Revenue	Percent Decrease
1										
2	Basic Service Charge:									
3		36,639	Bills	$ 19.94	730,582	36,639	Bills	$ 18.14	664,793	
4	Total	36,639	Bills		730,582	36,639	Bills		664,793	-9.0%
5										
6	Energy Charge:									
7		10,575	MWH	$ 56.76	600,263	10,575	MWH	$ 51.65	546,210	
8	Total	10,575	MWH		600,263	10,575	MWH		546,210	-9.0%
9										
10										
11										
12	Total Base Revenue:				1,330,845				1,211,002	-9.0%
13										
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Rate Schedule GSD, GSDT

Line No.	Type of Charges	Present Revenue Calculation Units		Charge/Unit	$ Revenue	Proposed Revenue Calculation Units		Charge/Unit	$ Revenue	Percent Decrease
1	Basic Service Charge:									
2	Standard - Secondary	157,303	Bills	$ 33.24	5,228,752	157,303	Bills	$ 30.25	4,757,902	
3	Standard - Primary	812	Bills	$ 144.03	116,890	812	Bills	$ 131.06	106,364	
4	Standard - Subtransmission	-	Bills	$ 1,096.82	-	0	Bills	$ 998.05	-	
5	T-O-D - Secondary	14,214	Bills	$ 33.24	472,473	14,214	Bills	$ 30.25	429,927	
6	T-O-D - Primary	766	Bills	$ 144.03	110,327	766	Bills	$ 131.06	100,392	
7	T-O-D - Subtransmission	25	Bills	$ 1,096.82	27,421	25	Bills	$ 998.05	24,951	
8	Total	173,120	Bills		5,955,863	173,120			5,419,537	-9.0%
9										
10	Energy Charge:									
11	Standard - Secondary	4,327,159	MWH	$ 17.54	75,898,369	4,327,159	MWH	$ 15.96	69,063,716	
12	Standard - Primary	298,377	MWH	$ 17.54	5,233,533	298,377	MWH	$ 15.96	4,762,253	
13	Standard - Subtransmission	-	MWH	$ 17.54	-	-	MWH	$ 15.96	-	
14	T-O-D On-Peak - Secondary	537,358	MWH	$ 32.11	17,254,565	537,358	MWH	$ 29.22	15,700,791	
15	T-O-D On-Peak - Primary	264,905	MWH	$ 32.11	8,506,100	264,905	MWH	$ 29.22	7,740,125	
16	T-O-D On-Peak - Subtrans.	518	MWH	$ 32.11	16,633	518	MWH	$ 29.22	15,135	
17	T-O-D Off-Peak - Secondary	1,479,672	MWH	$ 11.59	17,149,398	1,479,672	MWH	$ 10.55	15,605,094	
18	T-O-D Off-Peak - Primary	730,501	MWH	$ 11.59	8,466,507	730,501	MWH	$ 10.55	7,704,097	
19	T-O-D Off-Peak - Subtrans.	1,521	MWH	$ 11.59	17,628	1,521	MWH	$ 10.55	16,041	
20	Total	7,640,011	MWH		132,542,733	7,640,011	MWH		120,607,252	-9.0%
21										
22	Demand Charge:									
23	Standard - Secondary	11,357,612	kW	$ 10.70	121,526,448	11,357,612	kW	$ 9.74	110,582,984	
24	Standard - Primary	750,006	kW	$ 10.70	8,025,064	750,006	kW	$ 9.74	7,302,407	
25	Standard - Subtransmission	-	kW	$ 10.70	-	-	kW	$ 9.74	-	
26	T-O-D Billing - Secondary	3,803,267	kW	$ 3.61	13,729,794	3,803,267	kW	$ 3.28	12,493,425	
27	T-O-D Billing - Primary	1,901,141	kW	$ 3.61	6,863,119	1,901,141	kW	$ 3.28	6,245,095	
28	T-O-D Billing - Subtrans.	5,568	kW	$ 3.61	20,100	5,568	kW	$ 3.28	18,290	
29	T-O-D Peak - Secondary	3,672,362	kW (1)	$ 7.09	26,037,047	3,672,362	kW (1)	$ 6.45	23,692,409	
30	T-O-D Peak - Primary	1,824,974	kW (1)	$ 7.09	12,939,066	1,824,974	kW (1)	$ 6.45	11,773,902	
31	T-O-D Peak - Subtrans.	4,905	kW (1)	$ 7.09	34,776	4,905	kW (1)	$ 6.45	31,645	
32	Total	17,817,594	kW		189,175,415	17,817,594	kW		172,140,157	-9.0%
33										
34	(1) Not included in Total.									
35										

Continued on Page 6

Supporting Schedules:

Recap Schedules: E-13a

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FLORIDA PUBLIC SERVICE COMMISSION

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Rate Schedule GSD, GSDT

Line No.	Type of Charges	Present Revenue Calculation Units		Charge/Unit		$ Revenue	Proposed Revenue Calculation Units		Charge/Unit		$ Revenue	Percent Decrease
1	Continued from Page 8											
2												
3	Delivery Voltage Credit:											
4	Standard Primary	663,959	kW	$	(0.87)	(577,644)	663,959	kW	$	(0.79)	(525,627)	
5	Standard - Subtransmission	-	kW	$	(2.69)	-	-	kW	$	(2.45)	-	
6	T-O-D Primary	1,539,592	kW	$	(0.87)	(1,339,445)	1,539,592	kW	$	(0.79)	(1,218,828)	
7	T-O-D Subtransmission	8,490	kW	$	(2.69)	(22,838)	8,490	kW	$	(2.45)	(20,782)	
8	Total	2,212,041	kW			(1,939,927)	2,212,041	kW			(1,765,237)	-9.0%
9												
10	Emergency Relay Charge:											
11	Standard Secondary	437,907	kW	$	0.69	302,156	437,907	kW	$	0.63	274,947	
12	Standard Primary	166,511	kW	$	0.69	114,893	166,511	kW	$	0.63	104,547	
13	Standard - Subtransmission	-	kW	$	0.69	-	-	kW	$	0.63	-	
14	T-O-D Secondary	749,073	kW	$	0.69	516,860	749,073	kW	$	0.63	470,317	
15	T-O-D Primary	771,690	kW	$	0.69	532,466	771,690	kW	$	0.63	484,517	
16	T-O-D Subtransmission	-	kW	$	0.69	-	-	kW	$	0.63	-	
17	Total	2,125,181	kW			1,466,375	2,125,181	kW			1,334,328	-9.0%
18												
19	Power Factor Charge:											
20	Standard Secondary	12,038	MVARh	$	2.22	26,724	12,038	MVARh	$	2.02	24,318	
21	Standard Primary	12,054	MVARh	$	2.22	26,760	12,054	MVARh	$	2.02	24,350	
22	Standard - Subtransmission	0	MVARh	$	2.22	-	0	MVARh	$	2.02	-	
23	T-O-D Secondary	12,613	MVARh	$	2.22	28,001	12,613	MVARh	$	2.02	25,479	
24	T-O-D Primary	10,522	MVARh	$	2.22	23,359	10,522	MVARh	$	2.02	21,255	
25	T-O-D Subtransmission	142	MVARh	$	2.22	315	142	MVARh	$	2.02	287	
26		47,369	MVARh			105,159	47,369	MVARh			95,690	-9.0%
27												
28												
29												
30												
31												
32												
33												
34												
35												

Supporting Schedules: Recap Schedules: E-13a

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Line No.	Type of Charges	Present Revenue Calculation: Units		Charge/Unit		$ Revenue	Proposed Revenue Calculation: Units		Charge/Unit		$ Revenue	Percent Decrease
1	Continued from Page 9											
2												
3	Power Factor Credit:											
4	Standard Secondary	28844	MVARh	$	(1.11)	(32,017)	28844	MVARh	$	(1.01)	(29,134)	
5	Standard Primary	16646	MVARh	$	(1.11)	(18,477)	16646	MVARh	$	(1.01)	(16,813)	
6	Standard - Subtransmission	0	MVARh	$	(1.11)	-	0	MVARh	$	(1.01)	-	
7	T-O-D Secondary	108106	MVARh	$	(1.11)	(119,998)	108106	MVARh	$	(1.01)	(109,192)	
8	T-O-D Primary	59840	MVARh	$	(1.11)	(66,422)	59840	MVARh	$	(1.01)	(60,441)	
9	T-O-D Subtransmission	0	MVARh	$	(1.11)	-	0	MVARh	$	(1.01)	-	
10		213,436	MVARh			(236,914)	213,436	MVARh			(215,580)	-9.0%
11												
12												
13	Metering Voltage Adjustment:											
14	Standard Primary	12,804,128	$		-1%	(128,041)	11,651,115	$		-1%	(116,511)	
15	Standard - Subtransmission	-	$		-2%	-	-	$		-2%	-	
16	T-O-D Primary	35,924,748	$		-1%	(359,247)	32,689,722	$		-1%	(326,897)	
17	T-O-D Subtransmission	66,615	$		-2%	(1,332)	60,617	$		-2%	(1,212)	
18	Total	48,795,492	$			(488,621)	44,401,455	$			(444,621)	-9.0%
19												
20												
21												
22												
23	Total Base Revenue:					326,580,082					297,171,525	-9.0%
24												
25												
26												
27												
28												
29												
30												
31												
32												
33												
34												
35												

Supporting Schedules: Recap Schedules: E-13a

TAMPA ELECTRIC COMPANY
DOCKET NO. 20180045-EI
EXHIBIT NO. ___ (WRA-1)
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FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: TAMPA ELECTRIC COMPANY

DOCKET NO. 20180045-EI

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

Type of data shown:
XX Projected Test year Ended 12/31/2019

Rate Schedule GSD Optional

Line No.	Type of Charges	Present Revenue Calculation Units		Charge/Unit	$ Revenue	Proposed Revenue Calculation Units		Charge/Unit	$ Revenue	Percent Decrease
1	Basic Service Charge:									
2	Optional - Secondary	19,672	Bills	$ 33.24	653,897	19,672	Bills	$ 30.25	595,014	
3	Optional - Primary	307	Bills	$ 144.03	44,217	307	Bills	$ 131.06	40,235	
4	Optional - Subtransmission	-		$ 1,096.82	-	-		$ 998.05	-	
5	Total	19,979	Bills		698,114	19,979	Bills		635,249	-9.0%
6										
7	Energy Charge:									
8	Optional - Secondary	388,398	MWH	$ 68.12	26,457,672	388,398	MWH	$ 61.99	24,075,157	
9	Optional - Primary	12,811	MWH	$ 68.12	872,685	12,811	MWH	$ 61.99	794,100	
10	Total	401,209	MWH		27,330,357	401,209	MWH		24,869,257	-9.0%
11										
12	Demand Charge:									
13	Optional - Secondary	2,406,400	kW	$ -	-	2,406,400	kW	$ -	-	
14	Optional - Primary	97,955	kW	$ -	-	97,955	kW	$ -	-	
15	Total	2,504,355	kW		-	2,504,355			-	0.0%
16										
17	Delivery Voltage Credit:									
18	Optional - Primary	6,070	MWH	$ (2.30)	(13,961)	6,070	MWH	$ (2.09)	(12,704)	
19	Optional - Subtransmission	-	MWH	$ (7.02)	-	-	MWH	$ (6.39)	-	
20	Total	6,070	MWH		(13,961)	6,070	MWH		(12,704)	-9.0%
21										
22	Emergency Relay									
23	Optional - Secondary	11,959	MWH	$ 1.74	20,809	11,959	MWH	$ 1.58	18,935	
24	Optional - Primary	1,632,647	MWH	$ 1.74	2,840,806	1,632,647	MWH	$ 1.58	2,584,991	
25	Total	1,644,606	MWH		2,861,614	1,644,606	MWH		2,603,926	-9.0%
26										
27	Metering Voltage Adjustment:									
28	Optional - Primary	3,699,530	$	-1%	(36,995)	3,366,387	$	-1%	(33,664)	
29	Optional - Subtransmission	-	$	-2%	-	-	$	-2%	-	
30	Total	3,699,530	$		(36,995)	3,366,387	$		(33,664)	-9.0%
31										
32										
33										
34	Total Base Revenue:				30,839,130				28,062,064	-9.0%
35										

Supporting Schedules: Recap Schedules: E-13a

TAMPA ELECTRIC COMPANY
DOCKET NO. 20180045-EI
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FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: TAMPA ELECTRIC COMPANY

DOCKET NO. 20180045-EI

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

Type of data shown:
XX Projected Test year Ended 12/31/2019

Rate Schedule SBF, SBFT

Line No.	Type of Charges	Present Revenue Calculation Units		Charge/Unit	$ Revenue	Proposed Revenue Calculation Units		Charge/Unit	$ Revenue	Percent Decrease
1										
2	Basic Service Charge:									
3	Standard Secondary	0	Bills	$ 60.93	-	0	Bills	$ 55.44	-	
4	Standard Primary	0	Bills	$ 171.72	-	0	Bills	$ 156.26	-	
5	Standard Subtransmission	0	Bills	$ 1,124.52	-	0	Bills	$ 1,023.26	-	
6	T-O-D Secondary	0	Bills	$ 60.93	-	0	Bills	$ 55.44	-	
7	T-O-D Primary	37	Bills	$ 171.72	6,354	37	Bills	$ 156.26	5,781	
8	T-O-D Subtransmission	50	Bills	$ 1,124.52	56,226	50	Bills	$ 1,023.26	51,163	
9	Total	87	Bills		62,580	87	Bills		56,944	-9.0%
10										
11	Energy Charge - Supplemental:									
12	Standard Secondary	0	MWH	$ 17.54	-	-	MWH	$ 15.96	-	
13	Standard Primary	0	MWH	$ 17.54	-	-	MWH	$ 15.96	-	
14	Standard Subtransmission	0	MWH	$ 17.54	-	-	MWH	$ 15.96	-	
15	T-O-D On-Peak - Secondary	0	MWH	$ 32.11	-	-	MWH	$ 29.22	-	
16	T-O-D On-Peak - Primary	28,197	MWH	$ 32.11	905,406	28,197	MWH	$ 29.22	823,874	
17	T-O-D On-Peak - Subtrans.	-	MWH	$ 32.11	-	-	MWH	$ 29.22	-	
18	T-O-D Off-Peak - Secondary	0	MWH	$ 11.59	-	-	MWH	$ 10.55	-	
19	T-O-D Off-Peak - Primary	84,550	MWH	$ 11.59	979,935	84,550	MWH	$ 10.55	891,691	
20	T-O-D Off-Peak - Subtrans.	-	MWH	$ 11.59	-	-	MWH	$ 10.55	-	
21	Energy Charge - Standby:									
22	T-O-D On-Peak -Secondary	-	MWH	$ 10.12	-	-	MWH	$ 9.21	-	
23	T-O-D On-Peak - Primary	2,133	MWH	$ 10.12	21,586	2,133	MWH	$ 9.21	19,642	
24	T-O-D On-Peak - Subtrans.	2,001	MWH	$ 10.12	20,250	2,001	MWH	$ 9.21	18,427	
25	T-O-D Off-Peak -Secondary	-	MWH	$ 10.12	-	-	MWH	$ 9.21	-	
26	T-O-D Off-Peak - Primary	6,304	MWH	$ 10.12	63,796	6,304	MWH	$ 9.21	58,052	
27	T-O-D Off-Peak - Subtrans.	5,914	MWH	$ 10.12	59,850	5,914	MWH	$ 9.21	54,460	
28	Total	129,099	MWH		2,050,822	129,099	MWH		1,866,146	-9.0%
29										
30										
31										
32										
33										
34										
35										

Supporting Schedules:

Recap Schedules: E-13a

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: TAMPA ELECTRIC COMPANY

DOCKET NO. 20180045-EI

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

Type of data shown:
XX Projected Test year Ended 12/31/2019

Rate Schedule SBF, SBFT

Line No.	Type of Charges	Present Units		Present Charge/Unit		$ Revenue	Proposed Units		Proposed Charge/Unit		$ Revenue	Percent Decrease
1	Continued from Page 13											
2												
3	Demand Charge - Supplemental:											
4	Standard Secondary	-	kW	$ 10.70		-	-	kW	$ 9.74		-	
5	Standard Primary	-	kW	$ 10.70		-	-	kW	$ 9.74		-	
6	Standard Subtransmission	-	kW	$ 10.70		-	-	kW	$ 9.74		-	
7	T-O-D Billing - Secondary	-	kW	$ 3.61		-	-	kW	$ 3.28		-	
8	T-O-D Billing - Primary	187,866	kW	$ 3.61		678,196	187,866	kW	$ 3.28		617,125	
9	T-O-D billing - Subtransmission	-	kW	$ 3.61		-	-	kW	$ 3.28		-	
10	T-O-D Peak - Secondary	-	kW (1)	$ 7.09		-	-	kW (1)	$ 6.45		-	
11	T-O-D Peak - Primary	181,526	kW (1)	$ 7.09		1,287,019	181,526	kW (1)	$ 6.45		1,171,123	
12	T-O-D Peak - Subtransmission	-	kW (1)	$ 7.09		-	-	kW (1)	$ 6.45		-	
13	Demand Charge - Standby:											
14	T-O-D Facilities Reservation - Sec.	-	kW	$ 2.15		-	-	kW	$ 1.96		-	
15	T-O-D Facilities Reservation - Pri.	111,712	kW	$ 2.15		240,181	111,712	kW	$ 1.96		218,553	
16	T-O-D Facilities Reservation - Sub.	239,672	kW	$ 2.15		515,295	239,672	kW	$ 1.96		468,892	
17	T-O-D Power Supply Res. - Sec.	-	kW (1)	$ 1.71	/ kW-mo.	-	-	kW (1)	$ 1.56	kW-mo.	-	
18	T-O-D Power Supply Res. - Pri.	55,882	kW (1)	$ 1.71	/ kW-mo.	95,558	55,882	kW (1)	$ 1.56	kW-mo.	86,953	
19	T-O-D Power Supply Res. - Sub.	181,235	kW (1)	$ 1.71	/ kW-mo.	309,912	181,235	kW (1)	$ 1.56	kW-mo.	282,004	
20	T-O-D Power Supply Dmd. - Sec.	-	kW (1)	$ 0.68	/ kW-day	-	-	kW (1)	$ 0.62	kW-day	-	
21	T-O-D Power Supply Dmd. - Pri.	340,955	kW (1)	$ 0.68	/ kW-day	231,849	340,955	kW (1)	$ 0.62	kW-day	210,971	
22	T-O-D Power Supply Dmd. - Sub.	265,610	kW (1)	$ 0.68	/ kW-day	180,615	265,610	kW (1)	$ 0.62	kW-day	164,350	
23	Total	539,250	kW			3,538,625	539,250	kW			3,219,972	-9.0%
24												
25												
26	Power Factor Charge Supplemental & Standby:											
27	Standard Secondary	-	MVARh	$ 2.22		-	-	MVARh	$ 2.02		-	
28	Standard Primary	-	MVARh	$ 2.22		-	-	MVARh	$ 2.02		-	
29	Standard Subtransmission	-	MVARh	$ 2.22		-	-	MVARh	$ 2.02		-	
30	T-O-D Secondary	-	MVARh	$ 2.22		-	-	MVARh	$ 2.02		-	
31	T-O-D Primary	5,575	MVARh	$ 2.22		12,377	5,575	MVARh	$ 2.02		11,262	
32	T-O-D Subtransmission	1,114	MVARh	$ 2.22		2,473	1,114	MVARh	$ 2.02		2,250	
33		6,689				14,850	6,689				13,512	-9.0%
34	(1) Not included in Total.											
35												

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Supporting Schedules:
Recap Schedules: E-13a

TAMPA ELECTRIC COMPANY
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FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: TAMPA ELECTRIC COMPANY

DOCKET NO. 20180045-EI

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

Type of data shown:
XX Projected Test year Ended 12/31/2019

Rate Schedule SBF, SBFT

Line No.	Type of Charges	Present Revenue Calculation Units		Charge/Unit		$ Revenue	Proposed Revenue Calculation Units		Charge/Unit		$ Revenue	Percent Decrease
1	Continued from Page 14											
2												
3	Power Factor Credit Supplemental & Standby:											
4	Standard Secondary	-	MVARh	$	(1.11)	-	-	MVARh	$	(1.01)	-	
5	Standard Primary	-	MVARh	$	(1.11)	-	-	MVARh	$	(1.01)	-	
6	Standard Subtransmission	-	MVARh	$	(1.11)	-	-	MVARh	$	(1.01)	-	
7	T-O-D Secondary	-	MVARh	$	(1.11)	-	-	MVARh	$	(1.01)	-	
8	T-O-D Primary	6,826	MVARh	$	(1.11)	(7,577)	6,826	MVARh	$	(1.01)	(6,895)	
9	T-O-D Subtransmission	-	MVARh	$	(1.11)	-	-	MVARh	$	(1.01)	-	
14	Total	6,826	MVARh			(7,577)	6,826	MVARh			(6,895)	-9.0%
15												
16	Delivery Voltage Credit - Supplemental.:											
17	Standard Primary	-	kW	$	(0.87)	-	-	kW	$	(0.79)	-	
18	Standard Subtransmission	-	kW	$	(2.69)	-	-	kW	$	(2.45)	-	
19	T-O-D Primary	187,866	kW	$	(0.87)	(163,443)	187,866	kW	$	(0.79)	(148,725)	
20	T-O-D Subtransmission	-	kW	$	(2.69)	-	-	kW	$	(2.45)	-	
21	Delivery Voltage Credit. - Standby.:											
22	T-O-D Primary	111,712	kW	$	(0.69)	(77,081)	111,712	kW	$	(0.63)	(70,140)	
23	T-O-D Subtransmission	239,672	kW	$	(2.16)	(517,692)	239,672	kW	$	(1.97)	(471,073)	
24	Total	539,250	kW			(758,216)	539,250	kW			(689,939)	-9.0%
25												
26	Emergency Relay Charge - Supplemental and Standby.											
27	Standard Secondary	-	kW	$	0.69	-	-	kW	$	0.63	-	
28	Standard Primary	-	kW	$	0.69	-	-	kW	$	0.63	-	
29	Standard Subtransmission	-	kW	$	0.69	-	-	kW	$	0.63	-	
30	T-O-D Secondary	-	kW	$	0.69	-	-	kW	$	0.63	-	
31	T-O-D Primary	177,812	kW	$	0.69	122,690	177,812	kW	$	0.63	111,642	
32	T-O-D Subtransmission	-	kW	$	0.69	-	-	kW	$	0.63	-	
33		177,812				122,690	177,812				111,642	-9.0%
34												
35												
36												
37												
34												
35												

Supporting Schedules:

Recap Schedules: E-13a

TAMPA ELECTRIC COMPANY
DOCKET NO. 20180045-EI
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WITNESS: ASHBURN
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FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: TAMPA ELECTRIC COMPANY

DOCKET NO. 20180045-EI

EXPLANATION: By rate schedule, calculate revenues under present and proposed rates for the test year. If any customers are to be transferred from one schedule to another, show revenues separately for the transfer group. Correction factors are used for historic test years only. The total base revenue by class must equal that shown in Schedule E-13a. The billing units must equal those shown in Schedule E-15.
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Type of data shown:
XX Projected Test year Ended 12/31/2019

Rate Schedule SBF, SBFT

Line No.	Type of Charges	Present Revenue Calculation Units		Present Charge/Unit	Present $ Revenue	Proposed Revenue Calculation Units		Proposed Charge/Unit	Proposed $ Revenue	Percent Decrease
1	Continued from Page 15									
2										
3	Metering Voltage Adjustment - Supplemental and Stanby.:									
4	Standard Primary	-	$	-1.0%	-	-	$	-1.0%	-	
5	Standard Subtransmission	-	$	-2.0%	-	-	$	-2.0%	-	
6	T-O-D Primary	4,390,492	$	-1.0%	(43,905)	3,995,128	$	-1.0%	(39,951)	
7	T-O-D Subtransmission	570,703	$	-2.0%	(11,414)	519,311	$	-2.0%	(10,386)	
8	Total	4,961,195	$		(55,319)	4,514,439	$		(50,337)	-9.0%
9										
10										
11										
12	Total Base Revenue:				4,968,455				4,521,046	-9.0%
13										
14										
15										
16										
17										
18										
19										
20										
21										
22										
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24										
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30										
31										
32										
33										
34										
35										

Supporting Schedules: Recap Schedules: E-13a

TAMPA ELECTRIC COMPANY
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FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: TAMPA ELECTRIC COMPANY

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EXPLANATION: By rate schedule, calculate revenues under present and proposed rates for the test year. If any customers are to be transferred from one schedule to another, show revenues separately for the transfer group. Correction factors are used for historic test years only. The total base revenue by class must equal that shown in Schedule E-13a. The billing units must equal those shown in Schedule E-15.
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Type of data shown:
XX Projected Test year Ended 12/31/2019

Rate Schedule IS, IST

Line No.	Type of Charges	Present Revenue Calculation Units		Charge/Unit	$ Revenue	Proposed Revenue Calculation Units		Charge/Unit	$ Revenue	Percent Decrease
1										
2	Basic Service Charge:									
3	Standard Pri.	74	Bills	$ 689.11	50,994	74	Bills	$ 627.06	46,402	
4	Standard Subtrans.	-	Bills	$ 2,627.94	-	-	Bills	$ 2,391.29	-	
5	T-O-D Primary	113	Bills	$ 689.11	77,821	113	Bills	$ 627.06	70,813	
6	T-O-D Subtransmission	100	Bills	$ 2,627.94	263,793	100	Bills	$ 2,391.29	240,038	
7	Total	287	Bills		392,608	287	Bills		357,254	-9.0%
8										
9	Energy Charge:									
10	Standard Primary	40,657	MWH	$ 27.74	1,127,825	40,657	MWH	$ 25.24	1,026,264	
11	Standard Subtransmission	-	MWH	$ 27.74	-	-	MWH	$ 25.24	-	
12	T-O-D On-Peak - Pri.	31,603	MWH	$ 27.74	876,667	31,603	MWH	$ 25.24	797,723	
13	T-O-D On-Peak - Subtrans.	83,117	MWH	$ 27.74	2,305,666	83,117	MWH	$ 25.24	2,098,040	
14	T-O-D Off-Peak - Pri.	84,068	MWH	$ 27.74	2,332,046	84,068	MWH	$ 25.24	2,122,045	
15	T-O-D Off-Peak - Subtrans.	262,242	MWH	$ 27.74	7,274,593	262,242	MWH	$ 25.24	6,619,516	
16	Total	501,687	MWH		13,916,797	501,687	MWH		12,663,589	-9.0%
17										
18	Demand Charge:									
19	Standard Primary	100,581	kW	$ 2.19	220,272	100,581	kW	$ 1.99	200,437	
20	Standard Subtrans.	-	kW	$ 2.19	-	-	kW	$ 1.99	-	
21	T-O-D Billing - Primary	224,684	kW	$ 2.19	492,058	224,684	kW	$ 1.99	447,748	
22	T-O-D Billing - Subtrans.	933,861	kW	$ 2.19	2,045,156	933,861	kW	$ 1.99	1,860,989	
23	T-O-D Peak - Primary	-	kW (1)	$ -	-	-	kW (1)	$ -	-	
24	T-O-D Peak - Subtrans.	-	kW (1)	$ -	-	-	kW (1)	$ -	-	
25	Total	1,259,126	kW		2,757,486	1,259,126	kW		2,509,174	-9.0%
26										
27	Power Factor Charge:									
28	Standard Primary	6,653	MVARh	$ 2.22	14,770	6,653	MVARh	$ 2.02	13,440	
29	Standard Subtrans.	-	MVARh	$ 2.22	-	-	MVARh	$ 2.02	-	
30	T-O-D Primary	12,242	MVARh	$ 2.22	27,177	12,242	MVARh	$ 2.02	24,730	
31	T-O-D Subtransmission	15,573	MVARh	$ 2.22	34,572	15,573	MVARh	$ 2.02	31,459	
32	Total	34,468	MVARh		76,519	34,468	MVARh		69,628	-9.0%
33										
34	(1) Not included in Total.									
35										

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Supporting Schedules: Recap Schedules: E-13a

TAMPA ELECTRIC COMPANY
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FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: TAMPA ELECTRIC COMPANY

DOCKET NO. 20180045-EI

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

Type of data shown:
XX Projected Test year Ended 12/31/2019

Rate Schedule IS, IST

Line No.	Type of Charges	Present Revenue Calculation Units		Charge/Unit		$ Revenue	Proposed Revenue Calculation Units		Charge/Unit		$ Revenue	Percent Decrease
1	Continued from Page 17											
2												
3	Power Factor Credit:											
4	Standard Primary	3,228	MVARh	$	(1.11)	(3,583)	3,228	MVARh	$	(1.01)	(3,260)	
5	Standard Subtrans.	-	MVARh	$	(1.11)	-	-	MVARh	$	(1.01)	-	
6	T-O-D Primary	3,542	MVARh	$	(1.11)	(3,932)	3,542	MVARh	$	(1.01)	(3,578)	
7	T-O-D Subtransmission	-	MVARh	$	(1.11)	-	-	MVARh	$	(1.01)	-	
8	Total	6,770	MVARh			(7,515)	6,770	MVARh			(6,838)	-9.0%
9												
10	Emergency Relay Service											
11	Standard Primary	-	kW	$	0.86	-	-	kW	$	0.78	-	
12	Standard Subtrans.	-	kW	$	0.86	-	-	kW	$	0.78	-	
13	T-O-D Primary	-	kW	$	0.86	-	-	kW	$	0.78	-	
14	T-O-D Subtransmission	-	kW	$	0.86	-	-	kW	$	0.78	-	
15	Total	-	kW			-	-	kW			-	0.0%
16												
17	Delivery Voltage Credit:											
18	Standard Primary	100,581	kW	$	-	-	100,581	kW	$	-	-	
19	Standard Subtrans.	-	kW	$	(0.60)	-	-	kW	$	(0.55)	-	
20	T-O-D Primary	223,155	kW	$	-	-	223,155	kW	$	-	-	
21	T-O-D Subtransmission	935,390	kW	$	(0.60)	(561,234)	935,390	kW	$	(0.55)	(510,695)	
22	Total	1,259,126	kW			(561,234)	1,259,126	kW			(510,695)	-9.0%
23												
24	Metering Voltage Adjustment:											
25	Standard Primary	1,359,284	$		0%	-	1,236,881	$		0%	-	
26	Standard Subtrans.	-	$		-1%	-	-	$		-1%	-	
27	T-O-D Primary	3,724,017	$		0%	-	3,388,669	$		0%	-	
28	T-O-D Subtransmission	11,098,752	$		-1%	(110,988)	10,099,309	$		-1%	(100,993)	
29	Total	16,182,054	$			(110,988)	14,724,859	$			(100,993)	-9.0%
30												
31												
32												
33	Total Base Revenue:					16,463,674					14,981,119	-9.0%
34												
35												

Supporting Schedules: Recap Schedules: E-13a

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: TAMPA ELECTRIC COMPANY

DOCKET NO. 20180045-EI

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

Type of data shown:
XX Projected Test year Ended 12/31/2019

Rate Schedule SBI

Line No.	Type of Charges	Present Revenue Calculation Units		Charge/Unit		$ Revenue	Proposed Revenue Calculation Units		Charge/Unit		$ Revenue	Percent Decrease
1												
2	Basic Service Charge:											
3	T-O-D Primary	0	Bills	$ 717		-	0	Bills	$ 652.26		-	
4	T-O-D Subtransmission	66	Bills	$ 2,656		175,272	66	Bills	$ 2,416.50		159,489	
5	Total	66	Bills			175,272	66	Bills			159,489	-9.0%
6												
7	Energy Charge - Supplemental:											
8	T-O-D On-Peak - Pri.	-	MWH	$ 27.74		-	-	MWH	$ 25.24		-	
9	T-O-D On-Peak - Subtrans.	12,109	MWH	$ 27.74		335,904	12,109	MWH	$ 25.24		305,656	
10	T-O-D Off-Peak - Pri.	-	MWH	$ 27.74		-	-	MWH	$ 25.24		-	
11	T-O-D Off-Peak - Subtrans.	40,470	MWH	$ 27.74		1,122,638	40,470	MWH	$ 25.24		1,021,544	
12	Energy Charge - Standby:											
13	T-O-D On-Peak - Pri.	-	MWH	$ 11.15		-	-	MWH	$ 10.15		-	
14	T-O-D On-Peak - Subtrans.	62,784	MWH	$ 11.15		700,042	62,784	MWH	$ 10.15		637,003	
15	T-O-D Off-Peak - Pri.	-	MWH	$ 11.15		-	-	MWH	$ 10.15		-	
16	T-O-D Off-Peak - Subtrans.	183,017	MWH	$ 11.15		2,040,640	183,017	MWH	$ 10.15		1,856,880	
17	Total	298,380	MWH			4,199,223	298,380	MWH			3,821,082	-9.0%
18												
19	Demand Charge - Supplemental:											
20	T-O-D Billing - Primary	-	kW	$ 2.19	kW	-	-	kW	$ 1.99	kW	-	
21	T-O-D Billing - Subtrans.	134,292	kW	$ 2.19	kW	294,099	134,292	kW	$ 1.99	kW	267,616	
22	T-O-D Peak - Primary	-	kW (1)	$ -	kW	-	-	kW (1)	$ -	kW	-	
23	T-O-D Peak - Subtrans.	-	kW (1)	$ -	kW	-	-	kW (1)	$ -	kW	-	
24	Demand Charge - Standby:											
25	T-O-D Facilities Reservation - Pri.	-	kW	$ 1.61	kW	-	-	kW	$ 1.47	kW	-	
26	T-O-D Facilities Res. - Subtrans.	2,400,000	kW	$ 1.61	kW	3,864,000	2,400,000	kW	$ 1.47	kW	3,516,047	
27	T-O-D Bulk Trans. Res. - Pri.	-	kW (1)	$ 1.33	kW-mo.	-	-	kW (1)	$ 1.21	kW-mo.	-	
28	T-O-D Bulk Trans. Res. - Subtrans.	280,026	kW (1)	$ 1.33	kW-mo.	372,435	280,026	kW (1)	$ 1.21	kW-mo.	338,897	
29	T-O-D Bulk Trans. Dmd. - Pri.	-	kW (1)	$ 0.53	kW-day	-	-	kW (1)	$ 0.48	kW-day	-	
30	T-O-D Bulk Trans Dmd. - Subtrans.	13,285,009	kW (1)	$ 0.53	kW-day	7,041,055	13,285,009	kW (1)	$ 0.48	kW-day	6,407,007	
31	Total	2,534,292	kW			11,571,589	2,534,292	kW			10,529,566	-9.0%
32												
33												
34	(1) Not included in Total.											
35												

Continued on Page 16

Supporting Schedules:

Recap Schedules: E-13a

TAMPA ELECTRIC COMPANY
DOCKET NO. 20180045-EI
EXHIBIT NO. ___ (WRA-1)
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FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: TAMPA ELECTRIC COMPANY

DOCKET NO. 20180045-EI

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

Type of data shown:
XX Projected Test year Ended 12/31/2019

Rate Schedule SBI

Line No.	Type of Charges	Present Units		Present Charge/Unit		Present $ Revenue	Proposed Units		Proposed Charge/Unit		Proposed $ Revenue	Percent Decrease
1	Continued from Page 19											
2												
3	Power Factor Charge Supplemental & Standby:											
4	T-O-D Primary	-	MVARh	$	2.22	-	-	MVARh	$	2.02	-	
5	T-O-D Subtransmission	84,156	MVARh	$	2.22	186,826	84,156	MVARh	$	2.02	170,003	
6	Total	84,156	MVARh			186,826	84,156	MVARh			170,003	-9.0%
7												
8	Power Factor Credit Supplemental & Standby:											
9	T-O-D Primary	-	MVARh	$	(1.11)	-	-	MVARh	$	(1.01)	-	
10	T-O-D Subtransmission	26,619	MVARh	$	(1.11)	(29,547)	26,619	MVARh	$	(1.01)	(26,886)	
11	Total	26,619	MVARh			(29,547)	26,619	MVARh			(26,886)	-9.0%
12												
13	Emergency Relay Charge - Supp.											
14	T-O-D Primary	-	kW	$	0.86	-	-	kW	$	0.78	-	
15	T-O-D Subtransmission	-	kW	$	0.86	-	-	kW	$	0.78	-	
16	Total	-	kW			-	-	kW			-	0.0%
17												
18	Delivery Voltage Credit - Supplemental.:											
19	T-O-D Primary	-	kW	$	-	-	-	kW	$	-	-	
20	T-O-D Subtransmission	134,292	kW	$	(0.60)	(80,575)	134,292	kW	$	(0.55)	(73,319)	
21	Delivery Voltage Credit. - Standby.:											
22	T-O-D Primary	-	kW	$	-	-	-	kW	$	-	-	
23	T-O-D Subtransmission	2,400,000	kW	$	(0.37)	(888,000)	2,400,000	kW	$	(0.34)	(808,036)	
24	Total	2,534,292	kW			(968,575)	2,534,292	kW			(881,355)	-9.0%
25												
26	Metering Voltage Adjustment - Supplemental and Stanby.:											
27	T-O-D Primary	-	$		0.0%	-	-	$		0.0%	-	
28	T-O-D Subtransmission	14,959,515	$		-1.0%	(149,595)	13,612,410	$		-1.0%	(136,124)	
29	Total	14,959,515	$			(149,595)	13,612,410	$			(136,124)	-9.0%
30												
31												
32												
33	Total Base Revenue:					14,985,193					13,635,775	-9.0%
34												
35												

Supporting Schedules:

Recap Schedules: E-13a

TAMPA ELECTRIC COMPANY
DOCKET NO. 20180045-EI
EXHIBIT NO. ___ (WRA-1)
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FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: TAMPA ELECTRIC COMPANY

DOCKET NO. 20180045-EI

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

Type of data shown:
XX Projected Test year Ended 12/31/2019

Rate Schedule LS-1 (Energy Service)

Line No.	Type of Charges	Present Revenue Calculation Units		Charge/Unit		$ Revenue	Proposed Revenue Calculation Units		Charge/Unit		$ Revenue	Percent Decrease
1												
2	Basic Service Charge:	2,937	Bills	$	11.62	34,128	2,937	Bills	$	10.57	31,055	-9.0%
3												
4	Energy Charge	173,595	MWH	$	27.41	4,758,239	173,595	MWH	$	24.94	4,329,759	-9.0%
5												
6												
7	Total Base Revenue:					4,792,367					4,360,814	-9.0%
8												
9												
10												
11												
12												
13												
14												
15												
16												
17												
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33												
34												
35												

Supporting Schedules: E-13d

Recap Schedules: E-13a

Rollup Base Revenue by Rate Class

TAMPA ELECTRIC COMPANY
DOCKET NO. 20180045-EI
EXHIBIT NO. ___ (WRA-1)
WITNESS: ASHBURN
DOCUMENT NO. 2
PAGE 1 OF 1
FILED: 05/31/2018

FLORIDA PUBLIC SERVICE COMMISSION

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

Type of data shown:
XX Projected Test year Ended 12/31/2019

COMPANY: TAMPA ELECTRIC COMPANY
DOCKET NO. 20180045-EI

($000)

12CP & 1/13 - all demand

Line No.	Rate	(1) Base Revenue at Present Rates	(2) Base Revenue Under Proposed Rates	Decrease (3) Dollars (2) - (1)	Decrease (4) Percent (3) / (1)
1	RS, RSVP-1	670,187	609,837	(60,350)	-9.0%
2	GS, GST	69,340	63,096	(6,244)	-9.0%
3	CS	1,331	1,211	(120)	-9.0%
4	GSD, GSDT	326,580	297,172	(29,409)	-9.0%
5	GSD Optional	30,839	28,062	(2,777)	-9.0%
6	SBF, SBFT	4,968	4,521	(447)	-9.0%
7	IS, IST	16,464	14,981	(1,483)	-9.0%
8	SBI	14,985	13,636	(1,349)	-9.0%
9	LS-1 (Energy Service)	4,792	4,361	(432)	-9.0%
10	LS-1 (Facilities)	43,545	43,545	-	0.0%
11					
12					
13	TOTAL	$ 1,183,032	$ 1,080,421	$ (102,611)	-8.7%
14					
15					
16					
17					
18					
19					
20					
21					
22	Summary by Rate Class				
23	RS	670,187	609,837	(60,350)	-9.0%
24					
25	GS	70,671	64,307	(6,364)	-9.0%
26					
27	GSD	362,388	329,755	(32,633)	-9.0%
28					
29	IS	31,449	28,617	(2,832)	-9.0%
30					
31	Lighting	48,337	47,906	(432)	-0.9%
32					
33	TOTAL	1,183,032	1,080,421	(102,611)	-8.7%
34					
35					
36					

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

Recap Schedules:

TAMPA ELECTRIC COMPANY
DOCKET NO. 20180045-EI
EXHIBIT No. ______ (WRA-1)
WITNESS: ASHBURN
DOCUMENT NO. 3

Typical Bills Reflecting

Tax Reform

TAMPA ELECTRIC COMPANY
DOCKET NO. 20180045-EI
EXHIBIT NO. ___ (WRA-1)
WITNESS: ASHBURN
DOCUMENT NO. 3
PAGE 1 OF 4
FILED: 05/31/2018

FLORIDA PUBLIC SERVICE COMMISSION

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

Type of data shown:
XX Projected Test year Ended 12/31/2019

COMPANY: TAMPA ELECTRIC COMPANY
DOCKET NO. 20180045-EI

RS - RESIDENTIAL SERVICE

	RATE SCHEDULE RS		BILL UNDER PRESENT RATES							BILL UNDER PROPOSED RATES							DECREASE		COSTS IN CENTS/KWH	
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)	(20)
Line No.	TYPICAL KW	KWH	BASE RATE	FUEL CHARGE	ECCR CHARGE	CAPACITY CHARGE	ECRC CHARGE	GRT CHARGE	TOTAL	BASE RATE	FUEL CHARGE	ECCR CHARGE	CAPACITY CHARGE	ECRC CHARGE	GRT CHARGE	TOTAL	DOLLARS (16)-(9)	PERCENT (17)/(9)	PRESENT (9)/(2)*100	PROPOSED (16)/(2)*100
1	0	-	$ 16.62	$ -	$ -	$ -	$ -	$ 0.43	$ 17.05	$ 15.12	$ -	$ -	$ -	$ -	$ 0.39	$ 15.51	$ (1.54)	-9.0%	-	-
2																				
3	0	100	$ 22.00	$ 2.82	$ 0.25	$ 0.07	$ 0.34	$ 0.65	$ 26.13	$ 20.02	$ 2.82	$ 0.25	$ 0.07	$ 0.34	$ 0.60	$ 24.09	$ (2.03)	-7.8%	26.13	24.09
4																				
5	0	250	$ 30.07	$ 7.05	$ 0.62	$ 0.17	$ 0.86	$ 0.99	$ 39.75	$ 27.36	$ 7.05	$ 0.62	$ 0.17	$ 0.86	$ 0.92	$ 36.97	$ (2.78)	-7.0%	15.90	14.79
6																				
7	0	500	$ 43.52	$ 14.09	$ 1.23	$ 0.33	$ 1.72	$ 1.56	$ 62.45	$ 39.60	$ 14.09	$ 1.23	$ 0.33	$ 1.72	$ 1.46	$ 58.43	$ (4.02)	-6.4%	12.49	11.69
8																				
9	0	750	$ 56.97	$ 21.14	$ 1.85	$ 0.50	$ 2.57	$ 2.13	$ 85.15	$ 51.84	$ 21.14	$ 1.85	$ 0.50	$ 2.57	$ 2.00	$ 79.89	$ (5.26)	-6.2%	11.35	10.65
10																				
11	0	1,000	$ 70.43	$ 28.18	$ 2.46	$ 0.66	$ 3.43	$ 2.70	$ 107.85	$ 64.08	$ 28.18	$ 2.46	$ 0.66	$ 3.43	$ 2.53	$ 101.35	$ (6.50)	-6.0%	10.79	10.13
12																				
13	0	1,250	$ 86.38	$ 37.73	$ 3.08	$ 0.83	$ 4.29	$ 3.39	$ 135.68	$ 78.60	$ 37.73	$ 3.08	$ 0.83	$ 4.29	$ 3.19	$ 127.70	$ (7.98)	-5.9%	10.85	10.22
14																				
15	0	1,500	$ 102.33	$ 47.27	$ 3.69	$ 0.99	$ 5.15	$ 4.09	$ 163.51	$ 93.11	$ 47.27	$ 3.69	$ 0.99	$ 5.15	$ 3.85	$ 154.06	$ (9.45)	-5.8%	10.90	10.27
16																				
17	0	2,000	$ 134.23	$ 66.36	$ 4.92	$ 1.32	$ 6.86	$ 5.48	$ 219.17	$ 122.14	$ 66.36	$ 4.92	$ 1.32	$ 6.86	$ 5.17	$ 206.77	$ (12.40)	-5.7%	10.96	10.34
18																				
19	0	3,000	$ 198.04	$ 104.54	$ 7.38	$ 1.98	$ 10.29	$ 8.26	$ 330.49	$ 180.20	$ 104.54	$ 7.38	$ 1.98	$ 10.29	$ 7.80	$ 312.20	$ (18.29)	-5.5%	11.02	10.41
20																				
21	0	5,000	$ 325.65	$ 180.90	$ 12.30	$ 3.30	$ 17.15	$ 13.83	$ 553.12	$ 296.32	$ 180.90	$ 12.30	$ 3.30	$ 17.15	$ 13.08	$ 523.05	$ (30.08)	-5.4%	11.06	10.46

Line No.		PRESENT	PROPOSED
22			
23			
24		PRESENT	PROPOSED
25	CUSTOMER CHARGE	16.62 $/Bill	15.12 $/Bill
26	DEMAND CHARGE	- $/KW	- $/KW
27	ENERGY CHARGE		
28	0 - 1,000 KWH	5.381 ¢/kWH	4.896 ¢/kWH
29	Over 1,000 KWH	6.381 ¢/kWH	5.806 ¢/kWH
30	FUEL CHARGE		
31	0 - 1,000 KWH	2.818 ¢/kWH	2.818 ¢/kWH
32	Over 1,000 KWH	3.818 ¢/kWH	3.818 ¢/kWH
33	CONSERVATION CHARGE	0.246 ¢/kWH	0.246 ¢/kWH
34	CAPACITY CHARGE	0.066 ¢/kWH	0.066 ¢/kWH
35	ENVIRONMENTAL CHARGE	0.343 ¢/kWH	0.343 ¢/kWH
36			
37			

38 Note: Cost recovery clause factors are the current 2018 factors. 2018 fuel clause factors used for both PRESENT and PROPOSED bills above includes the fuel benefit of Tranche #1 of SoBRA.

39

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

Recap Schedules:

SCHEDULE A-2 | FULL REVENUE REQUIREMENTS BILL COMPARISON - TYPICAL MONTHLY BILLS |

FLORIDA PUBLIC SERVICE COMMISSION

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

Type of data shown:
XX Projected Test year Ended 12/31/2019

COMPANY: TAMPA ELECTRIC COMPANY
DOCKET NO. 20180045-EI

GS - GENERAL SERVICE NON-DEMAND

	RATE SCHEDULE GS		BILL UNDER PRESENT RATES							BILL UNDER PROPOSED RATES							DECREASE		COSTS IN CENTS/KWH	
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)	(20)
Line No.	TYPICAL KW	KWH	BASE RATE	FUEL CHARGE	ECCR CHARGE	CAPACITY CHARGE	ECRC CHARGE	GRT CHARGE	TOTAL	BASE RATE	FUEL CHARGE	ECCR CHARGE	CAPACITY CHARGE	ECRC CHARGE	GRT CHARGE	TOTAL	DOLLARS (16)-(9)	PERCENT (17)/(9)	PRESENT (9)/(2)*100	PROPOSED (16)/(2)*100
1	0	-	$ 19.94	$ -	$ -	$ -	$ -	$ 0.51	$ 20.45	$ 18.14	$ -	$ -	$ -	$ -	$ 0.47	$ 18.61	$ (1.84)	-9.0%	-	-
2																				
3	0	100	$ 25.62	$ 3.13	$ 0.23	$ 0.06	$ 0.34	$ 0.75	$ 30.14	$ 23.31	$ 3.13	$ 0.23	$ 0.06	$ 0.34	$ 0.69	$ 27.77	$ (2.37)	-7.9%	30.14	27.77
4																				
5	0	250	$ 34.13	$ 7.83	$ 0.58	$ 0.15	$ 0.86	$ 1.12	$ 44.66	$ 31.06	$ 7.83	$ 0.58	$ 0.15	$ 0.86	$ 1.04	$ 41.51	$ (3.15)	-7.1%	17.87	16.60
6																				
7	0	500	$ 48.32	$ 15.66	$ 1.16	$ 0.30	$ 1.72	$ 1.72	$ 68.88	$ 43.97	$ 15.66	$ 1.16	$ 0.30	$ 1.72	$ 1.61	$ 64.42	$ (4.46)	-6.5%	13.78	12.88
8																				
9	0	750	$ 62.51	$ 23.49	$ 1.74	$ 0.45	$ 2.57	$ 2.33	$ 93.09	$ 56.88	$ 23.49	$ 1.74	$ 0.45	$ 2.57	$ 2.18	$ 87.32	$ (5.77)	-6.2%	12.41	11.64
10																				
11	0	1,000	$ 76.70	$ 31.32	$ 2.32	$ 0.60	$ 3.43	$ 2.93	$ 117.31	$ 69.80	$ 31.32	$ 2.32	$ 0.60	$ 3.43	$ 2.76	$ 110.22	$ (7.08)	-6.0%	11.73	11.02
12																				
13	0	1,250	$ 90.89	$ 39.15	$ 2.90	$ 0.75	$ 4.29	$ 3.54	$ 141.52	$ 82.71	$ 39.15	$ 2.90	$ 0.75	$ 4.29	$ 3.33	$ 133.12	$ (8.39)	-5.9%	11.32	10.65
14																				
15	0	1,500	$ 105.08	$ 46.98	$ 3.48	$ 0.90	$ 5.15	$ 4.14	$ 165.73	$ 95.62	$ 46.98	$ 3.48	$ 0.90	$ 5.15	$ 3.90	$ 156.03	$ (9.71)	-5.9%	11.05	10.40
16																				
17	0	2,000	$ 133.47	$ 62.64	$ 4.64	$ 1.20	$ 6.86	$ 5.35	$ 214.16	$ 121.45	$ 62.64	$ 4.64	$ 1.20	$ 6.86	$ 5.05	$ 201.83	$ (12.33)	-5.8%	10.71	10.09
18																				
19	0	3,000	$ 190.23	$ 93.96	$ 6.96	$ 1.80	$ 10.29	$ 7.78	$ 311.01	$ 173.10	$ 93.96	$ 6.96	$ 1.80	$ 10.29	$ 7.34	$ 293.44	$ (17.57)	-5.6%	10.37	9.78
20																				
21	0	5,000	$ 303.75	$ 156.60	$ 11.60	$ 3.00	$ 17.15	$ 12.62	$ 504.72	$ 276.40	$ 156.60	$ 11.60	$ 3.00	$ 17.15	$ 11.92	$ 476.67	$ (28.05)	-5.6%	10.09	9.53
22																				
23	0	8,500	$ 502.42	$ 266.22	$ 19.72	$ 5.10	$ 29.16	$ 21.09	$ 843.71	$ 457.18	$ 266.22	$ 19.72	$ 5.10	$ 29.16	$ 19.93	$ 797.31	$ (46.40)	-5.5%	9.93	9.38

Line No.		PRESENT	PROPOSED
24			
25			
26		PRESENT	PROPOSED
27	CUSTOMER CHARGE	19.94 $/Bill	18.14 $/Bill
28	ENERGY CHARGE	5.676 ¢/kWH	5.165 ¢/kWH
29	FUEL CHARGE	3.132 ¢/kWH	3.132 ¢/kWH
30	CONSERVATION CHARGE	0.232 ¢/kWH	0.232 ¢/kWH
31	CAPACITY CHARGE	0.060 ¢/kWH	0.060 ¢/kWH
32	ENVIRONMENTAL CHARGE	0.343 ¢/kWH	0.343 ¢/kWH
33			
34			
35			
36			
37	Note: Cost recovery clause factors are the current 2018 factors. 2018 fuel clause factors used for both PRESENT and PROPOSED bills above includes the fuel benefit of Tranche #1 of SoBRA.		
38			
39			

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

Recap Schedules:

TAMPA ELECTRIC COMPANY
DOCKET NO. 20180045-EI
EXHIBIT NO. ___ (WRA-1)
WITNESS: ASHBURN
DOCUMENT NO. 3
PAGE 3 OF 4
FILED: 05/31/2018

FLORIDA PUBLIC SERVICE COMMISSION

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

Type of data shown:
XX Projected Test year Ended 12/31/2019

COMPANY: TAMPA ELECTRIC COMPANY
DOCKET NO. 20180045-EI

GSD - GENERAL SERVICE DEMAND

	RATE SCHEDULE GSD		BILL UNDER PRESENT RATES							BILL UNDER PROPOSED RATES							DECREASE		COSTS IN CENTS/KWH	
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)	(20)
Line	TYPICAL		BASE	FUEL	ECCR	CAPACITY	ECRC	GRT	TOTAL	BASE	FUEL	ECCR	CAPACITY	ECRC	GRT	TOTAL	DOLLARS	PERCENT	PRESENT	PROPOSED
No.	KW	KWH	RATE	CHARGE	CHARGE	CHARGE	CHARGE	CHARGE		RATE	CHARGE	CHARGE	CHARGE	CHARGE	CHARGE		(16)-(9)	(17)/(9)	(9)/(2)*100	(16)/(2)*100
1	75	10,950	$ 779.15	$ 342.95	$ 22.01	$ 5.15	$ 37.45	$ 30.43	$ 1,217.14	$ 708.99	$ 342.95	$ 22.01	$ 5.15	$ 37.45	$ 28.63	$ 1,145.18	$ (71.96)	-5.9%	11.12	10.46
2	75	19,163	$ 1,171.85	$ 600.17	$ 65.25	$ 15.00	$ 65.54	$ 49.17	$ 1,966.98	$ 1,066.33	$ 600.17	$ 65.25	$ 15.00	$ 65.54	$ 46.47	$ 1,858.75	$ (108.23)	-5.5%	10.26	9.70
3	75	32,850	$ 1,411.93	$ 1,028.86	$ 65.25	$ 15.00	$ 112.35	$ 67.52	$ 2,700.91	$ 1,284.78	$ 1,028.86	$ 65.25	$ 15.00	$ 112.35	$ 64.26	$ 2,570.51	$ (130.40)	-4.8%	8.22	7.82
4	75	49,275	$ 1,654.30	$ 1,536.27	$ 65.25	$ 15.00	$ 168.52	$ 88.19	$ 3,527.53	$ 1,505.33	$ 1,536.27	$ 65.25	$ 15.00	$ 168.52	$ 84.37	$ 3,374.74	$ (152.79)	-4.3%	7.16	6.85
5																				
6	500	73,000	$ 5,006.00	$ 2,286.36	$ 146.73	$ 34.31	$ 249.66	$ 198.03	$ 7,921.09	$ 4,555.21	$ 2,286.36	$ 146.73	$ 34.31	$ 249.66	$ 186.47	$ 7,458.74	$ (462.35)	-5.8%	10.85	10.22
7	500	127,750	$ 7,623.98	$ 4,001.13	$ 435.00	$ 100.00	$ 436.91	$ 323.00	$ 12,920.01	$ 6,937.44	$ 4,001.13	$ 435.00	$ 100.00	$ 436.91	$ 305.40	$ 12,215.87	$ (704.14)	-5.5%	10.11	9.56
8	500	219,000	$ 9,224.50	$ 6,859.08	$ 435.00	$ 100.00	$ 748.98	$ 445.32	$ 17,812.88	$ 8,393.83	$ 6,859.08	$ 435.00	$ 100.00	$ 748.98	$ 424.02	$ 16,960.92	$ (851.97)	-4.8%	8.13	7.74
9	500	328,500	$ 10,840.31	$ 10,241.81	$ 435.00	$ 100.00	$ 1,123.47	$ 583.09	$ 23,323.68	$ 9,864.14	$ 10,241.81	$ 435.00	$ 100.00	$ 1,123.47	$ 558.06	$ 22,322.48	$ (1,001.20)	-4.3%	7.10	6.80
10																				
11	2000	292,000	$ 19,924.28	$ 9,145.44	$ 586.92	$ 137.24	$ 998.64	$ 789.55	$ 31,582.07	$ 18,130.10	$ 9,145.44	$ 586.92	$ 137.24	$ 998.64	$ 743.55	$ 29,741.88	$ (1,840.19)	-5.8%	10.82	10.19
12	2000	511,000	$ 30,396.18	$ 16,004.52	$ 1,740.00	$ 400.00	$ 1,747.62	$ 1,289.44	$ 51,577.76	$ 27,659.00	$ 16,004.52	$ 1,740.00	$ 400.00	$ 1,747.62	$ 1,219.26	$ 48,770.40	$ (2,807.36)	-5.4%	10.09	9.54
13	2000	876,000	$ 36,798.28	$ 27,436.32	$ 1,740.00	$ 400.00	$ 2,995.92	$ 1,778.73	$ 71,149.25	$ 33,484.59	$ 27,436.32	$ 1,740.00	$ 400.00	$ 2,995.92	$ 1,693.76	$ 67,750.60	$ (3,398.65)	-4.8%	8.12	7.73
14	2000	1,314,000	$ 43,261.52	$ 40,967.24	$ 1,740.00	$ 400.00	$ 4,493.88	$ 2,329.81	$ 93,192.44	$ 39,365.82	$ 40,967.24	$ 1,740.00	$ 400.00	$ 4,493.88	$ 2,229.92	$ 89,196.85	$ (3,995.59)	-4.3%	7.09	6.79
15																				
16																				

Line		PRESENT					PROPOSED				
18		GSD	GSDT		GSD OPT.		GSD	GSDT		GSD OPT.	
19	CUSTOMER CHARGE	33.24	33.24	$/Bill	33.24	$/Bill	30.25	30.25		30.25	$/Bill
20	DEMAND CHARGE	10.70	-	$/KW	-	$/KW	9.74	-	$/KW	-	$/KW
21	BILLING	-	3.61	$/KW	-	$/KW	-	3.28	$/KW	-	$/KW
22	PEAK	-	7.09	$/KW	-	$/KW	-	6.45	$/KW	-	$/KW
23	ENERGY CHARGE	1.754	-	¢/KWH	6.812	¢/KWH	1.596	-	¢/KWH	6.199	¢/KWH
24	ON-PEAK	-	3.211	¢/KWH	-	¢/KWH	-	2.922	¢/KWH	-	¢/KWH
25	OFF-PEAK	-	1.159	¢/KWH	-	¢/KWH	-	1.055	¢/KWH	-	¢/KWH
26	FUEL CHARGE	3.132	-	¢/KWH	3.132	¢/KWH	3.132	-	¢/KWH	3.132	¢/KWH
27	ON-PEAK		3.330	¢/KWH	-	¢/KWH		3.330	¢/KWH	-	¢/KWH
28	OFF-PEAK		3.047	¢/KWH	-	¢/KWH		3.047	¢/KWH	-	¢/KWH
29	CONSERVATION CHARGE	0.87	0.87	$/KW	0.201	¢/KWH	0.87	0.87	$/KW	0.201	¢/KWH
30	CAPACITY CHARGE	0.20	0.20	$/KW	0.047	¢/KWH	0.20	0.20	$/KW	0.047	¢/KWH
31	ENVIRONMENTAL CHARGE	0.342	0.342	¢/KWH	0.342	¢/KWH	0.342	0.342	¢/KWH	0.342	¢/KWH

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

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

Recap Schedules:

SCHEDULE A-2 | FULL REVENUE REQUIREMENTS BILL COMPARISON - TYPICAL MONTHLY BILLS

FLORIDA PUBLIC SERVICE COMMISSION

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

Type of data shown:
XX Projected Test year Ended 12/31/2019

COMPANY: TAMPA ELECTRIC COMPANY
DOCKET NO. 20180045-EI

IS - INTERRUPTIBLE SERVICE

	RATE SCHEDULE IS-1		BILL UNDER PRESENT RATES								BILL UNDER PROPOSED RATES								DECREASE		COSTS IN CENTS/KWH	
Line No.	(1) TYPICAL KW	(2) KWH	(3) BASE RATE	(4) CCV CREDIT	(5) FUEL CHARGE	(6) ECCR CHARGE	(7) CAPACITY CHARGE	(8) ECRC CHARGE	(9) GRT CHARGE	(10) TOTAL	(11) BASE RATE	(12) CCV CREDIT	(13) FUEL CHARGE	(14) ECCR CHARGE	(15) CAPACITY CHARGE	(16) ECRC CHARGE	(17) GRT CHARGE	(18) TOTAL	(19) DOLLARS (16)-(9)	(20) PERCENT (17)/(9)	(21) PRESENT (9)/(2)*100	(22) FINAL (16)/(2)*100
1	500	127,750	$5,327.90	-$1,772.75	$3,961.53	$335.00	$70.00	$425.79	$214.04	$8,561.50	$4,848.12	-$1,772.75	$3,961.53	$335.00	$70.00	$425.41	$201.73	$8,069.03	$ (492)	-5.8%	6.70	6.32
2	500	219,000	$7,859.17	-$3,039.00	$6,791.19	$335.00	$70.00	$729.93	$326.83	$13,073.11	$7,151.45	-$3,039.00	$6,791.19	$335.00	$70.00	$729.27	$308.66	$12,346.58	$ (727)	-5.6%	5.97	5.64
3	500	328,500	$10,896.70	-$4,558.50	$10,140.80	$335.00	$70.00	$1,093.91	$460.97	$18,438.87	$9,915.45	-$4,558.50	$10,140.80	$335.00	$70.00	$1,093.91	$435.81	$17,432.46	$ (1,006)	-5.5%	5.61	5.31
4																						
5	1,000	255,500	$9,966.68	-$3,545.50	$7,923.06	$670.00	$140.00	$851.58	$410.41	$16,416.22	$9,069.18	-$3,545.50	$7,923.06	$670.00	$140.00	$850.82	$387.37	$15,494.92	$ (921)	-5.6%	6.43	6.06
6	1,000	438,000	$15,029.23	-$6,078.00	$13,582.38	$670.00	$140.00	$1,459.85	$635.99	$25,439.45	$13,675.85	-$6,078.00	$13,582.38	$670.00	$140.00	$1,458.54	$601.25	$24,050.02	$ (1,389)	-5.5%	5.81	5.49
7	1,000	657,000	$21,104.29	-$9,117.00	$20,281.59	$670.00	$140.00	$2,187.81	$904.27	$36,170.96	$19,203.85	-$9,117.00	$20,281.59	$670.00	$140.00	$2,187.81	$855.54	$34,221.79	$ (1,949)	-5.4%	5.51	5.21
8																						
9	5,000	1,277,500	$47,076.96	-$17,727.50	$39,615.28	$3,350.00	$700.00	$4,257.91	$1,981.35	$79,253.99	$42,837.68	-$17,727.50	$39,615.28	$3,350.00	$700.00	$4,254.08	$1,872.55	$74,902.08	$ (4,352)	-5.5%	6.20	5.86
10	5,000	2,190,000	$72,389.71	-$30,390.00	$67,911.90	$3,350.00	$700.00	$7,299.27	$3,109.25	$124,370.13	$65,871.01	-$30,390.00	$67,911.90	$3,350.00	$700.00	$7,292.70	$2,941.94	$117,677.55	$ (6,693)	-5.4%	5.68	5.37
11	5,000	3,285,000	$102,765.01	-$45,585.00	$101,407.95	$3,350.00	$700.00	$10,939.05	$4,450.69	$178,027.70	$93,511.01	-$45,585.00	$101,407.95	$3,350.00	$700.00	$10,939.05	$4,213.41	$168,536.42	$ (9,491)	-5.3%	5.42	5.13

Line		PRESENT IS	PRESENT IST		PROPOSED IS	PROPOSED IST	
12							
13							
14							
15	CUSTOMER CHARGE	689.11	689.11	$/Bill	627.06	627.06	$/Bill
16	DEMAND CHARGE	2.19	2.19	$/KW	1.99	1.99	$/KW
17	PEAK DEMAND CHARGE	-	-	$/KW	-	-	$/KW
	ENERGY CHARGE	2.774	-	¢/kWH	2.524	-	¢/kWH
18	ON-PEAK ENERGY CHARGE	-	2.774	¢/kWH	-	2.524	¢/kWH
19	OFF-PEAK ENERGY CHARGE	-	2.774	¢/kWH	-	2.524	¢/kWH
20	DELIVERY VOLTAGE CREDIT	-	-	$/KW	-	-	$/KW
21	FUEL CHARGE	3.101	-	¢/kWH	3.101	-	¢/kWH
22	ON-PEAK	-	3.297	¢/kWH	-	3.297	¢/kWH
23	OFF-PEAK	-	3.017	¢/kWH	-	3.017	¢/kWH
24	CONSERVATION CHARGE	0.67	0.67	$/KW	0.67	0.67	$/KW
25	CAPACITY CHARGE	0.14	0.14	$/KW	0.14	0.14	$/KW
26	ENVIRONMENTAL CHARGE	0.333	0.333	¢/kWH	0.333	0.333	¢/kWH
27							
28	GSLM-2 CONTRACT CREDIT VALUE	(10.13)	(10.13)	$/kW	(10.13)	(10.13)	$/kW
29							

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

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

Recap Schedules:

TAMPA ELECTRIC COMPANY
DOCKET NO. 20180045-EI
EXHIBIT NO. ___ (WRA-1)
WITNESS: ASHBURN
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FILED: 05/31/2018

TAMPA ELECTRIC COMPANY
DOCKET NO. 20180045-EI
EXHIBIT No. ______ (WRA-1)
WITNESS: ASHBURN
DOCUMENT NO. 4

Redlined Tariffs

Reflecting Tax Reform

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

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

RESIDENTIAL SERVICE

SCHEDULE: RS

AVAILABLE: Entire service area.

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

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

Resale not permitted.

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

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

MONTHLY RATE:

Basic Service Charge:
$~~16.62~~15.12

Energy and Demand Charge:

First 1,000 kWh	~~5.381~~4.896¢ per kWh
All additional kWh	~~6.381~~5.806¢ per kWh

MINIMUM CHARGE: The Basic Service Charge.

FUEL CHARGE: See Sheet Nos. 6.020 and 6.021.

Continued to Sheet No. 6.031

ISSUED BY: N. G. Tower, President **DATE EFFECTIVE:** ~~September 1, 2018~~

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

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

GENERAL SERVICE - NON DEMAND

SCHEDULE: GS

AVAILABLE: Entire service area.

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

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

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

MONTHLY RATE:

Basic Service Charge:

Metered accounts	$~~19.94~~18.14
Un-metered accounts	$~~16.62~~15.12

Energy and Demand Charge:
5.~~676~~165¢ per kWh

MINIMUM CHARGE: The Basic Service Charge.

EMERGENCY RELAY POWER SUPPLY CHARGE: The monthly charge for emergency relay power supply service shall be 0.~~171~~156¢ per kWh of billing energy. This charge is in addition to the compensation the customer must make to the Company as a contribution-in-aid of construction.

Continued to Sheet No. 6.051

ISSUED BY: N. G. Tower, President **DATE EFFECTIVE:** ~~September 1, 2018~~

TECO TAMPA ELECTRIC AN EMERA COMPANY

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

GENERAL SERVICE - DEMAND

SCHEDULE: GSD

AVAILABLE: Entire service area.

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

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

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

MONTHLY RATE:

STANDARD		OPTIONAL	
Basic Service Charge:		Basic Service Charge:	
Secondary Metering Voltage	$ ~~33.24~~30.25	Secondary Metering Voltage	$ ~~33.24~~30.25
Primary Metering Voltage	$ ~~144.03~~131.06	Primary Metering Voltage	$ ~~144.03~~131.06
Subtrans. Metering Voltage	$~~1,096.82~~998.05	Subtrans. Metering Voltage	$~~1,096.82~~998.05

STANDARD	OPTIONAL
Demand Charge: $~~10.70~~9.74 per kW of billing demand	Demand Charge: $0.00 per kW of billing demand
Energy Charge: 1.~~754~~596¢ per kWh	Energy Charge: 6.~~812~~199¢ per kWh

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

Continued to Sheet No. 6.081

ISSUED BY: N. G. Tower, President **DATE EFFECTIVE:** ~~September 1, 2018~~

TECO TAMPA ELECTRIC AN EMERA COMPANY

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

Continued from Sheet No. 6.080

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

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

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

POWER FACTOR: Power factor will be calculated for customers with measured demands of 1,000 kW or more in any one billing period out of twelve (12) consecutive billing periods ending with the current billing period. When the average power factor during the month is less than 85%, the monthly bill will be increased 0.~~222~~202¢ for each kVARh by which the reactive energy numerically exceeds 0.619744 times the billing energy. When the average power factor during the month is greater than 90%, the monthly bill will be decreased 0.~~111~~101¢ for each kVARh by which the reactive energy is numerically less than 0.484322 times the billing energy.

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

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

DELIVERY VOLTAGE CREDIT: When a customer under the standard rate takes service at primary voltage, a discount of ~~87~~79¢ per kW of billing demand will apply. A discount of $2.~~69~~45 per kW of billing demand will apply when a customer under the standard rate takes service at subtransmission or higher voltage.

Continued to Sheet No. 6.082

ISSUED BY: N. G. Tower, President **DATE EFFECTIVE:** ~~September 1, 2018~~

TECO TAMPA ELECTRIC AN EMERA COMPANY

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

Continued from Sheet No. 6.081

When a customer under the optional rate takes service at primary voltage, a discount of 0.~~230~~209¢ per kWh will apply. A discount of 0.~~702~~639¢ per kWh will apply when a customer under the optional rate takes service at subtransmission or higher voltage.

EMERGENCY RELAY POWER SUPPLY CHARGE: The monthly charge for emergency relay power supply service shall be ~~69~~63¢ per kW of billing demand for customers taking service under the standard rate and 0.~~174~~158¢/kWh for customer taking service under the optional rate. This charge is in addition to the compensation the customer must make to the Company as a contribution-in-aid of construction.

FUEL CHARGE: See Sheet Nos. 6.020 and 6.021.

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

CAPACITY CHARGE: See Sheet Nos. 6.020 and 6.021.

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

FLORIDA GROSS RECEIPTS TAX: See Sheet No. 6.021.

FRANCHISE FEE CHARGE: See Sheet No. 6.021.

PAYMENT OF BILLS: See Sheet No. 6.022.

ISSUED BY: N. G. Tower, President **DATE EFFECTIVE:** ~~September 1, 2018~~

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

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

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

SCHEDULE: IS

AVAILABLE: Entire Service Area.

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

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

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

MONTHLY RATE:

Basic Service Charge:

Primary Metering Voltage	$ ~~689.11~~627.06
Subtransmission Metering Voltage	$~~2,627.94~~2,391.29

Demand Charge:

$~~2.19~~1.99 per KW of billing demand

Energy Charge:

2.~~774~~524¢ per KWH

Continued to Sheet No. 6.086

ISSUED BY: N. G. Tower, President **DATE EFFECTIVE:** ~~September 1, 2018~~

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

~~TWENTIETH~~ TWENTY-FIRST REVISED SHEET NO. 6.086
CANCELS ~~NINETEENTH~~ TWENTIETH REVISED SHEET NO. 6.086

Continued from Sheet No. 6.085

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

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

POWER FACTOR: When the average power factor during the month is less than 85%, the monthly bill will be increased 0.~~222~~202¢ for each kVARh by which the reactive energy numerically exceeds 0.619744 times the billing energy. When the average power factor during the month is greater than 90%, the monthly bill will be decreased 0.~~111~~101¢ for each kVARh by which the reactive energy is numerically less than 0.484322 times the billing energy.

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

DELIVERY VOLTAGE CREDIT: When the customer furnishes and installs all subtransmission or higher voltage to utilization voltage substation transformation, a discount of ~~60~~55¢ per KW of billing demand will apply.

EMERGENCY RELAY POWER SUPPLY CHARGE: The monthly charge for emergency relay power supply service shall be ~~86~~78¢ per KW of billing demand. This charge is in addition to the compensation the customer must make to the Company as a contribution-in-aid of construction.

Continued to Sheet No. 6.087

ISSUED BY: N. G. Tower, President **DATE EFFECTIVE:** ~~September 1, 2018~~

TECO TAMPA ELECTRIC AN EMERA COMPANY

~~TWENTY-NINTH~~THIRTIETH REVISED SHEET NO. 6.290
CANCELS TWENTY-~~EIGHTH~~ NINTH REVISED SHEET NO. 6.290

CONSTRUCTION SERVICE

SCHEDULE: CS

AVAILABLE: Entire service area.

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

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

MONTHLY RATE:
Basic Service Charge: $~~19.94~~18.14

Energy and Demand Charge: 5.~~676~~165¢ per kWh

MINIMUM CHARGE: The Basic Service Charge.

FUEL CHARGE: See Sheet Nos. 6.020 and 6.021.

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

CAPACITY CHARGE: See Sheet Nos. 6.020 and 6.021.

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

FLORIDA GROSS RECEIPTS TAX: Sheet No. 6.021.

FRANCHISE FEE CHARGE: See Sheet No. 6.021.

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

PAYMENT OF BILLS: See Sheet No. 6.022.

TECO TAMPA ELECTRIC AN EMERA COMPANY

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

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

SCHEDULE: GST

AVAILABLE: Entire service area.

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

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

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

MONTHLY RATE:

Basic Service Charge:
$~~22.16~~20.16

Energy and Demand Charge:
~~14.488~~13.183¢ per kWh during peak hours
~~1.545~~1.406¢ per kWh during off-peak hours

Continued to Sheet No. 6.321

ISSUED BY: N. G. Tower, President **DATE EFFECTIVE:** ~~September 1, 2018~~

Continued from Sheet No. 6.320

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

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

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

MINIMUM CHARGE: The Basic Service Charge.

BASIC SERVICE CHARGE CREDIT: Any customer who makes a one time contribution in aid of construction of $94.00 (lump-sum meter payment), shall receive a credit of $~~2.22~~2.02 per month. This contribution in aid of construction will be subject to a partial refund if the customer terminates service on this optional time-of-day rate.

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

EMERGENCY RELAY POWER SUPPLY CHARGE: The monthly charge for emergency relay power supply service shall be 0.~~171~~156¢ per kWh of billing energy. This charge is in addition to the compensation the customer must make to the Company as a contribution-in-aid of construction.

FUEL CHARGE: See Sheet Nos. 6.020 and 6.021.

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

Continued to Sheet No. 6.322

TECO TAMPA ELECTRIC AN EMERA COMPANY

TWENTY-~~FOURTH~~ FIFTH REVISED SHEET NO. 6.330
CANCELS TWENTY-~~THIRD~~ FOURTH REVISED SHEET NO. 6.330

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

SCHEDULE: GSDT

AVAILABLE: Entire service area.

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

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

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

MONTHLY RATE:

Basic Service Charge:

Secondary Metering Voltage	$ ~~33.24~~30.25
Primary Metering Voltage	$ ~~144.03~~131.06
Subtransmission Metering Voltage	$~~1,096.82~~998.05

Demand Charge:

$~~3.61~~3.28 per kW of billing demand, plus
$~~7.09~~6.45per kW of peak billing demand

Energy Charge:

~~3.211~~2.922¢ per kWh during peak hours
~~1.159~~1.055¢ per kWh during off-peak hours

Continued to Sheet No. 6.331

ISSUED BY: N. G. Tower, President **DATE EFFECTIVE:** ~~September 1, 2018~~

TECO TAMPA ELECTRIC AN EMERA COMPANY

~~TWENTIETH~~ TWENTY-FIRST REVISED SHEET NO. 6.332
CANCELS ~~NINETEENTH~~ TWENTIETH REVISED SHEET NO. 6.332

Continued from Sheet No. 6.331

POWER FACTOR: Power factor will be calculated for customers with measured demands of 1,000 kW in any billing period out of twelve (12) consecutive billing periods ending with the current billing period. When the average power factor during the month is less than 85%, the monthly bill will be increased 0.~~222~~202¢ for each kVARh by which the reactive energy numerically exceeds 0.619744 times the billing energy. When the average power factor during the month is greater than 90%, the monthly bill will be decreased 0.~~111~~101¢ for each kVARh by which the reactive energy is numerically less than 0.484322 times the billing energy.

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

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

DELIVERY VOLTAGE CREDIT: When the customer takes service at primary voltage a discount of ~~87~~79¢ per kW of billing demand will apply. When the customer takes service at subtransmission or higher voltage, a discount of $2.~~69~~ 45 per kW of billing demand will apply.

EMERGENCY RELAY POWER SUPPLY CHARGE: The monthly charge for emergency relay power supply service shall be ~~69~~63¢ per kW of billing demand. This charge is in addition to the compensation the customer must make to the Company as a contribution-in-aid of construction.

FUEL CHARGE: See Sheet Nos. 6.020 and 6.021.

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

CAPACITY CHARGE: See Sheet Nos. 6.020 and 6.021.

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

FLORIDA GROSS RECEIPTS TAX: See Sheet No. 6.021.

FRANCHISE FEE CHARGE: See Sheet No. 6.021.

PAYMENT OF BILLS: See Sheet No. 6.022.

ISSUED BY: N. G. Tower, President **DATE EFFECTIVE:** ~~September 1, 2018~~

TECO TAMPA ELECTRIC AN EMERA COMPANY

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

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

SCHEDULE: IST

AVAILABLE: Entire Service Area.

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

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

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

Basic Service Charge:

Primary Metering Voltage	$ ~~689.11~~627.06
Subtransmission Metering Voltage	$~~2,627.94~~2,391.29

Demand Charge:
$~~2.19~~1.99per KW of billing demand

Energy Charge:
2.~~774~~524¢ per KWH

Continued to Sheet No. 6.345

ISSUED BY: N. G. Tower, President **DATE EFFECTIVE:** ~~September 1, 2018~~

~~SECOND~~ THIRD REVISED SHEET NO. 6.345
CANCELS ~~FIRST~~ SECOND REVISED SHEET NO. 6.345

Continued from Sheet No. 6.340

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

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

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

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

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

POWER FACTOR: When the average power factor during the month is less than 85%, the monthly bill will be increased 0.~~222~~202¢ for each kVARh by which the reactive energy numerically exceeds 0.619744 times the billing energy. When the average power factor during the month is greater than 90%, the monthly bill will be decreased 0.~~111~~101¢ for each kVARh by which the reactive energy is numerically less than 0.484322 times the billing energy.

Continued to Sheet No. 6.350

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

Continued from Sheet No. 6.345

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

DELIVERY VOLTAGE CREDIT: When the customer furnishes and installs all subtransmission or higher voltage to utilization voltage substation transformation, a discount of ~~60~~55¢ per KW of billing demand will apply.

EMERGENCY RELAY POWER SUPPLY CHARGE: The monthly charge for emergency relay power supply service shall be ~~86~~78¢ per KW of billing demand. This charge is in addition to the compensation the customer must make to the Company as a contribution-in-aid of construction.

FUEL CHARGE: See Sheet Nos. 6.020 and 6.021.

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

CAPACITY CHARGE: See Sheet Nos. 6.020 and 6.021.

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

FLORIDA GROSS RECEIPTS TAX: See Sheet No. 6.021.

FRANCHISE FEE CHARGE: See Sheet No. 6.021.

PAYMENT OF BILLS: See Sheet No. 6.025.

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

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

Continued from Sheet No. 6.560

MONTHLY RATES:
Basic Service Charge: $~~16.62~~15.12

Energy and Demand Charges: 5.~~695~~182¢ per kWh (for all pricing periods)

MINIMUM CHARGE: The Basic Service Charge.

FUEL CHARGE: See Sheet Nos. 6.020 and 6.021.

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

CAPACITY CHARGE: See Sheet Nos. 6.020 and 6.021.

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

FLORIDA GROSS RECEIPTS TAX: See Sheet No. 6.021.

FRANCHISE FEE CHARGE: See Sheet No. 6.021.

PAYMENT OF BILLS: See Sheet No. 6.022.

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

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

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

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

Continued to Sheet No. 6.570

ISSUED BY: N. G. Tower, President **DATE EFFECTIVE:** ~~September 1, 2018~~

~~THIRTEENTH~~ FOURTEENTH
REVISED SHEET NO. 6.600
CANCELS ~~TWELFTH~~
THIRTEENTH REVISED SHEET
NO. 6.600

FIRM STANDBY AND SUPPLEMENTAL SERVICE

SCHEDULE: SBF

AVAILABLE: Entire service area.

APPLICABLE: Required for all self-generating Customers whose generating capacity in kilowatts (exclusive of emergency generation equipment) exceeds 20% of their site load in kilowatts and who take firm service from the utility. Also available to self-generating Customers whose generating capacity in kilowatts does not exceed 20% of their site load in kilowatts, but who agree to all the terms and conditions of this rate schedule. Resale not permitted.

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

LIMITATION OF SERVICE: A customer taking service under this tariff must sign a Tariff Agreement for the Purchase of Firm Standby and Supplemental Service. (See Sheet No. 7.600)

MONTHLY RATE:

Basic Service Charge:

Secondary Metering Voltage	$ ~~60.93~~55.44
Primary Metering Voltage	$ ~~171.72~~156.26
Subtransmission Metering Voltage	$~~1,124.52~~1,023.26

CHARGES FOR STANDBY SERVICE:

Demand Charge:

$ ~~2.15~~1.96 per kW-Month of Standby Demand
(Local Facilities Reservation Charge)

plus the greater of:

$ ~~1.71~~1.56 per kW-Month of Standby Demand
(Power Supply Reservation Charge) or

$ 0.~~68~~62 per kW-Day of Actual Standby Billing Demand
(Power Supply Demand Charge)

Energy Charge:

~~1.01~~2.921¢ per Standby kWh

Continued to Sheet No. 6.601

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

DATE EFFECTIVE: ~~January 16, 2017~~

TECO TAMPA ELECTRIC AN EMERA COMPANY

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

Continued from Sheet No. 6.600

CHARGES FOR SUPPLEMENTAL SERVICE:

Demand Charge:
$~~10.70~~9.74 per kW-Month of Supplemental Billing Demand (Supplemental Billing Demand Charge)

Energy Charge:
1.~~754~~596¢ per Supplemental kWh

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

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

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

BILLING UNITS:

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

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

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

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

Continued to Sheet No. 6.602

ISSUED BY: N. G. Tower, President **DATE EFFECTIVE:** ~~September 1, 2018~~

Continued from Sheet No. 6.601

Contract Standby Demand - As established pursuant to the Tariff Agreement for the Purchase of Firm Standby and Supplemental Service. Anytime a customer registers a Standby Demand that is higher than the existing Contract Standby Demand, that Standby Demand will become the new Contract Standby Demand, beginning with the following period.

Standby Demand - The greater of Contract Standby Demand or the amount by which Metered Demand exceeds Supplemental Billing Demand, but no greater than Normal Generation.

Actual Standby Billing Demand - The summation of the daily amounts by which the highest on-peak measured 30-minute interval kW demands served by the Company exceed the monthly Supplemental Billing Demand.

Energy Units: Energy provided by the Company during each 30-minute period up to the Supplemental Demand level shall be billed as Supplemental kWh. The remaining energy shall be billed as Standby kWh.

MINIMUM CHARGE: The Basic Service Charge, Local Facilities Reservation Charge, Power Supply Reservation Charge, and any Minimum Charge associated with optional riders.

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

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

POWER FACTOR: When the average power factor during the month is less than 85%, the monthly bill will be increased 0.202¢ for each kVARh by which the reactive energy numerically exceeds 0.619744 times the billing energy. When the average power factor during the month is greater than 90%, the monthly bill will be decreased 0.101¢ for each kVARh by which the reactive energy is numerically less than 0.484322 times the billing energy.

Continued to Sheet No. 6.603

TECO TAMPA ELECTRIC AN EMERA COMPANY

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

Continued from Sheet No. 6.602

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

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

DELIVERY VOLTAGE CREDIT: When the customer takes service at primary voltage, a discount of ~~87~~79¢ per kW of Supplemental Demand and ~~69~~63¢ per kW of Standby Demand will apply.

When the customer takes service at subtransmission or higher voltage, a discount of $2.~~69~~ 45 per kW of Supplemental Demand and $~~2.16~~1.97 per kW of Standby Demand will apply.

EMERGENCY RELAY POWER SUPPLY CHARGE: The monthly charge for emergency relay power supply service shall be ~~69~~63¢ per kW of Supplemental Demand and Standby Demand. This charge is in addition to the compensation the customer must make to the Company as a contribution-in-aid of construction.

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

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

CAPACITY CHARGE: See Sheet Nos. 6.020 and 6.021.

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

FLORIDA GROSS RECEIPTS TAX: See Sheet No. 6.021.

FRANCHISE FEE CHARGE: See Sheet No. 6.021.

PAYMENT OF BILLS: See Sheet No. 6.022.

ISSUED BY: N. G. Tower, President **DATE EFFECTIVE:** ~~September 1, 2018~~

~~TENTH~~ ELEVENTEENTH REVISED SHEET NO. 6.605
CANCELS ~~NINTH~~ TENTH REVISED SHEET NO. 6.605

TECO TAMPA ELECTRIC AN EMERA COMPANY

TIME-OF-DAY
FIRM STANDBY AND SUPPLEMENTAL SERVICE
(OPTIONAL)

SCHEDULE: SBFT

AVAILABLE: Entire service area.

APPLICABLE: Required for all self-generating Customers whose generating capacity in kilowatts (exclusive of emergency generation equipment) exceeds 20% of their site load in kilowatts and who take firm service from the utility. Also available to self-generating Customers whose generating capacity in kilowatts does not exceed 20% of their site load in kilowatts, but who agree to all the terms and conditions of this rate schedule. Resale not permitted.

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

LIMITATION OF SERVICE: A Customer taking service under this tariff must sign a Tariff Agreement for the Purchase of Firm Standby and Supplemental Service. (See Sheet No. 7.600)

MONTHLY RATE:

Basic Service Charge:

Secondary Metering Voltage	$ ~~60.93~~55.44
Primary Metering Voltage	$ ~~171.72~~156.26
Subtransmission Metering Voltage	$~~1,124.52~~1,023.26

CHARGES FOR STANDBY SERVICE:

Demand Charge:

$ ~~2.15~~1.96 per kW-Month of Standby Demand (Local Facilities Reservation Charge)

plus the greater of:

$ ~~1.71~~1.56 per kW-Month of Standby Demand (Power Supply Reservation Charge) or

$ 0.~~68~~62 per kW-Day of Actual Standby Billing Demand (Power Supply Demand Charge)

Energy Charge:

~~1.012~~.921¢ per Standby kWh

Continued to Sheet No. 6.606

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

DATE EFFECTIVE: ~~January 16, 2017~~

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

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

Continued from Sheet No. 6.605

CHARGES FOR SUPPLEMENTAL SERVICE

Demand Charge:

$~~3.61~~3.28 per kW-Month of Supplemental Demand (Supplemental Billing Demand Charge), plus
$~~7.09~~6.45 per kW-Month of Supplemental Peak Demand (Supplemental Peak Billing Demand Charge)

Energy Charge:

~~3.211~~2.922¢ per Supplemental kWh during peak hours
~~1.159~~1.055¢ per Supplemental kWh during off-peak hours

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

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

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

BILLING UNITS:

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

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

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

Continued to Sheet No. 6.607

ISSUED BY: N. G. Tower, President **DATE EFFECTIVE:** ~~September 1, 2018~~

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

~~THIRTEENTH~~ FOURTEENTH REVISED SHEET NO. 6.608
CANCELS ~~TWELFTH~~ THIRTEENTH REVISED SHEET NO. 6.608

Continued from Sheet No. 6.607

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

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

POWER FACTOR: When the average power factor during the month is less than 85%, the monthly bill will be increased 0.~~222~~202¢ for each kVARh by which the reactive energy numerically exceeds 0.619744 times the billing energy. When the average power factor during the month is greater than 90%, the monthly bill will be decreased 0.~~111~~101¢ for each kVARh by which the reactive energy is numerically less than 0.484322 times the billing energy.

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

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

DELIVERY VOLTAGE CREDIT: When the customer takes service at primary voltage, a discount of ~~87~~79¢ per kW of Supplemental Demand and ~~69~~63¢ per kW of Standby Demand will apply.

When the customer takes service at subtransmission or higher voltage, a discount of $2.~~69~~ 45 per kW of Supplemental Demand and $~~2.15~~1.97 per kW of Standby Demand will apply.

EMERGENCY RELAY POWER SUPPLY CHARGE: The monthly charge for emergency relay power supply service shall be ~~69~~63¢ per kW of Supplemental Demand and Standby Demand. This charge is in addition to the compensation the customer must make to the Company as a contribution-in-aid of construction.

Continued to Sheet No. 6.609

ISSUED BY: N. G. Tower, President **DATE EFFECTIVE:** ~~September 1, 2018~~

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

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

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

SCHEDULE: SBI

AVAILABLE: Entire service area.

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

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

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

MONTHLY RATE:

Basic Service Charge:

Primary Metering Voltage	$~~716.81~~652.26
Subtransmission Metering Voltage	$~~2,655.64~~2,416.50

Demand Charge:

$~~2.19~~1.99 per KW-Month of Supplemental Demand (Supplemental Demand Charge)
$~~1.61~~1.47 per KW-Month of Standby Demand (Local Facilities Reservation Charge)

plus the greater of:
$~~1.33~~1.21 per KW-Month of Standby Demand (Power Supply Reservation Charge); or
$0.~~53~~ 48 per KW-Day of Actual Standby Billing Demand (Power Supply Demand Charge)

Continued to Sheet No. 6.705

ISSUED BY: N. G. Tower, President **DATE EFFECTIVE:** ~~September 1, 2018~~

~~FOURTH~~ FIFTH REVISED SHEET NO. 6.705
CANCELS ~~THIRD~~ FOURTH REVISED SHEET NO. 6.705

Continued from Sheet No. 6.700

Energy Charge:
2.~~774~~524¢ per Supplemental KWH
1.~~115~~015¢ per Standby KWH

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

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

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

BILLING UNITS:

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

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

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

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

Continued to Sheet No. 6.710

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

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

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

Continued from Sheet No. 6.710

POWER FACTOR: When the average power factor during the month is less than 85%, the monthly bill will be increased 0.~~222~~202¢ for each kVARh by which the reactive energy numerically exceeds 0.619744 times the billing energy. When the average power factor during the month is greater than 90%, the monthly bill will be decreased 0.~~111~~101¢ for each kVARh by which the reactive energy is numerically less than 0.484322 times the billing energy.

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

DELIVERY VOLTAGE CREDIT: When the customer furnishes and installs all subtransmission or higher voltage to utilization voltage substation transformation, a discount of ~~60~~55¢ per KW of Supplemental Demand and ~~37~~34¢ per KW of Standby Demand will apply.

EMERGENCY RELAY POWER SUPPLY CHARGE: The monthly charge for emergency relay power supply service shall be ~~86~~78¢ per KW of Supplemental Demand and Standby Demand. This charge is in addition to the compensation the customer must make to the Company as a contribution-in-aid of construction.

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

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

CAPACITY CHARGE: See Sheet Nos. 6.020 and 6.021.

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

FLORIDA GROSS RECEIPTS TAX: See Sheet No. 6.021.

FRANCHISE FEE CHARGE: See Sheet No. 6.021.

PAYMENT OF BILLS: See Sheet No. 6.022.

ISSUED BY: N. G. Tower, President **DATE EFFECTIVE:** ~~September 1, 2018~~

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

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

Continued from Sheet No. 6.800

MONTHLY RATE:

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

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

[1] Closed to new business
[2] Lumen output may vary by lamp configuration and age.
[3] Wattage ratings do not include ballast losses.
[4] The Base Energy charges are calculated by multiplying the kWh times the lighting base energy rate of ~~2.741~~2.494¢ per kWh for each fixture.

Continued to Sheet No. 6.806

ISSUED BY: N. G. Tower, President **DATE EFFECTIVE:** ~~September 1, 2018~~

Continued from Sheet No. 6.805

MONTHLY RATE:

Metal Halide Fixture, Maintenance, and Base Energy Charges:

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

[1] Closed to new business
[2] Lumen output may vary by lamp configuration and age.
[3] Wattage ratings do not include ballast losses.
[4] The Base Energy charges are calculated by multiplying the kWh times the lighting base energy rate of ~~2.741~~2.494¢ per kWh for each fixture.

Continued to Sheet No. 6.808

TECO TAMPA ELECTRIC AN EMERA COMPANY

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

Continued from Sheet No. 6.806

MONTHLY RATE:

LED Fixture, Maintenance, and Base Energy Charges:

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

[1] Closed to new business
[2] Average
[3] Average wattage. Actual wattage may vary by up to +/- 5 watts.
[4] The Base Energy charges are calculated by multiplying the kWh times the lighting base energy rate of 2.~~741~~494¢ per kWh for each fixture.

Continued to Sheet No. 6.810

ISSUED BY: N. G. Tower, President **DATE EFFECTIVE:** ~~September 1, 2018~~

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

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

Continued from Sheet No. 6.808

MONTHLY RATE:

LED Fixture, Maintenance, and Base Energy Charges:

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

[1] Average
[2] Average wattage. Actual wattage may vary by up to +/- 10 %.
[3] The Base Energy charges are calculated by multiplying the kWh times the lighting base energy rate of 2.~~741~~494¢ per kWh for each fixture.
[4] Enhanced Post Top. Customizable decorative options

Continued to Sheet No. 6.810

ISSUED BY: N. G. Tower, President **DATE EFFECTIVE:** ~~September 1, 2018~~

Continued from Sheet No. 6.810

Miscellaneous Facilities Charges:

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

NON-STANDARD FACILITIES AND SERVICES:

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

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

MINIMUM CHARGE: The monthly charge.

FUEL CHARGE: See Sheet Nos. 6.020 and 6.021.

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

CAPACITY CHARGE: See Sheet Nos. 6.020 and 6.021

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

FLORIDA GROSS RECEIPTS TAX: See Sheet No. 6.021

FRANCHISE FEE: See Sheet No. 6.021

PAYMENT OF BILLS: See Sheet No. 6.022

SPECIAL CONDITIONS:
On customer-owned public street and highway lighting systems not subject to other rate schedules, the monthly rate for energy served at primary or secondary voltage, at the company's option, shall be 2.~~741~~494¢ per kWh of metered usage, plus a Basic Service Charge of $~~11.62~~10.57 per month and the applicable additional charges as specified on Sheet Nos. 6.020 and 6.021.

Continued to Sheet No. 6.820

~~NINTH~~ TENTH REVISED SHEET NO. 8.070
CANCELS ~~EIGHTH~~ NINTH REVISED SHEET NO. 8.070

Continued from Sheet No. 8.061

CHARGES/CREDITS TO QUALIFYING FACILITY

A. Basic Service Charges

A monthly Basic Service Charge will be rendered for maintaining an account for a Qualifying Facility engaged in either an As-Available Energy or Firm Capacity and Energy transaction and for other applicable administrative costs. Actual charges will depend on how the QF is interconnected to the Company.

QFs not directly interconnected to the Company, will be billed $990 monthly as a Basic Service Charge.

Monthly Basic Service charges, applicable to QFs directly interconnected to the Company, by Rate Schedule are:

Rate Schedule	Basic Service Charge ($)	Rate Schedule	Basic Service Charge ($)
RS	15.~~00~~12	GST	20.~~00~~16
GS	18.~~00~~14	GSDT (secondary)	30.~~00~~25
GSD (secondary)	30.~~00~~25	GSDT (primary)	~~130.00~~131.06
GSD (primary)	~~130.00~~131.06	GSDT (subtrans.)	~~990.00~~998.05
GSD (subtrans.)	~~990.00~~998.05	SBFT (secondary)	55.~~00~~44
SBF (secondary)	55.~~00~~44	SBFT (primary)	~~155.00~~156.26
SBF (primary)	~~155.00~~156.26	SBFT (subtrans.)	~~1,015.00~~1,023.26
SBF (subtrans.)	~~1,015.00~~ 1,023.26	IST (primary)	~~622.00~~627.06
IS (primary)	~~622.00~~ 627.06	IST (subtrans.)	~~2,372.00~~2,391.29
IS (subtrans.)	~~2,372.00~~2,391.29		
SBI (primary)	~~647.00~~652.26		
SBI (subtrans.)	~~2,397.00~~2,416.50		

When appropriate, the Basic Service Charge will be deducted from the Qualifying Facility's monthly payment. A statement of the charges or payments due the Qualifying Facility will be rendered monthly. Payment normally will be made by the twentieth business day following the end of the billing period.

Continued to Sheet No. 8.071

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

DATE EFFECTIVE: ~~June 20, 2014~~

Continued from Sheet No. 8.308

Should the CEP elect a Net Billing Arrangement, the hourly net capacity and energy sales delivered to the purchasing utility shall be purchased at the utility's avoided capacity and energy rates, where applicable, in accordance with FPSC Rules 25-17.0825 and 25-17.0832, F.A.C. Purchases from the interconnecting utility shall be billed at the retail rate schedule, under which the CEP load would receive service as a customer of the utility.

Although a billing option may be changed in accordance with FPSC Rule 25-17.082, F.A.C., the Contracted Capacity may only change through mutual negotiations satisfactory to the CEP and the Company.

Basic Service charges that are directly attributable to the purchase of firm capacity and energy from the CEP are deducted from the CEP's total monthly payment. A statement covering the charges and payments due the CEP is rendered monthly and payment normally is made by the 20th business day following the end of the Monthly Period.

CHARGES/CREDITS TO THE CEP:

1. **Basic Service Charges:** A monthly Basic Service Charge will be rendered for maintaining an account for the CEP engaged in either an As-Available Energy or firm capacity and energy transaction and for other applicable administrative costs. Actual charges will depend on how the CEP is interconnected to the Company.

   CEPs not directly interconnected to the Company, will be billed $990 monthly as a Basic Service Charge.

   Monthly Basic Service charges, applicable to CEPs directly interconnected to the Company, by Rate Schedule are:

RATE SCHEDULE	BASIC SERVICE CHARGE ($)	RATE SCHEDULE	BASIC SERVICE CHARGE ($)
RS	15.~~00~~12		
GS	18.~~00~~14	GST	20.~~00~~16
GSD (secondary)	30.~~00~~ 25	GSDT (secondary)	30.~~00~~25
GSD (primary)	~~130.00~~131.06	GSDT (primary)	~~130.00~~ 131.06
GSD (subtrans.)	~~990.00~~998.05	GSDT (subtrans.)	~~990.00~~998.05
SBF (secondary)	55.~~00~~44	SBFT (secondary)	55.~~00~~44
SBF (primary)	~~155.00~~156.26	SBFT (primary)	~~155.00~~156.26
SBF (subtrans.)	~~1,015.00~~1,023.26	SBFT (subtrans.)	~~1,015.00~~1,023.26
IS (primary)	~~622.00~~627.06	IST (primary)	~~622.00~~627.06
IS (subtrans.)	~~2,372.00~~2,391.29	IST (subtrans.)	~~2,372.00~~2,391.29
SBI (primary)	~~647.00~~652.26		
SBI (subtrans.)	~~2,397.00~~2,416.50		

Continued to Sheet No. 8.314

TAMPA ELECTRIC COMPANY
DOCKET NO. 20180045-EI
EXHIBIT No. ______ (WRA-1)
WITNESS: ASHBURN
DOCUMENT NO. 5

Clean Tariffs

Reflecting Tax Reform

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

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

RESIDENTIAL SERVICE

SCHEDULE: RS

AVAILABLE: Entire service area.

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

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

Resale not permitted.

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

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

MONTHLY RATE:

Basic Service Charge:
$15.12

Energy and Demand Charge:

First 1,000 kWh	4.896¢ per kWh
All additional kWh	5.806¢ per kWh

MINIMUM CHARGE: The Basic Service Charge.

FUEL CHARGE: See Sheet Nos. 6.020 and 6.021.

Continued to Sheet No. 6.031

GENERAL SERVICE - NON DEMAND

SCHEDULE: GS

AVAILABLE: Entire service area.

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

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

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

MONTHLY RATE:

Basic Service Charge:

Metered accounts	$18.14
Un-metered accounts	$15.12

Energy and Demand Charge:

5.165¢ per kWh

MINIMUM CHARGE: The Basic Service Charge.

EMERGENCY RELAY POWER SUPPLY CHARGE: The monthly charge for emergency relay power supply service shall be 0.156¢ per kWh of billing energy. This charge is in addition to the compensation the customer must make to the Company as a contribution-in-aid of construction.

Continued to Sheet No. 6.051

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

TWENTY-FOURTH REVISED SHEET NO. 6.080
CANCELS TWENTY-THIRD REVISED SHEET NO. 6.080

GENERAL SERVICE - DEMAND

SCHEDULE: GSD

AVAILABLE: Entire service area.

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

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

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

MONTHLY RATE:

	STANDARD	OPTIONAL
Basic Service Charge:		
Secondary Metering Voltage	$ 30.25	$ 30.25
Primary Metering Voltage	$ 131.06	$ 131.06
Subtrans. Metering Voltage	$ 998.05	$ 998.05
Demand Charge:	$9.74 per kW of billing demand	$0.00 per kW of billing demand
Energy Charge:	1.596¢ per kWh	6.199¢ per kWh

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

Continued to Sheet No. 6.081

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

Continued from Sheet No. 6.080

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

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

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

POWER FACTOR: Power factor will be calculated for customers with measured demands of 1,000 kW or more in any one billing period out of twelve (12) consecutive billing periods ending with the current billing period. When the average power factor during the month is less than 85%, the monthly bill will be increased 0.202¢ for each kVARh by which the reactive energy numerically exceeds 0.619744 times the billing energy. When the average power factor during the month is greater than 90%, the monthly bill will be decreased 0.101¢ for each kVARh by which the reactive energy is numerically less than 0.484322 times the billing energy.

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

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

DELIVERY VOLTAGE CREDIT: When a customer under the standard rate takes service at primary voltage, a discount of 79¢ per kW of billing demand will apply. A discount of $2.45 per kW of billing demand will apply when a customer under the standard rate takes service at subtransmission or higher voltage.

Continued to Sheet No. 6.082

TECO TAMPA ELECTRIC AN EMERA COMPANY

NINTH REVISED SHEET NO. 6.082
CANCELS EIGHTH REVISED SHEET NO. 6.082

Continued from Sheet No. 6.081

When a customer under the optional rate takes service at primary voltage, a discount of 0.209¢ per kWh will apply. A discount of 0.639¢ per kWh will apply when a customer under the optional rate takes service at subtransmission or higher voltage.

EMERGENCY RELAY POWER SUPPLY CHARGE: The monthly charge for emergency relay power supply service shall be 63¢ per kW of billing demand for customers taking service under the standard rate and 0.158¢/kWh for customer taking service under the optional rate. This charge is in addition to the compensation the customer must make to the Company as a contribution-in-aid of construction.

FUEL CHARGE: See Sheet Nos. 6.020 and 6.021.

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

CAPACITY CHARGE: See Sheet Nos. 6.020 and 6.021.

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

FLORIDA GROSS RECEIPTS TAX: See Sheet No. 6.021.

FRANCHISE FEE CHARGE: See Sheet No. 6.021.

PAYMENT OF BILLS: See Sheet No. 6.022.

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

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

SCHEDULE: IS

AVAILABLE: Entire Service Area.

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

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

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

MONTHLY RATE:

Basic Service Charge:

Primary Metering Voltage	$ 627.06
Subtransmission Metering Voltage	$2,391.29

Demand Charge:
$1.99 per KW of billing demand

Energy Charge:
2.524¢ per KWH

Continued to Sheet No. 6.086

Continued from Sheet No. 6.085

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

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

POWER FACTOR: When the average power factor during the month is less than 85%, the monthly bill will be increased 0.202¢ for each kVARh by which the reactive energy numerically exceeds 0.619744 times the billing energy. When the average power factor during the month is greater than 90%, the monthly bill will be decreased 0.101¢ for each kVARh by which the reactive energy is numerically less than 0.484322 times the billing energy.

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

DELIVERY VOLTAGE CREDIT: When the customer furnishes and installs all subtransmission or higher voltage to utilization voltage substation transformation, a discount of 55¢ per KW of billing demand will apply.

EMERGENCY RELAY POWER SUPPLY CHARGE: The monthly charge for emergency relay power supply service shall be 78¢ per KW of billing demand. This charge is in addition to the compensation the customer must make to the Company as a contribution-in-aid of construction.

Continued to Sheet No. 6.087

CONSTRUCTION SERVICE

SCHEDULE: CS

AVAILABLE: Entire service area.

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

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

MONTHLY RATE:
Basic Service Charge: $18.14

Energy and Demand Charge: 5.165¢ per kWh

MINIMUM CHARGE: The Basic Service Charge.

FUEL CHARGE: See Sheet Nos. 6.020 and 6.021.

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

CAPACITY CHARGE: See Sheet Nos. 6.020 and 6.021.

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

FLORIDA GROSS RECEIPTS TAX: Sheet No. 6.021.

FRANCHISE FEE CHARGE: See Sheet No. 6.021.

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

PAYMENT OF BILLS: See Sheet No. 6.022.

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

TWENTY-FOURTH REVISED SHEET NO. 6.320
CANCELS TWENTY-THIRD REVISED SHEET NO. 6.320

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

SCHEDULE: GST

AVAILABLE: Entire service area.

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

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

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

MONTHLY RATE:

Basic Service Charge:
$20.16

Energy and Demand Charge:
13.183¢ per kWh during peak hours
1.406¢ per kWh during off-peak hours

Continued to Sheet No. 6.321

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

TECO TAMPA ELECTRIC AN EMERA COMPANY

TWENTIETH REVISED SHEET NO. 6.321
CANCELS NINETEENTH REVISED SHEET NO. 6.321

Continued from Sheet No. 6.320

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

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

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

MINIMUM CHARGE: The Basic Service Charge.

BASIC SERVICE CHARGE CREDIT: Any customer who makes a one time contribution in aid of construction of $94.00 (lump-sum meter payment), shall receive a credit of $2.02 per month. This contribution in aid of construction will be subject to a partial refund if the customer terminates service on this optional time-of-day rate.

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

EMERGENCY RELAY POWER SUPPLY CHARGE: The monthly charge for emergency relay power supply service shall be 0.156¢ per kWh of billing energy. This charge is in addition to the compensation the customer must make to the Company as a contribution-in-aid of construction.

FUEL CHARGE: See Sheet Nos. 6.020 and 6.021.

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

Continued to Sheet No. 6.322

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

SCHEDULE: GSDT

AVAILABLE: Entire service area.

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

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

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

MONTHLY RATE:

Basic Service Charge:

Secondary Metering Voltage	$ 30.25
Primary Metering Voltage	$ 131.06
Subtransmission Metering Voltage	$ 998.05

Demand Charge:
$3.28 per kW of billing demand, plus
$6.45per kW of peak billing demand

Energy Charge:
2.922¢ per kWh during peak hours
1.055¢ per kWh during off-peak hours

Continued to Sheet No. 6.331

Continued from Sheet No. 6.331

POWER FACTOR: Power factor will be calculated for customers with measured demands of 1,000 kW in any billing period out of twelve (12) consecutive billing periods ending with the current billing period. When the average power factor during the month is less than 85%, the monthly bill will be increased 0.202¢ for each kVARh by which the reactive energy numerically exceeds 0.619744 times the billing energy. When the average power factor during the month is greater than 90%, the monthly bill will be decreased 0.101¢ for each kVARh by which the reactive energy is numerically less than 0.484322 times the billing energy.

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

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

DELIVERY VOLTAGE CREDIT: When the customer takes service at primary voltage a discount of 79¢ per kW of billing demand will apply. When the customer takes service at subtransmission or higher voltage, a discount of $2.45 per kW of billing demand will apply.

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

FUEL CHARGE: See Sheet Nos. 6.020 and 6.021.

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

CAPACITY CHARGE: See Sheet Nos. 6.020 and 6.021.

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

FLORIDA GROSS RECEIPTS TAX: See Sheet No. 6.021.

FRANCHISE FEE CHARGE: See Sheet No. 6.021.

PAYMENT OF BILLS: See Sheet No. 6.022.

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

SCHEDULE: IST

AVAILABLE: Entire Service Area.

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

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

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

Basic Service Charge:

Primary Metering Voltage	$ 627.06
Subtransmission Metering Voltage	$2,391.29

Demand Charge:
$1.99 per KW of billing demand

Energy Charge:
2.524¢ per KWH

Continued to Sheet No. 6.345

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

Continued from Sheet No. 6.340

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

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

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

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

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

POWER FACTOR: When the average power factor during the month is less than 85%, the monthly bill will be increased 0.202¢ for each kVARh by which the reactive energy numerically exceeds 0.619744 times the billing energy. When the average power factor during the month is greater than 90%, the monthly bill will be decreased 0.101¢ for each kVARh by which the reactive energy is numerically less than 0.484322 times the billing energy.

Continued to Sheet No. 6.350

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

TECO TAMPA ELECTRIC AN EMERA COMPANY

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

Continued from Sheet No. 6.345

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

DELIVERY VOLTAGE CREDIT: When the customer furnishes and installs all subtransmission or higher voltage to utilization voltage substation transformation, a discount of 55¢ per KW of billing demand will apply.

EMERGENCY RELAY POWER SUPPLY CHARGE: The monthly charge for emergency relay power supply service shall be 78¢ per KW of billing demand. This charge is in addition to the compensation the customer must make to the Company as a contribution-in-aid of construction.

FUEL CHARGE: See Sheet Nos. 6.020 and 6.021.

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

CAPACITY CHARGE: See Sheet Nos. 6.020 and 6.021.

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

FLORIDA GROSS RECEIPTS TAX: See Sheet No. 6.021.

FRANCHISE FEE CHARGE: See Sheet No. 6.021.

PAYMENT OF BILLS: See Sheet No. 6.025.

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

TECO TAMPA ELECTRIC AN EMERA COMPANY

TENTH REVISED SHEET NO. 6.565
CANCELS NINTH REVISED SHEET NO. 6.565

Continued from Sheet No. 6.560

MONTHLY RATES:
Basic Service Charge: $15.12

Energy and Demand Charges: 5.182¢ per kWh (for all pricing periods)

MINIMUM CHARGE: The Basic Service Charge.

FUEL CHARGE: See Sheet Nos. 6.020 and 6.021.

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

CAPACITY CHARGE: See Sheet Nos. 6.020 and 6.021.

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

FLORIDA GROSS RECEIPTS TAX: See Sheet No. 6.021.

FRANCHISE FEE CHARGE: See Sheet No. 6.021.

PAYMENT OF BILLS: See Sheet No. 6.022.

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

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

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

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

Continued to Sheet No. 6.570

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

FIRM STANDBY AND SUPPLEMENTAL SERVICE

SCHEDULE: SBF

AVAILABLE: Entire service area.

APPLICABLE: Required for all self-generating Customers whose generating capacity in kilowatts (exclusive of emergency generation equipment) exceeds 20% of their site load in kilowatts and who take firm service from the utility. Also available to self-generating Customers whose generating capacity in kilowatts does not exceed 20% of their site load in kilowatts, but who agree to all the terms and conditions of this rate schedule. Resale not permitted.

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

LIMITATION OF SERVICE: A customer taking service under this tariff must sign a Tariff Agreement for the Purchase of Firm Standby and Supplemental Service. (See Sheet No. 7.600)

MONTHLY RATE:

Basic Service Charge:

Secondary Metering Voltage	$ 55.44
Primary Metering Voltage	$ 156.26
Subtransmission Metering Voltage	$1,023.26

CHARGES FOR STANDBY SERVICE:

Demand Charge:

$ 1.96 per kW-Month of Standby Demand
(Local Facilities Reservation Charge)

plus the greater of:
$ 1.56 per kW-Month of Standby Demand
(Power Supply Reservation Charge) or
$ 0.62 per kW-Day of Actual Standby Billing Demand
(Power Supply Demand Charge)

Energy Charge:

.921¢ per Standby kWh

Continued to Sheet No. 6.601

Continued from Sheet No. 6.600

CHARGES FOR SUPPLEMENTAL SERVICE:

Demand Charge:
$9.74 per kW-Month of Supplemental Billing Demand (Supplemental Billing Demand Charge)

Energy Charge:
1.596¢ per Supplemental kWh

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

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

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

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

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

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

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

Continued to Sheet No. 6.602

Continued from Sheet No. 6.601

Contract Standby Demand - As established pursuant to the Tariff Agreement for the Purchase of Firm Standby and Supplemental Service. Anytime a customer registers a Standby Demand that is higher than the existing Contract Standby Demand, that Standby Demand will become the new Contract Standby Demand, beginning with the following period.

Standby Demand - The greater of Contract Standby Demand or the amount by which Metered Demand exceeds Supplemental Billing Demand, but no greater than Normal Generation.

Actual Standby Billing Demand - The summation of the daily amounts by which the highest on-peak measured 30-minute interval kW demands served by the Company exceed the monthly Supplemental Billing Demand.

<u>Energy Units:</u> Energy provided by the Company during each 30-minute period up to the Supplemental Demand level shall be billed as Supplemental kWh. The remaining energy shall be billed as Standby kWh.

<u>MINIMUM CHARGE</u>: The Basic Service Charge, Local Facilities Reservation Charge, Power Supply Reservation Charge, and any Minimum Charge associated with optional riders.

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

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

<u>POWER FACTOR</u>: When the average power factor during the month is less than 85%, the monthly bill will be increased 0.202¢ for each kVARh by which the reactive energy numerically exceeds 0.619744 times the billing energy. When the average power factor during the month is greater than 90%, the monthly bill will be decreased 0.101¢ for each kVARh by which the reactive energy is numerically less than 0.484322 times the billing energy.

Continued to Sheet No. 6.603

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

SEVENTEENTH REVISED SHEET NO. 6.603
CANCELS SIXTEENTH REVISED SHEET NO. 6.603

Continued from Sheet No. 6.602

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

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

DELIVERY VOLTAGE CREDIT: When the customer takes service at primary voltage, a discount of 79¢ per kW of Supplemental Demand and 63¢ per kW of Standby Demand will apply.

When the customer takes service at subtransmission or higher voltage, a discount of $2.45 per kW of Supplemental Demand and $1.97 per kW of Standby Demand will apply.

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

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

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

CAPACITY CHARGE: See Sheet Nos. 6.020 and 6.021.

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

FLORIDA GROSS RECEIPTS TAX: See Sheet No. 6.021.

FRANCHISE FEE CHARGE: See Sheet No. 6.021.

PAYMENT OF BILLS: See Sheet No. 6.022.

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

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

TIME-OF-DAY
FIRM STANDBY AND SUPPLEMENTAL SERVICE
(OPTIONAL)

SCHEDULE: SBFT

AVAILABLE: Entire service area.

APPLICABLE: Required for all self-generating Customers whose generating capacity in kilowatts (exclusive of emergency generation equipment) exceeds 20% of their site load in kilowatts and who take firm service from the utility. Also available to self-generating Customers whose generating capacity in kilowatts does not exceed 20% of their site load in kilowatts, but who agree to all the terms and conditions of this rate schedule. Resale not permitted.

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

LIMITATION OF SERVICE: A Customer taking service under this tariff must sign a Tariff Agreement for the Purchase of Firm Standby and Supplemental Service. (See Sheet No. 7.600)

MONTHLY RATE:

Basic Service Charge:

Secondary Metering Voltage	$ 55.44
Primary Metering Voltage	$ 156.26
Subtransmission Metering Voltage	$1,023.26

CHARGES FOR STANDBY SERVICE:

Demand Charge:

$ 1.96 per kW-Month of Standby Demand
(Local Facilities Reservation Charge)

plus the greater of:

$ 1.56 per kW-Month of Standby Demand
(Power Supply Reservation Charge) or

$ 0.62 per kW-Day of Actual Standby Billing Demand
(Power Supply Demand Charge)

Energy Charge:

.921¢ per Standby kWh

Continued to Sheet No. 6.606

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

Continued from Sheet No. 6.605

CHARGES FOR SUPPLEMENTAL SERVICE

Demand Charge:

$3.28 per kW-Month of Supplemental Demand (Supplemental Billing Demand Charge), plus

$6.45 per kW-Month of Supplemental Peak Demand (Supplemental Peak Billing Demand Charge)

Energy Charge:

2.922¢ per Supplemental kWh during peak hours

1.055¢ per Supplemental kWh during off-peak hours

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

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

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

BILLING UNITS:

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

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

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

Continued to Sheet No. 6.607

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

FOURTEENTH REVISED SHEET NO. 6.608
CANCELS THIRTEENTH REVISED SHEET NO. 6.608

Continued from Sheet No. 6.607

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

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

POWER FACTOR: When the average power factor during the month is less than 85%, the monthly bill will be increased 0.202¢ for each kVARh by which the reactive energy numerically exceeds 0.619744 times the billing energy. When the average power factor during the month is greater than 90%, the monthly bill will be decreased 0.101¢ for each kVARh by which the reactive energy is numerically less than 0.484322 times the billing energy.

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

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

DELIVERY VOLTAGE CREDIT: When the customer takes service at primary voltage, a discount of 79¢ per kW of Supplemental Demand and 63¢ per kW of Standby Demand will apply.

When the customer takes service at subtransmission or higher voltage, a discount of $2.45 per kW of Supplemental Demand and $1.97 per kW of Standby Demand will apply.

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

Continued to Sheet No. 6.609

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

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

SCHEDULE: SBI

AVAILABLE: Entire service area.

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

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

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

MONTHLY RATE:

Basic Service Charge:

Primary Metering Voltage	$652.26
Subtransmission Metering Voltage	$2,416.50

Demand Charge:

$1.99 per KW-Month of Supplemental Demand (Supplemental Demand Charge)
$1.47 per KW-Month of Standby Demand (Local Facilities Reservation Charge)

plus the greater of:
$1.21 per KW-Month of Standby Demand (Power Supply Reservation Charge); or
$0.48 per KW-Day of Actual Standby Billing Demand (Power Supply Demand Charge)

Continued to Sheet No. 6.705

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

FIFTH REVISED SHEET NO. 6.705
CANCELS FOURTH REVISED SHEET NO. 6.705

Continued from Sheet No. 6.700

Energy Charge:
2.524¢ per Supplemental KWH
1.015¢ per Standby KWH

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

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

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

BILLING UNITS:

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

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

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

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

Continued to Sheet No. 6.710

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

Continued from Sheet No. 6.710

POWER FACTOR: When the average power factor during the month is less than 85%, the monthly bill will be increased 0.202¢ for each kVARh by which the reactive energy numerically exceeds 0.619744 times the billing energy. When the average power factor during the month is greater than 90%, the monthly bill will be decreased 0.101¢ for each kVARh by which the reactive energy is numerically less than 0.484322 times the billing energy.

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

DELIVERY VOLTAGE CREDIT: When the customer furnishes and installs all subtransmission or higher voltage to utilization voltage substation transformation, a discount of 55¢ per KW of Supplemental Demand and 34¢ per KW of Standby Demand will apply.

EMERGENCY RELAY POWER SUPPLY CHARGE: The monthly charge for emergency relay power supply service shall be 78¢ per KW of Supplemental Demand and Standby Demand. This charge is in addition to the compensation the customer must make to the Company as a contribution-in-aid of construction.

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

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

CAPACITY CHARGE: See Sheet Nos. 6.020 and 6.021.

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

FLORIDA GROSS RECEIPTS TAX: See Sheet No. 6.021.

FRANCHISE FEE CHARGE: See Sheet No. 6.021.

PAYMENT OF BILLS: See Sheet No. 6.022.

TECO TAMPA ELECTRIC AN EMERA COMPANY

EIGHTH REVISED SHEET NO. 6.805
CANCELS SEVENTH REVISED SHEET NO. 6.805

Continued from Sheet No. 6.800

MONTHLY RATE:

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

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

[1] Closed to new business
[2] Lumen output may vary by lamp configuration and age.
[3] Wattage ratings do not include ballast losses.
[4] The Base Energy charges are calculated by multiplying the kWh times the lighting base energy rate of 2.494¢ per kWh for each fixture.

Continued to Sheet No. 6.806

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

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

SIXTH REVISED SHEET NO. 6.806
CANCELS FIFTH REVISED SHEET NO. 6.806

Continued from Sheet No. 6.805

MONTHLY RATE:

Metal Halide Fixture, Maintenance, and Base Energy Charges:

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

(1) Closed to new business
(2) Lumen output may vary by lamp configuration and age.
(3) Wattage ratings do not include ballast losses.
(4) The Base Energy charges are calculated by multiplying the kWh times the lighting base energy rate of 2.494¢ per kWh for each fixture.

Continued to Sheet No. 6.808

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

TECO TAMPA ELECTRIC AN EMERA COMPANY

SEVENTH REVISED SHEET NO. 6.808
CANCELS SIXTH REVISED SHEET NO. 6.808

Continued from Sheet No. 6.806

MONTHLY RATE:

LED Fixture, Maintenance, and Base Energy Charges:

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

(1) Closed to new business
(2) Average
(3) Average wattage. Actual wattage may vary by up to +/- 5 watts.
(4) The Base Energy charges are calculated by multiplying the kWh times the lighting base energy rate of 2.494¢ per kWh for each fixture.

Continued to Sheet No. 6.810

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

Continued from Sheet No. 6.808

MONTHLY RATE:

LED Fixture, Maintenance, and Base Energy Charges:

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

(1) Average
(2) Average wattage. Actual wattage may vary by up to +/- 10 %.
(3) The Base Energy charges are calculated by multiplying the kWh times the lighting base energy rate of 2.494¢ per kWh for each fixture.
(4) Enhanced Post Top. Customizable decorative options

Continued to Sheet No. 6.810

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

TECO TAMPA ELECTRIC AN EMERA COMPANY

SIXTH REVISED SHEET NO. 6.815
CANCELS FIFTH REVISED SHEET NO. 6.815

Continued from Sheet No. 6.810

Miscellaneous Facilities Charges:

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

NON-STANDARD FACILITIES AND SERVICES:

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

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

MINIMUM CHARGE: The monthly charge.

FUEL CHARGE: See Sheet Nos. 6.020 and 6.021.

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

CAPACITY CHARGE: See Sheet Nos. 6.020 and 6.021

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

FLORIDA GROSS RECEIPTS TAX: See Sheet No. 6.021

FRANCHISE FEE: See Sheet No. 6.021

PAYMENT OF BILLS: See Sheet No. 6.022

SPECIAL CONDITIONS:
On customer-owned public street and highway lighting systems not subject to other rate schedules, the monthly rate for energy served at primary or secondary voltage, at the company's option, shall be 2.494¢ per kWh of metered usage, plus a Basic Service Charge of $10.57 per month and the applicable additional charges as specified on Sheet Nos. 6.020 and 6.021.

Continued to Sheet No. 6.820

Continued from Sheet No. 8.061

CHARGES/CREDITS TO QUALIFYING FACILITY

A. Basic Service Charges

A monthly Basic Service Charge will be rendered for maintaining an account for a Qualifying Facility engaged in either an As-Available Energy or Firm Capacity and Energy transaction and for other applicable administrative costs. Actual charges will depend on how the QF is interconnected to the Company.

QFs not directly interconnected to the Company, will be billed $990 monthly as a Basic Service Charge.

Monthly Basic Service charges, applicable to QFs directly interconnected to the Company, by Rate Schedule are:

Rate Schedule	Basic Service Charge ($)	Rate Schedule	Basic Service Charge ($)
RS	15.12	GST	20.16
GS	18.14	GSDT (secondary)	30.25
GSD (secondary)	30.25	GSDT (primary)	131.06
GSD (primary)	131.06	GSDT (subtrans.)	998.05
GSD (subtrans.)	998.05	SBFT (secondary)	55.44
SBF (secondary)	55.44	SBFT (primary)	156.26
SBF (primary)	156.26	SBFT (subtrans.)	1,023.26
SBF (subtrans.)	1,023.26	IST (primary)	627.06
IS (primary)	627.06	IST (subtrans.)	2,391.29
IS (subtrans.)	2,391.29		
SBI (primary)	652.26		
SBI (subtrans.)	2,416.50		

When appropriate, the Basic Service Charge will be deducted from the Qualifying Facility's monthly payment. A statement of the charges or payments due the Qualifying Facility will be rendered monthly. Payment normally will be made by the twentieth business day following the end of the billing period.

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Continued from Sheet No. 8.308

Should the CEP elect a Net Billing Arrangement, the hourly net capacity and energy sales delivered to the purchasing utility shall be purchased at the utility's avoided capacity and energy rates, where applicable, in accordance with FPSC Rules 25-17.0825 and 25-17.0832, F.A.C. Purchases from the interconnecting utility shall be billed at the retail rate schedule, under which the CEP load would receive service as a customer of the utility.

Although a billing option may be changed in accordance with FPSC Rule 25-17.082, F.A.C., the Contracted Capacity may only change through mutual negotiations satisfactory to the CEP and the Company.

Basic Service charges that are directly attributable to the purchase of firm capacity and energy from the CEP are deducted from the CEP's total monthly payment. A statement covering the charges and payments due the CEP is rendered monthly and payment normally is made by the 20th business day following the end of the Monthly Period.

CHARGES/CREDITS TO THE CEP:

1. **Basic Service Charges:** A monthly Basic Service Charge will be rendered for maintaining an account for the CEP engaged in either an As-Available Energy or firm capacity and energy transaction and for other applicable administrative costs. Actual charges will depend on how the CEP is interconnected to the Company.

   CEPs not directly interconnected to the Company, will be billed $990 monthly as a Basic Service Charge.

   Monthly Basic Service charges, applicable to CEPs directly interconnected to the Company, by Rate Schedule are:

RATE SCHEDULE	BASIC SERVICE CHARGE ($)	RATE SCHEDULE	BASIC SERVICE CHARGE ($)
RS	15.12		
GS	18.14	GST	20.16
GSD (secondary)	30.25	GSDT (secondary)	30.25
GSD (primary)	131.06	GSDT (primary)	131.06
GSD (subtrans.)	998.05	GSDT (subtrans.)	998.05
SBF (secondary)	55.44	SBFT (secondary)	55.44
SBF (primary)	156.26	SBFT (primary)	156.26
SBF (subtrans.)	1,023.26	SBFT (subtrans.)	1,023.26
IS (primary)	627.06	IST (primary)	627.06
IS (subtrans.)	2,391.29	IST (subtrans.)	2,391.29
SBI (primary)	652.26		
SBI (subtrans.)	2,416.50		

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