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
DAVID A. PICKLES

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

DAVID A. PICKLES

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

A. My name is David A. Pickles. My business address is 702 North Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or the "company") as Vice President of Energy Supply and Electric Delivery/Energy Supply Asset Management.

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

A. I am responsible for ensuring the safe and reliable operation of all the generating assets at Tampa Electric, including solar operations. This includes oversight of all safety, environment, compliance, team member, operating, and capital budget management decisions in our Energy Supply department. I am also responsible for the Asset Management decisions for both Electric Delivery and Energy Supply. My focus is on ensuring overall system reliability through proper maintenance and investment strategies over the life cycle of all assets. I am responsible for fuel procurement, along with purchase power agreements. My responsibilities include electric system and resource planning in support of long-term system reliability, and I am also responsible for general procurement and contract activities for Tampa Electric.

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

A. I am a Chemical Engineer and a graduate of Dalhousie University based in Halifax, Nova Scotia, Canada. I am a registered Professional Engineer in the Province of Nova Scotia.

I joined Nova Scotia Power in 2001 as a Plant Engineer and held many roles over the next 15 years including Maintenance Manager, Plant Manager, Senior Plant Manager, Director, and Senior Director of Operations. In 2016, I became the Vice President of Operations for Emera Energy and was responsible for 1,100 MW of generating capacity in three American states and two Canadian provinces.

I joined Tampa Electric in 2018 and assumed responsibility over Big Bend Generating Station and Energy Supply's

Engineering and Project Management group. Most recently, I have served as Vice President of Energy Supply and Electric Delivery/Energy Supply Asset Management.

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

A. Yes. I have testified or filed testimony before the Nova Scotia Utility and Review Board in 2014 and 2015 in support of the Annual Capital Expenditure Plan; Application by Nova Scotia Power Inc. ("NSPI") for Approval of its Annual Capital Expenditure Plan for 2014 (M05998) and Application by NSPI for Approval of its Annual Capital Expenditure Plan for 2015 (M06514).

Q. What are the purposes of your direct testimony?

A. The purposes of my direct testimony are to (1) provide an overview of the company's Energy Supply system and how it has transformed over the years; (2) outline the company's future plans for Energy Supply; (3) demonstrate that the company's production plant construction program, capital budgets, and resulting energy supply rate base amounts for 2022 are reasonable and prudent; and (4) show that the company's proposed level of operations and maintenance expense ("O&M") for energy supply in the 2022 test year is reasonable and prudent.

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

A. My direct testimony addresses the company's overall electric generating system and explains how the Big Bend Modernization Project ("Big Bend Modernization"), early retirement of Big Bend Unit 3, and the addition of 600 MW_{ac} of utility scale solar generating capacity ("Future Solar") fit into Tampa Electric's overall plans. These projects are major components of our goal to make the company safer, cleaner, greener, and to improve the customer experience.

Tampa Electric witness J. Brent Caldwell will explain the details of the company's decision to invest in Big Bend Modernization, its phased approach to transforming the Big Bend Station, and why the project is prudent and in the best interests of our customers. He will also explain why retiring Big Bend Unit 3 in 2023, rather than its previously planned retirement date of 2041, is prudent and in the best interests of our customers.

Tampa Electric witness Davicel Avellan will explain how the changes underway at Big Bend Station will impact our depreciation and dismantlement rates and describe our need to recover the undepreciated net book value ("NBV") of the portions of Big Bend Units 1, 2, and 3 to be retired and obsolete inventory via capital recovery schedules.

Tampa Electric witness C. David Sweat will explain the details and projected costs of Tampa Electric's plans for Future Solar and how our phased approach for adding this cost-effective generation to our portfolio maximizes the available economies of scale and leverages lessons-learned from our SoBRA experience.

Tampa Electric witness Jose A. Aponte will demonstrate that each of the 11 planned Future Solar projects is cost-effective, prudent, and in the best interests of our customers.

Finally, Tampa Electric witness John C. Heisey will support our request to include fuel inventory in the company's working capital allowance. He will also explain how the changes we are making to the dispatch of coal-fired generation necessitate a modification to the traditional 98-day average burn inventory target for solid fuel.

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

A. Yes. Exhibit No. DAP-1, entitled "Exhibit of David A. Pickles" 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. My exhibit consists of 14 documents, as follows:

Document No. 1	List of Minimum Filing Requirement Schedules Sponsored or Co-Sponsored by David A. Pickles
Document No. 2	Thermal Efficiency (2013-2020)
Document No. 3	Emissions (2013-2020)
Document No. 4	System Equivalent Availability Factor ("EAF") (2013-2020)
Document No. 5	Environmental Regulations for Coal Fired Generation
Document No. 6	Summary of Big Bend Modernization Project and Costs by Phase
Document No. 7	Big Bend Unit 1 Retirement Assets
Document No. 8	Big Bend Unit 2 Retirement Assets
Document No. 9	Big Bend Unit 1 and 2 Obsolete Inventory

Document No. 10	Big Bend Unit 3 Retirement Assets
Document No. 11	Energy Supply Rate Base Growth (2013-2022)
Document No. 12	Energy Supply Capital Additions (2022-2023)
Document No. 13	Energy Supply O&M Expenses (2013-2022)
Document No. 14	2022 Energy Supply O&M Benchmark

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 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.

ENERGY SUPPLY OVERVIEW AND TRANSFORMATION

Q. Please describe the company's Energy Supply and Asset Management Department.

A. Our Energy Supply and Asset Management Department ("Energy Supply") has a combined staff of approximately 545 team members. Energy Supply combines all the necessary resources to support the company's thermal and solar generating operations; environmental management; engineering and project management; resource planning; system planning; natural gas and solid fuel procurement; energy trading; asset and capital management (for both Energy Supply and Electric Delivery); along with regulatory compliance (North American Electric Reliability Corporation ("NERC")/Federal Energy Regulatory Commission ("FERC")); procurement; and facility services.

Q. What role does safety play in Energy Supply?

A. Safety is our number one consideration. We are committed to the beliefs that all injuries are preventable and that no business interest can take priority over safety. We believe that safety is everyone's responsibility and that all our team members must be personally engaged in all aspects of safety.

The foundation of our safety program is a multi-tiered Safety Management System that sets minimum expectations for safety leadership; addresses risk management; prescribes programs, procedures, and practices; promotes safety communication, awareness, and training; cultivates a strong safety culture and safe behavior; sets contractor safety management standards; enhances asset integrity; establishes tools for measuring and reporting; prescribes incident management and investigation procedures; and includes auditing and compliance measures.

I am proud to report that the Occupational Safety and Health Administration ("OSHA") Recordable Injury rates in Energy Supply have improved since 2017 and that we had zero recordable injuries in 2018 with millions of exposure hours worked. I am pleased with the progress we have made and recognize that creating a safe work environment requires constant attention and a relentless pursuit of safety excellence.

The level of employee engagement in safety continues to improve overall safety performance across the entire organization. This was never more evident than our safety results in 2020. Our safety performance in 2020 was one of our best ever.

- Best incident rate with respect to recordable injuries.
- 1 million safe work hours without a recordable injury.
- 2 million work hours without a lost time injury.
- Lowest controllable vehicle incident rate with 12 accidents.

- Safely drove 1 million miles.

Q. What is Asset Management and how has the company integrated Asset Management techniques into its planning and operations?

A. Asset Management is a disciplined way of thinking and managing that aligns engineering, operations, maintenance, other technical and financial decisions, and processes for the purpose of optimizing the value of our assets throughout their lifecycles.

Tampa Electric strives to achieve its asset reliability goals by focusing on the following three Asset Management objectives.

The first objective is the integration of asset monitoring, health and risk assessment, work planning and scheduling, capital planning, outage planning, risk management, and other supporting asset management processes into continuous business processes.

The second objective is the broader engagement of team members and subject matter experts in these continuous processes, the establishment of asset management responsibilities throughout the organization, and ensuring team members are empowered with industry best practice through awareness and training.

Finally, we sustain the integrated processes and engagement of our teams through documentation and standardization of technical and business processes and the implementation of supporting operational and information technology systems.

We implement these Asset Management concepts in our short term (weekly planning and scheduling) and long term (outage planning) work management cycles.

Applying Asset Management principles gives us a comprehensive understanding of the condition of our assets and the risks associated with them and allows us to better identify and prioritize the work that needs to be done. This level of understanding enables us to improve our planning and scheduling of work, lowers the costs and risks of operating our system, and improves efficiency and reliability – all of which promote a positive customer experience.

Q. Please generally describe the company's current electric generating system.

A. Tampa Electric maintains a diverse portfolio of electric generating facilities to safely provide reliable, cost-effective electric power for its customers in an environmentally sensitive manner. Our generating portfolio consists of 15 generating units and five peaking units at three central generating stations, and 13 geographically dispersed solar sites, for a total of approximately 5,790 MW of winter peaking capacity. Our electric generating units include dual fuel (solid fuel/natural gas) steam units, combined cycle units ("CC"), combustion turbine ("CT") peaking units, an integrated gasification combined cycle ("IGCC") unit, and photovoltaic solar facilities ("Solar").

Q. Please describe the company's three central electric generating stations.

A. The company's three central electric generating stations are the Big Bend Power Station ("Big Bend"), the Polk Power Station ("Polk"), and the H.L. Culbreath Bayside Power Station ("Bayside").

Big Bend currently consists of Big Bend Units 2, 3, and 4, which are pulverized coal fired steam units. They are equipped with desulfurization scrubbers, electrostatic precipitators, and Selective Catalytic Reduction ("SCR") air pollution control systems. We modified each of the Big Bend units since our last rate case in 2013 so that they also can be fired with natural gas, *i.e.*, added dual-fuel capability.

Big Bend Unit 1 is in the process of being modernized and is not operating, but the other three units are in service. Units 2 and 3 are currently burning natural gas only and are scheduled for retirement in November 2021 and April 2023, respectively. Big Bend Unit 4 can operate on coal or natural gas. Big Bend CT4 is a natural gas aero derivative CT.

Bayside consists of two natural gas fired combined cycle ("NGCC") units and four aero derivative CTs. Bayside Unit 1 consists of three CTs, three Heat Recovery Steam Generators ("HRSG") and one steam turbine. Bayside Unit 2 consists of four CTs, four HRSGs, and one steam turbine. Bayside Units 3, 4, 5, and 6 are the four natural gas aero derivative CTs.

Polk has two units. Polk Unit 1 is a dual fuel IGCC/natural gas unit consisting of one CT, one HRSG, and one steam turbine. Polk Unit 2 uses four natural gas CTs, four HRSGs, and one steam turbine. Two of the Polk 2 CTs can use distillate oil as a back-up fuel. The Polk Unit 2 CTs were transformed into highly efficient CC generating units ("Polk 2 Conversion") in accordance with the Stipulation and Settlement Agreement ("2013 Stipulation") that resolved our last rate case.

Q. Please describe the company's existing Solar facilities.

A. Tampa Electric currently owns and operates 655 MW_{ac} of solar generating capacity at 13 geographically dispersed locations throughout its service territory. Our solar portfolio includes 632.1 MW_{ac} of single axis tracking PV solar at 11 sites in Hillsborough and Polk Counties, a 1.6 MW_{ac} fixed tilt solar PV rooftop canopy array located at the south parking garage at Tampa International Airport, a 1.4 MW_{ac} fixed tilt solar PV ground canopy array located at Legoland Florida, and a 19.8 MW_{ac} single axis tracking solar station coupled with a 12.6 MW battery storage unit located at Big Bend. 600 MW_{ac} of this capacity was installed in cost-effective increments pursuant to the company's 2017 Amended and Restated Stipulation and Settlement Agreement ("2017 Agreement"). All the company's solar assets have been placed into service since 2013.

Q. Please describe the mix of fuel the company currently uses to generate electricity and how it has changed since the company's last rate case in 2013.

A. The changes to our generating system have dramatically changed the mix of fuel we use to generate electricity.

We reduced our coal consumption in tons by approximately 90 percent since 2015.

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

By 2020, about 5 percent of our electricity was generated using coal, about 89 percent was natural gas-fired, and approximately 6 percent was from solar, and less than 1 percent from light oil.

We have 470 MW of capacity that can use distillate oil as a backup fuel at Polk, but the amount of distillate oil used each year is *de minimis*.

Q. Have the changes described above improved the company's thermal efficiency and environmental profile?

A. Yes. We have reduced our average net system heat rate (Btu/kWh), which reflects the thermal efficiency of our generating fleet, from about 9,200 in 2013 to 7,599 in 2020, an improvement of about 17 percent. We reduced our carbon emissions from 15.7 million tons in 2013 to about 8.8 million tons in 2020. By 2023, we will have reduced our carbon dioxide emissions by the equivalent of removing one million cars from local roadways. Document Nos. 2 and 3, respectively, in my exhibit provide more details about how our thermal efficiency and emissions profile have improved since 2013.

Q. Have these changes to the company's generating facilities helped reduce the company's annual fuel expenses?

A. Yes. Our annual fuel expenses, which are a direct pass-through to our customers, have declined by about 40 percent from a peak of over $700.0 million in 2014 to approximately $425.0 million in 2020. Year over year fuel variances from (2016-2020) can be found in MFR Schedule C-09. Some of this reduction is attributable to lower commodity prices, but we delivered the value of lower fuel prices to customers through prudent construction of solar generation, expansion of dual-fuel capability at our power plants, continued investments in efficient natural gas fired combines cycle technology, and careful dispatching of our generating units. By December 31, 2020, the Polk and SoBRA projects saved our customers over $184.0 million in fuel costs since 2013.

Q. Please describe the reliability of Tampa Electric's generating units since 2013.

A. The reliability of our generating fleet is measured by generating unit annual net EAF, which calculates the amount of time a unit is expected to be in service after accounting for planned and unplanned outages.

Our overall fleet EAF has improved from approximately 77 to 84 percent since 2013. Our fleetwide EAF is a weighted average of performance, with the NGCC fleet having a very high EAF (high 80s to low 90s) and the coal fleet operating in the low 70s. The lower EAF across the coal fleet is a result of higher wear and tear caused by coal combustion, corresponding longer duration planned maintenance outages, and the most recent major outage on Big Bend Unit 4.

Document No. 4 of my exhibit provides additional details on our system EAF since 2013.

Q. Have generation changes since 2013 enabled the company to make other operational changes?

A. Yes. The changes described above, together with changes in the natural gas market, have substantially changed how our generating fleet is dispatched and the level of O&M expenses required to sustain reliable operation. They have also enabled us to make significant staffing reductions at Big Bend through natural attrition. We are projecting further staffing reductions and expense savings as we implement Big Bend Modernization and retire Big Bend Unit 3. These O&M savings are reflected in the 2022 budget and O&M expense projections in 2023 and beyond.

Although the number of team members at Big Bend is declining, the number of people working in our Solar operations department is growing. This growth is being driven by the construction and operation of our Future Solar projects and by a transition of current Solar O&M responsibilities from external third-party support to in-house resources. This transition will help us to continue delivering cost competitive generation options and develop in-house Solar skills and knowledge.

Q. Are the changes described above the beginning of the transformation of the company's generating fleet?

A. No. The changes to our generating system described above, Big Bend Modernization and our Future Solar, are best understood as part of the company's long history of generation innovation and transformation to meet the needs of the times. Tampa Electric has adapted its generating portfolio to capture technological improvements and fuel price savings, in response to changing public policy concerns, and to embrace the evolving expectations of our customers.

Q. Please explain further.

A. During most of the 20th century, Tampa Electric relied on oil fired generation to serve its customers. Oil provided safe, reliable, and relatively inexpensive generation. A large portion of the oil used by Tampa Electric was imported to the United States from the Middle East under the supervision of the Organization of Petroleum Exporting Countries ("OPEC").

In the early 1970s, OPEC stopped selling oil to the United States. This oil embargo sent gas prices through the roof, and oil prices quadrupled.

Federal and state policy makers responded by promoting energy conservation and encouraging utilities to focus on coal, which at the time was plentiful in the United States and cheaper than oil as a generating fuel.

For example, the Commission adopted the oil backout cost recovery factor rule, Rule 25-17.16, Florida Administrative Code, in 1982 ("Oil Backout Rule") to allow Florida utilities to recover the cost of implementing supply side conservation projects whose primary purpose was the economic displacement of oil generated electricity.

Q. Did Tampa Electric respond to these economic and public policy changes?

A. Yes. First, the company converted its then oil-fired Gannon Units 1 through 4 to burn coal in the 1980s and recovered the costs of the conversion via the Oil Backout Rule.

Second, the company built Big Bend Units 1 through 4 in the 1970s and 1980s when the economy, reliability, and efficiency of coal and public policy considerations made doing so in the public interest.

Third, in 1996, the Tampa Electric Polk Unit 1 project came on-line with the assistance of a generous grant from the Department of Energy to test coal gasification, which was an innovative, more environmentally friendly alternative to traditional coal fired generation. This government sponsored project provided Tampa Electric significant power generation without the environmental consequences from the normal combustion of coal.

Fourth, the company retired its Hookers Point Power Station in 2003. Hookers Point was placed into service in the 1950s and consisted of five heavy oil conventional boiler and steam turbine units.

Q. Has the public policy in favor of coal and economics of coal-fired generation changed?

A. Yes. Concerns about the environment led to significant federal and state regulatory actions that forced utilities like Tampa Electric to install pollution control equipment to limit the emissions and other environmental impacts from coal-fired generation. The company added pollution control equipment at Big Bend in the 1990s and 2000s as required by legislative responses to growing concerns about the environment. The environmental regulations that affected coal-fired generation and how Tampa Electric complied with them are summarized in Document No. 5 of my exhibit.

The environmental compliance costs associated with burning coal have made generating electricity with natural gas an economically attractive alternative to coal. Improvements in CC generating technology, the recent improvements in hydraulic fracking technology, and the resulting abundant domestic sources of natural gas have further improved the relative economics and environmental value of natural gas and propelled the movement away from coal as a generating fuel.

Q. Has Tampa Electric responded to these changes?

A. Yes. Tampa Electric responded to these changes in 2002 and 2003 by converting its then coal-fired Gannon Station Units 5 and 6 to natural gas-fired Bayside Units 1 and 2. The company later added four natural gas-powered aero derivative units at Bayside and one natural gas-powered aero derivative unit at Big Bend. The Polk 2 Conversion and adding dual-fuel capability at Big Bend were also a response to the changing economics and public policy views of natural gas fired generation relative to coal.

Q. Were all the changes to the company's generating fleet described above prudent?

A. Yes. Each change was made considering the conditions and circumstances known at the time after careful internal studies that considered safety, reliability, economics, and then-existing environmental considerations. All were the subject of regulatory and intervenor scrutiny.

CURRENT AND FUTURE ENERGY SUPPLY PLANS

Q. Are technological improvements, fuel prices, and public policy considerations continuing to drive changes in how the company generates electricity?

A. Yes. Growing concern about our environment and global warming continue to increase and inform the actions of policy makers. Technology improvements have made solar generation a cost-effective alternative to natural gas-fired generation within the operating parameters of a utility's system. Battery storage technology continues to improve and is expected to make battery storage an important part of the electric grid, while further reducing our need to burn fossil fuels to generate electricity.

Absent an unforeseen change, the future of coal as a fuel for generating electricity appears to be ending, and the future is bright for renewable energy resources and batteries. In the meantime, however, we still depend on highly efficient NGCC technology to meet a large portion of our electric generation needs.

Q. How has Tampa Electric responded to these recent changes in favor of renewable energy?

A. First, beginning in 2014, Tampa Electric added relatively small solar projects to its electric system at the Tampa Airport, Legoland, and Big Bend. These projects include a 1.6 MW_{ac} fixed tilt solar PV rooftop canopy array located at the south parking garage at Tampa International Airport, a 1.4 MW_{ac} fixed tilt solar PV ground canopy array located at Legoland Florida, and a 19.8 MW_{ac} single axis tracking solar facility at Big Bend. These projects were prudent as an important part of the company's effort to become familiar with solar technology and how solar operates on its system.

Second, from 2017 to 2020, the company constructed 600 MW_{ac} of solar capacity pursuant to its 2017 Agreement. Together with its initial small solar projects, these cost-effective solar additions have allowed the company to power the equivalent of more than 100,000 homes, businesses, and schools. The prudence of these projects was determined as part of the 2017 Agreement and the SoBRA proceedings that approved them.

Third, the company has installed a 12.6 MW battery storage unit at Big Bend and coupled it with the single axis tracking solar facility there. This battery storage pilot is prudent as an effort by the company to learn how battery storage interacts with generation resources and how to best integrate them into our electric grid.

Fourth, the company is planning Future Solar in three phases from 2021 to 2023 as discussed further in the testimonies of Mr. Sweat and Mr. Aponte.

And finally, the company’s Big Bend Modernization is well underway and will convert part of Big Bend into state-of-the-art, highly efficient NGCC generation.

A. <u>BIG BEND MODERNIZATION PROJECT</u>

Q. Please describe the Big Bend Modernization Project.

A. As part of Big Bend Modernization, the company will retire Big Bend Unit 2 and repower Big Bend Unit 1 as a clean natural gas-fired two-on-one CC generating facility. Big Bend Unit 1 will be repowered with a new NGCC unit that will use the unit's existing steam turbine generator, and once-through cooling system. Big Bend Unit 1 will have a nominal net generating capacity of 1,090 MW when the repowering is complete. The analysis that led to the decision to proceed with the project and why the project is prudent are described in the direct testimony of Mr. Caldwell.

Q. What are your responsibilities for Big Bend Modernization?

A. I am responsible for ensuring that Commissioning support and start-up activities are coordinated with plant operating, maintenance, engineering staff and to ensure we have a fully trained team ready to support commercial operation upon project completion.

Big Bend Modernization will be constructed in two phases. The first phase will result in the operation of the two new highly efficient CTs in simple cycle mode, is expected to cost $409.4 million, and will be complete in December 2021. The second phase consists of the addition of the HRSG and will result in the unit's operation in CC mode, is expected to cost $495.2 million, and will be in service in December 2022. The total cost of the project is expected to be $904.6 million. Document No. 6 of my exhibit reflects a summary of Big Bend Modernization and costs by phase.

Q. What portions of Big Bend Modernization are complete?

A. The completed elements of the project and dates they were completed are:

Conceptual Engineering	May 2017
Preliminary Design and Engineering	January 2018
File Site Certification and Permit Applications	April 2018
Award Contracts	June 2019
Permits Received	July 2019
Big Bend Unit 1 Shutdown	June 2020

Q. Which elements of Big Bend Modernization remain to be completed?

A. The remaining project milestones are listed below, along with their estimated completion dates.

Simple Cycle First Fire	August 2021
Combustion Turbines in Service	December 2021
Big Bend Unit 2 Shutdown	December 2021
Combined Cycle Unit in Service	December 2022

Q. What portions of Big Bend Units 1 and 2 will be reused and which portions will be retired?

A. Some, but not all the component parts of Big Bend Unit 1 will be refurbished and re-used for the repowered Unit 1. Substantially all Big Bend Unit 2 will be retired as well as some plant equipment that is common to the two units.

The Big Bend Unit 1 assets to be retired had an undepreciated NBV of $122.9 million as of December 31, 2021, which amount will not be recovered by the time of retirement through the normal depreciation process. These assets generally include the existing boiler and most of the pollution control equipment and are listed in more detail in Document No. 7 of my exhibit.

The Big Bend Unit 2 assets to be retired had an undepreciated NBV of $171.3 million as of December 31, 2021, which amount will not be recovered by the time of retirement through the normal depreciation process. These assets include substantially all the property units associated with Big Bend Unit 2. The Big Bend Unit 2 assets to be retired in conjunction with the project are summarized in Document No. 8 of my exhibit.

Q. Are there items of inventory associated with the portions of Big Bend Units 1 and 2 to be retired as part of the project that will no longer be used and useful to provide electric service?

A. Yes. The dollar value of the obsolete inventory associated with the Big Bend Unit 1 Retirement Assets was approximately $1.0 million as of December 31, 2019, and includes all parts associated specifically for Unit 1. This inventory cannot be used in any of the company's other generating stations, has no salvage value, and will no longer be used or useful for the generation of electricity at Big Bend or otherwise.

The dollar value of the obsolete common inventory that could be utilized interchangeably for both Big Bend Unit 1 and Big Bend Unit 2 was approximately $4.1 million as of December 31, 2019 and includes all replacement parts associated with the Big Bend Units 1 and 2. This inventory cannot be used in any of the company's other generating stations, has no salvage value, and will no longer be used or useful for the generation of electricity at Big Bend or otherwise.

A schedule showing these items of obsolete inventory is included as Document No. 9 of my exhibit.

Q. What amounts of construction work in progress and electric plant in service are associated with Big Bend Modernization in the 2022 test year?

A. Phase One went in-service prior to the 2022 Test Year, thus there is $0 in Construction Work in Progress ("CWIP") and $383.9 million of Plant In-Service.

Phase Two goes in-service December 2022 during the 2022 Test Year, there is $0 in CWIP as this phase is earning Allowance for Funds Used During Construction ("AFUDC") and is Florida Public Service Commission ("FPSC") Adjusted out of CWIP in rate base (See Segregation of CWIP / Surveillance) and $34.3 million of Plant In-service (1/13 of the December 2022 addition amount of $445.7 million.

Q. What amounts of construction work in progress and electric plant in service are associated with Big Bend Modernization in calendar year 2023?

A. Phase One will go in-service prior to the 2022 Test Year, thus there is $0 in CWIP and $384.1 million of Plant In-Service. Phase Two goes in-service December 2022 during the 2022 Test Year, thus there is $0 in CWIP and $454.7 million of Plant In-Service in 2023.

Q. Please describe the procurement practices Tampa Electric used for Big Bend Modernization.

A. The company followed its well-established, formal bidding processes and procedures to procure all material, major equipment, and services for the project. These procurement activities were performed by the company's Procurement Department to ensure and maintain an unbiased, consistent, and objective procurement process. Key elements of the process included: requesting formal and well documented bids from three or more vendors, a full review of bidder qualifications, and a thorough review of their cost proposals. The company selected the best evaluated vendor based on these criteria to ensure the lowest reasonable cost for our company and our customers.

Q. Will Big Bend Modernization be completed as scheduled?

A. Yes. The CTs are expected to be in-service in December

2021, and the complete CC cycle unit schedule is on target and expected to be in service in December 2022.

Q. Will the Big Bend Modernization be completed within budget?

A. Yes. The project costs are within budget. Through February 2021, approximately 65 percent of costs have been incurred, and all major material and installation contracts have been awarded.

Q. Is Big Bend Modernization prudent and in the best interests of the company's customers?

A. Yes. The project costs are prudent and reasonable, and the project will go in service on time and within budget. The project is cost-effective and is a prudent investment to serve Tampa Electric's customers with lower fuel usage and less emissions. The testimony of Mr. Caldwell discusses the project's cost-effectiveness, as well as the savings and other benefits it will provide to customers.

B. EARLY RETIREMENT OF BIG BEND UNIT 3

Q. What are the company's plans for Big Bend Unit 3?

A. Big Bend Unit 3 is a pulverized coal-fired steam unit. It was placed in service in May 1976. It has a name-plate capacity of 445.5 MW and has summer and winter capability of 395 MW and 400 MW, respectively. The expected retirement date reflected in the company's previous depreciation study is 2041. The company has concluded that it is prudent and in the best interests of our customers to retire Unit 3 in April 2023.

Q. Why does the company plan to retire Unit 3 in 2023?

A. We accelerated the retirement of Unit 3 from 2041 because it will save customers money by, among other things, avoiding a very expensive, time consuming, and operationally challenging major outage that will be needed if Unit 3 is to continue operating beyond 2023. We estimate that the early retirement of Unit 3 will avoid total expenditures of $491.1 million ($298.0 million Net Present Value). It will also help make the company cleaner and greener. A full explanation of the reasons why the early retirement of Unit 3 is prudent is included in the testimony of Mr. Caldwell.

Q. Is April 2023 the right time to retire Unit 3?

A. Yes. Big Bend Modernization is expected be complete and in service in December 2022. Retiring Unit 3 as soon as practical after this date provides contingency in the event of unexpected Big Bend Modernization delays, it also keeps Unit 3 operational if needed to support manatee protection during the winter of 2022 through 2023 and allows Unit 3 to retire soon enough to avoid the major outage described above. Unit 3 will remain in service and be used and useful in the provision of electric service during the 2022 test year.

Q. What Big Bend Unit 3 assets will be retired?

A. The Unit 3 assets to be retired in April 2023 had an undepreciated NBV of $187.4 million as of December 31, 2021, which amount will not be recovered by the time of retirement through the normal depreciation process. These assets include substantially all the property units associated with Big Bend Unit 3. The Big Bend Unit 3 assets to be retired in April 2023 are listed in more detail, with their corresponding projected NBV as of December 31, 2021, in Document No. 10 of my exhibit.

C. <u>OVERALL ENERGY SUPPLY PLANS</u>

Q. How do the Future Solar projects, Big Bend Modernization, and early retirement of Big Bend Unit 3 fit into the company's overall generation plan?

A. Tampa Electric is on a journey to world class safety, improved environmental performance, and excellent customer experience. We will accomplish our safety goals through team member engagement, training, and a focus on safety 24 hours a day and seven days a week. We will accomplish our environmental goals through reduced carbon emissions, reduced coal combustion, and a transition to renewables.

The customer experience will improve through a focus on improving the overall reliability of our energy supply system by diversifying our generation portfolio through the introduction of renewable solar generation and seeking opportunities for increased distributed generation.

The Future Solar described by Mr. Sweat and Mr. Aponte are shown on MFR Schedule B-11 and are cost-effective additions that will enhance our fuel diversity and, because the cost of fuel for Solar is zero, will promote price stability for our customers. Solar, together with distributed generation and battery technology, will combine with our traditional centralized generating stations to provide a reliable and more efficient generation portfolio.

Big Bend Modernization additions are shown in MFR Schedule B-11 and will improve the company's overall system efficiency and generating system reliability; will make the Big Bend generating units more reliable on a stand-alone basis; and will enable the company to burn less coal, use less water, and generate less wastewater than under the status quo, making Tampa Electric cleaner and greener. The project will lower the emission of CO_2, SO_2, and NO_x relative to current projected levels. It also will enable the company to moderate the amount of money it must spend on solid fuel before the project is complete and to maintain an acceptable level of warm water discharge to the existing manatee sanctuary. It will complement the company's existing and planned solar projects by providing winter reserve margin, 24-7 energy, and regulation support for solar generation, which is an intermittent resource.

The flexibility and "following" ability inherent in the repowered Big Bend Unit 1 will effectively complement the company's utility scale solar. The repowered Big Bend Unit 1 will be able to quickly offset the variability of the solar plants by ramping up or reducing output. These reliability attributes produce fuel savings for customers by allowing solar to fully dispatch first where the NGCC plants can follow the solar output and curtailment. This ensures customers will receive a reliability benefit when solar wanes and fuel cost savings when solar is producing.

These major investments in NGCC technology and Solar will have an immediate and lasting positive effect through carbon reductions, increased reliability, reduced O&M expense, and headcount reductions.

Our investments in NGCC and Solar will require fewer worker hours to operate and maintain and are already allowing us to reduce team member headcount by managing attrition rates, reducing our use of contractors, and reassigning team members to jobs that add value to the transformed plant. These technologies also require fewer financial resources to operate and allow the company to retire solid fuel assets that cost more to operate and maintain. Indeed, the early retirement of Big Bend Unit 3 will significantly reduce the company’s carbon emissions and reduce its future environmental compliance risks.

Through these NGCC and Solar investments and the retirement of solid fuel assets, the company will maintain a diversified fuel portfolio and continue to develop fuel supply redundancies.

D. OTHER FUTURE ENERGY SUPPLY PLANS

Q. Does the company have generation plans beyond the 2022 test year?

A. Yes. In addition to Big Bend Modernization and Future Solar, which will go into service at different times in 2022 and 2023, the company's plans include a streamlined approach to meeting winter peaks with capacity enhancements at Bayside and the addition of distributed resources such as reciprocating engines and additional battery storage to be deployed in 50 to 60 MW increments.

We expect the combination of reciprocating engines and battery storage to deliver flexible, quick response peaking capacity. They will work in concert to provide cost savings, operational flexibility, environmental and reliability benefits for customers, and value through improved efficiency and system reliability. Our plans reflect an agile deployment of resources that will match the timing and capacity increments needed to satisfy the company's future reserve margin requirements.

Q. Is the company planning any innovative Energy Supply projects?

A. Yes. Tampa Electric has several innovative projects that will advance the company's understanding of symbiotic relationships available through Solar. These include an Agrivoltaics project and a Floating Solar project.

Agrivoltaics is a new way of combining renewable energy with agriculture by positioning plants or crops between elevated solar panels. This method may enable dual land use that will benefit the farming industry; help fulfill federal, state, and local government goals for supporting agribusiness; and increase farmable acreage as solar development continues. We have selected a seven-acre site at Big Bend for a demonstration project where approximately four acres will be farmed under a solar canopy that will be designed to produce 1.1 MWac.

We will also install a floating solar project in one of Big Bend's retention ponds. This project will test a beneficial use of retention ponds or other similar infrastructure and will produce 1 MWac of Solar energy. The company hopes to demonstrate that floating solar will reduce evaporation, conserve water, lower the installation and maintenance costs relative to other solar facilities, reduce exposure to wind events, and decrease algae growth in the pond.

2022 ENERGY SUPPLY RATE BASE

Q. How does the amount of production plant for the 2022 test year compare to the amount of production plant in the company's 2013 rate case?

A. The production plant has increased by $1.743 billion since 2013. It is projected to be $5.642 billion in 2022 versus $3.899 billion in 2013.

Q. What major projects since 2013 are reflected in this increase?

A. Approximately $545.3 million of this increase is attributable to the Polk 2 conversion approved and deemed prudent in the 2013 Stipulation and described above.

Another $865.7 million of this increase is attributable to the construction of the company's first 600 MWac of solar generation capacity that was authorized and deemed prudent in the 2017 Agreement and associated SoBRA proceedings. Approximately $411.8 million of the increase is attributable to the Big Bend Modernization, and $346.5 million is associated with Tranche One of Future Solar.

The remainder of the increase is attributable to prudently incurred annual sustaining capital expenditures required to maintain the operational and environmental reliability of the company's existing generating fleet and so that those generating units will remain used and useful for delivery of electric service to our customers.

In 2018, the company performed a major planned outage for Bayside steam turbine Unit 2 at a cost of $17.2 million, along with the replacement of the Polk Unit 1 gas turbine rotor, at a cost of $14.7 million.

In 2019, the company performed a major planned outage for the Big Bend 3 steam turbine at a cost of $7.8 million, along with phase one of a planned two-phase major outage on Big Bend Unit 4 at a cost of $39.9 million.

In the spring of 2020, the company completed Phase Two of the Big Bend 4 major outage, which included a steam turbine major outage, precipitator field replacement, duct work replacement, and boiler waterwall tube replacements at a cost of $56.1 million.

In 2021, Bayside will start a multi-year (2021-2023) project, addressing all seven natural gas turbines that will significantly improve operational efficiency and flexibility, as well as increase the station's output by more than 128 MW. This project has a total projected cost of $76.0 million.

Document No. 11 of my exhibit shows how these projects combine to make up the increase in the Energy Supply (production plant) portion of the company's rate base from 2013 to 2022.

Q. Please describe the major production plant additions for 2020, 2021 and 2022 as shown on MFR Schedules B-7, B-8, B-11, and B-12.

A. For 2020, major production plant additions include $185.0 million for completion of the final phase of the company's first 600 MWac of solar generation capacity, and $71.8 million in additions related to the completion of Phase Two of the Big Bend 4 major outage.

For 2021, major production plant additions include $347.6 million for the first tranche of Future Solar. Another $354.7 million of major plant additions in 2021 is related to the completion of the first phase of the Big Bend Modernization.

For 2022, major production plant additions include $234.5 million for the second tranche of Future Solar and $445.7 million related to the completion of the first phase of the Big Bend Modernization. Further major additions in 2022 include $50.3 million for the Bayside Unit 1 Major Outage and Advanced Hardware Upgrades, as well as $54.5 million fort the Polk Dual Fuel Expansion Project.

The remainder of the additions for these years is attributable to prudently incurred annual sustaining capital expenditures required to maintain the operational and environmental reliability of the company’s existing generating fleet and so that those generating units will remain used and useful for delivery of electric service to our customers.

Q. What major production plant projects are in Construction Work in Progress for 2022 as shown on MFR Schedule B-13.

A. For 2022, major production plant project balances in Construction Work in Progress include $377.1 million for the second phase of the Big Bend Modernization, $241.6

million for Future Solar, $35.3 million for Bayside Advanced Hardware, and $23.4 million for Distributed Generation.

Q. What is Tampa Electric's construction capital budget for Energy Supply in 2022 and 2023?

A. The Energy Supply construction capital budget totals $176.1 and $150.5 million for 2022 and 2023, respectively, as shown in Document No. 12 of my exhibit. This total is comprised of $101.7 and $126.5 million for recurring, non-expansion projects and $74.4 and $24.0 million for non-recurring, expansion projects in 2022 and 2023, respectively. These additions to rate base are prudent as described below.

Q. In general, how does Tampa Electric determine the construction program and capital budget for additional generation facilities?

A. Tampa Electric uses an Integrated Resource Planning ("IRP") process. The IRP process determines the timing, type, and amounts of additional resources required to maintain system reliability in a cost-effective manner. The process considers expected growth in customer demand, energy efficiency and conservation programs, existing and future demand-side management ("DSM") programs, and a wide range of supply-side generating technologies applicable to the company's service area. We also employ the Asset Management principles previously described in my direct testimony.

Q. What evaluations were performed before the company approved and began implementing its plans for Big Bend Modernization and Future Solar?

A. The specifics of the analyses used to develop and determine the cost-effectiveness of the Big Bend Modernization and the Future Solar are described in the direct testimony of Mr. Caldwell and Mr. Aponte, respectively.

Q. How does the company plan and manage its generation and other major capital improvement expansion projects?

A. The company has a mid-term planning process in place to manage its generation and other major capital improvement projects. As part of this process, the company conducts a screening analysis and develops a multi-year business plan. This plan includes capital and maintenance budget forecasts for projects deemed necessary to ensure safety, maintain or improve performance of existing stations, capacity, efficiency and reliability improvements, and environmental compliance. The company updates the business plan as new information is obtained.

Each year the company determines the capital plan for the following fiscal year. Information regarding generating unit availability, operating conditions, new regulations, and environmental compliance is reviewed and considered for inclusion in the capital plan. Some projects are required because of environmental or safety considerations or new regulations. Other projects are prioritized based upon their relative benefits. Through a review process, the projects are selected for inclusion in the next year’s budget. These projects are also initiated and executed by a project team in a method like that for new generation projects. Each project goes through an estimating and approval process to ensure its benefit and need. These projects are monitored for cost, schedule, and desired performance throughout the process until they are completed and in-service.

Q. Does the company consider planned generation outages when preparing its annual capital budget?

A. Yes. Planned outages have a capital and expense element.

The capital costs associated with 2022 planned outages are described below in this section of my direct testimony. The expenses associated with the planned outages for 2022 are discussed in the next section of my direct testimony.

Planned outages are defined as those outage periods that are anticipated and planned well in advance of the actual outage period, typically at least one year in advance. Forced outages, on the other hand, are not planned or scheduled, and can be the result of an in-service failure or imminent failure of some generating unit component. In addition, forced outages are typically short in duration and have greatly reduced scope-of-work versus planned outages.

The 2022 planned unit maintenance durations are shown for each unit in MFR Schedule F-8, page 11 of 24. There are 24 planned outages scheduled in 2022. We have scheduled a total of 48 planned outage weeks across our system. The planned outage schedule varies from year to year based on the maintenance requirements of each generating unit and the need for adequate generating capacity in service to reliably meet demand throughout the year.

Except for the major planned outage at Bayside described below, the planned maintenance outage activity for 2022 is typical of the past and expected future planned outage requirements.

Q. You previously explained the company's production plant rate base additions from 2013 to 2021, why they were prudent, and that they continue to be used and useful to serve the company's customers. Would you now please describe and explain the major additions to production plant rate base that will occur in the 2022 test year?

A. The company's major Energy Supply capital projects that will be in service in all or part of 2022 include:

225 MW of Future Solar – Our 2022 plans reflect 225 MWac of Future Solar constructed in 2021 and in service in December 2021 at an estimated capital cost of $315.1 million.

Big Bend Unit 4 Natural Gas Upgrade – This project will deliver increased load capability on natural gas, will be completed during the Fall 2021 outage, and will have a capital cost of approximately $9.0 million.

436 MW Big Bend Modernization steam turbine CC component

- The steam-related or CC component of the Big Bend Modernization will be completed in December 2022 at an estimated capital cost of $495.2 million.

67 MW Bayside Unit 1 Advanced Hardware Upgrades - The first phase of the planned upgrades to Bayside will commence in 2022 and will be completed in 2023. The advanced hardware will increase generating capacity while also improving operational efficiency and flexibility. The estimated capital cost in 2022 is $20.0 million.

Bayside Unit 1 planned major outage – This project will address the steam turbine and steam valves, HRSG attemperators, steam turbine and CT auxiliaries, and CT controls upgrade and is expected to have a capital cost of approximately $7.9 million.

Polk Dual Fuel Expansion Project – Polk currently has dual fuel capability on CTs 2 and 3 and the addition of fuel oil capability on CTs 4 and 5 is planned for 2022 and is expected to have a capital cost of approximately $54.5 million.

Distributed Generation – In support of a streamlined approach to meeting winter peaks, distributed generation development will begin in 2021 and conclude in 2024. Utilizing reciprocating engine technology, the estimated 2022 capital cost is $48.6 million.

Q. Why are each of these major projects prudent and how will they benefit the company and its customers?

A. **225 MW of Future Solar** – Mr. Aponte provides a more detailed overview of the benefits of our Future Solar.

Big Bend Unit 4 Natural Gas Upgrade – The planned upgrade will provide dispatch flexibility of Big Bend Unit 4 and will provide additional fuel savings opportunities while natural gas is more economic than coal.

436 MW Big Bend Modernization steam turbine CC component – Mr. Caldwell's testimony thoroughly explains the benefits of Big Bend Modernization and our related 2022 plant additions.

67 MW Bayside Unit 2 Advanced Hardware Upgrades - Gas turbines require regular overhauls on time- and start-based intervals. The timing of these overhauls for Bayside Units 1 and 2 are 2022 and 2023, respectively. The company also will make an incremental investment over the base overhaul investments, which will result in significant increased generation capacity, improved heat rate performance, and operational flexibility. The added generation will come at an approximate cost of $403 per kW, which is significantly less than any other known alternative.

Bayside Unit 1 planned outage – All generating assets require major maintenance outages on a four to five-year rotation and Bayside Unit 1 is scheduled for 2022. The planned refurbishment of major generating assets delivers a high degree of availability and aids in optimizing operational efficiency.

Polk Dual Fuel Expansion Project – Dual fuel capability provides a level of protection from natural gas fuel shortages and from short-term price spikes in natural gas pricing.

Distributed Generation – With a goal of improving the customer experience and the overall reliability of our energy supply system, the addition of distributed generation will continue to diversify the generation portfolio.

Q. With these projects, what does the company expect its summer and winter reserve margins to be in 2022 and 2023?

A. The company’s 2020 Ten Year Site Plan shows that in 2022 the summer reserve margin will be 29 percent and the winter reserve margin will be 20 percent. Following the completion of the planned 2022 projects, the 2023 summer reserve margin will be 36 percent and the winter reserve margin will be 22 percent. Solar generation does not contribute to the winter peak hour, which typically occurs at the hour of 7:01 to 08:00 a.m., resulting in higher summer reserve margins when the Solar *is* available at the system’s peak time. The company must plan for its greatest load at the winter peak and a 20 percent reserve margin at that time. Solar generation, while not contributing to a peak capacity need in these analyses, provides zero-cost fuel and environmental benefits throughout the year.

Q. Does the company’s proposed rate base for 2022 include any Property Held for Future Use?

A. Yes. MFR Schedule B-15 reflects approximately $11.6 million of property held for future use. This property was purchased as buffer land to prevent encroachment by surrounding residential development and to support the long-term and viable operation of the Big Bend Power Station.

2022 ENERGY SUPPLY O&M EXPENSES

Q. What are Tampa Electric's production O&M and non-recoverable fuel expenses budgeted for 2022 and how has the amount varied over time?

A. Document No. 13 of my exhibit shows the Tampa Electric Energy Supply department production O&M costs, excluding all costs recovered through cost recovery clauses, are budgeted to be $111.1 million in 2022. This is $8.7 million less than the amount incurred in 2013. In fact, O&M expenses (excluding cost recovery clauses) increased from $119.8 million in 2013 to a peak of $146.4 million in 2016.

Since 2016, Tampa Electric has reduced its production O&M expenses by transitioning to cleaner and more affordable sources of fuel with a concentration on natural gas operations and the addition of renewables such as Solar. At Big Bend, for example, which has historically been the company's primary solid fuel facility, we reduced operating expenses from a high of $79.6 million in 2015 to $43.0 million in 2022. This demonstrates some of the cost savings the company has achieved by switching from solid fuel to natural gas operations, which in turn have moderated our need for rate relief.

Q. How do these spending levels compare with what would be expected using the Consumer Price Index for Urban Consumers ("CPI-U") escalation factors using 2013 as a benchmark?

A. The CPI-U is the measure used by the Commission to benchmark O&M expenses for production plant. Document No. 14 of my exhibit shows that the actual expenses have generally been below what would be expected using the CPI-U as a cost escalator. The company implemented cost control measures from 2013 to 2020 to hold production O&M expenses below the levels expected with inflation. Our budgeted production O&M expenses for the 2022 test year are more than $28.6 million less than the 2012 O&M Benchmark Variance by Function as noted in MFR Schedule C-37.

Q. Please describe the change in outside professional services for the historical and projected test year.

A. Production (O&M) outside professional services, excluding all costs recovered through cost recovery clauses, included in the amounts on MFR schedule C-16, are approximately $26.3 million in 2022, compared to approximately $30.2 million in 2020. Primary drivers for this reduction include approximately $4.3 million included in the 2020 amount for completion of phase II of the Big Bend Unit 4 major outage, offset by approximately $3.0 million of outside services related to the 2022 Bayside major outage. Further reductions to the 2022 total are related to a $1.7 million reduction in solar outside services as that work will transition in-house. The remainder of the reduction of outside services expense in 2022 as compared to 2020 are a result of achieving cost efficiencies as the Company shifts from coal-fired generation to cleaner and more environmentally friendly sources of generation, which typically entail less maintenance than solid-fuel generation. Planned spending in 2022 is prudent and in line with historical expenditures.

Q. Please describe the favorable production O&M benchmark variances shown on MFR Schedules C-37, C-38, C-39, and C-41.

A. As shown on MFR Schedules C-37, C-38, C-39, and C-41, production O&M, excluding all costs recovered through cost recovery clauses, is budgeted to be $28.6 million, or 21.6 percent, favorable to the 2012 benchmark. The shift from coal-fired generation to cleaner and more environmentally friendly sources of generation has reduced overall cost of maintenance for the fleet. Production O&M steadily rose from 2012 to 2016 as maintenance costs on the solid fuel units continued to increase. The age of the units and wear and tear related to the use of solid fuel pushed maintenance costs higher each year until the spend peaked in 2016. In early 2017, commencement of operation of the Polk 2 Combined Cycle would effectively change the dispatch order and reduce the utilization of solid fuel- based units from baseline to economic dispatch. Cost controls and efficiencies achieved through the greater utilization of natural gas and later the addition of solar generation, resulted in a reduction of approximately 24.1 percent to labor costs, and approximately 40.5 percent reduction in outside services and materials costs, from the peak of production expense in 2016.

Q. How has the company managed to stay below the O&M benchmark for 2022 production expenses?

A. O&M production expenses have been trending down since 2016 as the company shifted from coal-fired generation to natural gas-fired generation. The Polk 2 Conversion dramatically changed the dispatch order of Polk 2 versus Big Bend units, resulting in lower O&M expenses. Polk Unit 2 has transitioned from primarily being a peaking facility to a baseload facility, and Big Bend has transitioned to an economic dispatch facility. This has resulted in less demand on Big Bend, which reduces wear and tear and the level of expenses we incur in Energy Supply. As part of our preparation for Big Bend Modernization, we have reduced staffing levels primarily through attrition and team members seeking opportunities elsewhere within the company. This benefited the overall O&M production expenses for Energy Supply.

Q. Does the company incur O&M expenses in conjunction with a planned outage?

A. Yes. Maintenance, as defined by FERC accounting instructions, conducted during planned outages is charged to O&M expense. Maintenance consists of large tasks that are performed infrequently and have a long duration. Typical examples are steam turbine inspections and repairs, replacement of large heat transfer surfaces in the boiler, and refurbishment of large motors and pumps. The maintenance performed during these outages is required to ensure the safe, reliable operation of the generating units.

Q. What is the O&M impact of planned outages on Tampa Electric's generating units in the 2022 test year?

A. Routine planned maintenance outages and the associated O&M costs, across all operating units is in line with historic spending and routine work scope. Planned major outages are required on a regular four- to five-year cycle and efforts are taken to stagger out these major outages to minimize the impact to O&M spending in any one year. For the 2022 test year, Bayside Unit 1 has a planned major outage, which is estimated to cost $6.0 million in O&M expense.

Q. Please describe the O&M work planned for the Bayside major planned outage.

A. The O&M work associated with the 2022 outage at Bayside station is estimated to cost $6.0 million. The scope of work includes the open and close activity; steam turbine rotor and blade inspection; bearing and seal cleaning, inspection, and maintenance; lift oil and seal oil flushes; and steam turbine valve cleaning, inspection, and maintenance.

Q. Has Tampa Electric taken other measures to control generation O&M costs while maintaining a safe and productive workplace?

A. Yes, Tampa Electric applies many different approaches to control cost, including the Asset Management methodologies previously described to manage O&M expenses. Other areas of focus include centralized contractor work planning and dispatch across all 3 generating facilities. Having a broader view of work demands allows for a more efficient and effective way to control contractor head count and contractor spending. We perform ongoing assessments of in-house capabilities and cost effectiveness versus an external contractor approach. Transitioning Solar operation and maintenance to in-house resources has provided cost reduction opportunities while also providing jobs for team members that may be impacted by the modernization of Big Bend.

Q. Is the overall level of production O&M expense for 2022 reasonable?

A. Yes. O&M expenses for 2022 are reasonable and will be managed close to 2020 levels. We will accomplish this by carefully managing the planned Bayside steam turbine major outage which, by itself, will have a $6.0 million impact to the O&M budget. We will mitigate inflation and standard labor increases by applying Asset Management procedures, implementing cost savings and continuous improvement initiatives, centralizing contractor coordination and contractor reductions, reducing wear and tear due to the transition to natural gas at Big Bend and Polk 1, and reducing staff levels at Big Bend.

SUMMARY

Q. Please summarize your direct testimony.

A. My direct testimony provides an overview of the company's generating system and its evolution since the 1950's and describes the company's future for its generating system. I describe how the Company's construction program and capital budget for 2022 and projections for 2023 and beyond are reasonable and prudent. I also demonstrate that the company's proposed O&M expenses for Energy Supply in the 2022 test year are reasonable and prudent. I explain how the company is using a disciplined approach to Asset Management to inform its decision-making in both Electric

Delivery and Energy Supply.

Tampa Electric's Energy Supply area is safer, cleaner, and greener, and provides a better customer experience than in 2013; however, our work is not complete. To continue delivering the value our customers expect, we must plan for the long term and invest now to create an even cleaner, greener, and more efficient energy future. The projects described in my testimony will further improve our safety, reliability, customer experience, and environmental profile and are prudent and in the best interests of our customers.

Q. Does this conclude your prepared direct testimony?

A. Yes, it does.

EXHIBIT

OF

DAVID A. PICKLES

Table of Contents

TAMPA ELECTRIC COMPANY
DOCKET NO. 20210034-EI
EXHIBIT NO. DAP-1
WITNESS: PICKLES
DOCUMENT NO. 1
PAGE 1 OF 1
FILED: 04/09/2021

LIST OF MINIMUM FILING REQUIREMENT SCHEDULES

SPONSORED OR CO-SPONSORED BY DAVID A. PICKLES

MFR Schedule	Title
B-07	Plant Balances By Account And Sub-Account
B-08	Monthly Plant Balances Test Year-13 Months
B-11	Capital Additions and Retirements
B-12	Production Plant Additions
B-13	Construction Work in Progress
B-15	Property Held for Future Use-13 Month Average
C-06	Budgeted Versus Actual Operating Revenues and Expenses
C-08	Detail of Changes in Expenses
C-09	Five Year Analysis-Change in Cost
C-16	Outside Professional Services
C-33	Performance Indices
C-34	Statistical Information
C-37	O&M Benchmark Comparison by Function
C-38	O&M Adjustments by Function
C-39	Benchmark Year Recoverable O&M Expenses by Function
C-40	O&M Compound Multiplier Calculation
C-41	O&M Benchmark Variance by Function
F-08	Assumptions

THERMAL EFFICIENCY (2013-2020)

Total System	**Net EAF%**	**Net Heat Rate**
2013	82.72	9,277
2014	84.33	9,322
2015	80.04	9,057
2016	77.45	9,186
2017	77.75	8,488
2018	80.47	8,259
2019	84.22	7,918
2020	81.32	7,599
Average	81.04	8,638
Max	84.33	9,322
Min	77.45	7,599

EMISSIONS (2013-2020)

Year	CO_2 Total (tons)	Reduction from 2013 (tons)	Reduction from 2013 (%)
2013	15,685,795	0	0%
2014	16,214,881	-529,086	-3%
2015	15,281,846	403,949	3%
2016	13,648,898	2,036,897	13%
2017	13,253,306	2,432,489	16%
2018	11,844,601	3,841,194	24%
2019	9,301,229	6,384,566	41%
2020	8,814,554	6,871,241	44%

SYSTEM EQUIVALENT AVAILABILITY FACTOR ("EAF") (2013-2020)

Total System	Net EAF%
2013	82.72
2014	84.33
2015	80.04
2016	77.45
2017	77.75
2018	80.47
2019	84.22
2020	81.32
Average	81.04
Max	84.33
Min	77.45

ENVIRONMENTAL REGULATIONS FOR COAL FIRED GENERATION

The primary environmental air regulations that affect coal generation are the Acid Rain Program, New Source Review (NSR), New Source Performance Standards (NSPS), National Emission Standards for Hazardous Air Pollution (NESHAP), and National Ambient Air Quality Standards (NAAQS), and State of Florida regulations, based on the 1977 Clean Air Act (CAA) and Amendments (1990),

Title IV of the CAA sets a goal of reducing annual SO_2 emissions by 10 million tons below 1980 levels. To achieve these reductions, the law required a two-phase tightening of the restrictions placed on fossil fuel-fired power plants. Phase I began in 1995 and affected 263 units at 110 mostly coal-burning electric utility plants located in 21 eastern and mid-western states. An additional 182 units joined Phase I of the program as substitution or compensating units, bringing the total of Phase I affected units to 445. Phase II, which began in the year 2000, tightened the annual emissions limits imposed on these large, higher emitting plants and also set restrictions on smaller, cleaner plants fired by coal, oil, and gas, encompassing more than 2,000 units in all.

Florida Department of Environmental Protection (FDEP) has been delegated authority to administer the federal NSR or Prevention of Significant Deterioration ("PSD") program adopted by the Environmental Protection Agency ("EPA"). A basic description of the PSD program follows. The FDEP, pursuant to the delegated PSD program adopted in Florida, permits and regulates major sources of air pollution in areas that are designated as currently attaining Ambient Air Quality Standards ("AAQS") or designated as unclassifiable.

Section 111 of the CAA, NSPS, requires EPA establish federal emission standards for source categories that cause or contribute significantly to air pollution. These standards are intended to promote use of the best air pollution control technologies, taking into account the cost of such technology and any other non-air quality, health, and environmental impact and energy requirements. The NSPS are codified in the Code of Federal Regulations at 40 CFR 60.

EPA has enacted primary and secondary NAAQS for 6 air pollutants (40 CFR 50). Primary NAAQS are intended to protect the public health, and secondary NAAQS are intended to protect the public welfare from any known or anticipated adverse effects associated with the presence of pollutants in the ambient air. Florida has also adopted AAQS.

The provisions of the CAA that address the control of HAP emissions, or air toxics, are found in Section 112. Section 112 of the CAA includes provisions for the promulgation of National Emission Standards for Hazardous Air Pollutions (NESHAPs), or Maximum Achievable Control Technology (MACT) standards, as well as several related programs to enhance and support the NESHAPs program. On December 16, 2011, EPA issued the final Mercury and Air Toxic Standards Rule to reduce emissions of toxic air pollutants from power plants. Specifically, these mercury and air toxics standards (MATS) for power plants will reduce emissions from new and existing coal and oil-fired electric utility steam generating units (EGUs).

FDEP emission standards and general requirements are contained in Section 62-210 F.A.C., Stationary Source General Requirements (air permitting), Section 62-212, Stationary Source - Preconstruction Review, and Section 62-296 F.A.C., Stationary Sources Emission Standards

TAMPA ELECTRIC COMPANY
DOCKET NO. 20210034-EI
EXHIBIT NO. DAP-1
WITNESS: PICKLES
DOCUMENT NO. 6
PAGE 1 OF 1
FILED: 04/09/2021

SUMMARY OF BIG BEND MODERNIZATION PROJECT AND COSTS BY PHASE

	2017	2018	2019	2020	2021	2022	2023	Grand Total
Phase 1 w/o AFUDC	11,917	21,670,211	138,003,475	117,410,251	98,633,579	599,423	-	376,328,856
Phase 2 w/o AFUDC	-	22,805,017	91,150,715	135,329,066	94,749,293	54,604,126	37,902,271	436,540,488
BB Mod w/o AFUDC	**11,917**	**44,475,228**	**229,154,190**	**252,739,318**	**193,382,872**	**55,203,549**	**37,902,271**	**812,869,344**
Phase 1 AFUDC	145	369,651	5,096,836	12,842,629	14,768,798	16,411	-	33,094,471
Phase 2 AFUDC	-	508,745	3,194,317	10,953,831	20,255,208	23,745,260	-	58,657,362
Total BB Mod AFUDC	**145**	**878,396**	**8,291,153**	**23,796,460**	**35,024,006**	**23,761,672**	**-**	**91,751,833**
Phase 1 w AFUDC	12,062	22,039,862	143,100,311	130,252,880	113,402,377	615,834	-	409,423,327
Phase 2 w AFUDC	-	23,313,762	94,345,032	146,282,898	115,004,501	78,349,386	37,902,271	495,197,850
Total BB Mod w AFUDC	**12,062**	**45,353,624**	**237,445,343**	**276,535,778**	**228,406,878**	**78,965,221**	**37,902,271**	**904,621,177**

BIG BEND UNIT 1 RETIREMENT ASSETS

	NBV
Depr Group	**12/31/2021**
311.41 Str & Improvements-BB1	1,750,961
312.41 Boiler Plant Eq-BB1	59,809,670
314.41 Turbogenerator Units-BB1	16,189,077
315.41 Accessory Electric Eq-BB1	7,855,895
316.41 Misc Power Plant Eq-BB1	334,867
353.00 Station Equipment	901,269
BB1-Boiler 1	**86,841,739**
311.51 Str & Improve-BB1 SCR	12,137,517
312.51 Boiler Plant Eq-BB1 SCR	19,051,089
315.51 Accessory Elect Eq-BB1 SCR	4,379,093
316.51 Misc Power Plt Eq-BB1 SCR	459,778
BB1-SCR 1	**36,027,477**

	12/31/2021	Recovered through		10 Years
	NBV	**ECRC Clause**	**Rate Base**	**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**	**48,153,262**
Dismantlement Reserve Deficiency				
Big Bend Unit #1	28,471,852		28,471,852	2,847,185
Big Bend Unit #2	39,642,284		39,642,284	3,964,228
Big Bend Unit #3	42,974,672		42,974,672	4,297,467
	111,088,808	**-**	**111,088,808**	**11,108,881**
Net	**592,621,427**	**153,873,002**	**438,748,425**	**59,262,143**

BIG BEND UNIT 2 RETIREMENT ASSETS

	NBV
Depr Group	**12/31/2021**
311.46 Str & Improve-BB1&2 FGD	2,126,377
312.46 Boiler Plant Eq-BB1&2 FGD	23,987,977
315.46 Accessory Elect Eq-BB1&2 FGD	4,494,232
316.46 Misc Power Plt Eq-BB1&2 FGD	281,743
BB2-FGD 1/2	**30,890,328**
312.40 Boiler Plant Eq-BBCM	105,458
311.42 Str & Improvements-BB2	2,868,091
312.42 Boiler Plant Eq-BB2	51,080,916
314.42 Turbogenerator Units-BB2	23,743,167
315.42 Accessory Electric Eq-BB2	10,628,815
316.42 Misc Power Plant Eq-BB2	45,129
353.00 Station Equipment	539,902
390.00 Structures & Improvements	12,985
BB2-Boiler 2	**89,024,462**
311.52 Str & Improve-BB2 SCR	14,180,632
312.52 Boiler Plant Eq-BB2 SCR	28,828,493
315.52 Accessory Elect Eq-BB2 SCR	7,866,351
316.52 Misc Power Plt Eq-BB2 SCR	516,215
BB2-SCR 2	**51,391,691**

	12/31/2021	Recovered through		10 Years
	NBV	ECRC Clause	Rate Base	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**	**48,153,262**
Dismantlement Reserve Deficiency				
Big Bend Unit #1	28,471,852		28,471,852	2,847,185
Big Bend Unit #2	39,642,284		39,642,284	3,964,228
Big Bend Unit #3	42,974,672		42,974,672	4,297,467
	111,088,808	**-**	**111,088,808**	**11,108,881**
Net	**592,621,427**	**153,873,002**	**438,748,425**	**59,262,143**

BIG BEND UNIT 1 AND 2 OBSOLETE INVENTORY

YEAR	UNIT 1	COMMON 1 & 2	TOTAL
2019	650,586	4,119,507	4,770,093
2020	296,447	-	296,447
GRAND TOTAL	947,033	4,119,507	5,066,540

TAMPA ELECTRIC COMPANY
DOCKET NO. 20210034-EI
EXHIBIT NO. DAP-1
WITNESS: PICKLES
DOCUMENT NO. 10
PAGE 1 OF 1
FILED: 04/09/2021

BIG BEND UNIT 3 RETIREMENT ASSETS

	NBV
Depr Group	**12/31/2021**
312.40 Boiler Plant Eq-BBCM	606,654
311.43 Str & Improvements-BB3	4,833,631
312.43 Boiler Plant Eq-BB3	95,210,521
314.43 Turbogenerator Units-BB3	29,557,805
315.43 Accessory Electric Eq-BB3	10,077,658
316.43 Misc Power Plant Eq-BB3	1,027,632
352.00 STR and Improvements	1,074
353.00 Station Equipment	3,882,814
BB3-Boiler 3	**145,197,789**
311.53 Str & Improve-BB3 SCR	12,616,853
312.53 Boiler Plant Eq-BB3 SCR	22,682,119
315.53 Accessory Elect Eq-BB3 SCR	6,414,904
316.53 Misc Power Plt Eq-BB3 SCR	445,260
BB3-SCR 3	**42,159,136**
Total	**481,532,622**

	12/31/2021	Recovered through		10 Years
	NBV	**ECRC Clause**	**Rate Base**	**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**	**48,153,262**
Dismantlement Reserve Deficiency				
Big Bend Unit #1	28,471,852		28,471,852	2,847,185
Big Bend Unit #2	39,642,284		39,642,284	3,964,228
Big Bend Unit #3	42,974,672		42,974,672	4,297,467
	111,088,808	**-**	**111,088,808**	**11,108,881**
Net	**592,621,427**	**153,873,002**	**438,748,425**	**59,262,143**

TAMPA ELECTRIC COMPANY
DOCKET NO. 20210034-EI
EXHIBIT NO. DAP-1
WITNESS: PICKLES
DOCUMENT NO. 11
PAGE 1 OF 1
FILED: 04/09/2021

Energy Supply Rate Base Growth (2013-2022)

est_chg_type	(Multiple Items)												
VP	ENERGY SUPPLY												
Sum of total		year											
RPA CapEx Adj	**Director**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**Grand Total**
Growth	ES-Bayside Power Station								1,000,000	31,000,000	19,999,998	24,000,003	76,000,001
	ES-Big Bend Station		38,832,395	4,881,622	291,399	3,177							44,008,593
	ES-Energy Supply Services		4,475,207	(45,063)	42,714								4,472,857
	ES-Engineer & Project Management	76,927,598	188,927,653	156,800,634	75,699,878	8,972,545	7,156,822	9,818,387	51,323				524,354,841
	(blank)									-	54,472,500		54,472,500
Growth Total		**76,927,598**	**232,235,255**	**161,637,193**	**76,033,991**	**8,975,722**	**7,156,822**	**9,818,387**	**1,051,324**	**31,000,000**	**74,472,498**	**24,000,003**	**703,308,793**
Sustain	ES-Bayside Power Station	19,317,903	23,295,590	30,923,250	52,878,174	30,866,628	25,838,165	25,364,641	13,458,092	23,930,818	40,064,051	52,060,975	337,998,288
	ES-Big Bend Station	105,474,407	88,114,298	63,868,467	43,430,755	38,009,014	40,646,927	72,590,582	80,247,979	56,599,147	33,491,446	48,165,478	670,638,499
	ES-Energy Supply Services	19,219,076	6,696,092	2,628,315	4,577,333	2,838,471	6,524,675	59,311	192,726				42,735,998
	ES-Engineer & Project Management	3,967,673	168,635	10,263,492	30,493,655	3,595,653	117,742	121,124	151,642	4,275,000	3,025,000	1,500,000	57,679,614
	ES-Environmental, Health & Safety	676,182	2,783,780	787,219	2,171,821	1,860,019	1,036,961	488,066	770,253	745,000	1,075,000	860,000	13,254,301
	ES-Fuels		47,330	6,257,117	405,466	8,272	73,508	288,521	4,015,822	2,969,600	2,140,750	2,311,068	18,517,455
	ES-Planning, Strategy & Compliance	436,318	192,347	1,845,594	409,441	133,208	647,269	124,246	225,653			1,615,764	5,629,841
	ES-Polk Power Station	22,679,853	11,962,276	21,111,109	17,094,645	35,130,175	33,545,231	18,206,021	17,487,951	25,578,215	21,872,109	19,995,307	244,662,891
Sustain Total		**171,771,411**	**133,260,347**	**137,684,562**	**151,461,290**	**112,441,440**	**108,430,477**	**117,242,512**	**116,550,119**	**114,097,781**	**101,668,356**	**126,508,592**	**1,391,116,887**
Grand Total		**248,699,009**	**365,495,602**	**299,321,756**	**227,495,281**	**121,417,162**	**115,587,299**	**127,060,899**	**117,601,443**	**145,097,781**	**176,140,854**	**150,508,595**	**2,094,425,680**

TAMPA ELECTRIC COMPANY
DOCKET NO. 20210034-EI
EXHIBIT NO. DAP-1
WITNESS: PICKLES
DOCUMENT NO. 12
PAGE 1 OF 1
FILED: 04/09/2021

ENERGY SUPPLY CAPITAL ADDITIONS 2022-2023

Sum of total RPA CapEx Adj	Director	2022	2023
Growth	ES-Bayside Power Station	19,999,998	24,000,003
	ES-Big Bend Station		
	ES-Energy Supply Services		
	ES-Engineer & Project Management		
	ES-Dual Fuel Pok	54,472,500	
Growth Total		**74,472,498**	**24,000,003**
Sustain	ES-Bayside Power Station	40,064,051	52,060,975
	ES-Big Bend Station	33,491,446	48,165,478
	ES-Energy Supply Services		
	ES-Engineer & Project Management	3,025,000	1,500,000
	ES-Environmental, Health & Safety	1,075,000	860,000
	ES-Fuels	2,140,750	2,311,068
	ES-Planning, Strategy & Compliance		1,615,764
	ES-Polk Power Station	21,872,109	19,995,307
Sustain Total		**101,668,356**	**126,508,592**
Grand Total		**176,140,854**	**150,508,595**

TAMPA ELECTRIC COMPANY
DOCKET NO. 20210034-EI
EXHIBIT NO. DAP-1
WITNESS: PICKLES
DOCUMENT NO. 13
PAGE 1 OF 1
FILED: 04/09/2021

TAMPA ELECTRIC COMPANY

O&M EXPENDITURES- EXCLUDING CLAUSES (2013-2022) - $1000's

ENERGY SUPPLY

By Cost Element	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Labor & Fringe	65,829	67,873	68,056	69,751	68,971	62,854	60,590	57,026	56,709	58,153
Employee Expenses	901	925	1,014	1,172	599	793	1,177	729	968	1,036
Outside Services	36,378	39,274	52,320	59,484	48,535	41,972	34,944	48,135	30,096	29,892
Materials & Supplies	42,103	46,986	39,712	37,644	30,260	21,681	18,765	16,673	18,257	19,509
Utilities	633	1,415	2,700	2,846	3,043	3,426	1,711	2,228	2,332	2,296
Other	(1,060)	635	567	935	954	1,673	2,637	2,338	3,790	3,799
Non Recoverable Fuel	765	731	600	226	-	-	-	-	12	13
Subtotal	**145,550**	**157,839**	**164,969**	**172,058**	**152,362**	**132,399**	**119,825**	**127,130**	**112,164**	**114,699**
Less ECRC	(25,741)	(30,569)	(26,789)	(25,634)	(21,511)	(11,416)	(5,688)	(17,971)	(3,480)	(3,569)
Energy Supply - Total	**119,809**	**127,270**	**138,181**	**146,424**	**130,850**	**120,983**	**114,137**	**109,159**	**108,684**	**111,129**

ENERGY SUPPLY O&M ACTUALS VS. BENCHMARK (2013-2022)