AUSLEY McMULLEN

Attorneys and Counselors at Law
123 South Calhoun Street
P.O. Box 391 32302
Tallahassee, FL 32301
P: (850) 224-9115
F: (850) 222-7560
ausley.com

April 2, 2024

ELECTRONIC FILING

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

Re: Docket 20240026-EI; Petition for Rate Increase by Tampa Electric Company

Dear Mr. Teitzman:

Attached for filing on behalf of Tampa Electric Company in the above-referenced docket is the Direct Testimony of Kris Stryker and Exhibit No. KS-1.

Thank you for your assistance in connection with this matter.

(Document 5 of 32)

Sincerely,

J. Jeffry Wahlen

cc: All parties

JJW/ne
Attachment

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 20240026-EI

IN RE: PETITION FOR RATE INCREASE

BY TAMPA ELECTRIC COMPANY

PREPARED DIRECT TESTIMONY AND EXHIBIT

OF

CARLOS ALDAZABAL

TABLE OF CONTENTS

PREPARED DIRECT TESTIMONY AND EXHIBIT

OF

CARLOS ALDAZABAL

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

CARLOS ALDAZABAL

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

A. My name is Carlos Aldazabal. 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 Energy Supply.

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

A. I am responsible for the safe, efficient, and reliable operation of Tampa Electric's electric generating and energy storage assets. My duties include oversight of all safety, environment, compliance, team member, operating, and capital budget management activities in our Energy Supply department. These include power plant operations; resource planning; origination and trading; and emerging technologies. I am also responsible for the company's general procurement and contracting activities.

I report to our President and Chief Executive Officer, Archie Collins. One officer, one senior director, and eight directors report directly to me. Together we lead the Energy Supply department.

Q. Please summarize your educational background and business experience.

A. I received a Bachelor of Science degree in Accounting and a Master of Accountancy degree from the University of South Florida in Tampa, in 1991 and 1995, respectively. I am licensed as a Certified Public Accountant in the State of Florida and have 28 years of electric utility experience.

I began my career at Florida Power Corporation (now Duke Energy Florida) and joined Tampa Electric's accounting department in 1999. After four years, I moved into the company's regulatory affairs department where I eventually became Vice President of Regulatory for both Tampa Electric and its affiliate, Peoples Gas System. I was given a special assignment in Electric Delivery in 2019 to gain operations experience before moving to my current position in 2021.

I have worked in the areas of fuel and interchange accounting, surveillance reporting, budgeting and analysis, cost recovery clause management, rate case management, investor relations, transmission engineering and operations, fleet management, stores management, procurement, and Energy Supply.

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

A. Yes. I have testified or filed testimony before the Commission on behalf of Tampa Electric in the Commission's annual Fuel & Purchased Power proceedings from 2005 to 2012.

Q. What are the purposes of your direct testimony?

A. The purposes of my direct testimony are to (1) describe the company's Energy Supply system; (2) summarize our successes transforming Energy Supply since our last rate case; (3) outline the company's future Energy Supply plans; and (4) demonstrate that the Energy Supply rate base amounts and operations and maintenance ("O&M") expense levels for the 2025 test year are reasonable and prudent. I will also explain the South Tampa Resilience, Polk 1 Flexibility, Polk Fuel Diversity, Bearss Operations Center, and Corporate Headquarters projects, which are included in our proposed 2026 and 2027 subsequent year adjustments ("SYA"), why these projects are prudent, and how they will benefit our customers.

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

A. I have overall responsibility for the capital investments and O&M expenses for the Energy Supply area; however, Tampa Electric witness Kris Stryker, Vice President Clean Energy and Emerging Technology, reports to me and will discuss the solar generating and energy storage additions included in our 2025 test year and SYA. Tampa Electric witness Jose Aponte, Manager Resource Planning, will show that the generation, solar, and energy storage included in our 2025 test year and 2026 and 2027 SYA are cost effective.

Tampa Electric witness Richard Latta, Utility Controller, will compile the 2025 rate base amounts and O&M expense levels described in my testimony with similar information from other witnesses to calculate the company's 2025 revenue requirement and proposed 2025 base rate increase. He also uses the project costs in my testimony for the five SYA projects listed above to calculate the revenue requirements for our proposed 2026 and 2027 SYA. Our proposed 2026 and 2027 SYA also include specific solar, energy storage, and Electric Delivery Projects that are explained by Mr. Stryker and Tampa Electric witness David Lukcic, Senior Director Operational Technology and Strategy, in their testimony.

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

A. Yes. Exhibit No. CA-1, entitled "Exhibit of Carlos Aldazabal" 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 nine documents, as follows.

Document No. 1	List of Minimum Filing Requirement Schedules Sponsored or Co-Sponsored by Carlos Aldazabal
Document No. 2	Generation Mix
Document No. 3	Total System Heat Rate (2013-2023)
Document No. 4	Total CO_2 Emissions (2013-2023)
Document No. 5	System Heat Rate and Fuel Savings
Document No. 6	Total System Net EAF Percentage
Document No. 7	Solar Projects 2021-2023

Document No. 8	Headquarters Evaluation Scorecard
Document No. 9	Headquarters Evaluation
Document No. 10	Energy Supply Capital Expense Summary 2022-2025

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

A. Yes. I sponsor or co-sponsor 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.

(1) ENERGY SUPPLY OVERVIEW

Q. Please describe the company's Energy Supply area.

A. Our Energy Supply area has a combined staff of approximately 620 employee team members. Its functions include thermal and solar generating operations; environmental management; engineering and project management; resource planning; capital planning; natural gas origination and trading; energy trading; general company procurement; stores and inventory management for Energy Supply and Energy Delivery; and facility services.

It includes the Clean Energy and Emerging Technology group led by Mr. Stryker.

Q. What role does safety play in Energy Supply?

A. Safety is our number one priority. We are committed to the beliefs that all injuries are preventable and that no business interest can take priority over safety. We believe that everyone is responsible for safety and that all 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 communications, awareness, and training; cultivates a strong safety culture and safe behavior; sets contractor safety management standards; enhances asset integrity; establishes tools for measurement and reporting; prescribes incident management and investigates procedures; and includes auditing and compliance measures.

I am proud that Tampa Electric’s Energy Supply organization has finished in the top two quartiles when compared to other electric utilities in the Southeast Electric Exchange for the last three years. Additionally, in 2023 the company achieved an overall 0.70 incident rate, which is a six percent improvement from our five-year average.

Q. Please describe the Clean Energy and Emerging Technology group.

A. The Clean Energy and Emerging Technology group is devoted to diversifying the company’s generation mix in a cost-effective manner for customers. They develop our solar and energy storage projects and explore innovative technologies to support our thermal generation units. Mr. Stryker further explains this group and the work it performs in his testimony.

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. Our generation portfolio consists of 14 thermal generating units and five thermal peaking units at three central generating stations, and 22 geographically dispersed solar sites, for a total of approximately 6,433 megawatts ("MW") of winter peaking capacity. Our generating fleet includes a dual fuel (solid fuel/natural gas) steam unit; combined cycle units ("CC"); combustion turbine ("CT") peaking units, some of which are dual fuel (natural gas/oil); a dual fuel (petcoke/natural gas) integrated gasification combined cycle ("IGCC") unit; and photovoltaic solar facilities ("solar").

Q. Please describe the company's 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 consists of two units. The Big Bend Unit 1 modernization project was completed and went in service in December 2022. The repowered Big Bend Unit 1 is a natural gas fired two-on-one generating facility. Big Bend Unit 4 is a pulverized coal fired steam unit equipped with a desulfurization scrubber, electrostatic precipitator, and a Selective Catalytic Reduction ("SCR") air pollution control system. We added dual fuel capability to Big Bend Unit 4 in 2013 so it can also be fired with natural gas.

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

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 CT, four HRSG, and one steam turbine. Two of the Polk Unit 2 CT can use distillate oil as a back-up fuel. The Polk Unit 2 CT were transformed into highly efficient CC generating units ("Polk 2 Conversion") in 2017.

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

A. Tampa Electric currently owns and operates solar facilities with approximately 1,250 MW of generating capacity at 22 geographically dispersed locations throughout its service territory. All 21 solar facilities are single axis tracking with capacities ranging from 19.8 MW to 74.5 MW. The Big Bend Solar facility includes a 12.6 MW energy storage unit. The company also owns and operates five small solar sites with a combined generating capacity of less than 8 MW. Mr.

Stryker discusses our future planned solar projects in his testimony.

Q. Please describe the company’s current fuel mix for generating electricity.

A. Since 2013, Tampa Electric has dramatically changed the mix of fuel we use to generate electricity. In 2013, our generation mix was 58.7 percent coal, 41.2 percent natural gas, less than 0.1 percent light oil, and 0 percent solar. In 2023, about 3.8 percent of our electricity was generated using coal, about 87.6 percent was natural gas-fired, approximately 8.6 percent was from solar, and less than 0.1 percent from light oil. The company reduced its tons of coal consumption by approximately 92 percent since 2013. Document No. 2 of my exhibit depicts how our generation mix has changed in the last decade.

Q. Have these changes improved the company’s thermal efficiency?

A. Yes. We measure our thermal efficiency by calculating our average net system heat rate (Btu/kWh). This calculation measures the amount of fuel energy we use to generate electric energy, so a lower number means that we are more efficient because our system needs and uses less fuel energy to generate a kilowatt-hour (“kWh”) of electricity.

Our system heat rate has declined from 9,277 in 2013 to 6,755 in 2023, an improvement of about 27 percent over the last decade. This heat rate reduction means lower air emissions from power generation and lower fuel costs for customers. Documents No. 3 and 4, respectively, in my exhibit detail 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. While market dynamics impact the price of natural gas, reducing our system heat rate has generated significant fuel savings for customers. For example, when our system heat rate was approximately 9,000, and assuming a natural gas price of $4 per MMBtu, it would cost $36 to generate one megawatt-hour (“MWh”) of electricity. However, with our current heat rate of approximately 6,700, the cost to generate that same electricity would be $26.80 per MWh, which means over 25 percent lower fuel costs for customers.

As the company continues to add solar and make efficiency improvements to its existing generating assets, the company's system heat rate will continue to decline and result in lower fuel costs for customers. Document No. 5 of my exhibit shows how our system heat rate has declined since 2016 and the corresponding estimated fuel savings associated with that decline.

Q. Please describe the reliability of Tampa Electric's generating units since 2017.

A. The reliability of our generating fleet is measured by generating unit annual net Equivalent Availability Factor ("EAF"), which reflects the amount of time our generating units are expected to be in service after accounting for planned and unplanned outages.

We have improved our overall fleet EAF from approximately 78 percent to 81 percent since 2017. Our fleetwide EAF is a weighted average of performance, with the NGCC fleet having a higher EAF (high 80's to low 90's) and our older dual fuel boiler units operating in the low 70's. The lower EAF across the boiler units is a result of higher wear and tear caused by coal combustion, resulting in boiler tube leaks, which corresponds to longer duration planned maintenance outages. The recent retirement of Big Bend Unit

3 in 2023 will yield a higher system EAF starting in 2024. Document No. 6 of my exhibit provides additional details on our system EAF since 2017.

(2) ENERGY SUPPLY TRANSFORMATION SINCE LAST RATE CASE

Q. What major changes did the company make in its Energy Supply area since its last rate case in 2021?

A. The settlement agreement in our 2021 rate case ("2021 Agreement") facilitated two major transformations in Energy Supply. First, we added over 600 MW of solar generating capacity. Second, we executed our Big Bend Modernization Project.

Q. Please describe the solar facilities placed in service during the term of the 2021 Agreement.

A. From late 2021 to 2023, the company installed an additional 595.3 MW of cost-effective solar additions through 11 individual facilities as an installed total cost of approximately $850 million. The revenue requirement associated with these facilities was recovered via two generation base rate adjustments ("GBRA") approved in the 2021 Agreement and is included in our current base rates and charges. These additions brought total solar capacity on Tampa Electric’s system to over 1.25 gigawatts, or enough to power 200,000 homes. Document No. 7 of my exhibit shows additional details about these projects.

Q. Were these projects constructed and placed in service consistent with the costs and dates estimated in the company’s 2021 rate case and 2021 Agreement?

A. Three of the four projects planned in 2021 slipped into the first part of 2022, which made them eligible for Production Tax Credits (“PTC”) benefiting customers. Due to the signing of the Inflation Reduction Act (“IRA”), competition for large scale solar components has increased resulting in cost pressures on any materials not under contract. While the PTC improves the cost-effectiveness of these projects, those benefits were partially offset by higher component and materials costs. Mr. Stryker provides additional details on the higher material and component costs in his direct testimony. All 11 projects contemplated in the 2021 Settlement Agreement were placed in service by the end of 2023.

Q. Please describe the Big Bend Modernization Project.

A. The Big Bend Modernization Project transformed the way we generate electricity at Big Bend Station. Design work began in 2017, and field work began in 2019. The company retired Big Bend Unit 2, refurbished the Big Bend Unit 1 steam turbine and generator, and replaced the Unit 1 boiler and coal processing equipment with two new, highly efficient General Electric 7HA.02 combustion turbines and associated heat recovery steam generators.

The Big Bend Modernization project was constructed in two phases. In phase one, the company constructed two new highly efficient CT in simple cycle mode and placed them in service in 2021. The second phase involved the addition of the HRSG, facilitating the unit's operation in CC mode, and was completed in December 2022.

The repowered Big Bend Unit 1 went into service in December 2022 and now is the company's most efficient natural gas combined cycle unit. We repowered Unit 1 as a clean natural gas-fired two-on-one CC generating facility using an existing steam turbine generator and once-through cooling system. Big Bend Unit 1 now has a nominal 1,120 MW of winter capacity and 1,055 MW of summer capacity with a 6,300 heat rate.

Q. Did the company construct and place the Big Bend

Modernization Project in service consistent with the costs and dates estimated in the company's 2021 rate case and 2021 Agreement?

A. Yes. We forecasted the total cost of the project to be $904.6 million, and the actual cost was $875 million. This was an extraordinary accomplishment under the challenging supply chain and macroeconomic environment conditions at the time. We attribute the lower cost to exceptional project planning and the use of creative contract terms for projects of this size and scope, such as use of competitive bidding of fixed pricing terms for major equipment and use of competitive bidding followed by open book negotiation for the construction contract once the design was finalized.

Q. What other activities did the company undertake in the Energy Supply area to benefit customers since 2021?

A. Our other activities fall into three categories, new energy storage capacity at Big Bend, an Advanced Gas Path project at Bayside, and other smaller, more routine improvements.

BIG BEND ENERGY STORAGE

Q. Please describe the company's energy storage project.

A. The company installed a 12.6 MW energy storage unit at Big Bend and coupled it with a single axis tracking solar facility there. The energy storage unit went into service in December 2019 with a total project cost of $11.5 million. This energy storage pilot has provided valuable insights on how storage interacts with generation resources and how best to integrate them into our electric grid. This project benefited customers as it has provided valuable insights on how to optimally operate these storage systems and how to utilize them to drive down system heat rate.

BAYSIDE ADVANCED GAS PATH PROJECT

Q. What is an Advanced Gas Path ("AGP") Project?

A. AGP technology is a proprietary performance enhancement solution developed by General Electric for combustion turbines that consists of improvements to the cooling systems, hot section parts redesign, and sealing to maximize output, efficiency, and flexibility from existing assets. It is a proven technology that has been installed on hundreds of gas turbines. The company has applied the AGP solution to Bayside Units 1 and 2.

Q. Please describe the Bayside Unit 1 AGP project.

A. The company completed the AGP work described above for Bayside Unit 1 in 2022, which resulted in a 10 percent increase in unit output and a heat rate improvement of nearly five percent. This translates to direct fuel savings for customers. By installing fast start capability, we can synchronize Bayside Unit 1 to the grid in six to seven minutes, which is a 55 percent improvement. That translates to better operating efficiency and an improved system heat rate, which reduces fuel costs for customers.

Q. Please describe the Bayside Unit 2 AGP project.

A. The Bayside Unit 2 AGP project is essentially the same as the Unit 1 project. We expect to complete the Bayside Unit 2 portion of the project in the Spring of 2024 and to see the same type of improvements to Bayside Unit 2 that we experienced for Bayside Unit 1.

Q. Why were the Bayside AGP projects needed?

A. Yes. The Bayside AGP upgrades were initiated to help meet and maintain our winter reserve margin requirements. Our analysis showed these projects were a very low-cost option to add 128 MW of output capacity compared to other generation options. We also anticipated that the projects would reduce unit heat rate, generate fuel savings for customers, and provide operational flexibility by improving start times, which helps us react quickly to load and supply changes.

Q. What alternatives did the company consider?

A. The company considered batteries and other new generation options, but the cost-effectiveness of these projects compared to the next best option was \$86.6 million favorable to customers.

Q. What did the company do to ensure the projects were or will be completed at the lowest reasonable cost?

A. The company issued a request for proposal ("RFP") to multiple vendors for Output and Efficiency enhancements for the seven Bayside 7FA combustion turbines. From that RFP, two main vendors were selected for further discussions. After more detailed discussions and negotiations with both vendors, General Electric ("GE") was selected as our preferred vendor for the upgrades. We then engaged in negotiations with GE for final pricing for the upgrades. We negotiated firm turn-key pricing to eliminate any price or market volatility and other unknowns associated with the outage. For the remainder of the work not covered by the GE contract, primarily the HRSG and balance of plant work, we issued another firm price, turn-key RFP to vendors. Two vendors, Central Maintenance and Welding and TEIC, were selected for the remainder of the required work. During the outage, we tracked all additional work through the "Extra Work Authorization" process to ensure the validity of the request. Finally, we ensured cost management with direct Tampa Electric supervision over all contractors onsite.

Q. Are the Bayside AGP projects prudent?

A. Yes. The Bayside AGP projects are part of Tampa Electric's continuing effort to improve the efficiency, sufficiency, and adequacy of its facilities. As previously stated, these projects were needed to meet a winter reserve margin requirement. These innovative technologies result in direct fuel savings for customers. The improved unit flexibility also helps support renewable generation on the grid because the faster response time of the turbines helps with solar intermittency that can occur during afternoon storms, cloud cover, and sunrise and sundown, which has direct fuel savings for customers. These investments in emerging technologies at Bayside will allow us to deliver safe, reliable, and efficient power to customers for many years to come.

OTHER PROJECTS

Q. What other projects did the company undertake in the settlement period to improve Energy Supply?

A. The company also invested capital at Polk to improve reliability by upgrading the relays on the generator step-up transformers ("GSU") and station transformers, replaced the 13kV bus and insulators in CT 2, replaced the brush rigging on CT 2 through 5, and performed switchgear feeder relay upgrades. That work will translate to improved unit reliability and availability.

Investments at Bayside in addition to the AGP work include a steam turbine major outage with rotor replacements, valve overhauls, exciter replacements, and controls upgrades, which will provide long-term reliability of the station. Another major investment was the refurbishment of the 60-year-old cooling water intake structure, which required refurbishment for safety and long-term reliability. Finally, the station also replaced circulating water pumps and added a vacuum priming system which helped improve unit heat rate and upgraded protection relays that were no longer supported by the manufacturer.

Investments at Big Bend include replacement of the Big Bend Unit 4 furnace waterwall tubing to improve reliability and heat rate as the new tubing allows for increased header pressure and capacity. A new natural gas addition to the Big Bend Unit 4 boiler created a full capacity dual fuel operation design. Lastly, in 2024, heat rate improvements will be realized with the replacement of the A and B Big Bend Unit 4 hot air expansion joints and pulverizer inlet ductwork. The C and D pulverizer joints and ducts were replaced in 2023.

<u>RESULTS</u>

Q. Have the addition of solar, Big Bend Modernization, AGP, and the other capital projects during the settlement period enabled the company to change the way Energy Supply operates to benefit customers?

A. Yes. The changes described above have substantially changed how our generating fleet is dispatched and the level of O&M expenses required to sustain reliable operation. Overall Energy Supply employee count will decline in 2024 and remain constant in 2025.

Q. Please explain.

A. We are adding employees to operate and maintain our new solar facilities but need fewer employees at Big Bend for a net employee reduction in 2024.

We use a combination of in-house and contractor resources to operate and maintain our solar facilities but consider market dynamics to increase and decrease our use of outside contractor services while deliberately working to "build our bench" with employees who are skilled solar operators. This will allow us to keep solar operating costs down while developing in-house solar skills and knowledge.

The Big Bend Modernization project enabled us to make staffing and contractor reductions at Big Bend as we continue to shift away from older generation, which requires more operating and maintenance personnel, to more efficient combined cycle units, like repowered Big Bend

Unit 1, that need fewer people to operate and maintain.

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, and economics.

(3) 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. Technology improvements and tax incentives have made solar generation a cost-effective alternative to natural gas-fired generation. Energy storage technology continues to improve and provides capacity to store power with a lower cost to generate and helps reduce costs to customers.

Absent an unforeseen change, the economic viability of coal for generating electricity will continue to erode, while the future will remain bright for renewable energy resources and storage capacity. However, as shown in

Document No. 6 of my exhibit, Tampa Electric still relies heavily on highly efficient NGCC technology to meet a large portion of our electric generation needs. Natural gas plays a vital and strategic role in meeting the energy needs of our customers and will continue playing a crucial role despite the company’s commitment to fuel cost reduction and fuel diversity.

Q. What future plans does the company have for Energy Supply?

A. In 2024 and 2025, the company plans to add additional solar generating capacity, energy storage capacity, and begin a small project, funded primarily by United States Department of Energy grants, to investigate the suitability of the geological conditions at and near Polk for underground carbon storage. Mr. Stryker describes these projects and why they are prudent in his testimony.

We have three major planned outages in 2025 and will be making structural improvements at our generating stations. I will explain these later in my testimony.

Q. Does the company have other plans for Energy Supply in 2026 and 2027?

A. Yes. The company plans to place in service six additional solar facilities and four energy storage capacity facilities in 2024, 2025, and 2026. These projects, some of which are included in the company's proposed SYA, are explained by Mr. Stryker.

The company is also planning a Polk 1 Flexibility Project, a Polk Fuel Diversity Project, and a South Tampa Resilience Project. I will describe each of these projects in the SYA section of my testimony, below.

STRUCTURE IMPROVEMENTS AT GENERATION STATIONS

Q. What are the company's plans to upgrade structures at its generating facilities?

A. While many of the generating units have gone through conversions, many of the administrative buildings that house the support staff are still the original buildings. These buildings require improvements to HVAC systems, lighting, layout, and facilities and no longer meet building codes.

Q. Why are these improvements needed?

A. Tampa Electric's generation stations have all been in service for several decades. For example, some of the existing buildings at Big Bend and Bayside are more than 50 years old. Those buildings are no longer up to code or ADA compliant. As repairs are needed, it is sometimes necessary to remodel the buildings and bring them up to existing codes to obtain permits to proceed with the necessary work. These improvements allow employees to occupy the space in a safe manner with updated facilities.

(4) 2025 RATE BASE AND O&M EXPENSES

RATE BASE

Q. How does Tampa Electric determine the construction program and capital budget for the Energy Supply area?

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.

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 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 new environmental or safety regulations or considerations. Other projects are prioritized based upon their relative benefits. Through a review process, the projects are selected for inclusion in the budget for the next year. These projects are 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. This process has been particularly challenging over the last several years due to inflation. To illustrate, material costs such as Grain Oriented Electrical Steel (GOES) have doubled since January 2020, and transformers needed for our solar sites have also increased nearly 50 percent.

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

A. Yes. A proper asset management and maintenance program is critical to ensure the company's generating assets are reliable and perform as designed. Tampa Electric works with the original equipment manufacturer ("OEM") of each critical asset to ensure outages are taken at the appropriate intervals and the needed maintenance is performed. The company also has entered into Contract Service Agreements ("CSA") with GE, who is the OEM for many of our CT, to help monitor these assets and ensure parts are available during planned outages. The company plans the outages during the shoulder months to ensure generation resource availability, as well as plans for internal and external resources to oversee and perform the work.

Q. How much capital did the company invest or plan to invest in the Energy Supply area in 2022 through 2024?

A. The company has invested or plans to invest approximately $1.95 billion in capital in Energy Supply projects from 2022 through 2024. Of that capital, approximately $474.8 million was for solar projects and the Big Bend Modernization costs approved as part of our 2021 Settlement Agreement. The remaining $1.48 billion includes $114.3 million associated with Environmental Cost Recovery Clause ("ECRC") and Clean Energy Transition Mechanism ("CETM") projects, $372.8 million for future solar and storage capacity as described in Mr. Stryker's testimony, and $394.3 million for the corporate headquarters and Bearss Operation Center. The remaining $598.6 million is related to other rate base capital and SYA projects described later in my testimony.

Q. What major projects are included in the total for 2022 to 2024?

A. Major projects for 2022 to 2024 fall into eight categories. Those categories consist of outage capital; plant improvement non-outage capital; blanket capital; ECRC Capital; CETM capital; AFUDC capital; building renovation capital; and other.

Q. How much capital does the company expect to invest in the Energy Supply area in 2025?

A. In 2025, the company is planning on spending $845.5 million in capital to operate the generating system and address future growth safely and reliably.

Q. What major outages are included in the total for 2025?

A. There are three major needed outages happening in 2025. These include a 70-day major outage for Bayside Unit 1, a 70-day outage for Polk Unit 2, and a one-month outage for Big Bend Unit 4.

Q. Please explain each of the three major outages planned for 2025, what capital work will be done, the expected cost, and why the expenditures are prudent.

A. Bayside Unit 1 requires a major outage to replace the steam turbine Low Pressure ("LP"), High Pressure ("HP"), and Intermediate Pressure ("IP") rotors. Additionally, an overhaul of the steam valves and an upgrade of the steam turbine controls are necessary. The total expected capital costs of the Bayside Unit 1 outage are expected to be $14.5 million. This outage is necessary because the run hours on the steam turbine are expected to be 380,000 and beyond the recommended OEM design of 250,000 hours.

Polk Unit 2 requires a major outage to perform a steam turbine and generator major inspection, HP/IP turbine seals replacement, blade feathering, IP rotor blade replacements, and main steam valve and actuator inspections. The total capital cost for this work is anticipated to be $6 million assuming the inspected items do not require additional capital discovered during inspection. This outage is necessary because the OEM recommends a major overhaul at 50,000 hours of operation, which includes opening and inspecting the turbine and replacement of parts as prescribed in the OEM's Technical Information Letters. This will be the first time opening the turbine since installation in 2017, and the unit is expected to be at 66,000 hours of operation when completed. These turbine overhauls are critical to maintain system reliability and efficiency.

Big Bend Unit 4 requires a one-month outage for compressed air system improvements, seawall cathodic protection, boiler circulating pump work, and intake screen replacement. The anticipated capital costs to perform this work are $3.1 million, and it is needed to continue safe, reliable unit operation.

Q. Please identify and describe the other major capital expenditures planned for 2025 in the Energy Supply area.

A. In addition to outage capital, and capital needed to maintain existing equipment as well as respond to unplanned outages, capital is being devoted to solar and energy storage capacity projects described in Mr. Stryker's testimony. Capital also is needed for the SYA projects described later in my testimony and the corporate headquarters and Bearss Operation Center also described later in my testimony. Finally, capital is needed for dismantlement activities at Big Bend as part of our CETM, and a small amount of capital is needed for building renovations.

Q. How does the amount of production plant for the 2025 test year compare to the amount of production plant in the company's 2021 rate case?

A. The production plant will increase by approximately $1.5 billion since 2021. It is projected to be $7.8 billion in 2025 versus $6.3 billion in 2021.

Q. Please describe the major production plant additions for 2023, 2024, and 2025 as shown on MFR Schedules B-7, B-8, B-11, and B-12.

A. For 2023, major production plant additions included $29.6 million for the Bayside Unit 1 Major Outage and Advanced Hardware Upgrades, and $355.4 million for the final tranche of wave 2 solar.

For 2024, major production plant additions include $49.9 million for the Bayside Unit 2 Major Outage and Advanced Hardware Upgrades, $158.1 million for future solar, and $20.0 million for energy storage capacity.

For 2025, major production plant additions include $244.9 million for future solar, $147.5 million for energy storage capacity, $113.3 million for the South Tampa Resilience project, and $65.5 million for Polk 1 fuel flexibility.

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 2025 as shown on MFR Schedule B-13?

A. The Energy Supply Construction Work in Progress major production plant projects for 2025 include $247 million for solar, $55.9 million for South Tampa Resilience, $5.8 million for Polk fuel diversity and fuel flexibility projects and $44.5 million for an environmental compliance project.

Q. With these projects, what does the company expect its summer and winter reserve margins to be in 2025 and 2026?

A. Tampa Electric expects its 2025 summer reserve margin to be 30.5 percent and winter reserve margin to be 22.9 percent. For 2026, the summer reserve margin is expected to be 30.4 percent and the winter reserve margin to be 23.1 percent.

O&M EXPENSES

Q. How have the company's operating expenses for production changed since its last rate case?

A. The production expense has increased by $121.0 million, the majority of which is due to increased fuel costs, and $28.2 million is related to base rate expenditures. The increase in base rate expenditures represents a 29 percent increase above 2022 levels.

Q. What items are causing the increase in operating expenses?

A. The increase in operating expenses is driven by three major outages taking place in 2025 and incremental solar operations costs to manage the new solar sites. The necessary outage work and associated costs are described later in my testimony.

Q. What is the forecasted amount for 2025 O&M expense, and is the amount reasonable?

A. The forecasted 2025 O&M Production expense is $809.2 million, of which $125.1 million are base rate expenditures. These expenses are necessary to operate the generation assets in a safe, reliable manner and are reasonable.

Q. What is the performance against the O&M benchmark for 2020 of the company’s functional expense for production?

A. The production expense is higher than the benchmark by $10.9 million. The variance compared to the benchmark is due to the timing of planned outages at the company's generating units for the continued safe, reliable operation of the units. The difference is also caused by increased solar generation that provides safe, low-cost energy to our customers.

Q. What steps has the company taken to reduce O&M expenses in Energy Supply?

A. Numerous steps have been taken to manage and reduce O&M expenses within Energy Supply. First, budgets are set in a bottom-up approach to ensure the spending is necessary and prudent and then scrutinized in a top-down manner to reduce discretionary costs. Comparisons to prior year budgets and results are evaluated, and variances must be justified and explained. An Energy Supply scorecard is developed that includes an O&M goal that incents team members to control costs. Individual generation station budgets are also managed, and station scorecards are shared with team members throughout the year. In addition, an Energy Supply continuous improvement pilot initiated in 2024 encourages team members to find ways to reduce O&M expenses.

Q. What was the employee count for Energy Supply 2022, 2023, and 2024?

A. The actual employee count for Energy Supply in 2022 was 581, increasing to 607 in 2023 and expected to be 613 in 2024.

Q. What is the projected employee count for Energy Supply in 2025?

A. Energy Supply expects employee count to remain at 613 in 2025.

Q. What factors caused the need to change the employee count?

A. Changes in employee count can be attributed to changes in generating stations and workload. The retirement of Big Bend Unit 2 and Unit 3 helped reduce contractors and employee count; however, the Big Bend Modernization project and new solar sites required additional employees. The increase in employee count since 2022 is primarily driven by the increase in solar technicians needed to perform maintenance on the solar sites.

Q. How has Tampa Electric been able to manage its O&M benchmark for the 2025 production expenses?

A. The Energy Supply organization and the company as a whole understand that O&M expense control is strategically important. Additionally, there is an inherent competitiveness between generation stations to manage their costs and achieve the best performance metrics. Work is competitively bid, and employee oversight of service contract work takes place to ensure the work is performed and billed in accordance with agreed upon terms. Preferred source contracts are rarely used and require senior leadership approval with accompanying justification. Lastly, to ensure O&M expense is an important consideration for all employees, it is an incentive goal for team members in the Energy Supply area and the Tampa Electric organization.

Q. Does Tampa Electric incur O&M expenses in conjunction with a planned outage?

A. Yes. During planned outages there is a significant amount of work that must be performed that cannot be capitalized and is treated as O&M expense. 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 expense for planned major outages on Tampa Electric's generating units in the 2025 test year?

A. There are extensive O&M costs in major outages that are required on a regular four-to-five-year cycle, and efforts are made to stagger these outages to levelize O&M spending. For the 2025 test year, Bayside Unit 1, Big Bend Unit 4, and Polk Unit 2 have planned major outages, and the estimated cost is $14.5 million in incremental O&M expense.

Q. Please describe the work for the major planned outages in the 2025 test year that will cause O&M expenses to be incurred.

A. The Bayside Unit 1 work is estimated to cost $6.5 million. Big Bend Unit 4 outage work is expected to cost $2.0 million, and the Polk Unit 2 outage O&M expense is expected to cost $6.0 million. The scope of this work includes opening and closing the casing, including vendor costs for generator and valve inspections and scaffolding. Other O&M expenses during these major outages include duct repairs; flushing lube oil and seal oil systems; valve maintenance, including internal parts replacements; motor and GSU maintenance; and, for the coal unit, cleaning ash from the precipitator and boiler slag blasting. This work is necessary and recurring during major outages.

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 costs, including an asset management program to manage expenses. The company focuses on centralized contractor work planning and dispatch across all three generating stations. This 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. We utilize internal resources to perform solar operations and maintenance activities, which has reduced costs while providing jobs for team members affected by the modernization of Big Bend.

Q. Is the overall level of production O&M expense for 2025 reasonable?

A. Yes. O&M expenses for 2025 are reasonable and prudent. If the incremental O&M costs associated with the additional solar sites requiring operations and maintenance personnel and the three major outages are excluded, O&M expenses will be managed close to 2022 levels. We will accomplish this by carefully managing all three major outages which, by themselves, will have a $14.5 million impact to the O&M budget. We will continue to mitigate inflation and standard labor increases by applying Asset Management procedures, implementing cost savings and continuous improvement initiatives, centralizing contractor coordination and contractor reductions. The company’s O&M expenses are also mitigated by the reduction in reducing wear and tear on units due to the transition to natural gas at Big Bend and conversion of Polk Unit 1 to a simple cycle natural gas unit.

(5) SYA PROJECTS

Q. Please list the SYA projects for which you are responsible in this proceeding.

A. I am responsible for explaining the Polk 1 Flexibility Project, the South Tampa Resilience Project, the Bearss Operations Center, and the company's new Corporate Headquarters, all of which are included in the company's proposed 2026 SYA. I also explain the Polk Fuel Diversity Project, which is included in the company's proposed 2027 SYA.

<u>POLK 1 FLEXIBILITY PROJECT – 2026 SYA</u>

Q. Please describe the Polk 1 Flexibility Project and why it is necessary.

A. The Polk 1 Flexibility Project consists of converting our existing Polk Unit 1 CC unit to a highly efficient simple cycle unit with the latest technology to better utilize that asset. It is expected to cost $80.5 million and to be in service in May 2025.

The Polk Unit 1 CC plant has been in operation for the past 27 years. The unit uses early GE 7FA turbine technology and is a one-of-a-kind installation because it is supplied fuel via the coal gasification process. Gas turbines like Polk Unit 1 require "major maintenance" at defined intervals set by the OEM, which is GE in this case. These maintenance intervals are determined by the number of running hours, stops, and starts. Polk Unit 1 requires major maintenance in 2025 to ensure the assets remain safe and reliable. However, the existing combustion system is no longer supported by GE.

Since 2018, Polk Unit 1 has been fueled with natural gas rather than syngas generated in the gasifier. Undertaking an "in kind" overhaul in 2025 would result in a unit that remains tied to the gasifier. The company reviewed all options and determined that converting the unit to simple cycle operation would provide the most customer benefits. This approach results in lower costs, improves the efficiency of the unit, and results in a nimbler asset that can follow system loads more quickly. In the event petcoke becomes more cost-effective than natural gas in the future, Tampa Electric retains the option to convert the unit to CC operation by modifying and performing maintenance on the HRSG.

Q. How will this project benefit customers?

A. The Polk Unit 1 conversion to simple cycle has an estimated fuel benefit of $40 million, and an estimated cumulative present value revenue requirements ("CPVRR") benefit of $166.9 million compared to maintaining the same configuration. It will have lower operating costs because of the updated and advanced technology, shifting the maintenance cycles from every 8,000 hours to every 32,000 hours, and improved reliability due to the reduced maintenance intervals. The simple cycle configuration increases the unit's flexibility, allowing fast starts, increased ramp rates, and lower turndowns, which will allow the company to better optimize our lower cost system assets. The simple cycle unit will also have an improved heat rate, which along with flexibility are the main drivers for fuel savings.

<u>SOUTH TAMPA RESILIENCE PROJECT – 2026 SYA AND 2027 SYA</u>

Q. Please describe Tampa Electric's South Tampa Resilience Project.

A. The South Tampa Resilience Project is a Distributed Energy Resource ("DER") facility located on MacDill Air Force Base ("MAFB") consisting of two phases. The first phase includes two Reciprocating Internal Combustion Engine ("RICE") units with a capacity of 37.6 MW and has an expected commercial in-service date of April 2025. The second phase includes two additional RICE units and an Energy Storage Capacity System. Phase 2 is expected to be in service in June of 2026. The South Tampa Resilience Project generating units will serve all Tampa Electric customers during normal operations, providing electricity to MAFB and the surrounding community. In the extremely rare event of a validated threat to the military base, this project supports national security as MAFB can be electrically islanded and entirely powered by the South Tampa Resilience Project.

Q. Why is the South Tampa Resilience Project needed?

A. The four reciprocating engines are quick start units that are designed to start at a moment's notice. That quick start capability provides the company flexibility to better manage its resources and additional resilience in the middle of a dense load center. MAFB provided no cost access to the site in exchange for the added level of resilience.

Q. What alternatives to the project did the company consider?

A. There were no alternatives to the project due to MAFB's resilience and redundancy requirements. While the load requirements for the base were only 26 MW, there was an opportunity to serve the base, help alleviate transmission constraints, and improve resilience in South Tampa by adding generation in a relatively small footprint.

Q. What steps did the company take to ensure the project was completed at the lowest reasonable cost?

A. The company followed prudent procurement practices for the South Tampa Resilience Project. All major contracts were competitively bid and thoroughly evaluated prior to contract award. Tampa Electric staffed the project with skilled project management, engineering, and construction management staff to ensure that the work was completed in an efficient, high-quality manner. Tampa Electric's site management team engages frequently with the suppliers and construction team to identify opportunities to remove obstacles and resolve potential concerns. Progress in the field is cross-checked with invoices to ensure that the project is billed consistently with the contract terms. Payment of invoices occurs only after Tampa Electric confirms that the contract requirements have been met. These practices help to ensure that Tampa Electric delivers a high quality, reliable, and safe power plant at the lowest reasonable cost.

Q. What benefits will the project provide to customers?

A. The South Tampa Resilience Project strengthens the company's near-term reserve margins and further insulates customers from an extreme weather event such as winter storm Uri in Texas that occurred in February 2021 and storm Elliott along the U.S. east coast in December 2022. Additionally, customers benefit by having four cost-effective, highly reliable resources that can be dispatched instead of larger CT, more frequently resulting in fuel savings. The cumulative projected fuel savings to customers for this project is expected to be $137.9 million.

Q. Will the project require new employees?

A. Yes. These four reciprocating engines and energy storage capacity will require five additional employees. There will be multiple shifts during the week plus weekend shifts to monitor and maintain the reciprocating engines, which will be available for dispatch around the clock.

Q. What is the total cost for the South Tampa Resilience

Project?

A. The total cost of the South Tampa Resilience Project excluding energy storage is forecasted to be approximately $160 million, including AFUDC.

Q. Is the project prudent?

A. Yes. The project will help Tampa Electric maintain summer and winter reserve margins greater than 20 percent as load continues to grow. The project is expected to achieve $137.9 million in fuel savings for customers and will provide additional resilience in a highly populated, dense load center with limited space to add transmission or new generation.

<u>BEARSS OPERATIONS CENTER – 2026 SYA</u>

Q. Please describe Tampa Electric's Bearss Operations Center and Energy Management System ("EMS") project.

A. The Bearss Operations Center is a modern, storm-hardened, secure operation center that will replace Tampa Electric's Energy Control Center ("ECC") and Ybor Data Center. The Bearss Operations Center and EMS project is a multi-year project to physically relocate Tampa

Electric's control and data centers into a single, Category 5 hurricane rated facility. This new facility is designed to withstand major hurricanes, protect all company cyber assets, and operate the utility command and control capabilities for the next 40 years. The project includes EMS upgrades, such as new map boards and dispatching consoles, to properly match the operating assets within the Bearss Operations Center.

Q. Please describe Tampa Electric's existing ECC.

A. Tampa Electric's ECC became operational in 1989. The facility houses the company's grid operations functions. The building was designed using 1980s technology and building codes, and the existing ECC is approaching the end of its useful life.

Q. Please describe Tampa Electric's existing Ybor Data Center.

A. Tampa Electric's Ybor Data Center also became operational in 1988. This facility serves as Tampa Electric's prime data center and customer contact center. The building was designed using 1980s technology and building codes. Like the existing ECC, this facility is not hardened to withstand a major hurricane and is located within a storm evacuation zone.

Q. Why did the company conclude that it needed to replace the ECC and Ybor Data Center?

A. The company's decision is based on three main factors – storm resilience, space needs, and strategic objectives.

Q. How will construction of the Bearss Operations Center improve storm resilience?

A. The existing ECC is at risk from high storm surge. The facility is in Hillsborough County evacuation zone B and is located just a half mile from the Palm River, which directly connects to Tampa Bay. If a major hurricane tracked directly into Tampa Bay, the ECC would not be able to withstand the wind speeds and storm surge expected in its location, meaning the company would be forced to relocate operations control to the company's much smaller alternate Secure Center. Similarly, the Ybor Data Center is located only a short distance from Tampa Bay and would be subject to high winds and storm surge in the event of a major hurricane tracking into Tampa Bay. The new Bearss Operations Center will be located in a safer, higher, and more inland location and will be designed to withstand major hurricane winds up to 171 mph sustained.

Q. What are the company's space needs that drive the need for the Bearss Operations Center?

A. In 2021, the company performed an assessment of the space necessary to accommodate current and future operations functions. The assessment concluded that the existing ECC was at its maximum capacity, with limited space to expand for customer growth and emerging business requirements.

Q. What are the strategic objectives that drive the need for the Bearss Operations Center?

A. The Bearss Operations Center is designed to accommodate the company's future grid reliability requirements and grid decentralization. The facility will incorporate new industry best practices, including a Renewables Control Center ("RCC") and a Diagnostic and Drone Center ("DDC"). The company also will be able to implement an EMS upgrade to properly match the operating assets within the Bearss Operations Center, such as new map boards and dispatching consoles.

Q. How did the company determine that the Bearss Operations Center Project is the best option to address the resilience, space, and strategic needs you described?

A. Tampa Electric implemented a systematic approach to evaluate how to address these needs. This approach included several steps.

First, Tampa Electric sought industry-wide advice and input from our Southeastern Electric Exchange and North American Transmission Forum Partners and conducted site reviews of several control centers to support information gathering.

Second, the company issued a RFP from reputable and experienced Architecture and Engineering ("A&E") firms with expertise in programming, evaluating, and designing Control Centers and Data Centers. Tampa Electric ultimately selected an A&E firm through this process.

Third, Tampa Electric and the A&E firm worked together in two phases to select the best option to address these needs.

Q. Please describe the two phases in the selection process.

A. In Phase I, Tampa Electric and the A&E contractor worked together to evaluate existing Tampa Electric facilities and future space plans for those facilities; potential new site locations; and conceptual site layouts. Site location criteria included size, security risk, flood zone, storm surge exposure, topography, environmental conditions, distance from strongest winds from hurricane, employee commute, site ingress and egress, proximity to major highways, proximity to load center, water supply, and relay service capability.

In Phase II, the company considered the location options and criteria identified in Phase I and developed site and building construction documents for the new facility and for renovations of existing facilities.

At the end of this process, Tampa Electric determined that the Bearss location was the best option to meet the company's needs.

Q. Why was the Bearss location selected as the best option?

A. As previously stated, the current ECC and Grid Control Center has reached its end of useful life as it is approaching 40 years old using 1980's technology and building codes. A modern, more resilient, storm-hardened facility will allow Tampa Electric to respond faster to customer outages without having to recover its own control of the grid first. The design for the new facility also considered other potential threats such as physical, biological, and chemical, to further enhance the resilience of the facility. The ability to implement new technologies will provide customers with more reliable service in both ‘blue sky’ and ‘black sky’ conditions. It will also serve to attract and retain the best and brightest employees to implement, operate, and maintain these new technologies.

Q. Please explain the process Tampa Electric employed for awarding contracts for the construction and design of Bearss Operations Center.

A. In accordance with Tampa Electric procurement processes and procedures, the company identified an initial list of potentially qualified candidates and sent RFP to these candidates. From these RFP, the company evaluated each candidate based on experience, expertise, and capability, along with pricing. In the case of the design team, each candidate was provided with a full description of the project and with detailed requirements. Once the detailed design documents were developed with the successful design team, this information was provided to the list of potential construction candidates for their submittal. Each construction submittal was evaluated based on experience, expertise, and capability, along with pricing.

Q. What is the total project cost for the Bearss Operations Center and EMS project?

A. The total project cost for the Bearss Operations Center and the EMS project is $335.0 million. The budgeted costs are as follows.

Land Acquisition Costs	$ 10.9 million
Architectural Services	$ 6.1 million
Facility Construction Costs	$224.1 million
EMS	$ 27.6 million
IT & Telecomm Costs	$ 24.1 million
Other Owners Costs	$ 22.9 million
Contingency	$ 19.3 million
Total	$335.0 million

Q. Please provide a background of the purpose of EMS and why the upgrade is needed.

A. The upgrade is necessary for several reasons. First, the current version of the EMS software does not have the capabilities to support the grid’s overall performance and will be going out of support. The existing version of EMS went in-service in 2017. Typically, Tampa Electric upgrades the EMS environment every seven years to stay current with industry requirements and the evolution of information technologies. Second, the BOC facility will have new situational awareness features such as visual displays, alarming features, operator consoles, and training simulators, all needing a new EMS configuration to ensure system monitoring and control integrity. Finally, the latest release of the EMS platform offers new functionalities.

Q. What new benefits will customers see from the EMS Upgrade?

A. There are numerous customer benefits for the new EMS Upgrade. As mentioned above, the new EMS system will provide new functionalities. These include features that will strengthen and modernize the grid; provide flexibility to accommodate new technology options and advancements; optimize the use of our generation system by incorporating energy storage capabilities, improving the generation and transmission of renewables; provide Wide Area Monitor System (“WAMS”) capabilities that provide insights on system oscillations and inertia, allowing the company to proactively identify and address system stability issues; and provide Intelligent Alarm Processes ("IAPS") that will enable faster and more informed decision making during abnormal system conditions. This upgrade will have the additional benefits of coupling EMS to a new operation center expanding situational awareness, expanding controls, and driving broader customer reliability satisfaction.

This upgrade will also enhance the company's dispatching capabilities by providing:

1. Access up-to-date forecasts for renewable energy production.
2. Utilize renewable energy dispatch to manage congestion, stability, and other factors.
3. Improve equipment lifespan, reduce losses, and enhance security through VAR dispatch.
4. Control battery charging and dispatch.
5. Enable the Distributed Energy Resource System (DERMS).
6. Efficiently manage different types of assets, such as storage and solar power.
7. Model energy storage systems and renewable energy sources.

8. Use forecasted values when real-time data is not available.

Q. What is the status of the Bearss Operation Center?

A. The Bearss Operation Center is currently under construction with an anticipated in-service date of June 2025. As of December 2023, the construction project is approximately 20 percent complete. By the end of 2024, the Bearss Operation Center is expected to be 90 percent complete.

The EMS project started in January 2023 and is approximately 32 percent complete. The EMS in-service date aligns with the first day of dispatching, which is expected to be October 1, 2025.

Q. What is the estimated certificate of occupancy date for the Bearss Operation Center?

A. The estimated certificate of occupancy for the Bearss Operation Center is May 29, 2025.

Q. How will the Bearss Operations Center benefit customers?

A. The Bearss Operation Center project is part of Tampa

Electric's continuing effort to improve the efficiency, resiliency, and reliability of its facilities. Tampa Electric's customers will see many benefits from the project. As I mentioned previously, the current ECC and Grid Control Center is nearly 40 years old and has reached the end of its useful life. Having a more resilient, storm hardened facility will allow Tampa Electric to respond faster to customer outages without the need to relocate to the backup control center. The design for the new facility also considered other potential threats such as physical, biological, and chemical, to further enhance the resilience of the facility. The ability to implement new technologies will provide customers with more reliable service in both blue sky and black sky conditions. It will also serve to attract and retain the best and brightest employees to implement, operate, and maintain these new technologies.

Tampa Electric Corporate Headquarters – 2026 SYA

Q. Please describe Tampa Electric's Corporate Headquarters Project ("Corporate Headquarters").

A. Tampa Electric is relocating its corporate headquarters from its current location in TECO Plaza in Downtown Tampa to a new 18-story tower in Midtown Tampa. Tampa Electric will purchase a portion of the new tower as well as the rights to approximately 740 parking spaces. The new corporate headquarters will house Tampa Electric and our affiliate Peoples Gas System, Inc. ("Peoples"). Tampa Electric will occupy six floors, Peoples will occupy three floors, and employees of both will share two assembly floors containing meeting rooms and amenities for both companies. Each company will own its share of the tower. Construction of the new tower is still underway, and Tampa Electric expects to receive a Certificate of Occupancy in the Summer of 2025 with an anticipated in-service date of June 1, 2025.

Q. Why is the Corporate Headquarters project necessary?

A. Tampa Electric has leased TECO Plaza for 40 years. The company's existing lease expires in 2025. As the expiration date for the lease approached, the company began a formal process to evaluate multiple options for the company's future corporate headquarters needs. At the end of this process, the company determined that the new Corporate Headquarters was the best option for both the company and for customers.

Q. Please describe the process the company used to evaluate the options to meet its corporate office needs.

A. Tampa Electric formed an internal team of 18 members that partnered with Colliers International to explore the option to lease or own several buildings in the Tampa area. These locations included TECO Plaza as well as other buildings in Midtown Tampa, the Water Street District, International Plaza, and Tampa Heights. The internal team developed ten scoring criteria for each option including resilience and security, connection to community, walkability, parking, nearby amenities, talent recruitment, dedicated elevators, dedicated lobby, building signage, and sustainability. The team then heard presentations from developers and scored all options according to these criteria. A copy of the final scorecard for all options is included as Document No. 8 of my exhibit. Based on this scoring, the team selected the Midtown location as the best option to meet the company's office space needs.

Q. How will customers benefit from the Corporate Headquarters project?

A. The Corporate Headquarters project is part of Tampa Electric's continuing effort to improve the efficiency, sufficiency, and adequacy of its facilities. Customers will benefit from this project in several ways. First, owning office space is a better value proposition for customers than leasing because it should result in the accumulation of equity. Second, the Midtown location provides greater resilience in harsh weather conditions as compared to TECO Plaza because of its inland location and because it will be built to modern code standards. Third, the Midtown location offers modern facilities, dedicated parking, and more efficient floor layouts that will accommodate more team members, reduce space needs in the future, and improve employee satisfaction, which should result in lower employee turnover and costs. Finally, the new headquarters will provide flexibility by providing Tampa Electric with a right of first refusal to lease vacant space on other floors in the building and the right to sublease portions of the floors it will own if they are not needed.

Q. Did the company consider renovating or upgrading the existing office space in TECO Plaza?

A. Yes, we considered improving the existing office space, and the internal team determined that this was not in the best interests of the company or customers. The primary basis for this decision is that the cost of completing a project to upgrade TECO Plaza to modern standards and extending the existing lease agreement would be similar to purchasing the new office space in Midtown. Furthermore, there are several issues with TECO Plaza that would not be resolved by a renovation project. First, TECO Plaza's location in Downtown Tampa does not offer the same level of resilience as the new Corporate Headquarters location. This is especially concerning because the company's critical backup systems are located below mean sea level in the basement of the building. Second, the company's employee count is expected to eventually surpass the available footprint of the building. Third, TECO Plaza does not offer dedicated employee parking, which imposes an additional cost on employees. The lack of available space and parking can in turn cause issues with employee recruitment and retention and safety concerns for employees needing to walk to remote parking lots.

Q. What is Tampa Electric's cost for the Corporate Headquarters Project?

A. Tampa Electric's cost is $188.7 million, which includes the purchase of six entire floors and the pro-rated cost for the two floors shared with Peoples in the building tower, the rights to 740 parking spaces, and the completion of the interior floors.

Q. How does this cost compare to the other options considered?

A. Tampa Electric performed a net present value revenue requirement calculation for the new Corporate Headquarters and for scenarios in which the company renovates TECO Plaza and remains in that building and eventually purchases the existing building. As shown in Document No. 9 of my exhibit, the three scenarios are nearly equivalent in terms of cost over the next 30 years.

Q. What steps did the company take to ensure that it is obtaining the lowest reasonable cost for the design and construction of the Corporate Headquarters project?

A. In late 2020, anticipating the need for design services, Tampa Electric conducted a Request For Information ("RFI") in 2021 to select architects. During the process we interviewed architects with significant experience in the utility industry, including AECOM, Song & Associates, RE Lamb, Gensler, and HDR. Ultimately, Gensler was selected based on Tampa Electric's detailed evaluation criteria, which included account cost, project management skills, staffing, work plans, and quality control. Once Tampa Electric selected the Midtown location with advice from Gensler and Colliers International, the company worked with the Midtown building developers (Bromley and Highwoods Properties) to competitively select a contractor for the construction of the project. Tampa Electric evaluated a pool of five companies, including JE Dunn, Kast, Barr and Barr, DPR, and Brasfield and Gorrie. The company selected Brasfield and Gorrie based on over two dozen criteria used to evaluate the teams and pricing.

Q. Why doesn't Tampa Electric continue to lease its existing building?

A. Continuing to lease an aging building that was designed over 40 years ago, without parking infrastructure and with outdated systems and susceptible to low levels of flood waters, is not in Tampa Electric's best interest. Internal financial analyses were performed for an own versus lease scenario, which demonstrated that the purchase option provided a similar net present value ("NPV") value over a 30-year period.

<u>POLK FUEL DIVERSITY PROJECT – 2027 SYA</u>

Q. Please describe the Polk Fuel Diversity Project and why it is necessary.

A. Two of the five CT at Polk already have liquid fuel capabilities. The Polk Fuel Diversity project is a strategic effort to add additional fuel diversity to our generation mix at Polk by adding the same dual fuel capabilities to the remaining three CT using infrastructure that is already in place at the site. In the last five years Tampa Electric has retired two pulverized coal units, placed one in long-term reserve, and converted one into a highly efficient natural gas combined cycle unit. Now, over 80 percent of Tampa Electric's generation is fueled by natural gas. This project helps to mitigate fuel supply disruption risk and energy demand in excess of natural gas supply and transportation capability.

Q. What will the Polk Fuel Diversity project cost?

A. This project is estimated to cost approximately $53.9 million.

Q. What options did the company consider before undertaking this project?

A. The company explored multiple options for mitigating these risks and determined that adding additional liquid fuel capacity to the remaining three CT was the most cost-effective option. Initial screening options included the evaluation of capacity and storage, liquified natural gas ("LNG") storage, incremental firm gas transportation, solid fuel generation, purchased power, transmission, and renewable generation. After removing options that were too expensive or did not mitigate the fuel risk, the remaining viable options were LNG or oil.

Tampa Electric initially considered using LNG in a local storage facility to meet the backup fuel supply need. While this approach provided significant backup supply optionality and avoided generation unit modifications to burn liquid fuel, high capital expense and long-term O&M cost uncertainty coupled with permitting complexities and potential community opposition eliminated liquified natural gas as a viable option.

Tampa Electric also explored constructing an oil pipeline from the Port of Tampa Bay petroleum storage tanks to Bayside and adding liquid fuel capability to the CT and aero derivative units. This solution was appealing since it used existing assets and large quantities of oil located relatively close to the station. However, this option is not viable due to permitting uncertainty of constructing an oil pipeline under the shipping channel and terminal suppliers' unwillingness to commit large storage volumes reserved for Tampa Electric.

This left the options of adding oil to Polk--where oil tanks already exist and two units are dual fuel capable--or build new fuel oil capacity adjacent to Tampa Bay at either Bayside or Big Bend. Using Polk is the most logical option due to its inland location and existing infrastructure for operating and maintaining units with liquid fuel capability.

Q. How will this project benefit customers?

A. The Polk Fuel Diversity project is part of Tampa Electric's continuing effort to improve the efficiency, sufficiency, and adequacy of its facilities. This project will mitigate our customers' exposure to natural gas supply disruption risk. Adding additional backup liquid fuel capacity at Polk reduces Tampa Electric customers' risk of interruption from events including terrorism, cybersecurity, a major operational natural gas pipeline failure, or an extreme weather event like storm Uri that hit Texas in February of 2021 or storm Elliott that impacted the entire east coast of the United States in December 2022. Tampa Electric has a strong, diversified natural gas supply and transportation portfolio. But should an extreme event interrupt fuel supply or significantly increase demand in Florida, Tampa Electric will need all its resources, including additional oil at Polk, to overcome the loss of supply or with the dramatic increase in demand. The project is anticipated to be in service December 1, 2026.

(6) SUMMARY

Q. Please summarize your direct testimony.

A. My direct testimony provides an overview of the company's generating system and its evolution over the past decade to improve the reliability and efficiency of its generating assets resulting in significant fuel savings for customers. I describe how the company's capital budget for 2024 and projections for 2025 and beyond are reasonable and prudent. I also demonstrate that the company's proposed O&M expenses for Energy Supply in the 2025 test year are reasonable and prudent. I describe important capital projects that the company has placed in service to improve fuel diversity, resilience, reliability, customer experience, and environmental profile that are prudent and in the best interest of our customers.

Finally, I cover five SYA projects that are needed for generating system flexibility that results in fuel savings for customers, fuel diversity to generating systems, and resilience in a period of larger and more intense storms. While the company has been fortunate not to experience a direct impact from a major hurricane, it is crucial that we have an operations center and headquarters that are hardened and in non-flood prone areas so that the company can respond and restore service to customers during such an event.

Q. Does this conclude your direct testimony?

A. Yes, it does.

EXHIBIT

OF

CARLOS ALDAZABAL

Table of Contents

LIST OF MINIMUM FILING REQUIREMENT SCHEDULES

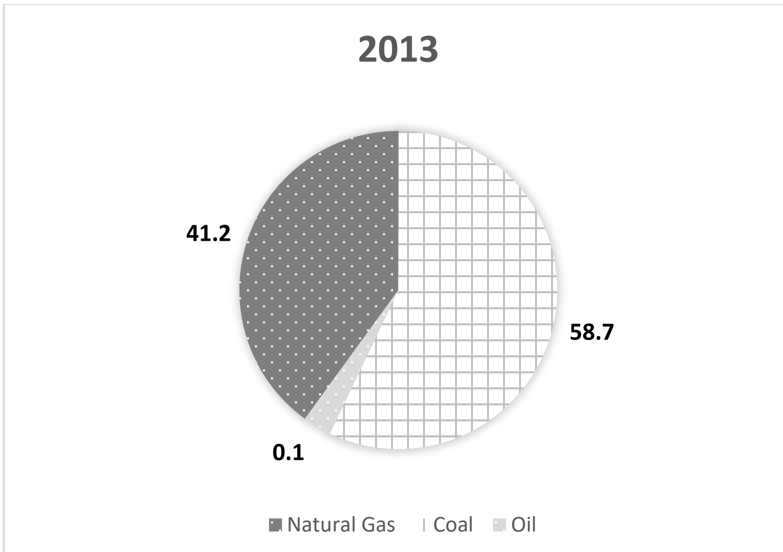
SPONSORED OR CO-SPONSORED BY CARLOS ALDAZABAL

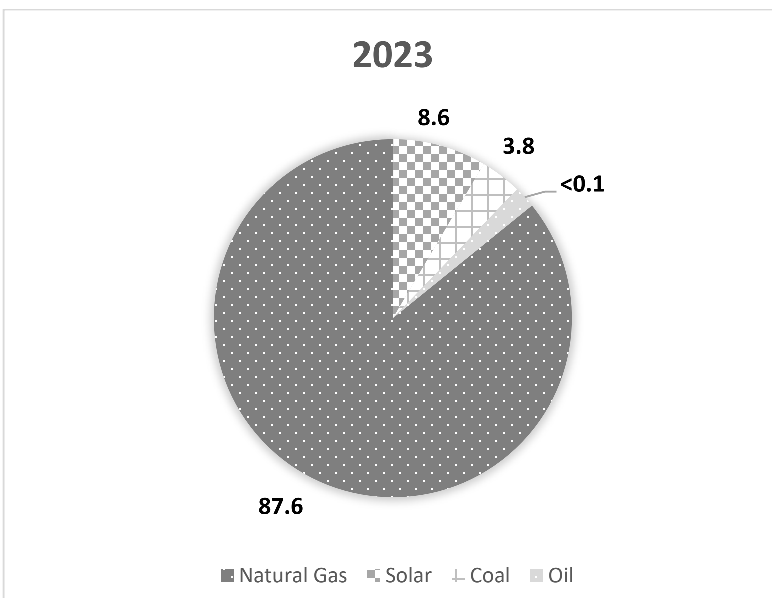
MFR Schedule	Title
B-02	Rate Base Adjustments
B-06	Jurisdictional Separation Factors-Rate Base
B-07	Plant Balances By Account And Sub-Account
B-08	Monthly Plant Balances Test Year-13 Months
B-09	Depreciation Reserve Balances by Account And Sub-Account
B-10	Monthly Reserve Balances Test Year-13 Months
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
B-18	Fuel Inventory By Plant
B-24	Leasing Arrangements
C-04	Jurisdictional Separation Factors-Net Operating Income
C-06	Budgeted Versus Actual Operating Revenues And Expenses
C-08	Detail Of Changes In Expenses
C-09	Five Year Analysis-Change In Cost

MFR Schedule	Title
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-05	Forecasting Models
F-08	Assumptions

Change in Generation Mix

2013 vs 2023





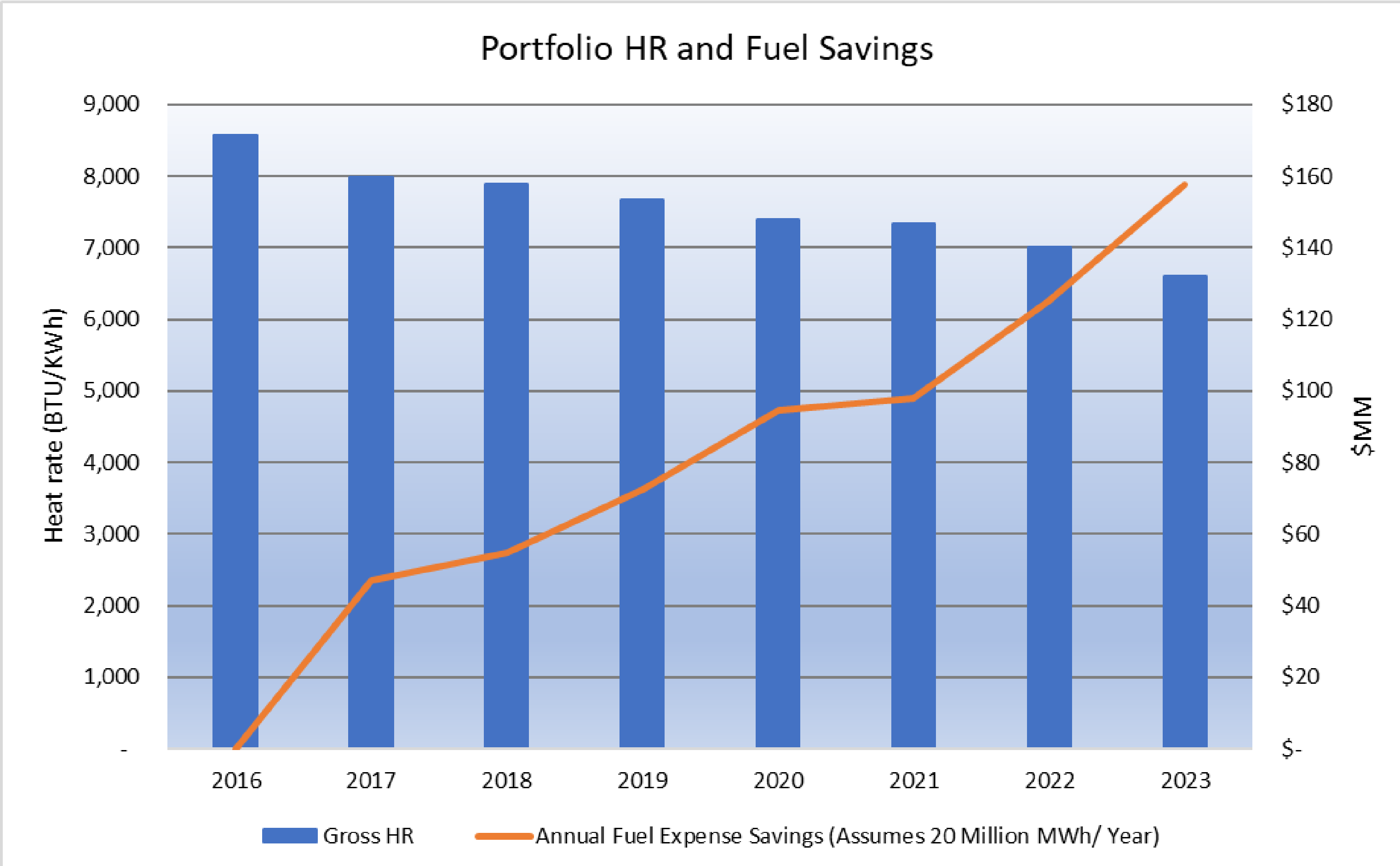
Total System Heat Rate

(2013-2023)

Total System	Net Heat Rate
2013	9,277
2014	9,322
2015	9,057
2016	9,186
2017	8,488
2018	8,259
2019	7,918
2020	7,599
2021	7,555
2022	7,202
2023	6,755
Average	8,238
Max	9,322
Min	6,755

Total CO_2 Emissions (2013-2023)

Year	CO2 Total (tons)	Reduction from 2013 (tons)	Reduction from 2013 (%)
2013	15,685,795	-	
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%
2021	8,930,745	6,755,050	43%
2022	8,834,398	6,851,397	44%
2023	8,269,985	7,415,810	47%



TAMPA ELECTRIC COMPANY
DOCKET NO. 20240026-EI
EXHIBIT NO. CA-1
WITNESS: ALDAZABAL
DOCUMENT NO. 5
PAGE 1 OF 1
FILED: 04/02/2024

Total System Net EAF Percentage

2017	77.75
2018	80.47
2019	84.22
2020	81.32
2021	82.03
2022	82.84
2023	81.34
Average	81.42
Max	84.22
Min	77.75

Solar Project 2021 -2023

Project	MW	Cost (Millions)	In-Service Date
Magnolia	74.5	$95.4	12/14/2021
Big Bend II Ph1	31.5	$43.1	1/2/2022
Mountain View	54.6	$81.2	4/11/2022
Jamison	74.5	$106.4	4/30/2022
Laurel Oaks	61.2	$81.1	12/1/2022
Riverside	55.2	$80.1	12/17/2022
Big Bend II Ph2	14.3	$20.2	11/21/2022
Juniper	70.0	$99.2	12/1/2023
Alafia	60.0	$87.9	12/1/2023
Lake Mabel	74.5	$101.2	12/1/2023
Dover	25.0	$43.3	12/1/2023
Total	**595.3**	**$839.1**	

Corporate Headquarters Scorecard

Average Team Member Scores							
HQ - TEC Criteria	**Points**	**Multiplier**	**Plaza**	**Mid-Town**	**Water Street**	**International Plaza**	**Max Points**
Connection to Community	10	10	49	81	80	63	100
Parking	10	9	20	84	55	75	90
Nearby Amenities	10	8	48	69	54	59	80
Talent Recruitment	10	7	35	59	59	47	70
Security and Resiliency	10	6	34	51	41	43	60
Walkability	10	5	31	41	35	34	50
Dedicated Lobby	10	4	26	33	32	31	40
Building Signature	10	3	21	28	26	24	30
Dedicated Elevators	10	2	19	19	18	17	20
Sustainability	10	1	5	9	9	9	10
Final Score			287	474	408	402	550
Percentage			52%	86%	74%	73%	

Headquarters Evaluation
Summary of Analysis

	Plaza Lease	Plaza Purchase	Midtown Purchase
Total Capital	$154.7M	$216.9M	$255.0M
Avg. Maintenance Capital	$0.6M	$0.6M	$0.1M
Average O&M	$10.4M	$8.8M	$3.6M
AFUDC Earned	-	-	$16.0M
Terminal Value Assumed	$0.0M	$62.2M	$255.0M
Financial Results:			
IRR	5.88%	6.10%	8.51%
NPV	($14.4M)	($13.0M)	$32.7M
Financial Impact to Customers:			
30 Year NPV of Revenue Requirement	$283.1M	$274.9M	$284.1M
60 Year NPV of Revenue Requirement	$331.8M	$325.4M	$345.6M

* includes $62.2M for Plaza purchase in 2044

Tampa Electric Portion	Plaza Lease	Plaza Purchase	Midtown Purchase
Total Capital	$114.5M	$160.5M	$188.7M
Avg. Maintenance Capital	$0.5M	$0.5M	$0.0M
Average O&M	$7.7M	$6.5M	$2.7M
AFUDC Earned	-	-	$11.9M
Terminal Value Assumed	$0.0M	$46.1M	$188.7M
Financial Results:			
IRR	5.88%	5.88%	8.51%
NPV	($10.6M)	($10.6M)	$24.2M
Financial Impact to Customers:			
30 Year NPV of Revenue Requirement	$209.5M	$203.4M	$210.2M
60 Year NPV of Revenue Requirement	$245.5M	$240.8M	$255.7M

* includes $46.1M for Plaza purchase in 2044

Tampa Electric

ENERGY SUPPLY

	2022	2023	2024	Total 2022-2024	2025	Total 2022-2025
Total Capital	521,316,096	701,322,870	730,475,644	**1,953,114,611**	845,454,015	**2,798,568,626**
ECRC	(6,692,230)	(22,688,020)	(6,875,767)	**(36,256,017)**	-	**(36,256,017)**
CETM	(11,367,712)	(42,987,391)	(23,656,329)	**(78,011,433)**	(33,255,933)	**(111,267,366)**
AFUDC - Settlement	(282,169,756)	(188,505,812)	(4,131,097)	**(474,806,665)**	-	**(474,806,665)**
AFUDC - Non-Settlement	(114,728,718)	(292,670,430)	(569,236,729)	**(976,635,877)**	(653,875,008)	**(1,630,510,885)**
Base Rate	**106,357,680**	**154,471,217**	**126,575,721**	**387,404,619**	**158,323,074**	**545,727,693**
Base Rate Projects						
BLANKETS	18,239,969	30,784,668	16,616,272	**65,640,909**	21,780,348	**87,421,257**
BUILDING RENOVATION CAPITAL	6,628,123	13,220,112	20,362,978	**40,211,213**	8,437,405	**48,648,619**
OTHER	4,641,156	1,530,448	9,426,741	**15,598,344**	17,055,632	**32,653,977**
OUTAGE	44,033,047	73,716,115	48,362,415	**166,111,577**	67,550,865	**233,662,442**
PLANT IMPROVEMENT (NON-OUTAGE)	25,060,744	33,938,889	28,714,147	**87,713,780**	33,320,409	**121,034,189**
SOLAR OPERATIONS	2,607,392	6,044,796	3,093,168	**11,745,355**	4,178,415	**15,923,770**
SOLAR	5,147,250	(4,763,810)	-	**383,440**	-	**383,440**
FUTURE SOLAR LAND	-	-	-	**-**	6,000,000	**6,000,000**
TOTAL	**106,357,680**	**154,471,217**	**126,575,721**	**387,404,619**	**158,323,074**	**545,727,693**
	-	-	-	-	-	-
AFUDC - Non-Settlement						
SYA	43,357,326	197,981,078	317,523,227	**558,861,632**	200,983,090	**759,844,722**
KRIS AFUDC	46,840,600	90,283,072	235,661,381	**372,785,052**	349,066,641	**721,851,693**
FUTURE YEAR	-	-	3,611,610	**3,611,610**	103,825,277	**107,436,887**
AGP UPGRADES	24,530,792	4,406,280	12,440,511	**41,377,583**	-	**41,377,583**
	$ 114,728,718	$ 292,670,430	$ 569,236,729	$ 976,635,877	$ 653,875,008	$ 1,630,510,885

85

TAMPA ELECTRIC COMPANY
DOCKET NO. 20240026-EI
EXHIBIT NO. CA-1
WITNESS: ALDAZABAL
DOCUMENT NO. 10
PAGE 1 OF 1
FILED: 04/02/2024