BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

In the Matter of:

DOCKET NO. 20210034-EI

Petition for rate increase by Tampa Electric Company.
_________________________________/

DOCKET NO. 20200264-EI

Petition for approval of 2020 depreciation and dismantlement study and capital recovery schedules, by Tampa Electric Company.
_________________________________/

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PROCEEDINGS: HEARING

COMMISSIONERS PARTICIPATING:
CHAIRMAN GARY F. CLARK
COMMISSIONER ART GRAHAM
COMMISSIONER ANDREW GILES FAY
COMMISSIONER MIKE LA ROSA
COMMISSIONER GABRIELLA PASSIDOMO

DATE: Thursday, October 21, 2021

TIME: Commenced: 9:30 a.m.
Concluded: 10:24 a.m.

PLACE: Betty Easley Conference Center
Room 148
4075 Esplanade Way
Tallahassee, Florida

REPORTED BY: DEBRA R. KRICK
Court Reporter

PREMIER REPORTING
112 W. 5TH AVENUE
TALLAHASSEE, FLORIDA

APPEARANCES:

J. JEFFRY WAHLEN, JAMES D. BEASLEY and MALCOLM N. MEANS, ESQUIRES, Ausley Law Firm, P.O. Box 391, Tallahassee, Florida 32302-0391, appearing on behalf of Tampa Electric Company (TECO).

RICHARD GENTRY, PUBLIC COUNSEL; CHARLES REHWINKEL, DEPUTY PUBLIC COUNSEL; ANASTACIA PIRRELLO and MARY ALISON WESSLING, ESQUIRES, OFFICE OF PUBLIC COUNSEL, c/o The Florida Legislature, 111 West Madison Street, Room 812, Tallahassee, Florida 32399-1400, appearing on behalf of the Citizens of the State of Florida (OPC).

JON C. MOYLE, JR. and KAREN A. PUTNAL, ESQUIRES, Moyle Law Firm, 118 North Gadsden Street, Tallahassee, Florida 32301; appearing on behalf of Florida Industrial Users Group (FIPUG).

THOMAS JERNIGAN, MAJOR HOLLY BUCHANAN, SERGEANT ARNOLD BRAXTON, EBONY PAYTON and SCOTT KIRK, Federal Executive Agencies, 139 Barnes Drive, Suite 1, Tyndall AFB, Florida 32403; appearing on behalf of the Federal Executive Agencies (FEA).

STEPHANIE EATON, ESQUIRE, Spilman Thomas & Battle, PLLC, 110 Oakwood Drive, Suite 500, Winston-Salem, NC, 27103, appearing on behalf of Walmart (WALMART).

APPEARANCES CONTINUED:

ROBERT SCHEFFEL WRIGHT and JOHN T. LAVIA, III, ESQUIRES, Gardner, Bist, Bowden, Dee, LaVia, Wright, Perry & Harper, P.A., 1300 Thomaswood Drive, Tallahassee, Florida 32308, appearing on behalf of Floridians Against Increased Rates, Inc. (FAIR).

MARK F. SUNDBACK, WILLIAM M. RAPPOLT and ANDREW P. MINA, ESQUIRES, 2099 Pennsylvania Ave., Suite 100, Washington DC, 20006, appearing on behalf of West Central Florida Hospital Utility Alliance (WCFHUA).

CHARLES MURPHY and WALT TRIERWEILER, ESQUIRES, FPSC General Counsel's Office, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850, appearing on behalf of the Florida Public Service Commission (Staff).

KEITH HETRICK, GENERAL COUNSEL; MARY ANNE HELTON, DEPUTY GENERAL COUNSEL, Florida Public Service Commission, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850, Advisor to the Florida Public Service Commission.

I N D E X

P R O C E E D I N G S

CHAIRMAN CLARK: Good morning, everyone. Today is October 21st, 9:30. I would like to call this administrative hearing to order.

I would ask staff, if they would, to please reads the notice this morning.

MR. MURPHY: Yes, sir.

By notice issued October 1, 2021, this time and place was set for a hearing in Docket Nos. 20210034-EI and 20200264-EI, to review the settlement agreement signed by all parties. The purpose of the hearing is set forth more fully in the notice.

CHAIRMAN CLARK: All right. We are going to take appearances next. I am going to start with Tampa Electric.

MR. WAHLEN: Morning, Commissioners. I am Jeff Wahlen with the Ausley McMullen Law Firm in Tallahassee appearing on behalf of Tampa Electric, with James D. Beasley and Malcolm Means of the same law firm.

CHAIRMAN CLARK: OPC.

MR. REHWINKEL: Good morning, Commissioners. Charles Rehwinkel, Deputy Public Counsel with the Office of Public Counsel appearing on behalf of

Tampa Electric's ratepayers.

I would also like to enter an appearance for Richard Gentry, the Public Counsel, for Anastacia Pirrello, lead counsel for the Office of Public Counsel in this case, and Ali Wessling.

Thank you.

CHAIRMAN CLARK: Thank you, Mr. Rehwinkel.

Florida Industrial Power Users Group.

MR. MOYLE: Thank you, Mr. Chairman, and good morning, Commissioners. Jon Moyle with the Moyle Law Firm on behalf of the Florida Industrial Power Users Group, FIPUG. And I would also like to enter an appearance for Karen Putnal with our firm.

Thank you.

CHAIRMAN CLARK: Thank you, sir.

Federal Executive Agencies.

MAJOR BUCHANAN: Good morning, Commissioners. I am Major Holly Buchanan from the Department of the Air Force on behalf of the Federal Executive Agencies.

CHAIRMAN CLARK: Thank you very much.

Walmart.

MS. EATON: Good morning, Commissioners. My name is Stephanie Eaton. I am here on behalf of Walmart, Inc.

CHAIRMAN CLARK: Florida Retail.

MR. WRIGHT: Thank you, Mr. Chairman and Commissioners. Robert Scheffel Wright with the Gardner Law Firm appearing on behalf of the Florida Retail Federation. I would also like to enter an appearance for my law partner, John T. Lavia, III.

Thank you.

CHAIRMAN CLARK: Thank you, sir.

West Central Florida Hospital Utility alliance.

MR. SUNBACK: Thank you, Mr. Commissioner -- Mr. Chairman, Commissioners. Mark Sundback on behalf of the WCF Hospital Utilities Alliance. I would like to also enter the appearances of William Rappolt and Andrew Mina of our firm.

Thank you.

CHAIRMAN CLARK: Thank you very much.

Staff.

MR. MURPHY: Charles Murphy and Walt Trierweiler for Commission Staff.

MS. HELTON: And Mary Anne Helton here as your Advisor, along with your General Counsel, Keith Hetrick.

CHAIRMAN CLARK: All right. Did I get everyone?

Next up preliminary matters, staff.
MR. MURPHY: There are none.
CHAIRMAN CLARK: All right. Good. This is going to move along pretty quick this morning. I say that, and then we get to opening statements, right, Mr. Wahlen?
We are going to hear opening statements now. We will -- I am going to ask everyone to please limit them to three minutes each. I am going to go through in the exact same order, and we will begin with you, Mr. Wahlen.
MR. WAHLEN: Thank you, Commissioners, and good morning.
Today Tampa Electric seeks approval of its 2021 stipulation and settlement agreement as corrected and clarified.
We worked hard to make the settlement unanimous and the agreement has been signed by all of the parties. It resolves all of the issues in our rate case and depreciation dockets, results in fair, just and reasonable rates, and is in the public interest. Tampa Electric urges you to approve it.
From the beginning, this case has been about how Tampa Electric is transforming itself in

preparing for the future. Tampa Electric has a long history with coal, but has taken major steps away from coal and is becoming a solar energy leader.

Since its last rate case, Tampa Electric has become safer, more reliable, more customer focused, and has made great strides in the customer service area. The company has reduced its carbon emissions from about 15.7 million tons in 2013 to about 8.8 million tons in 2020, and has plans for further reductions.

We view the 2021 agreement as an important steppingstone from Tampa Electric's past to a safer, cleaner, greener and even more customer focused future. The agreement validates the company's decision to retire Big Bend Coal Units 1, 2 and 3; repower Big Bend Unit 1 as a state-of-the-art highly efficient combined cycle plant; build 600 megawatts of additional solar generation, and to replace its automated metering system with an advanced metering infrastructure.

It includes an innovative Clean Energy Transition Mechanism, or CETM to ensure recovery of the remaining costs of the assets being retired to make way for the Big Bend modernization and AMI project.

It also provides additional benefits to low-income customers by increasing the availability of two conservation programs.

Our motion to approve the 2021 agreement identifies numerous reasons that this agreement is in the public interest. I won't list all of them, but would note that the agreement promotes predictability and certainty as similar companies' previous agreements approved by the Commission.

Tampa Electric appreciates the opportunity to be here, and would like to thank your staff for the professional and diligent manner in which they have reviewed the settlement and developed the framework for this hearing.

And I will conclude by thanking each of you for your attention, and by asking you to vote to approve the 2021 agreement.

Thank you.

CHAIRMAN CLARK: Thank you very much, Mr. Wahlen.

Mr. Rehwinkel.

MR. REHWINKEL: Thank you, Commissioners. Thank you to the signatories. And most of all, a heartfelt thank you to your staff for their thorough review of this 2021 agreement.

The Public Counsel is confident that this agreement is, in totality, in the best interest of the customers given the risks they faced at hearing and the benefits that they will receive over time.

Negotiating this agreement spanned a period of about 10 months, and involved a broad cross-section of parties, a robust discovery process that was both well in advance of and following the MFR filing, and importantly, included the outside experts of the OPC and the other parties.

Commissioners, I will highlight some of the provisions that represent significant value from the customers' standpoint.

First, the ROE of 9.95, when compared to Tampa Electric's filed ROE of 10.75, represents over $127 million in savings to customers when compared to the requested ROE given the risks we faced at hearing. Also, base rates are frozen for three years. This is a significant stay-out period.

Third, the Clean Energy Transition Mechanism, or CETM, innovatively recovers retirement costs related to legacy technology and outdated generation, and clears the way for implementation of technology that will benefit current and future customers in a balanced way. It's fair to customers; it's fair to the company, and ensures that the retirement costs collect collected are the actual costs.

While the consumer attorneys have been zealous advocates, we all recognize that the electrical industry is undergoing a significant change that is dictated in part by global conditions, and that the effects of these global conditions exist at the state and local level.

In the negotiation process, we asked: Should we do things the way they've always been done, or should we think about certain notions innovatively? All the parties did that thinking and, as a result, have submitted a comprehensive forward-looking agreement that is innovative and good for all concerned.

The Public Counsel urges your favorable vote because the deal is fair to all customers, and results in rates that are fair, just and reasonable, resolves all the issues in this case and is in the public interest.

Thank you and we ask for your favorable vote.

CHAIRMAN CLARK: Thank you, Mr. Rehwinkel.

Mr. Moyle.

MR. MOYLE: Thank you, Mr. Chairman.

Let me start by just thanking the parties. Tampa Electric, we negotiated with them for an extensive period of time. Negotiations were rigorous and thorough. Everyone handled themselves with professionalism. Your staff has done a great job, and I want to thank the Commission for making time today to consider this settlement agreement.

As you know, you have presided over a number of settlement agreements. I have been here many times where the Commission has said, I am glad that the parties were able to sit down and work through the differences. These rate cases are big, thick filings, and have a lot of issues, and we were able, over an extended period of time, to do that in this case.

I think it's meaningful that all the parties have signed on affirmatively, and I think that this rate case is fair. It has a number of provisions that I just want to make note of briefly.

You know, as has been mentioned, there is change afoot in the industry. You are seeing a lot less coal and a lot more renewable. And consistent with that, Big Bend modernization is part of this, and there is 600 megawatts of new solar going in.

I think those are good things. My clients, FIPUG, supports renewable energy if it's cost-effective and if it's needed. And we are satisfied that these 600 megawatts will well serve the public and are in the public interest.

Mr. Rehwinkel mentioned the ROE number. I think that anything under a single-digit ROE number is something to be lauded, and that's an important feature of this, that is in the public interest. And the agreement has a number of provisions that you have seen before in other settlement agreements. There is a tax provision. So if the -- if the federal government makes changes to the tax structure, those are incorporated in part of the settlement agreement and changes would be made consistent with federal tax changes.

The Storm Recovery Mechanism is one you have seen before and are familiar with. And the GBRA mechanism, Generation Based Rate Adjustment Mechanism, to allow recovery of certain assets during the three-year term, that's an important feature.

From my client's perspective, knowing for three years that we have predictability of base rates is important. It let's people conduct business planning.

So for those reasons, and more, we believe this agreement is in the public interest and should be supported, and we would ask that you do so when you get to that point in the proceeding.

Thank you.

CHAIRMAN CLARK: Thank you very much, Mr. Moyle.

Major Buchanan.

MAJOR BUCHANAN: Good morning, Commissioners.

The Federal Executive Agencies intervened in this case to ensure taxpayers' money allocated to MacDill Air Force Base's mission, as well as other federal agencies, was not unnecessarily burdened by excessive energy costs.

Energy costs comprise a significant portion of an installation's operations and maintenance fund, and this is no less at MacDill Air Force Base. The same funds used for electricity pay for a broad range of things that happen at a base, from training and equipping our airmen to hiring local contracts to mow the lawns. Unfortunately, because utilities are bills that must be paid, any increase in their cost means commanders must cut the costs of one or more of these other areas. My office's job is to ensure commanders only have to make these decisions when it is warranted and for fair, reasonable and cost-based amounts.

Additionally, we are dedicated to moving away from fossil fuels and being solely reliant on carbon-based energy sources. We see value in a diverse electric system that can provide its customers with energy from a wide variety of fuel sources including carbon free energy.

The unanimous 2021 settlement agreement you have before you accomplishes both of these goals. Over the past several months, we were able to work with the other parties to address these and other issues in a fair and reasonable manner for all involved.

While the settlement agreement is comprehensive and resolves all matters in this case, I am only going to touch on four aspects of the agreement that are particularly relevant to the Federal Executive Agencies.

First, the settlement agreement includes an appropriate reduction in Tampa Electric's proposed revenue requirement, resulting in a fair and reasonable revenue requirement for the company.

Second, the levelized cost recovery under the

Clean Energy Transition Mechanism fairly places an equal burden on current and future customers, while also providing appropriate recovery for Tampa Electric's transition from coal based generation to carbon free energy.

Third, the settlement agreement supports investments in renewable and cleaner energy sources such as an additional 600 megawatts of solar generation. These investments will create a more reliable and resilient system, which is vital to our national security interests.

Fourth, the settlement agreement transitions the cost of service methodology to one that results in more accurate cost assignment based on cost causation, which will produce sufficient price signals and allow customers to make more informed electric consumption decisions. Therefore, this new cost of service methodology promotes more efficient use of the system.

For these reasons, the Federal Executive Agencies submit that the settlement agreement appropriately balances the interest of Tampa Electric and its customers, results in just and reasonable rates, resolves all issues in this case and is in the public interest.

Thank you.

CHAIRMAN CLARK: Thank you very much, Major Buchanan.

Ms. Eaton.

MS. EATON: Good morning again, Commissioners. I am here on behalf of Walmart, Inc.

Walmart operates 386 retail units and eight distribution centers, and employs over 113,000 associates in Florida. Electricity is a significant operating cost for retailers such as Walmart.

Moreover, Walmart has long had aggressive and significant company-wide renewable energy goals, and on September 21st, 2020, Walmart announced new targets, including being supplied 100 percent by renewable energy by 2035, and zero carbon emissions in its operations, including its transportation fleet vehicles without the use of offsets by 2040.

As a result, Walmart intervenes in base rate cases such as this one to address issues of concern to its business operations in Florida, such as revenue requirement and the resulting impact on the utility's customers return on equity in light of the ROEs approved and trends for comparably situated utilities, cost of service issues impacting rate schedule and rate design, and the creation and/or expansion of solar energy offerings by utilities.

With 36 retail units and one distribution center served by TECO, Walmart would have intervened to contest certain aspects of TECO's filed case. However, Walmart is pleased to be one of the signatories to the 2021 stipulation and settlement agreement.

Walmart appreciates and acknowledges the willingness of the parties who collectively analyzed voluminous data, discovery responses and input from experts to reach the compromises that are embodied in the 2021 stipulation and settlement agreement, and we want to emphasize a few provisions that were significant to Walmart.

First, the reduction, a reduction in the as-filed revenue requirement was significant and included expenses that TECO agreed not to recover for rate-making purposes.

Second, the ROE was reduced to the agreed upon 9.95 percent, which is in line with this commission's approval of an ROE for Duke Energy Florida earlier this year, and was in -- is within the range of ROEs approved nationally in 2021.

Third, the cost of service methodology represents a forward-looking plan that encourages carbon reduction, and is more reflective of TECO's move away from coal to other fuel sources during the transformative period about which TECO described.

And fourth, the agreement includes TECO's commitment to build 600 megawatts of additional solar, which is complimentary to Walmart's own renewable energy goals, and allows for greater bill stability, which is of significant to Walmart as a customer of TECO's.

Taken as whole, Walmart believes that the 2021 stipulation and settlement agreement is fair, just and reasonable, and is in the public interest. Walmart appreciates the opportunity to participate in these proceedings, and joins the other settling parties in support of the 2021 stipulation and settlement agreement.

Thank you.

CHAIRMAN CLARK: Thank you very much, Ms. Eaton.

Mr. Wright.

MR. WRIGHT: Thank you, Mr. Chairman and Commissioners. Good morning.

Again, Schef Wright on behalf of the Florida Retail Federation, on whose behalf I want to thank you first for taking the time to hear my brief remarks and to consider this settlement.

I also want to thank all parties to this settlement agreement, including Tampa Electric Company for its professionalism and diligence as we worked through the process that began a year ago that got us here today. I want to thank all the other parties for their constructive participation, and especially thank the staff on behalf of the Retail Federation and myself personally, I have been doing this a long time, for their expeditious and professional handling of this settlement agreement.

The Retail Federation is a statewide organization of more than 8,000 members, many of whom receive their electric service from Tampa Electric Company. The Retail Federation's experience in settling and negotiating rate cases goes back decades.

My personal experience with settlements dates back to 2002, when I represented Lee County in a settlement of a general rate case approved by the Commission that brought substantial rate reductions to the utility's customers, and my experience has continued through at least negotiating and settling most of nearly every IOU rate case in this state since that time.

I agree with and support the comments of my colleagues, and including Mr. Wahlen of Tampa Electric, and I would like to add these few brief comments to theirs.

First, this unanimous settlement is the product of lengthy and very detailed negotiations among all the parties to this docket, negotiations that began roughly a year ago from now and continued our consummating -- continued through our consummating and filing the settlement agreement in early August.

Second, this settlement clearly meets all the requirements of Florida law applicable to such agreements. It resolves all issues in the case. It results in rates that are fair, just and reasonable, and it is in the public interest.

It's in the public interest chiefly because it results in rates that are fair, just and reasonable, not only to Tampa Electric's customers, but also to Tampa Electric Company. It is consistent with the regulatory compact because it provides for rates that are fair to both the utility and its customers, and rates that are sufficient for Tampa Electric to continue providing its customers with safe and reliable service.

Third, this settlement agreement recognizes that the world is changing, and the settlement affirmatively and substantially moves Tampa Electric in the right direction toward the lower carbon future that the world demands and that the world needs, and that Tampa Electric's parent company has embraced in a net zero goal by the year 2050.

In summary, this unanimous settlement is in the public interest, which is the cornerstone of your regulation pursuant to Chapter 366, and the Florida Retail Federation respectfully asks you to approve it today.

Thank you very much.

CHAIRMAN CLARK: Thank you, Mr. Wright.

Mr. Sundback.

MR. SUNDBACK: Thank you.

Hospitals respectfully urge that you approve this settlement given that it furthers the public interest. This settlement and its approval will recognize the constructive engagement of the parties to resolve not just limited term rate proceedings, but multiyear based rate case -- rate cases. That achieves efficiencies as well as consensual resolution that furthers not just the interest of the participants directly in the proceeding, but the public interest generally.

The settlement incorporates several forward-looking highly beneficial features. Let's talk about some of the benefits that arise from those features.

First, the features recognize the transition that this utility is going through from a coal-fired past to a renewable future. The features promote efficient investment and consumption decisions. The enhancement of efficiency is increasingly important in managing a utility's assets as we move away from coal-fired generation and into a renewable future.

Efficiency and cost allocation will dampen peak demand, reduce investment needed in generation, transmission and distribution assets, and thereby reduce rate base that otherwise would have to be funded by ratepayers. The settlement features will also promote a healthy economy in the utility's services territory.

There is an additional feature that has already been mentioned, we would like to commend to your attention the CETM, which utilizes level sayings and, as a result, at minimized cost to consumers and reduce the level of disputes concerning the timing and the qualification of recovery of costs for both Big Bend and the automated metering assets.

Approval of the settlement from our perspective will allow health care facilities to redeploy their resources from this proceeding to turn back to fighting COVID, our most serious public health challenge.

We respectfully urge that you approve the settlement as in the public interest.

Thank you so much for your time and attention.

CHAIRMAN CLARK: All right. Thank you, Mr. Sundback.

Did we get all of the parties?

All right. Let's move on to prefiled testimony.

Staff.

MR. MURPHY: Yes. All of the witness for TECO's -- witnesses for TECO's prefiled direct case have been excused with the understanding that their prefiled direct testimony and exhibits will be included in the record.

In addition, the parties have agreed to the admission of Staff's exhibits.

Staff asks that the prefiled direct testimony of all TECO witnesses be inserted into the record as though read.

CHAIRMAN CLARK: The testimony is inserted.

(Whereupon, prefiled direct testimony of A. Sloan Lewis was inserted.)

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 20210034-EI

IN RE: PETITION FOR RATE INCREASE
BY TAMPA ELECTRIC COMPANY

DIRECT TESTIMONY AND EXHIBIT
OF
A. SLOAN LEWIS

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

A. SLOAN LEWIS

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

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

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

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

Q. Please describe your educational background and professional experience.

A. I received a Bachelor of Science degree in Accounting from Florida State University in 1994 and a master's degree in Education from the University of North Florida in 1996. I joined Tampa Electric in 2000 as a Fuels Accountant and over the past 20 years have expanded my cost recovery clause responsibilities. Then in 2015, I was promoted to Manager, Regulatory Accounting with responsibility for all the cost recovery clauses and riders for Tampa Electric and Peoples Gas System. I was promoted to my current role of Director, Regulatory Accounting in 2017.

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

A. Yes. I filed testimony before this Commission in Docket No. 20200067-EI, Review of 2020-2029 Storm Protection Plan pursuant to Rule 25-6.030, F.A.C., Tampa Electric Company, and Docket No. 20200092-EI, which was the Commission's 2020 storm protection cost recovery clause proceeding.

Q. What are the purposes of your direct testimony?

A. My direct testimony describes the company's test year, the sources of the financial information used in the company's filing in this docket, the budgeting process and resulting financial statements, and then presents the details of the company's rate base, net operating income and revenue requirement calculations in this case.

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

A. Yes. Exhibit No. ASL-1, entitled "Exhibit of A. Sloan Lewis" was prepared under my direction and supervision. The contents of my exhibit were derived from the business records of the company and are true and correct to the best of my information and belief. It consists of 11 documents, as follows:

Document No. 1	List of Minimum Filing Requirement Schedules Sponsored or Co-Sponsored by A. Sloan Lewis
Document No. 2	Forecasted Income Statement Twelve Months Ended December 31, 2022
Document No. 3	Forecasted Income Statement Twelve Months Ended December 31, 2022 Budget Methodology

Document No. 4	Forecasted Income Statement Twelve Months Ended December 31, 2021
Document No. 5	Actual Income Statement Twelve Months Ended December 31, 2020
Document No. 6	Forecasted Monthly Balance Sheet 2022
Document No. 7	Forecasted 13-Month Average Balance Sheet as of December 31, 2022
Document No. 8	Forecasted 13-Month Average Balance Sheet as of December 31, 2022 Budget Methodology
Document No. 9	Forecasted 13-Month Average Balance Sheet as of December 31, 2021
Document No. 10	Actual 13-Month Average Balance Sheet as of December 31, 2020
Document No. 11	Forecasted Statement of Cash Flows for the Period Ended December 31, 2022

Q. Are you sponsoring or co-sponsoring any of Tampa Electric's Minimum Filing Requirements ("MFR") schedules?

A. Yes. I am sponsoring or co-sponsoring the MFR schedules listed in Document No. 1 of my exhibit. The data and information on these schedules were taken from the business records of the company and are true and correct to the best of my information and belief.

Q. How does your direct testimony relate to the testimony of other Tampa Electric witnesses in this case?

A. My direct testimony explains the budget process and why using a projected 2022 test year is appropriate in this case.

Tampa Electric witness Lorraine L. Cifuentes presents the customer, energy sales, and peak demand forecasts that form the basis for the budget underlying the financial information for our 2022 test year.

My direct testimony also presents the company's overall revenue requirement calculation. Other witnesses discuss specific parts of our revenue requirement. For example, Tampa Electric witness Davicel Avellan discusses our depreciation study and supports our requested level of depreciation expense and capital recovery amortization in the test year. Tampa Electric witnesses Dylan W. D'Ascendis and Kenneth D. McOnie present the company's proposed return on equity and equity ratio, respectively. Other witnesses address specific components of our rate base, show that our proposed plant additions are reasonable and prudent, and demonstrate that our operations and maintenance ("O&M") expenses are reasonable. Tampa Electric witness Jeffrey S. Chronister discusses how our financial profile has changed since our last rate case in 2013; addresses income taxes, the parent debt adjustment, affiliate transactions, all elements of our capital structure except equity ratio, and our proposed overall rate of return; presents information about our financial forecasts for 2023 and 2024; and proposes that the Commission approve generation base rate adjustments in those years.

2022 TEST YEAR

Q. What test year does the company propose to use for setting customer rates in this proceeding?

A. Tampa Electric proposes to use the projected twelve months ending December 31, 2022 as the test year in this case. This test year is appropriate because it reflects the conditions under which Tampa Electric will operate in the future and the company's anticipated capital and operating costs when our new rates will go into effect. A 2022 projected test year is also appropriate because it will best reflect the revenues necessary to recover the company's projected cost of service, including an appropriate return on the investments that will be used and useful to provide our customers with reliable service when the company's new customer rates are in effect.

Q. What does the company project its 2022 earned return on equity to be without the rate increase requested in this case?

A. Without the rate increase we are requesting in this case, the company’s projected earned ROE in 2022 is expected to be approximately 4.67 percent, far below the fair and reasonable ROE of 10.75 percent supported in the direct testimony of Mr. D’Ascendis. Our projections show that the company’s earned ROE will continue to decline below 4.67 percent in 2023 and 2024 without rate relief in those years. Continuing investments in the company’s infrastructure and increasing costs to serve customers reliably have outpaced our revenue growth, causing our projected ROE in 2022 to fall below the level needed to maintain Tampa Electric’s financial integrity. The company’s need to maintain financial integrity is discussed further in the direct testimony of Mr. McOnie.

SOURCES OF FINANCIAL INFORMATION

Q. What is the source of the data contained in the direct testimony and exhibits sponsored by you and the other company witnesses in this proceeding?

A. The historical data presented in the MFR schedules and as discussed in the direct testimony and exhibits of the company's witnesses is based on the books and records of the company. These books and records are maintained under the supervision of Mr. Chronister and are kept in the regular course of business in accordance with Generally Accepted Accounting Principles and the Uniform System of Accounts as prescribed by the Florida Public Service Commission and the Federal Energy Regulatory Commission ("FERC").

Since 2018, the company's books and records are audited annually by Ernst & Young, LLP, commonly known as EY, the company's independent auditors. Before 2018, the company's books and records were audited annually by PricewaterhouseCoopers, LLP, commonly known as PwC, the Company's former independent auditors. These annual financial statement audits, in conjunction with internal control testing required by Sarbanes-Oxley legislation, have shown that the company has a consistent, reliable system of internal controls over the company's accounting and financial reporting. The company's continuous internal control compliance gives financial statement users assurance of the quality and reliability of the information contained in the company's books and records as well as all Tampa Electric financial reports.

In addition, the company is audited on a regular basis by the FPSC and the Internal Revenue Service ("IRS"), and, from time to time, by other governmental agencies, including the FERC. The company makes regular monthly, quarterly, and annual reports to the FPSC and FERC and periodic, quarterly, and annual reports to the Securities and Exchange Commission ("SEC").

The projected data presented in the MFR schedules and as discussed in the direct testimony and exhibits of the company's witnesses is based on the forecasted financial statements generated from the company's budget process, which I describe below.

Q. In your opinion, do Tampa Electric's MFR schedules fairly present the company's financial condition and requested revenue increase based on the projected results for the 2022 test year?

A. Yes. The MFR schedules accurately represent historical, current, and projected activities and their associated expenditures and assumptions for 2020, 2021 and the 2022 test year.

BUDGET PROCESS

Q. Please generally describe the process that Tampa Electric used to prepare the 2022 test year budget.

A. The 2022 budget was prepared using an integrated process that combined the goals and objectives of the company with expected economic and financial conditions. We developed plans for projects and activities based on the company's obligation to serve and expectations of the requirements and challenges associated with that obligation. We developed these plans for projects and activities within each department and then consolidated them into overall company projections. Each department quantified its projects and activities into specific required work in its respective budgets. This process is described in more detail in MFR Schedules F-5 Forecasting Models and F-8 Assumptions.

Q. Did the company prepare its budget for the 2022 test year using the company's normal annual budget process described above?

A. Yes. The process described above reflects our normal budgeting process.

Q. Is the company's process for producing the budget for the projected test year the same as in prior years and previous rate cases?

A. Yes. Although the technological tools the company uses to prepare budgets have evolved, the basic process used to build our budgets is the same. We base our budgets on expected operating conditions. We rely on the experience and expertise of the company's operating team members to create our forecasts. Our front-line operating personnel and members of management work together to forecast necessary projects and activities, and their corresponding costs. Long-term planning, prioritizing resource needs, and finding available efficiencies drive the schedules and forecasts that support the company's budget. Operating personnel provide not only cost projections but also forecast other operating revenues that reduce the overall revenue requirement.

Q. How was the 2022 budget created?

A. We created our 2022 budget in our time-tested manner, namely by using an integrated process that generates a complete set of budgeted financial statements: income statement, balance sheet, and statement of cash flows. We constructed the income statement using various sources to forecast revenues and expenses. We created the balance sheet by starting with beginning balances and either forecasting monthly balances for the remainder of the year or forecasting monthly activity in the account for the remainder of the year, depending on the type of account. Then we prepared a statement of cash flows to determine the capital structure needs of the company and the required debt and equity needed during the budget year.

Q. What primary economic and financial conditions did the company consider in developing the 2022 test year budget?

A. Tampa Electric considered the following primary economic and financial conditions when preparing the 2022 budget: (1) the impact of load growth, which includes changes in the number of customers and usage per customer and (2) the impact of inflation, contract escalations, and other cost increases. Our budget is based on the company's Customer, Demand, and Energy forecasts, which are explained in the direct testimony of Mrs. Cifuentes. The company used a variety of indices and factors to estimate the effects of inflation and cost increases in the 2022 budget.

Q. Please discuss the Customer, Demand, and Energy forecasts and the revenue budget.

A. The Load Research and Forecasting section of the company's Regulatory Affairs department produced the Customer, Demand, and Energy forecasts, which reflects customer growth projections as well as load and consumption projections. Mrs. Cifuentes is responsible for this function and discusses key assumptions used to develop the forecasts in more detail in her direct testimony.

The company prepared the revenue budget by applying current tariff rates to electricity sales reflected in the Customer, Demand, and Energy forecasts by customer rate class. The company prepared detailed revenue projections by month and included the monthly data in the income statement.

It should be noted that the revenue amounts included in the company's MFR's for miscellaneous service revenue reflect the new rates that are being requested, as described in the testimony of Mr. Ashburn. The original 2022 company budget for miscellaneous service revenues was $25.9 million, reflecting the current rates. However, the company calculated the revenue requirement request using a net operating income (reflected on MFR Schedule C-1) which included $19.3 million, an amount approximately $6.6 million lower than would have been using our current rates. Our revenues reflects the new miscellaneous service rates requested on MFR Schedule E-13b.

Q. Please describe the company’s overall O&M and capital budgeting process.

A. Based on forecasted demand and energy, Tampa Electric determined the required capital investment necessary to serve the load reliably as well as the O&M needed to provide the quality of service customers expect. The company considered factors such as environmental and regulatory compliance, reserve requirements, and other items such as load location, changes in equipment and technology, and changes in required skill sets. These other items are covered by Tampa Electric witness David A. Pickles, C. David Sweat, Regan B. Haines, Melissa L. Cosby and Karen M. Mincey in greater detail. After determining the projects and activities needed to modernize, operate, and maintain a reliable system, the company estimated the costs associated with those projects and activities by analyzing the resources to be utilized and the price of those resources.

The company used different tools to determine the costs of the resources needed, depending on the type of resource. For example, as described in the direct testimony of Tampa Electric witness Marian C. Cacciatore, the compensation amounts reflected in our 2022 budget were set based on expected job market conditions.

Q. How did the company develop its detailed O&M and capital budgets?

A. Each operating department within the company developed detailed budgets for O&M and capital by month. Operating departments distinguished between O&M and capital based on the nature of the activity involved with consideration of accounting policies and practices. Each operating department weighed its options regarding how to perform O&M and capital work in the most cost-effective manner and then submitted a detailed operating budget to the Finance department.

The Finance department combined all of these budgets and data to produce a total projected amount of O&M and capital expenditures for the company. The activities and projects that are necessary to provide safe and reliable service to customers were planned by the departments that perform them, and the costs were developed using consistent assumptions. The officers of the company examined the budgets for reasonableness and consistency with our overall corporate objectives and initiatives. Finally, the budget was approved by the Board of Directors.

Q. Has Tampa Electric's budgeting process proven reliable in the past?

A. Yes. Tampa Electric's budgeting process has proven to be reliable in the past. Tampa Electric devotes significant effort to ensure our budgeting process is reliable because the company uses its budget information for investor presentations, business planning, and key decision-making. As shown on MFR Schedule C-6, the budgeting process has proven to be reliable as our actual results for company controllable amounts have closely tracked budgeted amounts. We also prepare and analyze budget variance reports and use these monthly analyses as part of the internal control system to manage our business and comply with the H.R. 3763 - Sarbanes-Oxley Act of 2002.

Q. What other factors enhance the reliability of the company's budget process?

A. Tampa Electric's budget process incorporates the American Institute of Certified Public Accountants ("AICPA") guidelines for preparing prospective financial information. The company's budgeting process conforms with all of the guidelines, including those related to quality, consistency, documentation, the use of appropriate accounting principles and assumptions, the adequacy of review and approval, and the regular comparison of financial forecasts with attained results.

Q. In your opinion, did the budgeting process that Tampa Electric used generate a fair and reasonable projection of the company's projected 2022 financial condition for use in this proceeding?

A. Yes. Tampa Electric used the same reasonable, reliable and time-proven budgeting process to produce its 2022 company budget. It fairly presents our expected financial results for 2022, with the assumption that new, lower miscellaneous service revenue rates will be approved, without the rate increase we are requesting in this case.

2022 BUDGETED FINANCIAL STATEMENTS

Q. Please describe the most material components used to develop the 2022 budgeted balance sheet and income statement.

A. The largest component of our 2022 budgeted balance sheet is net utility plant-in-service. Plant-in-service balances reflect the capital expenditures for property, plant, and equipment already invested as well as the construction cost contained in the near-term capital budget.

With the exception of fuel and interchange expenses, which are recovered through the fuel and purchased power and capacity cost recovery clauses and are not a subject in this proceeding, the largest cost component of the 2022 budgeted income statement is O&M expense. Depreciation and income tax expenses are also major portions of our income statement and are calculated based on projected plant balances, applicable depreciation rates, and deferral as well as federal and state income tax rules.

Q. What other key elements did Tampa Electric use to develop the 2022 budgeted financial statements?

A. In addition to the O&M and capital investment budgets, we developed our budgeted financial statements using our Customer, Demand and Energy forecasts, our revenue budget, our generation outage schedule, and our fuel budget.

2022 Budgeted Balance Sheet and Statement of Cash Flows

Q. How did Tampa Electric develop the 2022 Forecasted Balance Sheet?

A. The company's Finance Department prepared the 2022 Forecasted Balance Sheet, using data provided by departments throughout the company. We determined each line item using the same accounting principles, methods, and practices we use in accounting for historical data. Senior management approved the forecasted Balance Sheet after a thorough review, including final review and approval by the president of Tampa Electric and the Board of Directors.

A projected balance sheet is a representation of projected account balances at a point in time. Tampa Electric prepared the 2022 Forecasted Balance Sheet by beginning with projected balances as of December 31, 2020, and then adding forecasted balance sheet activity for 2021 and 2022. We prepared our 2021 Forecasted Balance Sheet as part of the company's annual budget process which began in late 2020. In January 2021, we updated the 2020 year-end Balance Sheet with actual amounts, then completed the 2021 and 2022 budgets using 2020 year-end amounts as the starting point.

Balance sheet forecast amounts were determined either by projecting balances or projecting activity that impacts balances. The company projected monthly balances for each month of the year for certain accounts, such as accounts receivable. For other accounts, the change or activity in the account was projected and then applied to the beginning balance in sequence each month to produce monthly balances. For instance, the company budgeted property, plant, and equipment balances using the projected timing of expenditures included in the capital budget and projected in-service dates for assets. An example of projections related to working capital is projected fuel inventory, as reflected in MFR Schedule B-18. The fuel purchases and fuel consumption is forecasted and then applied to the beginning balance in sequence each month to produce monthly balances. We projected other balance sheet accounts, such as accrued interest and projected interest payments, based on the activity reflected in the income statement. Tampa Electric prepared balance sheet data for each month of the year, as reflected in Document No. 6 of my exhibit, and used it to compute the 13-month average Balance Sheet. Document No. 7 of my exhibit reflects the result of that averaging process.

Q. How did Tampa Electric develop the 2022 Forecasted Statement of Cash Flows?

A. Tampa Electric determined the forecasted cash flows by projecting the cash and noncash components of budgeted net income and projecting the change in items included in the budgeted Balance Sheet. Our cash needs determined the debt and equity needed to operate the business, taking into account expected cash inflows and outflows as well as changes in accumulated deferred income taxes resulting from activity in budgeted property, plant, and equipment. Based on projected long-term debt issuances and equity infusions, we then forecasted short-term debt for the balance of cash needs each month.

Q. Please describe the documents in your exhibit that relate to the forecasted Balance Sheet and forecasted Statement of Cash Flows.

A. I provide the 2022 Forecasted Balance Sheet as Document No. 6 of my exhibit. Document No. 7 of my exhibit, entitled "Forecasted 13-Month Average Balance Sheet as of December 31, 2022", presents the 13-month average per books Balance Sheet. Document No. 8 of my exhibit, entitled "Forecasted 13-Month Average Balance Sheet as of

December 31, 2022 Budget Methodology," provides, line-by-line, the source or budget methodology for each item included in the 2022 Forecasted Balance Sheet. Document Nos. 9 and 10 of my exhibit provide the same information for forecasted 2021 and actual 2020, respectively, in the same format as Document No. 7 of my exhibit. Document No. 11 of my exhibit presents the Forecasted Statement of Cash Flows for the Period Ended December 31, 2022.

Q. In your opinion, do Tampa Electric's 2022 Forecasted Balance Sheet and Forecasted Statement of Cash Flows fairly and reasonably reflect the account balances and cash flows expected for the company in 2022?

A. Yes, they do. The projected Balance Sheet and Statement of Cash Flows are based on supportable levels of capital structure, plant in service, and working capital, and reflect appropriate and necessary expenditures for projects and activities at reasonable, prudent costs.

2022 Budgeted Income Statement

Q. How did Tampa Electric develop its 2022 Forecasted Income Statement?

A. The Finance Department prepared the 2022 Forecasted

Income Statement by assembling projected data prepared by numerous team members who specialize in different areas of the company’s operations. The company employed the same accounting principles, methods, and practices which the company employs for historical data to the projected data to prepare the forecasted Income Statement. Senior management approved the Income Statement budget after a thorough review, including final review and approval by the president of Tampa Electric and the Board of Directors.

Tampa Electric developed the income statement using forecasted revenues and other types of income, largely base revenues and the revenues from the five cost recovery clauses. The income statement also contains projections for off-system sales and other operating revenues such as rent revenues and miscellaneous service revenues.

To complete the income statement, we accumulated all operating expenses, including O&M expense, depreciation expense, property taxes, interest expense and interest income, and all below-the-line items. At this point, the company calculated income tax amounts to arrive at the net income.

Q. What methods and assumptions did Tampa Electric use to develop its 2022 Income Statement budget?

A. Tampa Electric provides a summary of the methods and assumptions used to develop the income statement on MFR Schedules F-5 and F-8. In short, the company used the reasonable cost estimates it developed for projects and activities, as I described earlier in my direct testimony.

Q. What factors affect the depreciation rates used in the 2022 budget?

A. The depreciation expense in the 2022 budget reflects the rates proposed in Tampa Electric's 2020 Depreciation Study submitted on December 30, 2020, in Docket No. 20200264-EI. Mr. Avellan describes the company's proposed depreciation rates and study in detail, and Tampa Electric witnesses Jeffrey T. Kopp and Charles R. Beitel support and explain the dismantlement studies the company commissioned for inclusion in the 2020 Depreciation Study. Our 2022 budgeted income statement also reflects the levels of capital recovery amortization discussed in Mr. Avellan's testimony.

Q. Please describe the documents in your exhibit that relate to the forecasted Income Statement.

A. Document No. 2 of my exhibit, entitled “Forecasted Income Statement Twelve Months Ended December 31, 2022” shows the expected results of operations for Tampa Electric under current rates. Document No. 3 of my exhibit, entitled “Forecasted Income Statement Twelve Months Ended December 31, 2022 Budget Methodology” sets forth, line-by-line, the source or budget methodology for each item included in the 2022 forecasted Income Statement. Document Nos. 4 and 5 of my exhibit provide the same information for forecasted 2021 and actual 2020, in the same format as Document No. 2 of my exhibit.

Q. In your opinion, does Tampa Electric’s 2022 Forecasted Income Statement fairly and reasonably reflect the revenues and expenses expected for the company in 2022?

A. Yes. The 2022 Forecasted Income Statement is based on supportable levels of revenues and expenses, with expenditures reflecting appropriate and necessary projects and activities at reasonable and prudent cost levels.

2022 RATE BASE

Q. Is the rate base that supports the revenue requirement calculation reasonable?

A. Yes. The projected rate base reflects appropriate amounts of net plant in service and working capital forecasted in the company's budgeted balance sheet. Tampa Electric projects the amount of rate base in the 2022 test year that is needed for reasonable, prudent investments and spending on assets that are used and useful in providing reliable electric service to our customers. Tampa Electric witnesses David A. Pickles, J. Brent Caldwell, Jose A. Aponte, C David Sweat, Regan B. Haines, Melissa L. Cosby, Karen M. Mincey, and Mr. Chronister address specific portions of our rate base growth in their direct testimony and explain why our rate base amounts for the 2022 test year are reasonable. FPSC Adjusted rate base reflects reasonable amounts for adjustments previously approved by the Commission.

Q. Is the company making any accounting policy changes in 2021 or 2022 that will affect rate base amounts for those years?

A. No. See MFR schedule B-25.

Q. Did the company include AFUDC-eligible construction work in progress ("CWIP") in rate base for the 2022 test year?

A. No. See MFR schedule B-14.

Q. Did the company adjust fuel inventory per books to reflect the 13-month average of 98-daily average burn standard used in the company's last rate case?

A. No. The company did not make that adjustment for the reasons explained in the direct testimony of Tampa Electric witness John C. Heisey. Our proposed level of fuel inventory by plant for the test year is shown on MFR Schedule B-18.

Q. Please describe the Commission adjustments to rate base shown in MFR Schedules B-1, B-2, B-6, and B-17.

A. The Commission adjustments to rate base, as shown in MFR Schedules B-1, B-2, B-6, and B-17, reflect Commission directives, policies, and decisions from previous rate proceedings. Specifically, these adjustments include: (1) removing the effect of items recoverable through the cost recovery clauses from net plant-in-service, (2) removing balances that earn allowance for funds used during construction ("AFUDC") from construction work in progress ("CWIP"), (3) removing the effect of items for which a return is provided elsewhere from working capital, such as deferred debits for clause-related under-recovery balances, (4) removing from net plant-in-service and working capital the right-of-use assets and liabilities for lease obligations, and (5) removing the effect of items that have been deemed non-utility or non-recoverable through retail base rates from rate base.

Q. After applying these adjustments, what is the total for the 13-month average rate base?

A. The jurisdictional adjusted 13-month average rate base, considering all of the adjustments and after applying the jurisdictional separation factors provided by Mr. Vogt, is $7,931,177,000 and is shown on MFR Schedule B-1.

NET OPERATING INCOME

Q. Is the net operating income that supports the revenue requirement calculation reasonable?

A. Yes. The projected net operating income reflects appropriate amounts of revenue and expense forecasted in the company's budgeted income statement. Tampa Electric projects the amount of net operating income in the 2022 test year that is associated with the transactions and activities engaged in to provide reliable electric service to our customers. Tampa Electric witnesses David A. Pickles, C David Sweat, Regan B. Haines, Melissa L. Cosby, Karen M. Mincey, Marian Cacciatore, David Avellan and Mr. Chronister address specific portions of our net operating income in their direct testimony and explain why our net operating income amounts for the 2022 test year are reasonable. The FPSC Adjusted net operating income shown on MFR Schedule C-1 reflects reasonable amounts for adjustments previously approved by the Commission.

Q. Did the company include lobbying expenses, other political expenses, or civic/charitable contributions when it calculated net operating income for the 2022 test year?

A. No. See MFR schedule C-18.

Q. From 2018 to 2020, did the company have gains or losses on the disposition of plant and property previously used to provide electric service?

A. No. See MFR schedule C-29.

Q. For 2021 and 2022, does the company project to have gains or losses on the disposition of plant and property previously used to provide electric service?

A. No. See MFR schedule C-29.

Q. What Allowance for Funds Used During Construction ("AFUDC") rate did the company use for qualifying projects in 2020, 2021, and the projected 2022 test year?

A. The company used the existing, approved 2014 AFUDC rates for qualifying projects in 2020, 2021, and the projected 2022 test year. An AFUDC rate change docket will be filed once the Actual Surveillance Report is produced using the December 31, 2021 books with a retroactive effective date of implementation being January 1, 2022.

Q. Please explain further the income tax true up for interest synchronization.

A. After we made the adjustments to rate base, as described above, we adjusted income tax expense to reflect the appropriate amount of interest expense based on the amount and cost of debt in the capital structure that was synchronized to the rate base.

Q. Did the company make a parent debt adjustment as contemplated in Rule 25-14.004, F.A.C.?

A. Yes. This adjustment is explained in the direct testimony of Mr. Chronister and is reflected on MFR Schedule C-3.

Q. Please describe the Commission adjustments the company made to Net Operating Income as shown in MFR Schedules C-1, C-2, C-3, C-4, and C-5.

A. The Commission adjustments described in MFR Schedules C-1, C-2, C-3, C-4, and C-5 reflect Commission directives, policies, and decisions from previous rate proceedings. Specifically, these adjustments include: (1) removing the revenues and expenses which are recoverable through the five cost recovery clauses, (2) removing franchise fee revenues and expenses, (3) removing gross receipts tax revenues and expenses, (4) the income tax true-up for interest synchronization, (5) a parent debt adjustment, and (6) removal of expenses that have been deemed non-utility or non-recoverable through retail base rates. Examples of these items include stockholder relations expenses and portion of industry association dues.

Q. After applying these adjustments, what is the total net operating income?

A. The jurisdictional adjusted net operating income, taking into account all the adjustments and after applying the jurisdictional separation factors provided by Mr. Vogt, is $309,380,000 and is shown on MFR Schedule C-1.

REVENUE REQUIREMENT

Q. How did the company calculate the amount of the revenue requirement increase it is requesting in this case?

A. Our total revenue requirement is the sum of the required return on our rate base plus the costs of providing electric service, grossed up for taxes and is shown on MFR Schedule A-1.

We calculated our requested increase by comparing the projected net operating income for 2022 to the net operating income that resulted from multiplying the 2022 13-month average rate base to the 2022 weighted average cost of capital, as shown on MFR Schedule A-1.

The 2022 System Per Books net operating income, 13-month average rate base, and capital structure calculations, as reflected in our MFR schedules, were based on Tampa Electric’s 2022 budgeted Income Statement, Balance Sheet and Statement of Cash Flows.

We then made regulatory adjustments to the system per books amounts for net operating income, rate base and capital structure. These regulatory adjustments include two types: (1) those that are necessary to comply with Commission directives, policies and decisions (“Commission adjustments”) and (2) those that are necessary to produce a test year that is indicative of ongoing revenue and expenditure levels (“company pro forma adjustments”). These adjustments are discussed in detail in the Rate Base and Net Operating income sections above. We then applied the jurisdictional separation factors, supported in the direct testimony of Tampa Electric witness Lawrence J. Vogt, to derive the jurisdictional amounts upon which the revenue requirement is calculated.

As shown on MFR Schedule A-1, we first applied the 6.67 percent required cost of capital to the jurisdictional adjusted average rate base of $7,931,177,000. resulting in a required jurisdictional net operating income of $529,010,000. Comparing the required jurisdictional net operating income to the jurisdictional net operating income based on the company's 2022 projected test year of $309,380,000 without a base rate increase, we calculated the net operating income deficiency for 2022 to be $219,629,000. After grossing this amount up for taxes, we computed our jurisdictional revenue deficiency for 2022 to be $294,995,000.

Q. Please describe the capital structure adjustments made in the revenue requirement calculation.

A. We made capital structure adjustments based on Commission precedent, shown on MFR Schedule D-1a. First, we removed the over/under-recovery amounts for our cost recovery clauses from short-term debt and deferred taxes because these are the components of the capital structure that are affected by the difference between the clause expense incurred and the clause revenues collected. We then performed the deferred income tax specific/pro rata adjustment over all sources except for tax credits. The deferred income tax adjustment calculation is illustrated in Exhibit No. 7 in the direct testimony of Mr. Chronister. Lastly, we used the traditional pro rata approach for the remaining adjustments, such as removing CWIP and rate base items associated with the cost recovery clauses.

Q. Did Tampa Electric make any company pro forma adjustments to calculate its 2022 revenue requirement?

A. No. The company did not make any pro forma adjustments to its 2022 revenue requirement.

Q. Has the company properly reflected the impact of accounting pronouncements that were issued since the company’s last rate proceeding?

A. Yes. The Financial Accounting Standards Board’s Accounting Standards Updates and other accounting guidance have been properly reflected in the company’s actual books and records.

It should be noted that ASC 842, on accounting for leases became effective in January 2019 for public companies with a calendar year-end. The standard requires leases to be recognized on the balance sheet for all agreements with a term of longer than twelve months and disclose key information about leasing arrangements. Our adoptions of

ASC 842 did not affect the revenue requirement calculations, because we made an FPSC adjustment to remove the lease impacts from rate base, as presented in MFR Schedule B-2.

Q. Did the company include rate proceeding expenses in the revenue requirement?

A. Yes. The company included rate proceeding expense in its 2022 budget based on an amortization over a four-year period starting in January 2022. As detailed in MFR Schedule C-10, the company included $604,250 of rate proceeding expense in the 2022 test year, which represents one fourth of the $2,417,000 total anticipated rate proceeding expenditures. The company's projected rate case expenses, proposed recovery period and proposed test year amount are reasonable.

Q. Does the company have any non-utility operations that use all or part of any utility plant that are not included in MFR schedule C-31?

A. No. See MFR schedule C-32.

Q. What revenue expansion factor did the company use to calculate its proposed rate increase?

A. The company's proposed revenue expansion factor is 1.34315, as shown on MFR schedule C-44 and was calculated using the regulatory assessment fee of 0.072 percent, a bad debt rate of 0.2 percent, and state and federal income tax rates of 5.5 and 21.0 percent, respectively as discussed in the direct testimony of Mr. Chronister.

Q. Is the company's revenue requirement calculation reasonable?

A. Yes. The revenue requirement calculation described above reflects reasonable amounts of rate base and net operating income and a reasonable rate of return, all of which reflect appropriate amounts for adjustments approved by the Commission in prior rate cases. All forecasted amounts included in the revenue requirement calculation are reasonable and prudent amounts associated with providing electric service in 2022.

SUMMARY

Q. Please summarize your direct testimony.

A. Tampa Electric's requested rate increase is based on a 2022 projected test year. This test year is appropriate as it reflects the conditions under which Tampa Electric will operate in the future, plus our anticipated capital and operating costs when new rates go into effect. This test year reflects the required level of revenues necessary to recover the costs to serve customers, including a reasonable return on investments to provide this service.

The financial data presented in the MFR schedules and as discussed in the direct testimony and exhibits of the company’s witnesses, are based on the books and records of the company and accurately represent historical, current, and projected activities and their associated expenditures and assumptions.

The 2022 budget was prepared using an integrated process that considers planned projects and activities of the company along with economic and financial conditions. Our plans are based on the company’s obligation to serve and expectations of our customers and other constituents. Our budget is reasonable and considers cost-effective ways to provide customers with reliable service.

Tampa Electric’s 2022 Budgeted Income Statement and monthly Balance Sheet are the starting points for calculating the revenue requirement since these forecasted financial statements are the basis for the System Per Books Net Operating Income as well as the 13-month average Rate Base and Capital Structure.

To calculate the FPSC Adjusted Net Operating Income, Rate Base, and Capital Structure, the company made certain regulatory adjustments to the System Per Books amounts. After these adjustments were made, jurisdictional separation factors were applied to System Per Books amounts to derive the jurisdictional amounts upon which the revenue requirement is calculated. Finally, my direct testimony details the company's calculation of the revenue requirement in this case. As shown on MFR Schedule A-1, after adjusting for taxes, there is a jurisdictional revenue deficiency of $295,995,000 million dollars for 2022.

Q. Does this conclude your direct testimony?

A. Yes, it does.

(Whereupon, prefiled direct testimony of Jeffrey S. Chronister was inserted.)

BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 20210034-EI
IN RE: PETITION FOR RATE INCREASE
BY 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 "company") as Vice President Finance and 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, which includes business planning and financial planning & analysis, as well as general accounting, regulatory accounting, plant accounting, regulatory tax accounting, and financial reporting.

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 the company in 1986. I started in Tampa Electric's Accounting department, moved to TECO Energy's Internal Audit department in 1987, and returned to the 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 as Controller of Tampa Electric since July 2009, and in my current position since July 2018.

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. I testified for Tampa Electric in Docket No. 20130040-EI, which was Tampa Electric's last base rate proceeding. I filed testimony in

Docket No. 20080317-EI, Tampa Electric Company’s Petition for An Increase in Base Rates and Miscellaneous Service Charges, Docket No. 19960007-EI, Tampa Electric’s Environmental Cost Recovery Clause, and Docket No. 19960688-EI, Tampa Electric’s environmental compliance activities for purposes of cost recovery. I filed testimony in Docket No. 20170271-EI, 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, Tampa Electric Company and in Docket No. 20200144-EI, Petition for Limited Proceeding to True-Up First and Second SoBRAs by Tampa Electric Company. I also served on a panel of witnesses during the final hearing in Docket No. 20200065-EI, which addressed the company’s amortization reserve for intangible software assets.

Q. What are the purposes of your direct testimony?

A. The purposes of my direct testimony are to: (1) describe the company’s previous and current regulatory settlement agreements, (2) discuss changes in the company’s financial profile from its last rate case through the test year 2022, (3) discuss affiliate transactions, (4) discuss income tax calculations and the company’s capital structure, and (5) discuss the company's projected financial condition in 2023 and 2024 and present regulatory options for those years, including the company's request for generation base rate adjustments ("GBRA").

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

A. Yes. Exhibit No. JSC-1 entitled, "Exhibit of Jeffrey S. Chronister" was prepared under my direction and supervision. The contents of my exhibit were derived from the business records of the company and are true and correct to the best of my information and belief. It consists of 11 documents, as follows:

Document No. 1	List of Minimum Filing Requirement Schedules Sponsored or Co-Sponsored by Jeffrey S. Chronister
Document No. 2	2013 Stipulation and Settlement Agreement
Document No. 3	2017 Amended and Restated Stipulation and Settlement Agreement
Document No. 4	2020 Stipulation and Settlement Agreement
Document No. 5	Key Financial Information: 2013-2022

Document No. 6	Revenue Requirement Impact of the Decrease in Weighted Average Cost of Debt
Document No. 7	Calculation of IRC Required Deferred Income Tax Adjustment
Document No. 8	Capital Structure Amounts and Ratios
Document No. 9	Capital Structure Ratios, Rates and Weighted Cost
Document No. 10	2023 and 2024 GBRA Calculations
Document No. 11	Proposed Tax Reform Mechanism

Q. Are you sponsoring any of Tampa Electric’s Minimum Filing Requirement (“MFR”) Schedules?

A. Yes. I am sponsoring or co-sponsoring the MFR Schedules listed in Document No. 1 of my exhibit. The contents of these MFR Schedules were derived from the business records of the company and are true and correct to the best of my information and belief.

KEY REGULATORY AGREEMENTS

Q. When did the company last file a petition seeking an increase in its general base rates and charges?

A. Tampa Electric last filed a petition to increase its general base rates and charges on February 4, 2013. Its petition was assigned Docket No. 20130040-EI. The issues in that case were resolved by a Stipulation and Settlement Agreement (“2013 Stipulation”) by and between Tampa Electric and a group of consumer parties consisting of the Office of Public Counsel (“OPC”), the Florida Industrial Power Users Group (“FIPUG”), the Florida Retail Federation (“FRF”), the West Central Florida Hospital Utility Alliance (“HUA”) and the Federal Executive Agencies (“FEA”) (collectively, “Consumer Parties”). The Commission approved the 2013 Stipulation by Order No. PSC-2013-0443-FOF-EI, issued on September 30, 2013. A copy of the 2013 Stipulation is included in Document No. 2 of my Exhibit No. JSC-1.

Q. Please describe the 2013 Stipulation.

A. As part of the 2013 Stipulation, Tampa Electric agreed that the general base rates provided for therein 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 2013 Stipulation set the company's midpoint return on equity at 10.25 percent, prescribed a 54 percent equity ratio for regulatory purposes, created a customer surcharge mechanism to recover certain storm-related restoration costs, authorized a $110 million GBRA for the Polk 2 through 5 Waste Heat Recovery Conversion Project, froze the company's then existing depreciation rates, established a 15-year amortization period for computer software, and specified certain cost of service and rate design principles for use during the term of the stipulation.

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 to the 2013 Stipulation 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. The Parties also discussed the company's desire to build 600 MW of cost-effective solar photovoltaic generation with cost recovery via a solar base rate adjustment mechanism ("SoBRA").

As a result of these discussions, Tampa Electric and 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, on November 27, 2017. A copy of the 2017 Agreement is included as Document No. 3 of my Exhibit No. JSC-1.

Q. Please describe the 2017 Agreement.

A. The 2017 Agreement amended and restated the 2013 Stipulation by extending the general base rate freeze included in the 2013 Stipulation and replacing the Polk GBRA mechanism with a SoBRA mechanism that authorized the company to recover the costs of up to 600 MW of qualifying solar generating projects, subject to a strict cost-effectiveness test and a cost cap to protect customers. It also included an asset optimization plan, a tax reform provision, and a storm cost recovery mechanism that have delivered real benefits to our customers. The agreement required the company to continue using its 2013 depreciation rates and preserved the company's authorized return on equity and equity ratio.

Tampa Electric witness Edsel L. Carlson, Jr. discusses the storm cost provisions in the 2013 Stipulation and 2017 Agreement in his testimony.

Q. Does the company believe that the 2013 Stipulation and 2017 Agreement served the public interest?

A. Yes. Both agreements promoted regulatory certainty and efficiency and have proven to be in the public interest. Pursuant to the 2017 Agreement, the Commission approved two general base rate decreases for Tampa Electric totaling approximately $107 million to promptly give customers the benefit of federal and state corporate income tax reform. The Commission also approved storm cost recovery for Tampa Electric of over $90 million for five named storms without imposing a general base rate increase or storm surcharge on customers.

The 2013 Stipulation allowed the company to harness the energy associated with waste heat at its Polk Power Station by converting Polk Units 2 through 5 into highly efficient combined cycle generating units. Under the 2017 Agreement, the company built and recovered the cost of its investments in 600 MW of cost-effective photovoltaic solar generating capacity and, during its term, began important transformational projects such as implementation of Advanced Metering Infrastructure ("AMI") and construction of the Big Bend Modernization Project.

Q. What impact did the SoBRA provision in the 2017 Agreement have on Tampa Electric and how did the SoBRA provision benefit customers?

A. The Commission approved four SoBRAs for Tampa Electric totaling 600 MW of solar capacity during the term of the 2017 Agreement, by orders issued on June 5, 2018, December 7, 2018, November 12, 2019, and November 20, 2020, respectively. The four SoBRAs increased the company's annual base revenues by approximately $100 million. They also increased the amount of energy we generated from solar to six percent of our 2020 total generation. SoBRA facilities have generated fuel savings of $77 million since the 2017 Agreement became effective. The company expects the fuel savings from this 600 MW of solar to exceed $700 million over the life of these solar assets.

Q. Did the 2013 Stipulation and 2017 Agreement address the company's depreciation and amortization rates?

A. Yes. Both agreements required Tampa Electric to continue using the depreciation and amortization rates approved by the Commission in 2012, relieved the company of the need to file depreciation and dismantlement studies every four years, and directed the company to file a depreciation study no more than one year nor less than 90 days before the filing of its next general rate proceeding, such that the proposed depreciation rates can be considered contemporaneously with the company’s next general rate proceeding. Tampa Electric filed a depreciation and dismantlement study with the Commission on December 30, 2020. Tampa Electric witnesses Davicel Avellan, Jeffrey T. Kopp, and Charles R. Beitel provide additional detail regarding depreciation and dismantlement in their testimony.

Q. Did the tax reform and storm cost provisions in the 2017 Agreement work together to benefit customers?

A. Yes. In December 2017, Tampa Electric filed a petition for storm cost recovery as contemplated in the 2017 Agreement. The company originally proposed a $4.00/1,000 kWh surcharge to recover $87.4 million of costs associated with named storms in 2015, 2016, and 2017 and to replenish its storm reserve. The company later amended its petition to increase its requested storm cost recovery amount to $102.5 million and to increase its proposed surcharge amount, and then requested approval of an Implementation Stipulation that allowed the company to use the projected income tax expense savings from the Tax Cut and Jobs Act of 2017 (“TCJA”) to offset its request for storm cost recovery. The Commission approved the Implementation Agreement by Order No. PSC-2018-0125-PCO-EI on March 7, 2018, and later approved a Storm Cost Settlement Agreement, by Order No. PSC- 2019-0234-AS-EI, dated June 14, 2019, in Docket No. 20170271-EI.

The 2017 Amended and Restated Agreement allowed the company to recover $91.3 million of incremental storm recovery costs by netting those costs for a nine-month period in 2018 against TCJA tax expense savings without imposing a surcharge on customer bills. The company also made an $11.5 million, one-time refund of tax expense savings to customers in January 2020.

Q. Did the Commission take other actions pursuant to the tax reform provision in the 2017 Agreement?

A. Yes. By Order No. PSC 2018-0457-FOF-EI, issued September 10, 2018 (“Federal Tax Reform Order”), the Commission approved a base rate reduction in the amount of approximately $102 million effective January 1, 2019 to reflect the impact of TCJA. It also approved a $5.0 million base rate reduction effective January 1, 2020 to reflect a temporary reduction in the State of Florida corporate income tax rate by Order No. PSC-2019-0524-PAA-EI, issued December 17, 2019 (“State Tax Reform Order”). Thus, the company reduced its base rates pursuant to the 2017 Agreement by about $107 million to return tax expense savings to customers.

Q. Did Tampa Electric enter into an additional Commission-approved settlement agreement in 2020?

A. Yes. Tampa Electric filed its Storm Protection Plan for 2020 to 2029 (“SPP”) on April 10, 2020. After submitting its SPP, the company entered into a settlement agreement with the OPC and other consumer parties to simplify issues associated with SPP cost recovery and resolve other pending issues.

The centerpiece of the 2020 Agreement was a proposal under which Tampa Electric reduced its base rates by approximately $15 million and agreed to recover all the costs (with limited exceptions) determined prudent by the Commission associated with activities in its SPP (operations and maintenance (“O&M”) expenses and capital projects) through the Storm Protection Plan Cost Recovery Clause (“SPPCRC”). This agreement streamlined the issues to be litigated in the 2020 SPPCRC docket and promoted regulatory certainty for the company and its customers.

The 2020 Agreement also completely resolved Docket No. 2020065-EI (Software Amortization Petition), and an item associated with the company’s Fourth SoBRA (Docket No. 20200064-EI). This agreement benefited customers by promoting transparency and simplifying implementation of the new SPPCRC, and the Commission voted to approve it on June 9, 2020.

Q. Did the company enter into a second settlement agreement in 2020?

A. Yes. On August 3, 2020, the company executed and filed a Stipulation and Settlement Agreement (“2020 SPP Settlement Agreement”) in the company’s SPP and SPP Cost Recovery Clause dockets. The 2020 SPP Agreement resolved the remaining issues in those two dockets by approving: (1) the company’s proposed 2020 SPP as filed; (2) its proposed SPP cost recovery amounts and factors to be effective January 1, 2021; and (3) the tariffs implementing the $15 million base rate reduction specified in the 2020 Agreement. The Commission approved the 2020 SPP Agreement by Order No. PSC-2020-0293-AS-EI, issued on August 28, 2020, in Docket Nos. 20200067-EI and 20200092-EI.

FINANCIAL PROFILE CHANGES FROM 2013 TO 2022

Q. Has the company's financial profile changed since its last rate case in 2013?

A. Yes. Tampa Electric witnesses Archibald D. Collins, David A. Pickles, Regan B. Haines, Melissa L. Cosby and Karen M. Mincey each explain how we have transformed the company and its operations, and how those operational changes benefit our customers. Showing how our financial profile has changed tells an important part of the story, so I have prepared an analysis showing how the company's expense profile has changed from the twelve-months ended December 31, 2013 and how our balance sheet has grown since December 31, 2013. Document No. 5 of my Exhibit No. JSC-1 contains a schedule summarizing key financial information about the company from 2013 to 2022.

Q. How did you choose these beginning points for your analysis?

A. We filed our 2013 rate case using a projected 2014 test year, but the 2013 Stipulation authorized the company to increase its base rates effective with the first billing cycle in November 2013. Beginning my analysis with expenses for 2013 and the balance sheet as of December 31, 2013 anchored the analysis in the period of time when the first general base rate increase authorized by the 2013 Stipulation went into effect. I will refer to these time frames in my testimony as “since 2013” or “since our last rate case.” In some instances, my analysis will reflect the seven years of actual results from 2013 to 2020, and in other instances I will make comparisons from 2013 to our projected 2022 test year, which will reflect nine years of change.

Q. In general, how has the company’s financial profile changed since its last rate case?

A. The company has invested to serve a growing customer base and transform our infrastructure to respond to customers’ needs and expectations, which has caused our rate base to grow. Even though our rate base grew, the company combined higher revenue – from customer growth and regulatory agreements - with cost controls to earn within its authorized range of returns on equity during the last seven years. However, we project our earned rate of return on equity to decline in 2021 and 2022 as we add new and important assets to our rate base. We project our earned return on equity for 2022 to be below five percent without the rate increase we are requesting in this case.

Q. How has the company's rate base grown since 2013?

A. Our System Per Books 13-month average rate base for 2020 was 67 percent higher than in 2013. The company's FPSC Adjusted 13-month average rate base for 2020 was 69 percent higher than in 2013. Our System Per Books 13-month average rate base for 2022 will be 98 percent higher than in 2013. Our FPSC Adjusted 13-month average rate base for 2022 will be 100 percent higher than in 2013.

The predominant driver of our rate base growth is the increase in our Net Utility Plant. The company's FPSC Adjusted Net Utility Plant has increased due to increases in both Net Plant in Service and the portion of Construction Work in Progress ("CWIP") that does not earn Allowance for Funds Used During Construction ("AFUDC"). Our system Per Books Net Utility Plant has increased due to those two items plus cost recovery clause Net Plant in Service, cost recovery clause CWIP, and the portion of CWIP that earns AFUDC.

Our FPSC Adjusted 13-month average Net Utility Plant in 2020 exceeded the 2013 amount by $2.7 billion, while the amount in 2022 is projected to exceed the 2013 amount by $3.9 billion. The company's FPSC Adjusted 13-month average

Net Utility Plant in 2020 was 68 percent higher than in 2013, and we project in 2022 that it will be 98 percent higher than in 2013.

Q. What caused the growth in Net Utility Plant?

A. The company's Net Utility Plant has grown because the company invested to meet the expectations of our customers, to provide safe and reliable service to our current and new customers, and to make our generating fleet units cleaner and greener. Our FPSC Adjusted 13-month average CWIP balance in 2020 was 146 percent higher than in 2013, and we project in 2022 that it will be 43 percent higher than in 2013. Our FPSC Adjusted 13-month average Net Plant in Service balance in 2020 was 65 percent higher than in 2013, and we expect in 2022 that it will be 100 percent higher than in 2013.

The company's FPSC Adjusted 13-month average Net Plant in Service balance in 2020 exceeded the 2013 amount by $2.5 billion, while the amount in 2022 is projected to exceed the 2013 balance by $3.8 billion.

Q. What major projects make up these plant increases?

A. The Plant in Service amounts for the key projects contributing to these increases are:

(1) The Polk 2 through 5 conversion approved in the 2013 Stipulation (2020 13-month average $648,778,851 and 2022 13-month average $648,778,851);

(2) 600 MW of solar generation assets recovered through the SoBRA mechanism in the 2017 Agreement (2020 13-month average $800,385,694 and 2022 13-month average $942,076,934); and

(3) The three major projects for which we seek cost recovery in this proceeding: Big Bend Modernization as described by Mr. Pickles and Mr. Caldwell (2022 13-month average $418,264,726), 600 MW of Future Solar explained by Tampa Electric witnesses Jose A. Aponte and C. David Sweat (2022 13-month average $341,547,139), and our AMI project described by Mr. Haines and Ms. Cosby (2022 13-month average $242,335,988).

The original or projected in-service amounts for these assets, including AFUDC, are shown below:

	In-Service Date	In-Service Amount (in millions)
Polk 2-5	2017	$649
600 MW SoBRA	2018–2021	$942
Big Bend Modernization	2021-2022	$868
Solar Wave 2	2021-2023	$814
AMI	2021	$242

Q. What was the annual average growth rate for Plant in Service since 2013?

A. The company's cumulative average growth rate ("CAGR") for 13-month average FPSC Adjusted Plant in Service from 2013 to 2020 was 6.0 percent, and for the nine years from 2013 to 2022 is expected to be 5.9 percent. Of this 2013 to 2022 CAGR percentage, 3.3 percent is attributable to the assets shown above, while 2.6 percent is attributable to all other asset additions such as infrastructure projects and sustaining capital.

Q. How have the company's base revenues grown since 2013?

A. Tampa Electric's base revenues in 2022, without the rate increase requested in this case, will be 28 percent higher than in 2013. Our 2022 base revenues, without rate relief, are projected to exceed the 2013 amount by approximately $258 million.

This base revenue growth is attributable to customer growth and rate increases authorized as part of the 2013 Stipulation and 2017 Agreements.

The estimated base revenue increase from customer growth from 2013 to 2022 is projected to be approximately $140 million.

The revenue increases from regulatory agreements from 2013 to 2022 is projected to be approximately $240 million.

These base rate increases were offset by base rate reductions of approximately $122 million associated with tax reform ($107 million) and removing SPP cost recovery from base rates to the SPPCRC ($15 million).

Q. Please explain the cost control efforts the company employed from 2013 to 2022.

A. As I mentioned earlier, Tampa Electric has focused on cost control in all areas of our operations. Through these efforts, we have realized significant savings in O&M

expenses, taxes other than income, income taxes, and interest expense. Our cost control results came from implementing specific cost control strategies; the addition of key assets; our focus on cost discipline, efficiency, and innovation; and our reliance on the size and financial integrity of the company.

Q. Please describe how the company's cost control efforts have reduced the company's level of O&M expenses.

A. Tampa Electric's total O&M expenses (clause and non-clause) are substantially lower than in 2013. We have greatly reduced the O&M expenses that we recover through clauses and the O&M expenses we recover through base rates are only slightly higher than in 2013.

Total O&M expenses, as reflected in System Per Books O&M, were $1.17 billion in 2013. As shown on MFR Schedule C-1, by 2022, the company projects System Per Books O&M to be $956 million, reflecting a decrease of over $200 million.

The O&M expense used to calculate the revenue requirement is FPSC Adjusted O&M, which reflects jurisdictional separation, removal of clause expenses and other Commission adjustments. FPSC Adjusted O&M was $335.9 million in 2013.

In 2020, that total was $350.9 million. As shown on MFR Schedule C-1, by 2022, the company projects FPSC Adjusted O&M to be $354.8 million. This reflects an average annual growth rate of only 0.6 percent per year.

In addition to the customer benefit of controlling the O&M that impacts base rates to sixth tenths of one percent per year, the company has also delivered, in real time, the benefit of lower bills to customers by reducing the expenses that are recovered through the Fuel Adjustment Clause. Fuel clause expenses in 2013 were $682.8 million. By 2022, the company projects fuel clause expenses to be $544.6 million, reflecting a decrease of almost $140 million.

Q. How has the company reduced its annual fuel expenses since 2013?

A. Although the amount of energy we sell each year has gone up since 2013, we have reduced our annual fuel expenses by more than 40 percent. Part of the decline can be attributable to lower natural gas prices, but we delivered the value of lower natural gas prices to our customers through prudent expansion of dual-fuel capability at our power plants, continued investments in efficient natural gas fired combined cycle technology, and careful dispatching of our generating units. In addition, our construction of cost-effective solar generation lowered fuel costs by adding zero fuel cost assets. Mr. Pickles discusses these efforts in his testimony.

Q. Is the 0.6 percent increase in O&M noted above the result of O&M increases in each functional area since 2013?

A. No. While the level of FPSC Adjusted O&M in 2022 is higher than 2013, our expense levels in most functional areas are lower than in 2013. What we pay for employee health benefits is higher than in 2013 and we have increased our O&M spending in the customer experience area, but we have dramatically reduced our energy production O&M expense levels. We reduced our energy production O&M expenses by applying cost discipline to internal resources and vendor spending, and by changing our fuel generation mix away from coal to natural gas and solar. Mr. Pickles explains this change and its impact on our operations in his testimony. Tampa Electric witnesses Marian C. Cacciatore and Ms. Cosby discuss our spending for employee health benefits and customer experience, respectively, in their testimony.

Q. Are the company’s cost control efforts reflected in the company’s performance against the Commission’s O&M

Benchmark test?

A. Yes. The Commission's O&M Benchmark test measures a company's projected test year O&M expense levels against the O&M expense levels in a benchmark year (2012 in this case) escalated annually by a multiplier reflecting inflation and customer growth. The company's results against the O&M Benchmark are shown on MFR Schedule C-37.

Overall, our results are excellent. Our projected 2022 total O&M expense amount is $43.9 million lower than the Commission benchmark amount. This is important evidence that the company's cost control efforts have worked, and that our projected 2022 O&M expense levels are reasonable.

Q. What is the performance against the O&M benchmark for 2022 in each of the company's functional expense areas?

A. As shown in MFR Schedule C-37, Tampa Electric is well below the benchmark in all functional areas with the exception of the customer experience area. The functional areas where our projected 2022 level of O&M expense are under the benchmark, and the amounts by which they are under, are:

Functional Area	O&M Expenses Under Benchmark (in millions)
Production	$28.6
Transmission	$6.1
Distribution	$2.9
Sales Expenses	$1.5
Administrative & General	$11.2

Q. Please explain the company’s O&M Benchmark results for 2022 in the Customer Experience area.

A. Our projected 2022 O&M expense levels in the Customer Experience area, collectively, are $6.4 million above the benchmark. This result reflects the significant resources we have dedicated to improving the experiences our customers receive from us, and our efforts to enable our customers to do business with the company when and where they want. Ms. Cosby demonstrates in her testimony how our increased spending in this area has made big improvements in our contact center service levels and in our J.D. Power customer satisfaction rankings.

Q. Does the company plan to incur economic development expenses in the 2022 test year?

A. Yes. The company has included $367,000 of economic development expenses in its calculation of the 2022 test year net operating income. This amount is well within the guidelines in Rule 25-6.0426, Florida Administrative Code. However, as I explain in the last section of my testimony, the company proposes to increase the amount of economic development expenses allowed for 2023 and 2024 surveillance reporting purposes.

Q. Has the company taken steps to control its Taxes Other Than Income expense?

A. Yes. Taxes Other Than Income expense reflects ad valorem property taxes, payroll taxes and tax-like charges that are "passed through" to customers such as franchise fees. Our cost control efforts in these areas are important because property tax and payroll tax expenses impact our revenue requirement.

Total non-pass-through expense, which mostly includes property and payroll taxes, was $61.7 million in 2013 and $75.3 million in 2020, an increase of only $13.6 million. As shown in MFR Schedule C-20, the projected amount in 2022 is $90.4 million and exceeds the 2013 amount by $28.8 million. The CAGR for Taxes Other Than Income from 2013 to

2020 was 2.88 percent, and for the nine years from 2013 to 2022 is expected to be 4.34 percent. Most of these increases are a function of the incremental property taxes on the value of the assets we have placed in service through 2020 and expect to place in service by 2022.

Q. Are the property tax increases since 2013 reasonable?

A. Yes. Our property tax expense in 2013 was $49.2 million, and was $62.8 million in 2020, an increase of only $13.6 million. We project our property tax expense level in 2022 to be $73.4 million, which would exceed the 2013 amount by $24.2 million. The CAGR for property tax expense from 2013 to 2020 was 3.55 percent, and for the nine years from 2013 to 2022 is expected to be 4.55 percent.

As shown above, the company's CAGR for 13-month average Plant in Service from 2013 to 2020 was 6.0 percent, and for the nine years from 2013 to 2022 is expected to be 5.9 percent. The fact that our property tax expenses have grown slower than the increase in our plant balances is the result of year-round work with the taxing authorities in the Tampa Electric service area and shows that our projected property tax expense for 2022 is reasonable.

Q. Has the company taken steps to control its Income Tax expense?

A. Yes. Income tax expense is the third largest operating expense affecting our revenue requirement, so we are always working to control income tax expenses. We cannot control the income tax rates imposed by state and federal taxing authorities, or changes to tax credits and deductibility of certain costs, but we do seek to optimize our federal and state income tax expenses by understanding, analyzing, and acting on federal and state legislative changes, new regulations, and guidance from taxing authorities and our advisors. We reduced our income tax expense levels since 2013 by promptly implementing federal and state tax reforms and through the prudent use of investment tax credits, research and development credits, bonus depreciation and tax repairs.

Q. What specific actions has the company taken since 2013 to reduce its income tax expense levels?

A. First, as mentioned above, the company promptly implemented the federal TCJA and the 2019 to 2021 temporary Florida state income tax rate reduction. These tax reforms generated annual savings to customers of $102 million and

$5 million, respectively, for a total of $107 million. The company promptly followed the tax reform provisions in the 2017 Agreement, used a portion of the savings to offset storm restoration costs, and made the credits and base rate reductions as specified in the agreement.

Second, the company generated approximately $380 million of solar investment tax credits through our solar investments. We amortized these credits to reduce income tax expense in accordance with tax normalization principles each year beginning in 2018 as follows:

2018	$1.4 million
2019	$5.4 million
2020	$7.2 million
2021	$8.9 million (projected)
2022	$11.2 million (projected)

Third, the company claimed research and development credits averaging $500,000 to $1.5 million annually from 2009 to 2020. These credits are available to Tampa Electric because we continue to invest in innovative energy storage, renewable energy and Energy Delivery technologies that will improve reliability and provide new functions, features and services for the company and its customers.

Finally, although they do not directly reduce income tax expense, the company has worked diligently to optimize the creation of accumulated deferred income taxes (“ADIT”), which are a source of zero-cost capital in our regulated capital structure. I discuss these efforts further below in the Income Tax and Capital Structure section of my testimony.

Q. Has the company taken steps to reduce its annual interest expense since 2013?

A. Yes. Our total interest expense has increased since 2013, because we are borrowing more to support the company’s growing rate base. However, we have reduced our weighted average cost of debt since 2013, which has reduced our overall required rate of return relative to our last rate case.

We lowered our weighted average cost of debt from 2.03 percent in 2013 to 1.58 percent in 2020 and project a weighted average cost of debt for 2022 of 1.49 percent. A schedule showing how short and long-term interest rates and our weighted average cost of debt has changed since 2013 is included in Document No. 6 of my Exhibit JSC-1.

We accomplished these reductions by relying on the size and financial integrity of the company and by proactively pursuing low-cost financing options. We expanded our short-term borrowing capabilities, replaced maturing long-term debt with lower interest instruments, and issued new debt at lower interest rates. We have aggressively pursued lower interest rates for the benefit of our customers.

Q. What is the impact of the decrease in the company's weighted average cost of debt on the company's revenue requirement?

A. Multiplying the 0.54 percent decrease in the weighted average cost of debt from 2013 to 2022, noted above (2.03 percent minus 1.49 percent), by the amount of rate base projected for 2022 as shown on MFR schedule A-1 yields Net Operating Income impact $43,006,015. As reflected in Document No. 6 of my Exhibit JSC-1, this equates to a lower revenue requirement amount for 2022 of $57,763,459.

Q. Please discuss depreciation expense since 2013.

A. As noted above, the 2013 Stipulation and 2017 Agreements both required Tampa Electric to continue using the depreciation and amortization rates approved by the Commission in 2012 and relieved the company of the need to file depreciation and dismantlement studies every four years. Although our depreciation expenses have grown as our rate base has grown, our agreement to use the 2012 depreciation rates has prevented depreciation expense increases attributable to depreciation rate increases. Depreciation expense during 2022 will be approximately $493 million, of which $46 million will be attributable to the higher depreciation rates in the study. Although the depreciation study filing moratorium in the 2013 Stipulation and 2017 Agreement reduced cost pressures during the term of the agreements by deferring rate-driven depreciation expense increases, delaying depreciation and dismantlement studies had the predictable effect of pushing a material depreciation expense increase into the 2022 test year.

Q. How have customers benefitted from all the cost control efforts you described above?

A. Our customers have benefitted from these cost control measures because they have allowed us to operate within the parameters outlined in the 2013 Stipulation and 2017 Agreement, which has allowed us to make it to the end of the term of the 2017 Agreement without seeking general base rate relief.

Q. Please explain further.

A. Since 2013, we have been operating under the 2013 Stipulation and 2017 Agreement, both of which prohibited us from seeking general base rate relief before the end of their terms unless our earning rate of return on equity fell below 9.25 percent on a monthly earnings surveillance report stated on an actual Commission thirteen-month average adjusted basis. The cost control efforts described above were a vital part of how the company refrained from seeking general base rate relief to be effective before January 1, 2022, while at the same time making important investments to make the company cleaner and greener, improve system reliability and generating efficiency, enhance the experience we provide to our customers, and improve customer satisfaction levels. Our efforts, together with thoughtful decisions by the Commission and collaboration with the Consumer Parties, have allowed us to fulfil our obligations under the 2013 Stipulation and 2017 Agreement.

Q. How will customers benefit from these cost control efforts in the future?

A. As the term of the 2017 Agreement expires and we move forward, the cost control efforts described above have moderated the company’s rate increase request in this proceeding.

AFFILIATE TRANSACTIONS

Q. Please describe the projected affiliate transactions included in the company’s 2022 test year.

A. The company forecasted transactions with affiliates that reflect the normal products and services exchanged with companies related to Tampa Electric. These items include products and services provided to affiliated companies, as well as products and services provided from affiliated companies to Tampa Electric. Tampa Electric provides services to affiliates and shares the costs with them, referring to them as “shared services”. Shared services are provided to many affiliates, but primarily to Peoples Gas System and New Mexico Gas Company. Tampa Electric receives services from other affiliates, primarily Emera, Inc.

Q. Can you provide additional detail regarding affiliate transactions?

A. Yes. Related party transactions are reflected on MFR

Schedule C-30, Transactions with Affiliated Companies, and MFR Schedule C-31, Affiliated Company Relationships – which reflects the diversification pages that will be contained in the 2020 Form 1 submission to the Commission and the diversification pages that were contained in the 2019 Form 1 submission to the Commission. In addition to the shared services discussed above, Tampa Electric engages in natural gas purchases and sales with Peoples Gas System and Emera Energy Services U.S., Inc. Tampa Electric Company also has an Asset Management Agreement (“AMA”) with Emera Energy Services U.S., Inc. for a portion of its natural gas storage capacity. These transactions are discussed further in the direct testimony of Tampa Electric witness John C. Heisey.

Q. Please describe the changes in affiliate relationships that have occurred since the company’s last rate case in 2013.

A. The company is a wholly owned subsidiary of TECO Energy, Inc., which was publicly traded on the New York Stock Exchange until December 2016. Tampa Electric’s largest sister company is Peoples Gas System. In 2014, TECO Energy acquired New Mexico Gas Company. At that time, TECO Energy formed TECO Services, Inc. (“TSI”) and moved all parent company employees and selected Tampa Electric shared services employees into TSI. In 2016, TECO Energy was acquired by Emera Inc., a Canadian utility holding company headquartered in Halifax, Nova Scotia. Emera stock is publicly traded on the Toronto Stock Exchange. On January 1, 2020, TSI’s shared service function and almost all TSI employees were transferred to Tampa Electric Company. The shared service functions have continued to operate consistently, and costs have been charged in the same manner, through this period of time.

Q. How does Tampa Electric determine the costs that it charges affiliated companies?

A. The costs for Tampa Electric shared services are charged to affiliate companies in one of three ways: [1] direct charges, [2] assessed charges and [3] allocated charges. Direct charges are made when an affiliate is solely receiving the product or service rendered by Tampa Electric. When multiple affiliates receive the same services, the company charges costs either through assessments or an allocation. Assessments are determined and distributed using cost-causative calculations based on certain metrics, such as head count or square footage. Shared costs that cannot be directly charged or assessed are allocated based on a Modified Massachusetts Method, which is a method that utilizes a combination of total operating revenues, total operating assets and net income as the basis of allocation. This method has been evaluated and deemed reasonable by the Commission in prior company proceedings.

Q. How do affiliated companies determine the costs that are charged to Tampa Electric?

A. The costs for products or services provided to Tampa Electric from affiliated companies are charged using similar methods to the ones described above. The company receives direct, assessed and allocated charges. The cost distribution is based on the nature of the service provided. Examples of these services include risk management, insurance and treasury. There are also Emera, Inc. functions that partner with Tampa Electric and charge for their involvement. Examples of these services include safety, legal, information technology and human resources.

Q. Are the projected affiliate transactions reflected in the 2022 test year reasonable?

A. Yes. The affiliated transactions reflected in the test year are reasonable. The services provided to affiliates and from affiliates are documented in agreements between the companies. Cost distributions for services exchanged between affiliates are based on agreed-upon methodologies. Both incoming and outgoing charges are subject to the internal control system for each company. The services provided by affiliates are appropriate and prudently incurred to achieve the most efficient and effective operation of functions that are vital to delivering utility service at a reasonable cost. The charging of costs to affiliates is reasonable and allows Tampa Electric to ensure a streamlined cost profile for functions required to prudently operate the business.

INCOME TAXES AND CAPITAL STRUCTURE

Q. How did the company calculate income tax expense for the 2022 test year?

A. We calculated income tax expense for the 2022 test year the same way we have for ratemaking purposes over the last four decades. Consistent with the company’s last three rate proceedings and long-standing Commission precedent, the company computed its test year income tax expense on a stand-alone basis. Our projected total income tax expense was based on our projected taxable income and the federal and state income tax laws, regulations, and rules expected to be in place during the 2022 test year.

As shown in MFR Schedule C-22, we calculated income tax expense using the federal and state rates expected to be in effect for the 2022 test year of 21 percent and 5.5 percent, respectively. We computed all net operating income and capital structure amounts using our reasonable budget projections, consistent regulatory treatments, and in compliance with the normalization requirements of the Internal Revenue Code.

We computed deferred taxes and the related accumulated deferred income tax based on the projected book/tax temporary differences for the 2022 forecasted period. We also included the forecasted flow back of excess deferred taxes in our tax expense calculation and calculated the flow-back in accordance with the Federal Tax Reform Order and the State Tax Reform Order described above.

Finally, we reduced our income tax expense by amortizing the benefit of investment tax credits generated by the company’s investments in qualified solar facilities on a normalized basis in accordance IRS normalization rules.

Q. Does Tampa Electric file a consolidated United States income tax return with other Emera companies?

A. Yes. Tampa Electric Company is a wholly owned subsidiary of TECO Energy, Inc., which is a wholly owned subsidiary of Emera United States Holdings, Inc. ("EUSHI"), which is a wholly owned subsidiary of Emera, Inc. Tampa Electric and the other TECO Energy companies file United States income tax returns on a consolidated basis with EUSHI. As shown on MFR Schedule C-27, Tampa Electric does not expect being included in a consolidated tax return will cause any significant benefit or detriment to Tampa Electric or its customers in the 2022 test year.

Q. Did the company make a parent debt adjustment when calculating its 2022 revenue requirement as contemplated in Rule 25-14.004, Florida Administrative Code?

A. Yes. Tampa Electric calculated a parent debt adjustment of $9.7 million using the capital structure of Emera Inc. We calculated this adjustment consistent with the methodology used by our affiliate, Peoples Gas System ("PGS"), and as specified in the Stipulation and Settlement Agreement in its last rate case that was approved by the Commission in Docket No. 20200051-GU on December 10, 2020. This adjustment decreased the company’s 2022 revenue requirement.

Q. Has Tampa Electric been making a parent debt adjustment in its annual and monthly earnings surveillance reports since 2013? If not, why?

A. No. In the company’s last base rate proceeding, we used the capital structure of then-parent company TECO Energy to calculate a parent debt adjustment. Tampa Electric’s parent TECO Energy has not had any debt on its balance sheet for many years and, as a result, Tampa Electric did not include a parent debt adjustment for surveillance reporting purposes during those periods. This is the company’s first general rate proceeding since TECO Energy was acquired by Emera, so we are making a parent debt adjustment in this case.

Q. Is the capital structure that supports your revenue requirement calculation reasonable?

A. Yes. MFR Schedule D-1a, Cost of Capital – 13 Month Average, shows the company’s proposed capital structure and overall weighted cost of capital (overall rate of return) for the 2022 test year. Our proposed overall rate of return for the 2022 test year is 6.67 percent.

Our proposed 2022 capital structure reflects a 55 percent equity ratio (investor sources) as proposed by Tampa Electric witness Kenneth D. McOnie, and the 10.75 percent midpoint return on equity supported by the testimony of Tampa Electric witness Dylan W. D’Ascendis.

The 55 percent equity target discussed in Mr. McOnie’s testimony culminated in a 54.93 percent year-end financial equity ratio in the 2022 budgeted balance sheet. The equity balances in the budget resulted in a 2022 13-month average System Per Books financial equity ratio of 54.53 percent, as reflected on MFR Schedule D-1a. Also, as reflected on MFR Schedule D-1a, the 2022 13-month average FPSC Adjusted financial equity ratio was 54.56 percent. The 54.56 percent equity ratio was the one used to calculate the 6.67 percent rate of return used to determine the 2022 revenue requirement.

The forecasted amounts for items such as zero cost deferred taxes were prepared using the budgeting process discussed by Ms. Lewis in her direct testimony. Customer deposit projections reflect both forecasted balances and the low-cost rates implemented recently by the

Commission.

Finally, forecasted short and long-term debt balances and rates reflect cash flow projections and cost rates that are documented in the company's transaction detail and reflected in the company's 2022 budget.

Q. Please describe the specific debt components and their cost rates in the company's proposed 2022 capital structure.

A. The specific debt components and cost rates are reflected in Document No. 6 of my Exhibit No. JSC-1. As noted above, the company has worked diligently to reduce its borrowing costs since 2013, and the results of these efforts are shown in my exhibit. The amount of short- and long-term debt in our projected 2022 capital structure and related weighted average interest rates are also reflected in Documents No. 8 and No. 9 of my Exhibit No. JSC-1.

Q. Please explain how the company reflected ADIT in the company's proposed 2022 capital structure.

A. The Commission has always viewed deferred taxes as a component of capital structure that supports rate base.

We included ADIT in our proposed 2022 capital structure as a zero-cost source of capital, which has the effect of lowering the overall weighted cost of capital, thus lowering the overall rate of return used to calculate the company’s revenue requirement. This approach conforms to the Commission’s long-standing practice. Also, consistent with previous rate case proceedings and tax normalization rules, we made an adjustment to decrease the projected 2022 accumulated deferred income tax amount by $12,891,677. The calculation of this adjustment is shown on Document No. 11 in my Exhibit No. JSC-1.

Q. Has the company optimized the ADIT in its capital structure?

A. Yes. The company has optimized the amount of ADIT in its capital structure in three ways: bonus depreciation deductions, accelerated tax depreciation on solar assets, and tax repairs deductions.

First, the company took full advantage of available bonus depreciation deductions on its federal income tax returns. Tampa Electric claimed more than $950 million in bonus depreciation from 2014 to 2020 but does not expect to claim additional bonus depreciation deductions beyond

2020. The TCJA generally eliminated bonus depreciation as an option for utilities effective January 1, 2018, but the bonus deduction was available for assets placed in service after January 1, 2018, if a binding contract was entered into before September 27, 2017. As a result, the company was able to claim close to $120 million of bonus depreciation from 2018 to 2020.

Second, our investments in solar generating facilities have generated more deferred taxes relative to other forms of generation. This is the result of the fact that we can deduct the cost of solar generating facilities over five years for federal income tax purposes but use a 30-year life for book depreciation. So, the resulting timing differences have generated over $110 million of ADIT taxes from 2018 to 2020. We expect the total ADIT from solar investments to be $155 million from 2018 to our projected 2022 test year.

Finally, Tampa Electric has continued to optimize its federal tax repairs deductions by expensing qualifying costs for generation, transmission, and distribution repairs for tax purposes. During the period from 2014 to 2020, the company generated approximately $660 million of tax repairs deductions. These deductions have increased the amount of ADIT in our capital structure by approximately $560 million in 2020. For the period from 2014 to 2022, the company expects to generate over $930 million of repairs deductions. These deductions have increased the amount of ADIT in our capital structure by approximately $770 million in 2022.

Q. What impact has the TCJA had on the ADIT in the company’s proposed 2022 capital structure?

A. The TCJA lowered the federal income tax rate, which was good for the company and our customers, but not all changes in the TCJA helped customers. All other things being equal, the TCJA has reduced the amount of ADIT in the company’s capital structure on a relative basis. This has required the company to maintain higher proportions of investor supplied capital in its capital structure, which has increased the company’s overall required rate of return and revenue requirement relative to pre-TCJA levels.

The TCJA caused the level of deferred taxes in the company’s capital structure to decline on a relative basis in two ways: (1) by reducing the tax rate used to value ADIT on the balance sheet and (2) by eliminating bonus depreciation for utilities like Tampa Electric.

Prior to 2018, the bonus depreciation provisions in the Internal Revenue Code allowed Tampa Electric to deduct as much as 50 percent of the cost of an asset in the year the asset went in service. Because the company records ADIT on book-tax timing differences, the short lives inherent in bonus tax depreciation created large timing differences in the early years of an asset and generated large ADIT increases relatively quickly.

Now that bonus depreciation is no longer available to Tampa Electric, the company must compute its federal income tax depreciation deduction using the longer lives in the Modified Accelerated Cost Recovery System ("MACRS"). Because asset lives under MACRS are longer than under bonus depreciation, the MACRS system generates smaller book-tax timing differences, which reduces the volume of ADIT being added to the company's capital structure each year.

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 by 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 must be met with increased debt and equity dollar support.

Q. Can you provide additional detail on the changing components of the company's capital structure?

A. Yes. Capital structure components through time are shown on Documents No. 8 and No. 9 in my Exhibit No. JSC-1.

FUTURE FINANCIAL PROJECTIONS AND REGULATORY OPTIONS

Q. How do you expect the company's financial profile and condition to change after 2022?

A. Our rate base will continue growing and we could be facing a federal income tax rate increase.

The second and final phase of our Big Bend Modernization project is expected to be placed into service in December 2022, so its first full year in service will be 2023. We will be placing the second tranche of Future Solar in service in late 2022, so its first full year in service will be 2023. The third tranche of Future Solar will be placed in service in late 2023, so its first full year in service will be 2024. Absent additional rate relief in 2023 and 2024, these plant additions will put pressure on our ability to earn within the range of return on equity the commission establishes in this proceeding.

Q. What are the amounts of incremental rate base for these plant additions in 2023 and 2024?

A. Document No. 10 of my Exhibit No. JSC-1 includes a schedule reflecting the projected original in-service amount for these assets, their projected 13-month average net book value for 2023 and 2024, the expected equity dollar support needed for these assets, and the impact each would have on the company’s Return on Equity.

Q. How would these asset additions impact company regulatory filings?

A. Given the expected rate base growth from normal plant additions and the major projects described above, and absent an alternative regulatory approach, the company anticipates that it would need to seek additional base rate relief for 2023 and 2024. Specifically, the company would expect to file another general request for base rate relief in 2022 seeking additional base revenues in 2023 and a general rate proceeding in 2023 seeking additional base revenues in 2024.

Q. Has the company considered alternatives to filing full general rate proceedings in these two years?

A. Yes. The company proposes that the Commission consider approving GBRAs to cover the asset additions described above. The first GBRA would be effective for the first billing cycle in 2023 in the amount of $102.2 million and would cover the revenue requirement associated with Phase Two of the Big Bend Modernization Project and the second tranche of our Future Solar. The second GBRA would become effective for the first billing cycle in 2024 in the amount of $25.6 million and would cover the third tranche of Future Solar.

Q. Have you prepared a schedule showing the revenue requirements to be recovered by the company's proposed two GBRAs?

A. Yes. Document No. 10 of my Exhibit No. JSC-1 shows the revenue requirement for the assets to be recovered through the two GBRAs using the 13-month average net book value in the first full year the asset is operating.

Q. What assumptions did you make when calculating the GBRAs shown in Document No. 10 of your Exhibit No. JSC-1?

A. The calculations on Document No. 10 start with the 13-month average rate base (net book value) amount for each GBRA project. That amount is then multiplied by the 2022 Rate of Return reflected in MFR Schedule A-1 of 6.67 percent. The resulting net operating income need for each project was multiplied by the NOI Multiplier reflected in MFR Schedule A-1 of 1.34315 to gross up the amount for taxes. This resulted in the calculated Return on Rate Base for each project.

O&M projections are based on amounts expected to be incurred by operations. Depreciation expense for each project uses the depreciation rates for 2022. Property tax expense is based on the prior year end net book value times an estimated percentage of the net book value of assets that is included in the property tax calculation. For Big Bend Modernization Phase 2, this percentage is 59 percent (consistent with historical percentages) and for Solar Wave 2 Tranche 2 and Tranche 3, this percentage is 20 percent (consistent with the solar property tax exemption percentage); this amount is then further multiplied by the projected millage rate of 1.70 percent.

Finally, we added the return on rate base to the operating expense total to determine the total Revenue Requirement for each project.

Q. What rate design principles does the company propose to use for calculating the customer rates needed to implement the GBRAs?

A. We propose that the rates to implement the GBRAs be calculated using the rate design methodology approved by the Commission for our general base rate increase to be effective with the first billing cycle in January 2022.

Q. Does Tampa Electric believe there is a reasonable chance that federal or state corporate income tax rates will increase above their current rates and become effective in 2022 or 2023?

A. Yes. The results of the 2020 general election have increased the prospects of a federal corporate income tax rate increase. Before he was elected, President Biden released a plan to raise the federal corporate income tax rate from 21 percent to 28 percent. Since the members of the same political party effectively control both houses of Congress and the executive branch, the chances of federal tax reform and a corporate tax rate increase are greater now than before the 2020 general election.

Q. What action should the Commission take if the federal corporate tax rate is increased?

A. It depends on when a higher federal income tax rate is enacted and becomes effective.

If a higher corporate income tax rate is enacted during this proceeding and becomes effective for the 2022 tax year, the new tax rate should be used to calculate the company's 2022 revenue requirement and 2022 rate increase. The Commission should also recalculate the company's proposed GBRAs to reflect the new federal income tax rate.

If a higher corporate income tax rate is enacted after this proceeding is over and becomes effective in calendar years 2022 or 2023, or if a higher tax rate is enacted for those years too late in this proceeding to be considered, Tampa Electric recommends that the Commission decide in this case to handle any such change using an approach like the one outlined in the tax reform provision of the 2017 Agreement. In the near term, while the company's 2022 base rate change and GBRAs are "fresh," a future tax rate change, whether up or down, should be handled using a consistent and fair methodology to calculate the impacts of the rate change on the company, and update the company's base rates and charges in an administratively efficient manner. Document No. 11 in my Exhibit No. JSC-1 reflects the company's proposal for addressing near-term tax reform. We ask that the Commission approve it in this proceeding.

Q. Why should the Commission approve the company's proposed method for addressing tax reform?

A. For two reasons.

First, as noted above, income tax expense is the third largest operating expense affecting our revenue requirement. The kind of federal tax rate increase included in the President's plan would immediately and significantly impair our ability to earn a fair rate of return. Having a thoughtful regulatory mechanism in place to deal with a near-term federal corporate income tax rate increase without a full revenue requirement proceeding will promote regulatory economy and efficiency and provide a measure of certainty that would likely be attractive to the investment community.

Second, the kind of tax reform methodology reflected in Document No. 11 of my Exhibit No. JSC-1 worked when federal and state tax rates went down and should work equally well if and when income tax rates go up. Tampa Electric took prompt action to lower its base rates by approximately $107 million when federal and state tax rates went down and should have the same opportunity to increase its rates if income tax rates go up.

Q. What approvals does the company seek for reporting economic development expenses in its earnings surveillance reports in 2023 and 2024?

A. Section 25-6.0426, Florida Administrative Code, governs how Tampa Electric reports economic development expenses for surveillance reporting purposes. Subsection (3) of that rule limits the amount of economic development expense that can be recognized for earnings surveillance reporting purposes. Subsection (4) of that rule specifies that the Commission will determine the level of sharing or prudent economic development costs and the future treatment of those costs for surveillance reporting purposes.

Tampa Electric has included $367,000 of economic development expenses in the calculation of net operating income for its 2022 test year, but intends to spend additional resources on economic development in 2023 and 2024. Those plans include adding team members to focus on economic development and increased spending on the types of economic development expenses allowed for recovery in Rule 25-6.0426. Accordingly, for surveillance reporting purposes in 2023 and 2024, the company seeks permission to incur up to $750,000 and $1.5 million in those years, respectively, with customer sharing at the 95 percent level contemplated in the rule. This additional spending is prudent and will benefit Tampa Electric's customers by contributing to the economic health and growth in our service territory.

SUMMARY

Q. Please summarize your direct testimony.

A. My direct testimony describes how the company's financial profile has changed since our last rate case, the steps we have taken to control expense levels, and how we calculated income tax expense for our 2022 test year. I also propose GBRAs for 2023 and 2024 and a tax reform methodology that, if approved in this case, would substantially reduce our need to seek an additional general base rate increase before 2025.

Since our last rate case, Tampa Electric has continued to transform the company into a safer and more customer-focused electric utility. Our generating fleet is cleaner, greener, and more efficient. These changes have also transformed the company’s financial profile, allowed us to lower fuel costs, to manage O&M expenses, operate within the boundaries of our 2013 Stipulation and 2017 Agreement and moderate our need for future rate increases.

Q. Does this conclude your direct testimony?

A. Yes, it does.

(Whereupon, prefiled direct testimony of William R. Ashburn was inserted.)

Attachment 1

Direct Testimony and Exhibit of William R. Ashburn		
Original Bates Page	*New Bates Page*	*Addition/Change*
33	33	MFR Schedule E-5 Present rates presentation revised to show IS which is part of present rates and eliminate values for GSLDPR and GSLDSU which are only under proposed rates. Proposed rates presentation revised to show GSLDPR and GSLDSU which part of proposed rates and eliminate values for IS which are only under present rates. Some rounding differences corrected from original MFR E-5.
34	34	MFR Schedule E-8 Columns A&B heading corrected to make clear it includes present COS under present revenues, and values included in columns A, B and C are revised to match the Present Rate Structure COS that was inadvertently omitted in original filing. Line 6 revised the rate class title from 'GSD, SBF (c)' to 'GSD (c)'. Line 8 inserted the IS rate class as reflected in the Present Rate Structure COS. The Rate Class Roman numerals were revised for V through VII because the IS rate class was inserted in column IV. Footnote (d) revised for the new IS rate class on line 8. Revised footnote letter (e) and inserted footnote letter (f) for column VII. Minor revisions to the wording for footnote (c) to clarify the proposed GSLDPR and GSLDSU rate classes. New column D added to show proposed revenues to support the proposed revenue requirement increase shown in original column D now reflected in column E. Proposed COS values in new columns H, I and J are revised to match the Proposed Rate Structure COS that was omitted in the original filing.

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 20210034-EI

IN RE: PETITION FOR RATE INCREASE

BY TAMPA ELECTRIC COMPANY

DIRECT TESTIMONY AND EXHIBIT

OF

WILLIAM R. ASHBURN

REVISED: 04/16/2021

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PREPARED 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, business address, occupation, and employer.

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

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

A. My present responsibilities include retail base rate design and tariff administration; regulatory oversight of conservation cost recovery clause, storm protection cost recovery clause, DSM program development, Federal Open Access Tariff formula rate updates, regulatory filings at the Florida Public Service Commission regarding rates and service programs; representation of the company in rulemaking and workshop proceedings; and related matters.

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.

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

A. Yes. I have testified or filed testimony before this Commission in many dockets. Most recently, I submitted direct testimony in Docket No. 20200144-EI, petition for limited proceeding to True-up First and Second Solar Base Rate Adjustments. I also filed direct testimony in Docket No. 20190136-EI, petition for limited proceeding to approve Third Solar Base Rate Adjustment, effective January 1, 2020, by Tampa Electric Company. I filed testimony before this Commission in Docket No. 20180045-EI, Consideration of the Tax Impacts Associated with Tax Cuts and Jobs Act of 2017 for Tampa Electric and Docket No. 20180133-EI, petition for limited proceeding to approve second solar base rate adjustment ("SoBRA"), effective January 1, 2019, by Tampa Electric Company. I also testified before this Commission in Docket No. 20170260-EI, petition for limited proceeding to approve first solar base rate adjustment, effective September 1, 2018, by Tampa Electric Company. I testified for Tampa Electric in Docket No. 20170210-EI as a member of a panel of witnesses during the November 6, 2017 hearing on the 2017 Amended and Restated Stipulation and Settlement Agreement ("2017 Agreement"). I also testified on behalf of Tampa Electric in Docket No. 20130040-EI regarding the company's petition for an increase in base rates and miscellaneous service charges and in Docket No. 20080317-EI which was Tampa Electric's previous base rate proceeding. I testified in Docket No. 20020898-EI regarding a self-service wheeling experiment and in Docket No. 20000061-EI regarding the company's Commercial/Industrial service rider. In Docket Nos. 20000824-EI, 20001148-EI, 20010577-EI, and 20020898-EI, I testified at different times for Tampa Electric and as a joint witness representing Tampa Electric, Florida Power & Light Company ("FP&L") and Progress Energy Florida, Inc. ("PEF") regarding rate and cost support matters related to the GridFlorida proposals. In addition, I represented Tampa Electric numerous times at workshops and in other proceedings regarding rate, cost of service, and related matters. I have also provided testimony and represented Tampa Electric before the Federal Energy Regulatory Commission ("FERC") in rate and cost of service matters.

Q. Please state the purpose of your direct testimony.

A. The purpose of my direct testimony is to present the proposed rates and service charges that will produce the company's proposed jurisdictional revenue requirement increase of $294,995 million. Specifically, I present the following information:

1) Explanation of the proposed rate design for the company's proposed service charges;

2) Explanation of the cost support and rate design for the company’s proposed lighting rates;

3) Explanation of the company's proposed base rate structure modifications, rate designs, and rates; and

4) Tariff schedules proposed to be approved which have been revised to reflect these rate design changes.

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

A. Yes, I am sponsoring Exhibit No. WRA-1 consisting of three documents, prepared under my direction and supervision. The contents of my exhibit were derived from the business records of the company and are true and correct to the best of my information and belief. These consist of:

Document No. 1	List Of Minimum Filing Requirement Schedules Sponsored Or Co-Sponsored By William R. Ashburn
Document No. 2	Development Of Proposed (Target) Base Revenue Increase By Rate Class
Document No. 3	Summary Of Resultant Class Parity Ratios

Q. Are you sponsoring any sections of Tampa Electric's Minimum Filing Requirement ("MFR") Schedules?

A. Yes. I am sponsoring or co-sponsoring the MFR Schedules shown in Document No. 1 of my exhibit. The data and information on these schedules were taken from the business records of the company and are true and correct to the best of my information and belief.

Q. Are Tampa Electric's forecast of base revenues from the sale of electricity and service charges, proposed rate design, and rate schedules provided as part of Tampa Electric's MFR Schedules?

A. Yes, they are provided within the portion of the MFR Schedules designated Section E, "Rate Schedules." Volume III contains the company's Lighting Incremental Cost Study which is a supplement to MFR Schedule E-13d.

Q. What are the company's primary goals for the proposed cost of service and rate design changes in this case?

A. There are two primary proposed structural changes that are reflected in the rate design proposals of Tampa Electric in this case. First is the proposed change to a daily basic service charge rather than a monthly basic service charge. Second is the closure of the IS rate schedules and opening of two new sets of rate schedules — GSLD Primary and GSLD Sub-transmission — to provide electric service to the transferred IS customers as well as the largest primary and sub-transmission served GSD customers. The two new sets of GSLD rate schedules better recognize the cost of providing service to customers taking service on the GSD schedules at higher voltages.

FORECAST OF BASE REVENUES AND SERVICE CHARGES

Q. Did the company prepare a forecast of base revenues from the sale of electricity for 2022? If so, how was the forecast of base revenues derived?

A. Yes. The base 2022 sales revenue forecast for present and proposed rates is summarized in MFR Schedule E-13a and calculated in detail in MFR Schedules E-13c and E-13d. I applied the rates currently in effect to the forecasted billing determinants I received from Witness Cifuentes to derive total annual base revenues forecasted for the 2022 test year before considering the proposed change in rates.

Q. What is the projected retail billed electric revenue for

2022?

A. The projected retail billed electric revenue shown in MFR Schedule E-13a for 2022 is $1,167,379,000 under present rates and $1,462,371,000 under proposed rates, an increase of $294,992,000. Any difference shown on MFR Schedule E-13a from other presentations of these numbers is due to rounding.

Q. Did the company prepare a forecast of service charge revenues? If so, how was the forecast of service charge revenues derived?

A. Yes. The 2022 forecast of service charge revenues for present and proposed rates is presented in MFR Schedule E-13b. I applied the current effective rates to the forecasted billing determinants to derive service charge revenues under current charges. This represents the forecasted amount of service charge revenues before any proposed change to rates is considered. The company is proposing changes to the current levels of service charges which will produce lower revenues than under the current service charges as well as beneficial changes to conditions of providing such services for customers with meters that will now be remotely turned on and off as a result of the

Automated Metering Infrastructure ("AMI") conversion project that Tampa Electric will have completed by the 2022 Test Year.

Q. What is the projected billed service charge revenue for 2022?

A. The projected billed service charge revenue shown in MFR Schedule E-13b for 2022 is $25,785,000 under present rates and $19,150,000 under proposed rates, a decrease of $6,635,000.

Q. What is the total amount of additional base revenues from the sale of electricity and service charges that are produced by the company's proposed rate design changes?

A. The total amount is $294,992,000 in additional revenues in 2022.

RATE DESIGN CRITERIA AND OBJECTIVES

Q. What criteria and objectives were used in designing the new rate schedules and how were they used in the rate design?

A. The basic criteria used in designing Tampa Electric's new rate schedules included 1) cost to serve the various classes, 2) rate history, 3) public acceptance of rate structures, 4) customer understanding and ease of application, 5) consumption and load characteristics of the classes, and 6) revenue stability and continuity. This Commission has recognized these criteria as good ratemaking practices.

Cost to serve is a major consideration in rate design. The use of derived unit cost is a major tool in the design of the company’s proposed rates. Tampa Electric witness Lawrence J. Vogt, through his direct testimony, is supporting the Tampa Electric proposed cost of service study, which provides cost support for the rate design I am proposing. Rate history is another important tool. This includes understanding how Tampa Electric rates were designed in the past, whether they achieved their intended objectives and what rate structures have been successfully applied in Florida and around the country by other utilities. I have worked in the regulatory area at Tampa Electric for over thirty years and am aware of the company’s rate history. In addition, I track rate decisions made by the Commission that affect other jurisdictional electric utilities and participate frequently in EEI rate committee meetings where alternative rate designs, as well as successes and failures of such rates, are discussed. Public acceptance of rate structures, customer understanding, and ease of application are important considerations. I obtain information from frequent contact with the company's customer service team members and interaction with some customers that I factor into my work. Class consumption and load characteristics are used both within the Cost of Service Study supported by Mr. Vogt as well as in the proposed design in developing appropriate projected billing determinants to assure successful recovery of revenue requirements. Revenue stability and continuity are criteria that factor into the rate design when selection of appropriate billing units to apply under the rates is considered, as well as the appropriate forecast of those billing units provided by witness Cifuentes.

Q. With these criteria in mind, did the company have specific objectives that were considered in the proposed rate design?

A. Yes. First and foremost, the rates should be designed for each rate schedule so that their application to the test year billing determinants produces the target class and the total required revenues. The company also had two other specific objectives for the rate design in this case: 1) to create two new sets of GSLD rate schedules open to all eligible customers which will reflect both the service provided to these customers at higher voltage levels and 2) to change the basic service charge to a daily rather than monthly basis to reduce the need for proration for short and long bills and better assign cost responsibility to rate collection.

Q. Did the company meet these objectives?

A. Yes. The proposed rates and tariffs incorporate both additional specific objectives previously described and produce the company's proposed revenue requirements.

PROPOSED SERVICE CHARGES

Q. What was the first step in designing rates and charges to produce the company's revenue requirement?

A. The first step was to determine revenues from service charges. Cost support for the development of service charges is provided in MFR Schedule E-7. This cost support formed the basis of the proposed changes in service charges that are shown on MFR Schedule E-13b. In total, the proposed changes produce $6,635,000 in reduced revenue.

These revenues serve as a credit to offset a portion of the revenue requirement that would otherwise increase the company's base rates.

Q. What change in delivery of services to customers, which result in collection of these service charges, has led to such reduced revenues associated with them?

A. The company has replaced most of its meters with AMI meters since the last time the Commission set the company's service charges. The AMI system will be fully utilized during the test year. This technology allows remote reading and operation of the meters installed at the customer premises and significantly reduces the need to roll trucks into the field to affect certain actions, including activation and deactivation of most meters for new and existing customers. This reduced cost has been reflected in the cost support for two of the charges that are assessed for these services, allowing a significant reduction in the proposed charges themselves as well as the revenues collected from them. This is just one of the many customer benefits that will result from this conversion. Tampa Electric witness Regan B. Haines provides additional detail regarding the customer benefits of the AMI system conversion in his testimony.

Q. What changes are being proposed for the company’s service charges?

A. The cost support that is presented in MFR Schedule E-7 indicated that certain service charges should be increased in price to better reflect the cost of providing those services and best provide cost recovery for them, while one stays the same and two are greatly reduced as discussed above. The proposed service charges are shown on MFR Schedule E-13b column 2.

PROPOSED (TARGET) CLASS REVENUES

Q. After setting prices for service charges, what was the next step in designing rates?

A. Next, the company designed base rates to meet the proposed (target) class revenues. In designing new rates, the company first attempted to move unit prices toward unit costs for the various classes to determine parity. “Parity” is the comparison of the rate of return of a class to the system average rate of return. The term is used interchangeably with the term “rate of return index.” Since parity is calculated by dividing the rate of return for a particular class by the system average rate of return, a class with parity of 100 percent would be earning the same rate of return as the system average, and a class with parity below 100 percent would be earning less than the system average. Parity is useful when determining the development of class revenue targets associated with the proposed base rate revenue increase.

Q. Please describe the procedure used to determine what portion of the company's proposed (target) base rate revenue increase was assigned to each rate class.

A. The focus in determining the portion of the company's proposed (target) base rate revenue increase to be assigned to each rate class is the proposed Cost of Service Study. The Cost of Service Study utilized for this purpose is discussed in the direct testimony of Mr. Vogt.

The first step in determining how much each rate class should share in the company's total revenue increase (*i.e.*, the shortfall between total revenue requirements and total revenues under current rates) is to determine for each rate class the shortfall between the costs allocated to that class and the revenues produced by applying current rates to the class's test year billing determinants. The next step is to determine how much of each class's revenue shortfall will be offset by revenues from Other Operating Revenues that will occur as part of the proceeding (*e.g.* any change in service charge revenues). Once the net revenue deficiency of each rate class has been determined, the final step is to identify whether any ratemaking policy considerations should limit the amount of any rate class's revenue increase. Where an increase limit is imposed on a rate class, the other rate classes must make up the deficiency. This deficiency is spread to those other rate classes in proportion to their respective cost of service requirement to the extent that this resultant increase does not exceed an imposed limit.

The completion of this three-step procedure produces what is referred to as the "target revenues" for each class. The target revenue is the level of revenue that the rate designer attempts to realize from a rate class through the design of proposed rate charges as applied to test year billing determinants.

Q. Did you prepare a document that develops the proposed class target revenues using the procedure you have just described?

A. Yes. Document No. 2 of my exhibit was prepared for that purpose.

Q. Was it necessary to limit any class's rate increase from being set at the increase indicated by the cost of service study?

A. No. No limits were imposed.

Q. Have you combined the revenue requirements of the Residential ("RS") and General Service Non-Demand ("GS") rate classes for developing the target revenues for these rate classes?

A. Yes. This is shown in Document No. 2 of my exhibit. It has been the company's practice since 1982 to set the base rate energy charges of the rate schedules associated with these two rate classes to be at the same rate level, with the only change to this practice being instituted in a prior company rate proceeding where an inverted energy rate design was adopted for the RS standard rate, while the Energy Planner time-differentiated rate maintained an energy rate at the same level as the GS standard energy rate. This practice has led to combining the revenue requirements of these two classes when apportioning target revenues in rate proceedings.

Q. Have you combined the revenue requirements of the General Service Demand ("GSD") and Interruptible Service ("IS") rate classes for purposes of developing the target revenues for these rate classes?

A. No. While Tampa Electric previously combined the revenue requirements of the GSD and IS rates classes, the company's rate proposal in this case is to create a new set of GSLD rates to serve the customers previously served under the IS rates and the largest sized, higher voltage served customers from the GSD set of rate classes. In addition, these customers are separated into two sets of rates, one for primary served customers and the other for subtransmission served customers. These two sets of GSLD rates would retain their separation and the company would target allocations of revenue increase and rate design for them individually.

Q. Were you able to design proposed rates for each rate class in order to produce each class's targeted revenues and reflect the requested increase?

A. Yes. The result of this design is shown in Document No. 3 of my exhibit, which shows a comparison of each class's target revenues and those revenues produced by the application of the proposed charges. It shows that the company's proposed revenues are equal to or very close to target revenues for each class, and the company's proposed revenues in total are within $1,462,371 of its total target revenue requirement. The exhibit also shows a comparison of each class's proposed revenues to its revenue requirement from the company's cost of service study and each class' resultant rate of return under the proposed rates. The company believes this exhibit demonstrates that the company has designed its proposed rates based on cost of service to the extent practical.

RATE DESIGN

Q. Please summarize the rate design changes or revisions the company is incorporating in its proposed base rates.

A. In summary, the following two major changes are proposed:

a. The company proposed to change basic service charges for all rate schedules, and the new proposed GSLD rate schedules, from the existing monthly charge basis to a daily charge basis that will utilize the days of billing contained in each bill as the billing determinant.

b. The company proposes elimination of the "closed to new business" IS rate schedules and transfer of the affected metered accounts to the newly proposed GSLD Primary and GSLD Subtransmission sets of rate schedules. The company would also transfer GSD primary and sub-transmission service metered accounts which exceed 1000 kW in demand to these new rate schedules. In addition, because the new GSLD sets of rate schedules are designed for service to only one voltage level of service each, the company would eliminate transformer ownership discounts and some meter level discounts for those rate schedules.

Q. You indicated that you revised basic rate charges in the various rate schedules in order that the proposed charges would result in the target revenues. To accomplish this, did you make any rate restructuring changes to any of your rate schedules?

A. Other than the closing of IS rate schedules, opening of two new GSLD rate schedules and change of basic service charge to a daily basis, the company is not proposing any rate restructuring changes. The company set the fixed Basic Service Charge in each rate schedule at its unit cost from the Cost of Service Study. The company revised the demand and energy charges in each rate schedule to produce the target revenues for each rate class. Tampa Electric also continued prior Commission-approved and prescribed practices to: (a) maintain the RS inverted energy rate with a one cent inversion after the 1,000 kWh usage level, (b) establish the GS energy rate at an effective RS average rate, (c) maintain an optional GSD energy rate set at 120 percent of the GS energy rate, (d) establish time of use energy and demand charges for the GST and GSDT rate schedules in the manner previously adopted, and (e) establish the standby rates in the manner prescribed by the Commission for the design of standby rates.

Q. Can you provide a brief history of the rate treatment afforded the current IS customers and why the company no longer needs to recognize these customers as a separate rate class for establishing their base rate charges but proposes new GSLD rate classes for service to them and to the larger GSD customers served at primary and subtransmission voltage?

A. Yes. For many years Tampa Electric has established and designed IS rate schedules to have lower base rate charges than other customers to recognize their "interruptibility" value. In Docket No. 080317-EI, the Commission approved a rate restructuring for the closed IS rate schedules whereby an IS customer's "interruptibility" would be treated as a demand-side or load management program. As load management participants, IS base rates were no longer required to be set less than that of firm customers. Instead, the IS customers receive interruptible demand credits for their participation as load management customers, and these credits are recovered from all customers through the ECCR clause. The interruptible demand credits are the same credits as had been previously established in Rate Schedules GSLM-2 and GSLM-3, which were also applicable to other general service demand customers desiring to be load management participants.

Q. Why did the Commission close the company's IS rate schedules to new customers?

A. Actually, the company's IS rate schedules were "closed to new business" even before the 2008 base rate proceeding. The IS-1 rate schedules were " closed to new business" in 1985 and the IS-3 rate schedules were "closed to new business" in 2000 when the GSLM-2 and GSLM-3 conservation programs were opened. The Commission's decision in Docket No. 080317-EI was a continuation of such closure for the IS rate schedules. In that proceeding, the company sought to permanently eliminate the already "closed" IS rate schedules on the basis that they were no longer necessary since interruptible service was openly available to any customer under the company's GSD rate schedules who wished to subscribe to the GSLM-2 or GSLM-3 rider as load management program participants. However, the Commission chose to maintain an IS rate class and accompanying rate schedules for those remaining metered accounts being served under the IS schedules and grandfathered them under the then closed IS schedules.

Q. How would you describe the company's proposal in this proceeding for treating customers being served under the IS rate schedules?

A. The company proposes an approach to final closure of the IS rate schedules by combining the remaining IS metered accounts with comparable higher voltage served customers from the GSD rate schedules to better reflect their load characteristics as a class and their utilization of the utility grid at higher voltage. The affected metered accounts would be transferred to the new GSLD rate schedules and continue to participate in the company's GSLM-2 or GSLM-3 load management program riders and obtain the same credits for interruptible service that they are paid now. As with other customers on the GSLM-2 and GSLM-3 riders, these transferred customers' loads will be included in the company's biannual filed assessment of need of non-firm electric service.

Q. Have you prepared any billing comparisons of the effect of transfer of the IS metered accounts and the GSD metered accounts being transferred to the proposed new GSLD rate schedules?

A. Yes. MFR Schedule E-13C shows the billing impact for the IS customers which are proposed to take service under the new GSLD schedules as well as the GSD customers which are similarly proposed to take service under the new GSLD schedules.

Q. Other than the transfer of IS metered accounts and certain GSD metered accounts to their applicable GSLD rate schedule, will the company's proposed rate changes result in any other customer transfers from one rate schedule to another?

A. None are projected.

Q. Does Tampa Electric propose any changes to the charges associated with Lighting Service Rate Schedule LS-1?

A. Yes. Those proposed changes are shown on MFR Schedule E-

13d. As the Commission is aware, Tampa Electric is converting all its outdoor lighting equipment utilizing High Pressure Sodium and Metal Halide fixtures to new highly efficient Light Emitting Diode ("LED") outdoor lighting facilities. As a result, the existing lighting offerings for High Pressure Sodium and Metal Halide lights are closed to new business. The company is conducting this conversion as a conservation program with recovery of the undepreciated plant balance of the existing facilities through the conservation cost recovery clause.

The company will not complete the conversion project until 2023. As a result, the company proposes to retain the existing lighting offerings for the High Pressure Sodium and Metal Halide lights in the lighting tariffs and MFR Schedules with an average rate increase applied to the fixture rates. The company proposes to leave the operation and maintenance charges for those lights at their current levels. Once the conversion is completed in 2023, and the company is no longer issuing bills for the affected closed light offerings, Tampa Electric expects to make a filing to remove those lighting offerings from the tariff at one time.

As in the company's previous rate cases, the company performed an incremental lighting study that is provided as a supplement to the MFR Schedules. The company utilized this study to determine the final rate proposals for the lighting and pole offerings that remain open. The company is not proposing any changes to the operations and maintenance costs for the open LED rate schedules in this rate case. The LED fixtures have not been in service long enough for the company to determine whether the current proposed operation and maintenance rates are no longer appropriate.

Q. Does Tampa Electric propose any other miscellaneous tariff changes?

A. Yes, along with tariff changes needed to accommodate the two new GSLD rate schedules in many sections of the tariff, some changes have been proposed within the definitions section of the tariff and in Section 5 to make clearer certain terms and conditions of service shown therein.

Q. Where can the results of the company's total rate design be found?

A. The revenue distribution by rate schedule is shown on MFR Schedule E-13a, supported by the detailed billing calculations in MFR Schedules E-13c and E-13d. The effect on customers' typical bills is shown on MFR Schedule A-2 and a comparison of present and proposed charges is shown on MFR Schedule A-3.

PARITY RESULTS OF PROPOSED RATE DESIGN

Q. Does your proposed rate design move rates closer to parity from a cost of service standpoint?

A. Yes. Document No. 3 of my exhibit presents the achieved class revenue requirement indices. Overall, most rate classes are reasonably close to parity. An index ratio of 1.00 indicates rates are set exactly on the cost of service. A ratio of less than 1.00 indicates that class is served below cost, and a class ratio of more than 1.00 indicates that class is served above cost.

SUMMARY

Q. Please provide a summary of the company’s proposed rates and Cost of Service Studies in this proceeding.

A. The support for, and design of, the proposed rates in the case as presented in the MFRs and proposed tariffs meet the company’s primary goals as articulated previously in my direct testimony. These rates are cost-based and reflect appropriately measured changes from the present rates that also reflect rate history, public acceptance of rate structures, customer understanding and ease of application, consumption and load characteristics of the classes, and will result in revenue stability and continuity.

Q. Does this conclude your direct testimony?

A. Yes, it does.

(Whereupon, prefiled direct testimony of Davicel Avellan was inserted.)

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 20210034-EI

IN RE: PETITION FOR RATE INCREASE

BY TAMPA ELECTRIC COMPANY

DIRECT TESTIMONY AND EXHIBIT

OF

DAVICEL AVELLAN

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

DAVICEL AVELLAN

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

A. My name is Davicel "David" Avellan. My business address is 702 North Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "company") as Director, Regulatory Plant and Tax Accounting.

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

A. I am responsible for overseeing all of the regulatory asset accounting and reporting, which includes maintaining the financial books and records of Tampa Electric and its natural gas distribution division - Peoples Gas System - relating to property, plant, and equipment, including depreciation, amortization, and asset retirement obligations. I am responsible for all depreciation and dismantlement studies filed with the Florida Public Service Commission ("Commission") and the Federal Energy

Regulatory Commission ("FERC"). I am also responsible for providing tax services to Tampa Electric Company, Peoples Gas System, and New Mexico Gas Company. My responsibilities include the preparation and filing of tax returns, tax accounting for internal and external purposes, tax planning, and managing federal and state income tax audits.

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

A. I attended the University of Tampa and graduated from the American Intercontinental University with a bachelor's degree in Accounting and Finance in 2006. I have worked in the Accounting groups at Tampa Electric; TECO Services, Inc.; TECO Energy, Inc.; and TECO Power Services Corporation for the last 26 years, with increasing responsibilities as Coordinator, Supervisor, Manager, and my current position of Director – Regulatory Plant & Tax Accounting. I have been active at the Edison Electric Institute ("EEI") and American Gas Association on their respective accounting committees, and currently serve as Chairman of EEI's Tax Systems and Technology Subgroup. I am also a member of the Society of Depreciation Professionals.

Q. Have you previously testified before the Florida Public Service Commission or other regulatory authority?

A. Yes. I have filed direct testimony with and been a sworn witness on behalf of New Mexico Gas Company for proceedings at the New Mexico Public Regulation Commission ("NMPRC") with the primary focus of my direct testimony related to income taxes. In addition, I have filed testimony in two depreciation-related dockets at the FERC. Those testimonies were filed in Docket No. ER20-1935-000 on May 29, 2020, in support of the company's request to add an intangible solar depreciation rate to its Open Access Transmission Tariff ("OATT") as of January 1, 2019, and in Docket No. ER20-1960-000 on June 2, 2020, to add a transmission energy storage depreciation rate to the same tariff as of May 15, 2020. They were accepted for filing by the FERC, respectively, on July 14, 2020, and July 2, 2020.

Q. What are the purposes of your direct testimony?

A. The purposes of my testimony are to: (1) provide background information about the company's current depreciation rates, (2) describe the process and results of the depreciation and dismantlement study prepared by Tampa

Electric and filed in Docket No. 20200264-EI on December 30, 2020, (3) support and justify the depreciation rates proposed by Tampa Electric to be effective January 1, 2022, and used in the Minimum Filing Requirements ("MFR") schedules for the 2022 test year, and (4) describe the capital recovery schedules proposed by Tampa Electric for the undepreciated net book value of assets, such as the portions of Big Bend Units 1, 2, and 3 electric generating units that are being retired, as described by Tampa Electric witness J. Brent Caldwell, and Automated Meter Reading ("AMR") meter retirements as described by Tampa Electric witness Regan B. Haines. I also support the amount of depreciation expense and amortization of capital cost recovery included in the calculation of 2022 test year net operating income.

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

A. Yes. Exhibit No. DA-1, entitled "Exhibit of Davicel Avellan" was prepared under my direction and supervision. The contents of my exhibit were derived from the books and records of the company and are true and correct to the best of my information and belief. My exhibit consists of two documents, as follows.

Document No. 1	List of Minimum Filing Requirement Schedules Sponsored or Co-Sponsored by Davicel Avellan
Document No. 2	Investment and cost associated with retirement of Big Bend Unit 1, 2, and 3, and AMR meter net book value proposed reclassification to FERC 182.2(Unrecovered Plant).

Q. Are you sponsoring any sections of Tampa Electric’s MFR schedules?

A. Yes. I am sponsoring or co-sponsoring the MFR schedules listed in Document No. 1 of my exhibit.

TAMPA ELECTRIC’S CURRENT DEPRECIATION RATES

Q. When were the company’s current depreciation rates approved by the Commission?

A. Tampa Electric filed its last depreciation study in 2011. The Commission approved depreciation rates for the company on April 3, 2012, by Order No. PSC-2012-0175-PAA-EI in Docket No. 20110131-EI. That Order became final on April 30, 2012, by Order No. PSC-2012-0226-CO-EI. The company used the rates approved in Docket No. 20110131-EI when it filed its most recent general rate case in 2013, Petition of Tampa Electric Company for an Increase in Base Rates and Service Charges, Docket No. 20130040-EI ("2013 rate case").

The company's 2013 rate case was resolved by stipulation. On September 8, 2013, Tampa Electric and the Consumer Parties – the Office of Public Counsel ("OPC"), Florida Industrial Power Users Group ("FIPUG"), Florida Retail Federation ("FRF"), Federal Executive Agencies ("FEA"), and West Central Florida Hospital Utility Alliance ("HUA") - filed a Stipulation and Settlement Agreement ("2013 Stipulation") that resolved all issues in Tampa Electric's 2013 rate case.

Paragraph 8 of the 2013 Agreement states:

> 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 Agreement to file any depreciation study or dismantlement study. The depreciation and amortization accrual rates in effect as of the effective date of this Agreement (except as modified for software by paragraph 11(b)) shall remain in effect throughout the Term. The Parties agree that the provisions of Rules 25-6.0436 and 25-

6.04364, F.A.C., pursuant to which depreciation and dismantlement studies are filed at least every four years will not apply to the company during the Term and that the Commission's approval of this Agreement shall excuse the company from compliance with the filing requirement of these rules during the Term. The company shall file a depreciation study no more than one year nor less than 60 days before the filing of its next general rate proceeding under Sections 366.06 and 366.07, Florida Statutes, such that the proposed depreciation rates can be considered contemporaneously with the company's next general rate proceeding.

Q. Is this provision still in effect today?

A. Yes. Tampa Electric amended and restated the 2013 Stipulation in 2017 and executed an agreement called 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 8 of the 2013 Stipulation, as detailed above, was included as paragraph 8 of the 2017 Agreement with certain clarifications.

Paragraph 8 of the 2017 Agreement states:

(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.

This explains why the company has not filed a depreciation study since 2011 and why the company filed a depreciation and dismantlement study on December 30, 2020 in anticipation of the current rate case filing.

Q. Other than approving the 2013 Stipulation and 2017 Agreement, has the Commission taken any other actions that affect the company's depreciation and amortization rates over this same period?

A. Yes. The Commission has entered orders addressing the depreciation of the company's Advanced Metering Infrastructure ("AMI") system, amortization of intangible software, and new depreciation rates for three new categories of plant assets.

Q. What action did the Commission take on depreciation of the company's AMI system?

A. The Commission approved a commencement date of January 1, 2022, for the depreciation of Tampa Electric's AMI program assets in Order No. PSC-2019-0327-PAA-EI, issued on August 9, 2019, in Docket No. 20190107-EI. The AMI meters will be fully functional and in-service at that time, meaning the system will be able to provide customer service tools, remote connection or disconnection of service, and information regarding customer energy usage.

As a part of this order, the Commission also directed Tampa Electric to continue to record depreciation expense on its existing AMR assets if replaced by AMI assets during the term of the 2017 Agreement, as addressed in Section 8 and described above.

Q. What actions did the Commission take regarding amortization of the company's intangible software?

A. In Order No. PSC-2013-0443-FOF-EI, issued September 30, 2013, the Commission approved the 2013 Stipulation and accordingly directed the company to begin using a 15-year amortization period for all intangible software.

In Order No. PSC-2015-0573-PAA-EI, the Commission approved the Company's Petition for Approval of Depreciation Rates for Solar Photovoltaic ("PV") generating units and associated units over a 30-year period with a whole life depreciation rate of 3.3 percent. As a result, the company created subaccount 303.99 for the intangible software associated with its solar PV facilities and is amortizing that software over 30 years.

In Docket No. 20200065-EI, the Commission approved the company's petition to eliminate the accumulated amortization reserve surplus for intangible software assets of approximately $16.0 million and to amortize it over 12 months, beginning in January 2020.

Q. What actions did the Commission take to approve depreciation rates for new categories of plant assets since 2013?

A. In Order No. PSC-2017-0391-PAA-EI, the Commission approved a 35-year average service life and a whole life depreciation rate of 2.9 percent for the Polk 2 combined cycle ("CC") unit, including heat recovery steam generator, steam turbine, and associated equipment. The combined cycle assets are unitized in the following plant account depreciation groups:

341.86 Structures and Improvements

342.86 Fuel Holders, Producers and Accessories

343.86 Prime Movers
345.86 Accessory Electric Equipment
346.86 Miscellaneous Power Plant Equipment

In Order No. PSC-2020-0116-PAA-EI, the Commission approved a 10-year average service life and a whole life depreciation rate of 10 percent for the company's energy storage equipment. The energy storage asset accounts include the following plant account depreciation groups:

348-Energy Storage Equipment-Production
351-Energy Storage Equipment-Transmission
363-Energy Storage Equipment-Distribution

The company's current battery storage assets are unitized into the plant account depreciation group 348.99 Energy Storage Equipment-Production.

As I previously stated, the Commission approved new depreciation rates for solar generating units by Order No. PSC-2015-0573-PAA-EI, including a 30-year service life and a whole life depreciation rate of 3.3 percent. The solar assets are unitized into the following plant account depreciation groups:

303.99 Intangible Plant
341.99 Structures and Improvements

343.99 Other Generation Plant

345.99 Accessory Electric Equipment

Q. Does the 2020 and 2021 financial information in the MFR schedules filed in this case reflect the Commission actions discussed above?

A. Yes.

TAMPA ELECTRIC'S 2020 DEPRECIATION AND DISMANTLEMENT STUDIES

Q. Did the company file a depreciation and dismantlement study "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 [this] rate proceeding" as required in the 2017 Agreement?

A. Yes. The company filed a depreciation and dismantlement study on December 30, 2020 in Docket No. 20200264-EI. I will refer to this study as the "2020 Depreciation Study" during the remainder of my testimony. Consistent with the 2017 Agreement, the company will file a motion to consolidate Docket No. 20200264-EI with this rate case docket shortly after the petition, testimony and MFRs are filed in this docket.

Q. Please generally describe the 2020 Depreciation Study and summarize the results of the study.

A. We employed generally accepted standard depreciation methods, procedures, and techniques in preparing the 2020 Depreciation Study. The table below shows the proposed changes in annual depreciation, based on 2019 Ending Gross Plant Balances, resulting from the proposed changes to depreciation rates and dismantlement accruals. The company has proposed to establish amortization schedules for: (1) the remaining net book values and dismantlement reserve deficiencies for Big Bend Unit 1, Big Bend Unit 2, and Big Bend Unit 3; and (2) the remaining net book value for AMR meters resulting from the systemwide conversion to AMI meters. The following change in expense levels does not include any impacts of these proposed amortization recovery schedules.

Steam Production Plant	$ 8,510,671
Other Production Plant	18,609,414
Subtotal Change in Generation	**27,120,085**

Transmission Plant	1,203,427
Distribution Plant	1,180,333
General Plant	95,468
Subtotal Change in TD&G	**2,479,228**
Dismantlement	$ 6,828,649
Total Change in Depreciation & Dismantlement	**$36,427,962**

The depreciation study is organized by functional group: Generation Production; Transmission, Distribution, and General Plant; and Dismantlement. Each of these groups also contains subdivisions. Generation Production plant is organized by Energy Supply power stations, units, and accounts stratified by life category composites. Transmission, Distribution & General plant is organized by plant accounts or sub-accounts. Dismantlement is organized by power station units.

The effective date of the implementation requested for changing depreciation rates and dismantlement accruals is January 1, 2022.

Q. Was the 2020 Depreciation Study prepared in accordance with FPSC Rules 25-6.0142, 25-6.0143, 25-6.0436, 25-

6.04361 and 25-6.04364?

A. Yes.

Q. What role did you play in preparing the 2020 Depreciation Study?

A. The 2020 Depreciation Study was prepared by Tampa Electric staff under my direct supervision.

Q. What definition of "depreciation" have you used in the preparation of the 2020 Depreciation Study and this testimony?

A. Utility depreciation recognizes the wear and tear on plant or equipment as it performs its intended function. Annual depreciation represents the reduction in useful life of the plant or equipment during one year of operation. The net of interim salvage value and cost of removal is adjusted against the reserve and is factored into the whole-life or remaining-life formulas used to calculate the annual depreciation rate of accrual per category of plant or equipment.

Q. What is the purpose of a depreciation and dismantlement study?

A. The purpose of a depreciation study is to estimate the useful service lives (average service life and average remaining life) of different components of plant or equipment. Each category of plant or equipment is based on the Code of Federal Regulations - Title 18: Conservation of Power and Water Resources, Chapter I, Subchapter C, Part 101, Electric Plant Chart of Accounts segregated by FERC function and designated by account numbers 301-399. The plant account in total, or stratification of equipment within a plant account, is analyzed for useful service life, net of interim salvage value and cost of removal factors in conjunction with vintage year plant costs and Iowa survivor curve plotting to calculate the annual depreciation rate for that plant account.

The purpose of the dismantlement study, which applies to all generating plant (Production Steam and Production Other), is to reserve funds for the final disposition and removal of a generating station or unit during end-of-life decommissioning. Each generating unit has its own terminal year based on when the unit was placed in-service and its estimated maximum life span. Each unit is provided an estimated cost for final disposition and removal that is escalated to the terminal year for calculating the annual dismantlement accrual. The standard dismantlement study determines these costs based on removal or demolition at the end of life of the entire station. Additional costs are incurred if units are removed while units at the station continue to operate, as described in the direct testimony of witness Charles R. Beitel.

Q. What steps, inputs, and data did you use to prepare the 2020 Depreciation Study?

A. The 2020 Depreciation Study is based on the continuing property record details per each plant account as of December 31, 2019. Generating unit (Production Steam and Production Other) plant accounts and equipment are stratified by retirement unit into varying average service lives and Iowa curve types for analysis, and the results are then aggregated into a composite rate for each plant account. An additional data point, called the terminal date of the generating unit, is also taken into consideration. The terminal date is the year when the generating unit will be taken out of service and dismantled. Using the terminal date, the Iowa curve analysis will begin to truncate the remaining life per vintage to fully recover the invested cost of each generating unit. Transmission, Distribution and General Plant equipment is studied at the plant account level for average service life and curve analysis. The underlying plant account retirement unit details are reviewed for primary drivers, each is assigned an average service life, and weighted averages are calculated, resulting in a composite average service life for curve type study purposes. Terminal dates are not used when studying perpetual Transmission, Distribution and General Plant account equipment. Annual salvage and cost of removal of historical information through 2019 and corresponding 5-year rolling averages are reviewed and input selections are made for net salvage factors to complete the whole life and remaining life formula calculations.

The dismantlement study is projected through a December 31, 2021, reserve starting point for modeling the change in annual accrual. The projection uses vendor-provided cost estimates in 2020 dollars subject to cost escalations using Moody's Analytics October 2020 indices for the GDP Chain Price Deflator (2012=100); Intermediate Goods, Producer Prices (1982=100); and Compensation Per Hour, Productivity and Costs (2012=100). The model performs a present value annual accrual calculation based on the estimated future cash flows that were escalated to each generating unit's terminal date. The dismantlement annual accrual per generating unit is based on an average of the next four years of projected annual accruals between 2022 and 2025.

Q. What classes of property are included in the 2020 Depreciation Study?

A. Tampa Electric plant or equipment is categorized by function into FERC electric plant accounts, specifically Steam Production Plant (311-317), Other Production Plant (341-348), Transmission Plant (350-359.1), Distribution Plant (361-374), General Plant (390-399.1), and Intangible Plant (303).

Q. What classes of property were not included in the 2020 Depreciation Study?

A. Tampa Electric does not have any plant or equipment categorized by the following FERC functions of electric plant accounts: Nuclear Production Plant (320-326), Hydraulic Production Plant (330-337), Regional Transmission and Market Operation Plant (380-387), and Intangible Plant (301-302). In addition, non-depreciable land costs assigned to FERC electric plant accounts 310, 340, 350, 360, and 389 were not included and utilize a zero percent depreciation rate.

Q. What depreciation systems did you use when preparing the 2020 Depreciation Study?

A. In 2016, Tampa Electric implemented a new depreciation software solution, PowerPlan's Depreciation Study module. The company utilizes Excel spreadsheets to aggregate the results of the module. We accomplish inclusion of our consultant dismantlement study results in the 2020 Depreciation Study through an Excel spreadsheet model that has been used in the company's previous depreciation study filings.

Q. What is a survivor curve, and how were survivor curves used in preparation of the 2020 Depreciation Study?

A. Iowa survivor curve analysis is a standard method for determining utility plant remaining life. The Iowa survivor curves were developed at the Iowa State College Engineering Experiment Station in the 1950s through the process of observation and classification of ages at which industrial property had been retired. These standardized patterns of asset retirement dispersion are organized into four broad classes of curve types: Right-Modal "R" curve, Left-Modal "L" curve, Symmetrical "S" curve, and Original Modal "O" curve. The purpose of Iowa curves is to enable the calculation of an average remaining life based on the average service life chosen. Remaining life calculations take the current age of each vintage of equipment within a plant account and then use the retirement rate projected by the appropriate Iowa curve to project the remaining life per each vintage. We chose the Iowa survivor curve for each plant account or stratified plant account based on historical precedent, comparable industry best practices, or advanced analytics, if available.

Q. What is the depreciation rate formula, *i.e.*, how are depreciation rates developed?

A. There are two depreciation rate formula techniques – whole life and remaining life. Under the whole life method, depreciation expense must cover invested capital and recognize credit for salvage and recover cost of removal over the average service life. This is expressed by the following formula:

$$\frac{100\% - (\text{Salvage }\% + \text{Cost of Removal }\%)}{\text{Average Service Life}}$$

Using the remaining life method, depreciation expense must cover invested capital, recognize credit for salvage, recover cost of removal, and be adjusted for the actual book reserve ratio over the average remaining life. This is expressed by the following formula:

$$\frac{100\% - (\text{Salvage } \% + \text{Cost of Removal } \%) - \text{Reserve } \%}{\text{Average Remaining Life}}$$

Q. What portion of the formula used to derive depreciation rates is supported by the study?

A. The study utilizes plant and depreciation reserve balances as of December 31, 2019. The study supports the remaining life formula calculation of depreciation rates and determines the average remaining life and theoretical reserve amounts based on inputs for vintage surviving plant balances, Iowa curve type, net salvage percentages, and average service life estimation.

Q. Please describe the work you performed in the first step of the 2020 Depreciation Study, *i.e.*, data collection.

A. Tampa Electric files an annual depreciation status report with the Commission. We extracted plant and depreciation reserve balances as of December 31, 2019, as seen on the annual status report pages B-7 and B-9, submitted on June 1, 2020, from the continuing property record in detail by asset retirement unit. We calculated historical net salvage activities for gross salvage and gross cost of removal, as seen on annual status report page B-9 and recorded them by year and 5-year rolling averages.

Q. Please describe the work you performed in the second step of the 2020 Depreciation Study, *i.e.,* analysis.

A. For production plant accounts, we analyzed the generating units for terminal date (end of life) year changes. Then we stratified each production generating unit plant account's asset retirement unit records into short, medium, and long-life categories. Each category is applied a different Iowa curve type, average service life and results aggregated by plant account. We analyzed the Transmission, Distribution and General Plant accounts on a non-stratified, perpetual (no terminal date) basis for applying a singular Iowa curve type, average service life and net salvage factor.

Q. Please describe the work you performed in the third step of the 2020 Depreciation Study, i.e. evaluation.

A. We performed initial analyses and had them reviewed internally by company engineers. The production generating unit terminal date assessments are critical for determining whether depreciation recovery of a specific unit needs to accelerate due to early shutdown or decelerate due to life extension. We compared Transmission, Distribution and General Plant account average service life assessments for property group cross-functional similarities or differences and for future program initiatives that could impact average service lives.

Tampa Electric considered its new Storm Protection Plan ("SPP") program initiative for this study. The activities were determined to be mostly wind mitigation outage prevention activities that would not cause average service life extension.

Q. Please describe the work you performed in the fourth step of the 2020 Depreciation Study, *i.e.,* calculation.

A. After evaluations were completed, we finalized inputs and factored them into the depreciation study software to produce the necessary output reports that yield the average remaining lives, theoretical reserves, and remaining life formula calculation of depreciation rates. We then summarized the study outputs on a spreadsheet in order to perform comparisons using existing depreciation rates and the study's proposed depreciation rates for the annual accrual change impacts.

Q. Did Tampa Electric commission a 2020 dismantlement study to be performed?

A. Yes. The company contracted with 1898 & Co. to perform the standard dismantlement study. This study considers the costs and accrual needed for dismantlement of each entire station at the end of the life of the longest-lived unit. Tampa Electric also contracted with Sargent & Lundy to perform a dismantlement study for the cost estimates related to the near-term dismantlement of Big Bend Units 1, 2, and 3 within a functioning power station. Witness Jeffrey S. Kopp with 1898 & Co. sponsors and describes the dismantlement study where removal is completed at the end of the entire plant life in his direct testimony. In his prepared direct testimony, Mr. Beitel with Sargent & Lundy sponsors and describes the dismantlement studies that provide the demolition and removal costs of Big Bend Units 1, 2, and 3 while the remaining units at the plant continue operating.

Q. Please explain how you incorporated the results of the 1898 & Co. and Sargent & Lundy dismantlement studies in the 2020 Depreciation Study.

A. We used the 1898 & Co. dismantlement cost estimates for all generating assets except for Big Bend Units 1, 2, and 3. We used the cost estimates from Sargent & Lundy for the Big Bend Units 1, 2, and 3 assets because these units will be demolished within an operating power plant, as described earlier in my testimony and in the testimony of Mr. Beitel.

PROPOSED DEPRECIATION RATES AND EXPENSE FOR 2022 TEST YEAR

Q. What depreciation rates does the company propose to use for its 2022 test year in this proceeding?

A. The company proposes to use the depreciation rates developed in its 2020 Depreciation Study as described above. Those rates are set forth by category of plant asset. The use of these rates is reflected in the 2022 financial data included in the company's MFR schedules filed in this case.

Q. Are the depreciation rates proposed for 2022 by the company reasonable?

A. Yes, based on the analyses performed to prepare the 2020 Depreciation Study filing and review and comparisons to other utilities' rates, the depreciation rates and expense levels proposed for 2022 are reasonable and should be approved.

Q. Have you compared the depreciation rates proposed by the company for 2022 to the depreciation rates being used by other public electric utilities in Florida?

A. Yes. Tampa Electric compared Production Steam, Production Other, Transmission, Distribution, and General Plant account metrics to other public utilities for depreciation rate, average service life, average remaining life, future net salvage, reserve ratio, and curve type, if data was available. The purpose was to compare proposed study metrics looking for outlier low or high data points, and focus was placed on average service life and future net salvage differences. Tampa Electric's proposed rates are comparable to those used by other electric utilities.

Q. Using the company's proposed depreciation rates, what is the amount of depreciation expense in the 2022 test year?

A. The amount of depreciation expense in the 2022 test year using the company's proposed depreciation rates and the proposed 10-year amortization period for recovery of the special capital recovery schedules for retiring assets is $493,324,106 as shown on MFR Schedule B-9. The table below is the detail by group:

PowerPlant Depr Group	2022	10-year Amortization Capital Recovery Schedule	Total 2022 Depreciation
Dismantlement	8,014,742	11,108,881	19,123,623
Acquisition Adjustments	236,709		236,709
SOFTWARE - Intangibles	29,516,555		29,516,555
ARO - Intangibles	5,493,447		5,493,447
GENERATION - Steam	45,258,426	47,619,458	92,877,884
GENERATION - Other	155,342,425		155,342,425
TRANSMISSION	33,038,697	532,506	33,571,203
DISTRIBUTION	123,196,423	3,614,687	126,811,110
VEHICLES - General	4,986,730		4,986,730
GENERAL - General	25,363,122	1,298	25,364,420
TOTAL	**430,447,276**	**62,876,830**	**493,324,106**

Q. How does the proposed depreciation expense amount for 2022 compare with the projected amount of depreciation expense for 2021, and how much of the increase is due to changes in depreciation rates?

A. The difference between the 2022 depreciation expense and the projected amount of 2021 depreciation expense, excluding the amortization of the capital recovery schedules, is $51,878,413. The table below sets out the differences in detail by group:

PowerPlant Depr Group	2021	2022	Difference
Dismantlement	1,186,094	8,014,742	6,828,648
Acquisition Adjustments	236,709	236,709	-
SOFTWARE - Intangibles	18,018,310	29,516,555	11,498,245
ARO - Intangibles	5,493,447	5,493,447	-
GENERATION - Steam	72,734,684	45,258,426	-27,476,259
GENERATION - Other	114,509,070	155,342,425	40,833,355
TRANSMISSION	29,412,703	33,038,697	3,625,994
DISTRIBUTION	109,213,822	123,196,423	13,982,601
VEHICLES - General	4,017,007	4,986,730	969,724
GENERAL - General	23,747,016	25,363,122	1,616,106
TOTAL	**378,568,863**	**430,447,276**	**51,878,413**

COST RECOVERY SCHEDULES

Q. Is the company proposing special cost recovery schedules for the portions of Big Bend Units 1, 2, and 3 to be retired, as discussed in the direct testimony of witness Caldwell?

A. Yes. Mr. Caldwell has shown that the early retirement of portions or all of Big Bend Units 1, 2, and 3 are prudent and that the associated investment will not be recovered by the time of retirement through the current depreciation rates. Accordingly, pursuant to FPSC Rule 25-6.0436(7), the company is requesting that the Commission approve a capital recovery schedule for the $481,532,619 of undepreciated Big Bend Units 1, 2, and 3 assets to be retired.

Q. Over what period does the company propose to recover the $481,532,619 of undepreciated Big Bend Units 1, 2, and 3 assets to be retired and why?

A. The company proposes to recover the $481,532,619 of the Big Bend Units 1, 2, and 3 remaining net book value over a 10-year period as reflected on MFR C-19. The company analyzed various alternatives and concluded that the 10-year amortization period reflects a prudent and reasonable time period that would mitigate the rate impact on customers.

Q. What is the resulting annual cost recovery amount if the FPSC approves the company’s proposal?

A. The annual cost recovery amount if the FPSC approved the company’s proposal is $48,153,263:

	12/31/2021 NBV	Recovered through ECRC Clause	Rate Base	10 Years Annual Amortization
BB1-Boiler 1	86,841,738		86,841,738	8,684,174
BB1-SCR 1	36,027,477	42,029,496	-6,002,019	3,602,748
BB2-Boiler 2	89,024,459		89,024,459	8,902,446
BB2-SCR 2	51,391,691	50,765,849	625,842	5,139,169
BB2-FGD 1/2	30,890,328	19,351,304	11,539,024	3,089,033
BB3-Boiler 3	145,197,790		145,197,790	14,519,779
BB3-SCR 3	**42,159,136**	41,726,353	432,783	**4,215,914**
Total	**$481,532,619**	**$153,873,002**	**$327,659,617**	**$48,153,263**

Q. Is the company proposing a special cost recovery schedule for the unrecovered value of AMR meters that were retired during the period the 2017 Settlement Agreement was effective?

A. Yes, the company is requesting that the Commission approve a capital recovery schedule to recover $36,146,873 for the remaining net book value of the AMR meters as reflected on MFR Schedule C-19.

Q. Over what period does the company propose to recover the $36,146,873 of undepreciated retired AMR meter assets and why?

A. The company proposes to recover the $36,146,873 of the AMR remaining net book value over a 10-year period. The company analyzed various alternatives and determined that a 10-year amortization period is prudent and reasonable because it provides a reasonable balance between timely recovery of the costs while mitigating the rate impact on customers.

Q. What is the resulting annual cost recovery amount if the Commission approves the company's proposal?

A. The annual cost recovery amount if the Commission approved the company's proposal would be $3,614,687.

	12/31/2021 NBV	**10 Years Annual Amortization**
AMR	36,146,873	3,614,687

Q. Is the company proposing a special cost recovery schedule for the Dismantlement Reserve Deficiency related to the early retirement of Big Bend Units 1, 2, and 3?

A. Yes, the company requests that the Commission approve a capital recovery schedule of $111,088,808 related to the Dismantlement Reserve Deficiency for the early retirement of Big Bend Units 1, 2, and 3.

Q. Over what period does the company propose to recover the $111,088,808 Dismantlement Reserve Deficiency for the early retirement of Big Bend Units 1, 2, and 3 and why?

A. The company proposes to recover the $111,088,808 Dismantlement Reserve Deficiency over a 10-year period. The company analyzed various alternatives and determined that a 10-year amortization period reflects a prudent and reasonable time period that would mitigate the rate impact on customers.

Q. What is the resulting annual cost recovery amount if the Commission approves the company's proposal?

A. The annual cost recovery amount if the Commission approves the company's proposal is $11,108,881:

Dismantlement Reserve Deficiency	**12/31/2021 NBV**	**10 Years Annual Amortization**
Big Bend Unit #1	28,471,852	2,847,185
Big Bend Unit #2	39,642,284	3,964,228
Big Bend Unit #3	42,974,672	4,297,467
	111,088,808	**11,108,881**

Q. What investments and costs associated with the retirement of Big Bend Units 1, 2, and 3, and AMR need to be considered as part of the ratemaking activity in this docket?

A. In general, there are two. The first is the projected undepreciated net book values of the Big Bend Units 1, 2, and 3, and AMR assets to be retired as of December 31, 2021, which are $517,679,493 is reflected on Document No. 2 of my exhibit. The second is the Dismantlement Reserve Deficiencies associated with the portions of Big Bend Units 1, 2, and 3 to be retired, which are $111,088,808 shown in our depreciation and dismantlement study and in Document No. 2 of my exhibit. The total of these amounts is $628,768,301 and represents the total amount the company proposes to include for a capital recovery schedule over ten years. This amount is shown on Document No. 2 of my exhibit.

Q. What is the total annual amortization expense associated with the company's proposed capital recovery schedule in the 2022 test year?

A. The total annual amortization expense in 2022 associated with our proposed capital recovery schedule is $62,876,830. Approximately $51,767,949 of this amount is attributable to recovery of the remaining net book value of the assets to be retired and $11,108,881 is for recovery of the dismantlement reserve deficiency associated with the Big Bend assets to be retired. These amounts are reflected on Document No. 2 of my exhibit and on MFR Schedule B-9.

Q. How are the Big Bend Unit 1, 2, and 3, and AMR meter net book values as of December 31, 2021 proposed for capital recovery schedules reflected in the 2022 test year MFR schedules submitted with this filing?

A. We accounted for the planned retirement of these assets by removing the asset costs from FERC account number 101 (Plant-in-Service) and recording them in FERC account number 108 (Accumulated Reserve) of December 31, 2021. The retirement of these assets is shown on MFR Schedules B-7 and B-9, and their net book values are embedded in the December 31, 2021 balances shown on MFR Schedule B-9. We reflected our proposed level of capital recovery schedule amortization (over ten years) in the reserve accruals for FERC account number 403 (Depreciation Expense) and FERC account number 108. For the 2022 test year, our proposed level of capital recovery schedule amortization and depreciation expense for the portion of Big Bend Units 1, 2, and 3 that will remain in service are shown on MFR Schedules B-7 and B-9. We used this approach to facilitate reforecasting actual monthly work order activities that have not been unitized from 107 CWIP (“Construction Work in Progress”) or 108 RWIP (“Retirement Work in Progress”) and to true-up final net book values as of December 31, 2021.

Once the Commission approves our proposed Net Book Value (“NBV”) amounts for capital recovery schedules and an amortization period, the net book value amounts, and amortization recovery period, we will record the actual retirements in our accounting records as of December 31, 2021, adjust the accumulated reserve for the net book values, create a regulatory debit account balance in FERC Account 182.2 (Unrecovered Plant) in December 2021, and begin amortizing the regulatory debit in January 2022. The company did not reflect the movement of the net book values into FERC account number 182.2 in its 2022 MFR schedules to maintain visibility to the asset groups in which each proposed amount resides. When the reclassification to 182.2 occurs, we will begin posting the amortization expenses to FERC 407 (Amortization of Property Losses for Unrecovered Plant). The journal entries we propose to account for the NBV portion of our proposed capital recovery schedule are reflected in Document No. 2 of my exhibit.

Q. How are the Big Bend Unit 1, 2, and 3 dismantlement reserve deficiencies proposed for capital recovery reflected in the projected 2022 MFR schedules submitted with this filing?

A. The company has included proposed amount of its annual amortization for the projected dismantlement reserve deficiency (approximately $11.1 million) in FERC account number 403 (Depreciation Expense) and FERC account number 108 (Accumulated Reserve). These amounts are included in MFR Schedule B-9. The company did not project in the forecasted balance sheet a movement of the dismantlement reserve deficiencies into FERC 182.2 Unrecovered plant (regulatory debit). When the reclassification to FERC 182.2 occurs, we will post the related amortization expenses to FERC 407 Amortization of property losses for unrecovered plant. The journal entries the company proposes to use to account for the dismantlement reserve deficiency portion of its proposed capital recovery schedule are shown in Document No. 2 of my exhibit.

Q. Are there any retirement amounts in the company's filing that need further explanation?

A. Yes, as reflected in the 2021 MFR Schedules B-7 and B-9 in account 31140 there is a $68.3 million retirement on line 5 related to Big Bend Common Structures and Improvements. As reflected on MFR Schedule F-8 budget assumptions, retirements of plant-in-service are based on a ratio of retirements to additions historical averages that is applied to infrastructure replacement projects additions. New expansion project additions have zero retirement budgeted. However, the Big Bend Modernization CT 5 and CT 6 project additions were considered a replacement activity and triggered an automatic budget retirement to occur out of Big Bend common.

Q. Does the $68.3 million retirement alter total rate base?

A. No, the $68.3 million retirement does not alter total rate base in 2022 since we debited accumulated reserve account 108 and credited gross plant account 101.

Q. What impact did this retirement have on book depreciation expense in 2022?

A. As a result of this retirement total book depreciation expense was reduced by $2.2 million:

	B-7 / B-9 Asset Retirement		2022 Depreciation Rate	2022 Depreciation Expense
311.40 Str & Improvements-BBCM	(68,339,560)	X	3.2%	(2,186,866)

GAINS AND LOSSES ON DISPOSITION OF PROPERTY

Q. Did the company have gains or losses on the disposition of plant and property previously used in providing electric service from 2018 to 2020?

A. No. See MFR Schedule C-29.

Q. Does the company project gains or losses on the disposition of plant and property previously used in providing electric service in 2021 and 2022?

A. No. See MFR Schedule C-29.

SUMMARY

Q. Please summarize your direct testimony.

A. The 2020 Depreciation Study and analysis performed under my supervision fully supports setting depreciation rates as I have described in my testimony. The depreciation rates proposed by Tampa Electric to be effective January 1, 2022 and used in the MFR schedules for the 2022 test year are reasonable and should be approved. For the reasons described in my direct testimony and the direct testimony of Mr. Caldwell and Mr. Haines, the capital recovery schedules proposed by Tampa Electric for the undepreciated net book value of retiring assets are reasonable and prudent and should be approved.

Q. Does this conclude your direct testimony?

A. Yes, it does.

(Whereupon, prefiled direct testimony of Edsel L. Carlson, Jr. was inserted.)

TAMPA ELECTRIC
AN EMERA COMPANY

BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 20210034-EI
IN RE: PETITION FOR RATE INCREASE
BY TAMPA ELECTRIC COMPANY

DIRECT TESTIMONY AND EXHIBIT
OF
EDSEL L. CARLSON, JR.

TAMPA ELECTRIC COMPANY
DOCKET NO. 20210034-EI
FILED: 04/09/2021

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

EDSEL L. CARLSON, JR.

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

A. My name is Edsel L. Carlson, Jr. My business address is 702 North Franklin Street, Tampa, Florida 33602. I am the Risk Manager for Tampa Electric Company ("Tampa Electric" or "company").

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

A. As Risk Manager, I am responsible for developing and achieving strategic risk management objectives for TECO Energy and its subsidiaries, including Tampa Electric. My responsibilities include identifying and assessing risk exposures; performing qualitative and quantitative risk analysis to determine the frequency and severity of loss exposures; and developing and implementing loss control strategies to prevent and mitigate loss exposures. I am also responsible for determining and implementing cost-effective strategies to finance risk, including risk retention or risk transfer; negotiating, procuring, allocating, and maintaining insurance programs; and property claims adjusting. I also serve as the risk management resource for all TECO Energy's subsidiaries and provide guidance regarding contractual risk management, merger and acquisition due diligence, and special project risk management. Finally, I serve as a resource for the development and implementation of risk management training and reporting for TECO Energy and its subsidiaries.

Q. Are you responsible for obtaining health insurance products for the company's team members?

A. No. Our Human Resource department is responsible for procuring those type of employee benefits. Tampa Electric witness Marian C. Cacciatore discusses employee benefits as part of total compensation in her direct testimony in this proceeding.

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

A. Yes. I submitted written testimony in the company's two most recent requests for general base rate relief, namely

Docket Nos. 20080317-EI and 20130040-EI.

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

A. I graduated from the University of South Florida with a Bachelor of Arts degree in Criminology and from Saint Leo University with a Master of Business Administration degree. I hold the Associate in Risk Management designation from Insurance Institute of America and a Fellow in Risk Management designation from Global Risk Management Institute, Inc. I have approximately 27 years of experience working in the company's Risk Management Department, where I have held the positions of Claims Adjuster and Risk Analyst. I have held my present position as Risk Manager since 2000.

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

A. Yes, Exhibit No. ELC-1, entitled "Exhibit of Edsel L. Carlson, Jr." was prepared under my direction and supervision. The contents of my exhibit were derived from the business records of the company and are true and correct to the best of my information and belief. It consists of the following five documents:

Document No. 1	List of Minimum Filing Requirement Schedules Sponsored or Co-Sponsored by Edsel L. Carlson, Jr.
Document No. 2	Storm Restoration Costs Charged to the Storm Reserve (2012-2019)
Document No. 3	Paragraph 5 of 2013 Stipulation
Document No. 4	Paragraph 5 of 2017 Agreement
Document No. 5	Order Approving Storm Cost Settlement Agreement

Q. Are you sponsoring or co-sponsoring any sections of Tampa Electric's Minimum Filing Requirements ("MFR") schedules?

A. Yes. I am sponsoring or co-sponsoring the MFR schedules listed in Document No. 1 of my Exhibit. The contents of these MFR schedules were derived from the business records of the company and are true and correct to the best of my information and belief.

Q. What are the purposes of your direct testimony?

A. My direct testimony addresses the most appropriate means for Tampa Electric to recover the storm damage and restoration costs associated with hurricanes and tropical storms on a going forward basis. I discuss the Commission's prior treatment of storm damage and restoration cost recovery for Tampa Electric. I also discuss the study performed by Tampa Electric witness Steven P. Harris of ABS Consulting on behalf of Tampa Electric and what that study suggests an appropriate annual accrual to our storm reserve to cover its uninsured windstorm loss reserves would be.

I explain why a continuation of the storm damage and restoration cost recovery mechanism prescribed in Tampa Electric's two most recent rate settlements is the best available methodology for storm cost recovery and in our customers' best interests. That mechanism was first contained in the company's 2013 Stipulation and Settlement Agreement ("2013 Stipulation"), which was approved by Order No. PSC-2013-0443-FOF-EI, issued on September 30, 2013. It was extended for use until December 31, 2021 in the company's 2017 Amended and Restated Stipulation and Settlement Agreement ("2017 Agreement"), approved by Order No. PSC-2017-0456-S-EI.

I also discuss the insurance currently available for storm cost recovery and other purposes and explain why our insurance costs are increasing.

PROPOSED METHODOLOGY FOR INCREMENTAL STORM COST RECOVERY

Q. Why does the company need a regulatory mechanism to recover the incremental storm costs associated with tropical storms and hurricanes?

A. Because of its geographic location, the State of Florida including Tampa Electric's service area, is subject to seasonal hurricanes and tropical storms. We can predict the chances that a tropical storm or hurricane will hit our service territory over a long time period using probabilistic modeling but cannot accurately predict in which specific years or where storms will hit, what size of storm will hit, or what the associated storm recovery costs will be for a specific storm or specific year.

Document No. 2 of my exhibit shows the storm restoration costs the company charged to its storm reserve, from 2012 to 2019, and reflects the variability of storm activity and storm damage and restoration costs. Sometimes these costs are relatively modest, and sometimes they are substantial.

Q. How has Tampa Electric traditionally accounted for storm costs in the rate making process?

A. Prior to the 2013 Stipulation, the Commission authorized

Tampa Electric and other utilities to account for these occurrences by maintaining a storm damage reserve, with annual expense accruals toward these reserves informed by probabilistic storm analysis of the expected storm related losses and the resulting impact on the accumulated storm damage reserve. This approach allowed the company to recover expected future storm recovery costs through base rates by using the annual accrual to create a reserve and then charging storm recovery costs against the reserve.

Q. Does Tampa Electric maintain a current level of storm damage reserve, and if so, in what amount?

A. Yes. As shown on MFR Schedule B-21, the reserve amount as of February 1, 2021 was $48,175,745. Without a storm damage reserve in place, the sudden and expected recovery costs for a storm could cause the company to earn below the bottom of its authorized range of return on equity, so the company proposes to continue maintaining a storm damage reserve as discussed below.

Q. What target level of storm damage reserve and what annual accrual did the Commission last approve for Tampa Electric?

A. The Commission last approved an $8 million annual storm damage accrual with a target reserve of $64 million after five years. This is reflected in Order No. PSC-09-0283-FOF-EI, issued April 30, 2009 in Docket No. 20080317-EI. The 2013 Stipulation reset the reserve target level to $55,860,642, and that reserve target level was affirmed in the 2017 Agreement. Tampa Electric proposes to maintain this target as part of its proposal explained below.

Q. Is the company currently recording an annual storm damage expense accrual on its income statement?

A. No. As part of the 2013 Stipulation, we agreed to stop recording an annual storm expense accrual, and to recover the allowable costs of storm restoration for tropical systems though a surcharge on customer bills after the storm reserve amount is completely exhausted. This approach was requested by the consumer parties to the stipulation, reflects a “pay at the pump” approach, and was re-affirmed in the 2017 Agreement.

The storm damage provisions from the 2013 Stipulation and 2017 Agreement are reproduced in Document Nos. 3 and 4 of my exhibit.

Q. Please describe the storm cost recovery methodology approved in the 2013 Stipulation and 2017 Agreement.

A. The storm damage provisions of the two agreements are essentially the same, but since the 2017 Agreement is the most recent and is still in effect, I will describe the storm damage provisions in the 2017 Agreement.

Paragraph 5 of the 2017 Agreement prescribes a storm cost recovery mechanism ("Storm Methodology") designed to allow for storm cost recovery in a manner most acceptable to our customers. The Storm Methodology eliminated the annual storm damage expense accrual, set the company's storm damage reserve target at $55.9 million, changed the way the reserve is replenished, authorized prompt cost recovery through a storm surcharge on customer bills, and established surcharge amounts based on the amount of storm costs to be recovered. The agreement that allows the company to use the Storm Methodology expires on December 31, 2021.

Q. Please describe how the Storm Methodology operates.

A. The Storm Methodology allows the company to petition the Commission for the replenishment of the storm reserve to its target level of $55.9 million once the level within the storm reserve is completely exhausted. This petition allows the company to begin recovering on an interim basis sixty days after the petition, storm related costs, and to recover those costs over a one-year period or longer, depending upon the rate impact of the storm related costs.

The surcharge recovery period under the Storm Methodology is 12 months if the storm costs do not exceed $4.00 per 1,000 kWh on monthly residential customer bills. If the storm costs exceed that level, the costs in excess of $4.00 per 1,000 kWh are recovered in a subsequent year or years as determined by the Commission, after a hearing or an opportunity for a hearing.

The $4.00 per 1,000 kWh cap in the Storm Methodology applies in aggregate for a calendar year; but Tampa Electric may petition the Commission to allow Tampa Electric to set an initial 12-month recovery amount greater than $4.00 per 1,000 kWh or for a period longer than 12 months if the company incurs more than $100 million of storm recovery costs that qualify for recovery in a given calendar year, including the amount needed to replenish the storm reserve to $55.9 million.

The Storm Methodology defines the storm recovery costs that can be recovered and includes procedural safeguards for the company, customers, and consumer parties who are substantially affected.

Q. Has the company used the Storm Methodology for the recovery of qualified storm restoration costs?

A. Yes. In December 2017, Tampa Electric filed a petition invoking the Storm Methodology as contemplated in the 2017 Agreement. The company originally proposed a $4.00 per 1,000 kWh surcharge to recover $87.4 million of costs associated with named storms in 2015, 2016, and 2017 and to replenish its storm reserve. The company later amended its petition to increase its requested storm cost recovery amount to $102.5 million and to increase its proposed surcharge amount, and then requested permission to use the projected income tax expense savings from the Tax Cut and Jobs Act of 2017 to offset its request for storm cost recovery. The Commission approved the latter proposal on March 7, 2018.

After a year of extensive discovery and negotiations with some of the consumer parties to the 2017 Agreement, the company filed a Storm Cost Settlement Agreement on April 9, 2019. As part of the settlement agreement, the company agreed to adopt process improvements for use in future storm cost recovery activities. The Commission approved the settlement agreement by Order No. PSC-2019-0234-AS-EI, dated June 14, 2019, in Docket No. 20170271-EI, a copy of which is included in Document No. 5 in my exhibit.

Although a surcharge never appeared on customer bills, the basic framework in the Storm Methodology allowed consumer parties to litigate the level of cost recovery requested, allowed tax savings to be used in lieu of a surcharge, and provided an efficient and reasonable way for the company to recover incremental storm recovery costs.

Q. What storm cost recovery methodology does Tampa Electric propose for Commission approval at this time?

A. Tampa Electric proposes that the Commission approve the Storm Methodology described above as the best way to secure our ability to continue providing reliable electric service, while at the same time preserving the interests of its customers. The Storm Methodology should continue in effect beginning January 1, 2022.

Q. Why is the Storm Methodology preferable to the annual accrual methodology and in the public interest?

A. The Storm Methodology has worked well. It is understandable and has provided predictability for us and our customers. We believe that our customers prefer the "pay at the pump" approach in the Storm Methodology over the annual expense accrual or "pay as you go" approach in effect prior to the 2013 Stipulation, because they have agreed to it twice. The Storm Methodology reasonably balances collecting sufficient storm costs to cover expected losses in advance with recovering all storm costs after an event, which could burden customers who may already be facing storm related hardships. It allows us to recover incremental storm damage costs that we incur, together with amounts needed to restore the company's reserve to $55.9 million, in a timely manner and in a way that mitigates the rate impact on customers.

Q. How does the Storm Methodology differ from the way Tampa Electric could seek recovery of storm costs that deplete the storm reserve if the Storm Methodology is not available?

A. The primary differences between the standard method in which Tampa Electric may seek a storm surcharge to recover storm restoration costs and the Storm Methodology are timing and the amount and period over which the storm surcharge is spread. Without the Storm Methodology, we could still petition the Commission to recover the costs of hurricanes and named tropical storms that deplete our storm reserve; however, the surcharge might not begin until after the hearing or other formal review by the Commission took place. Moreover, the amount of the surcharge would not be limited to $4.00 per kWh on a residential monthly bill or a 12-month period as set forth in the Storm Methodology. The Storm Methodology balances potential rate impact consideration with timely cost recovery from the customers who were receiving service at the time the damage occurred, while still providing every opportunity for the Commission and other parties to review our incremental storm restoration costs.

In some instances, delaying cost recovery until after a full evidentiary hearing as contemplated in the Commission’s rule could shift cost responsibility to customers who were not customers at the time of the storm and increases the likelihood that customers at the time of the storm who benefitted from our restoration efforts will not pay for the cost of those efforts because they have left our system. Thus, we believe that the Storm Methodology is better than the standard process in terms of mitigating potential rate impacts to customers while still establishing fair review processes and cost assignment to those customers who took service at the time of the storm.

Q. Please describe the documentation and accounting clarification Tampa Electric agreed to in the April 2019 Storm Cost Settlement Agreement?

A. The storm restoration cost process improvements were developed and implemented to provide best practices for the safe and timely restoration of services in a cost-effective manner. They require better documentation and communication of company expectations to vendors. The improved process consists of 10 new policies providing direction around contracting, vendor engagement, travel, and work. It also consists of five new enhanced processes regarding cost documentation, auditing, and regulatory recovery. These improved processes provide a more organized and transparent approach and ensure that the customer does not pay excessive or improper costs to restore their service after a storm. They are reflected in Document No. 5 of my exhibit.

Q. Does Tampa Electric propose to adhere to these documentation and accounting clarifications in the future?

A. Yes.

Q. What are the benefits of the Storm Methodology and why is it in the public interest to continue this methodology?

A. As stated earlier, the Storm Methodology has worked well. It is predictable for all involved. It allows for spreading the cost recovery beyond one year, depending upon the impact on rates. It allows for full due process for anyone affected by the way it operates. It has been approved by representatives of all customer classes. Also, it can be revisited in a future rate proceeding, if a more desirable alternative is developed.

Q. In the past, the company has expressed concerns about imposing a storm surcharge after a hurricane or tropical storm when customers may be incurring other storm-related costs. How does your proposal accommodate that concern?

A. We have always considered the impact rates and charges may have on our customers. However, our customers have expressed a preference for the surcharge approach like the one we are proposing now, as evidenced by the 2013 Stipulation and 2017 Agreement and the storm damage approach set forth in those agreements. This approach, which maintains a smaller reserve than indicated by Mr. Harris's loss study discussed further below and does not collect an annual accrual amount from customers, strikes a reasonable balance between timely recovery of storm-related costs and mitigates rate impacts from both an annual accrual and a storm surcharge after a major storm.

2021 STORM STUDY

Q. Have you reviewed the direct testimony and exhibit Mr. Harris has submitted in this proceeding?

A. Yes. The company asked Mr. Harris to prepare a Storm Damage Self-Insurance Reserve Study and are submitting it as part of this proceeding pursuant to Section 25-6.0143(1)(l).

Q. How does your Storm Methodology proposal compare with the substance of Mr. Harris' direct testimony.

A. Mr. Harris performed both a Hurricane Loss Analysis and a Reserve Performance Analysis. His studies simulated possible hurricanes and the impact they are projected to have on the company's storm damage reserve. His studies suggest that an annual storm reserve accrual of approximately $23.7 million would be required, over a long period of time, to cover the expected storm loss costs from all Category 1 through 5 hurricanes. The study indicates that using the Storm Methodology, no accrual and one-year recoveries, there is about a 70 percent likelihood that the reserve will have insufficient funds in one or more of the next five years, and that Tampa Electric will need to recover storm costs through the approved Storm Methodology. The company believes that his studies are reasonable and informative. For the reasons explained above, the company has opted to propose the Storm Methodology in lieu of an annual accrual to reach a target of over $100 million over a five-year period.

Q. When will Tampa Electric submit another storm damage study like the one performed by Mr. Harris in this proceeding?

A. We will file a new storm damage study in 2026 and can revisit this topic at that time if needed, or in a future rate proceeding.

PROPERTY INSURANCE

Q. What is the status of Tampa Electric's efforts to obtain commercial Transmission and Distribution ("T&D") Insurance?

A. The property insurance markets for T&D insurance coverage remain restricted, especially for Gulf and Atlantic coast locations. In the last several years, Tampa Electric has requested a price indication from its property insurance broker for commercial property insurance to cover its T&D facilities from storm related damage. Based on discussions with the broker, property insurance for the company's T&D

facilities at reasonable costs and deductible levels continues to be unavailable.

Q. Does the company have property insurance on other portions of its property?

A. Yes, Tampa Electric has property insurance on almost all of its assets with the exception of its T&D assets.

Q. Please describe changes in the property insurance market since the company's last rate case.

A. Between 2013, when the company filed its last rate case, and 2018, the insurance market was relatively robust. In 2018 we started seeing signs that market costs were increasing. In 2019 and 2020, this trend continued with premium increases as the market became more restricted. We anticipate that this will continue into 2021 and beyond.

Q. What is a "restricted" insurance market?

A. The insurance market is cyclical, and there are periods where demand for insurance exceeds supply, putting buyers at a disadvantage. This is known as a "restricted market." From 2013 to 2018, we experienced a "robust market" cycle due to relatively low catastrophic loss events and the influx of nontraditional investors in the insurance sector (naive capacity). This created a market where there was more supply than demand, and pricing gradually decreased for accounts with good loss history.

Robust markets usually take several years to materialize, as opposed to restricted markets that can develop rather quickly. Restricted markets typically affect insureds with less desirable loss exposures (like catastrophic loss exposures) more rapidly.

Q. What causes the market to become restricted?

A. There are three primary factors: (1) insurers' low premium investment income causing reliance on true underwriting profit; (2) increases in frequency and severity of losses; and (3) insurers' capacity decreases.

Under the insurance industry's basic business model, the insurer charges customers a risk premium, investing the premium for a return, and paying customer claims. Insurers apply the model on a class of business basis for numerous customers so that insurers can spread the risk of individual customers across the class. Insurers need to collect enough premium revenue and earn investment returns in amounts sufficient to cover their operating cost and claims. When insurers continually experience high loss ratios, the market will start to become restricted.

Q. How has the cost and availability of property insurance for other assets changed for Tampa Electric since 2013?

A. Tampa Electric expects its annual property insurance costs to be over $15.1 million in 2022 compared to $8.2 million in 2013. This increase was caused by three factors. First, the insurance market has become restricted, so insurance rates are higher. Second, the total and replacement values of the company's insurable property are higher. Third, we have recently constructed solar assets which are considered by the insurance industry to be more susceptible to loss than traditional generating assets.

Q. How much has the value of Tampa Electric's insured assets increased since 2013?

A. Our property insurance values increased from $5.2 billion in 2013 to $7.8 billion in 2021 and are projected to be over $8 billion in 2022. The investments we have made, and are making, that have contributed to this growth are explained by Tampa Electric witnesses Jeffrey S. Chronister, David A. Pickles, C. David Sweat, Melissa L. Cosby, and Karen M. Mincey.

Q. Have market changes caused Tampa Electric to change the manner or degree to which company facilities are insured?

A. Yes. At the 2020 property insurance renewal, Tampa Electric elected to increase its property insurance deductible from $10,000,000 to $15,000,000 in an effort to control the cost associated with the restricting market conditions. For the same reason, Tampa Electric also decided not to pursue increasing the coverage limit by $100,000,000 above the current $500,000,000 limit, even though the company's values and exposures have increased substantially since that limit was established in 2007. We also elected to self-insure Big Bend Unit 2 and parts of Unit 1.

OTHER INSURANCE

Q. Is Tampa Electric's insurance cost increasing for other types of insurance?

A. Yes, basically all lines of insurance have seen cost increases due to restricted market conditions. We estimate that approximately 50 percent of our 2022 insurance budget is for property insurance, 42 percent for general liability insurance, and eight percent for other lines of coverage. The general liability insurance covers the company's liability arising from claims for third party bodily injury and property damage. Our general liability insurance cost was $3.2 million in 2013 and is projected to be $12.9 million in 2022.

Q. Are the amounts the company expects to pay for property, general liability, and other insurance in 2022 reasonable?

A. Yes. We take several steps to ensure that the cost Tampa Electric pays for its insurance is reasonable. First, we contract with a quality insurance broker that has a tremendous amount of experience securing insurance coverage for the utility industry, and who has deep knowledge of all insurance markets. Our broker ensures that the terms and conditions of our insurance placement are fair and reasonable, and consistent with prevailing insurance market conditions.

Second, we procure insurance from financially secure insurers that are committed to the utility industry and are long term partners. Many of our insurers have been on our programs for several decades. Long term insurers typically charge lower premium over the long run than short term insurers.

Third, due to the size of our company and the exposure to extreme weather such as hurricanes, we use multiple insurers to cover our risks. Our primary insurance policies, such as property and general liability, are renewed annually, which is consistent with industry practice, and when we renew, our broker works with our existing and prospective insurer to provide the most favorable overall terms, and in this regard multiple insurers create competition.

Fourth, during the renewal process, we review our deductible levels, purchased limits and sub-limits to ensure that we purchase appropriate limits and retain a prudent amount of risk. This helps our overall insurance and risk transfer costs.

Finally, we ensure that our insurers understand our risks, which enable us to get the right products, in the right amounts and at the best cost.

SUMMARY

Q. Please summarize your direct testimony.

A. My direct testimony supports a continuation of the surcharge methodology approved by the Commission in the 2017 Agreement. At this time, we believe that the Storm Methodology is in the best interests of Tampa Electric's customers and will enable the company to manage storm cost recovery in a reasonable manner – one which has been shown to be beneficial to the customers we serve. Finally, we have examined the insurance market and have concluded that it is not a commercially available or economic alternative to what we are proposing for transmission and distribution assets.

Our insurance coverages and proposed costs for 2022 are reasonable and prudent. Although or general liability and property insurance costs have increased due to restricted market conditions and other factors associated with its risk exposures, the company has proactively managed its insurance program in a reasonable way that balances our risks with the costs we incur.

Q. Does this conclude your testimony?

A. Yes, it does.

(Transcript continues in sequence in Volume 2.)

CERTIFICATE OF REPORTER

STATE OF FLORIDA)
COUNTY OF LEON)

I, DEBRA KRICK, Court Reporter, do hereby certify that the foregoing proceeding was heard at the time and place herein stated.

IT IS FURTHER CERTIFIED that I stenographically reported the said proceedings; that the same has been transcribed under my direct supervision; and that this transcript constitutes a true transcription of my notes of said proceedings.

I FURTHER CERTIFY that I am not a relative, employee, attorney or counsel of any of the parties, nor am I a relative or employee of any of the parties' attorney or counsel connected with the action, nor am I financially interested in the action.

DATED this 1st day of November, 2021.

Debbie R Krick

____
DEBRA R. KRICK
NOTARY PUBLIC
COMMISSION #HH31926
EXPIRES AUGUST 13, 2024