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ELECTRONIC FILING

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

In re: Petition for Rate Increase by Tampa Electric Company	DOCKET NO. 20240026-EI
In re: Petition for approval of 2023 Depreciation and Dismantlement Study, by Tampa Electric Company	DOCKET NO. 20230139-EI
In re: Petition to implement 2024 Generation Base Rate Adjustment provisions in Paragraph 4 of the 2021 Stipulation and Settlement Agreement, by Tampa Electric Company	DOCKET NO. 20230090-EI

Dear Mr. Teitzman:

Attached for filing on behalf of Tampa Electric Company in the above-referenced docket is the Rebuttal Testimony of Carlos Aldazabal and Exhibit No. CA-2.

Thank you for your assistance in connection with this matter.

(Document 1 of 14)

Sincerely,

J. Jeffry Wahlen

cc: All parties

JJW/ne
Attachment

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 20240026-EI

PETITION FOR RATE INCREASE

BY TAMPA ELECTRIC COMPANY

REBUTTAL TESTIMONY AND EXHIBIT

OF

CARLOS ALDAZABAL

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OF

CARLOS ALDAZABAL

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

REBUTTAL 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. Are you the same Carlos Aldazabal who filed direct testimony in this proceeding?

A. Yes.

Q. Have your title and duties and responsibilities changed since the company filed your prepared direct testimony on April 2, 2024?

A. No.

Q. What are the purposes of your rebuttal testimony?

A. My rebuttal testimony serves three general purposes.

First, I will address the proposal from the Office of Public Counsel's ("OPC") witness Lane Kollen to disallow planned generation maintenance expense based on a normalized number.

Second, I will respond to the direct testimony of witness Karl Rábago, filed on behalf of the League of United Latin American Citizens ("LULAC") and Florida Rising, and his arguments that the Corporate Headquarters, Polk Fuel Diversity, and Sowuth Tampa Resilience Projects should be disallowed.

Third, I will respond to the direct testimony of Devi Glick, filed on behalf of the Sierra Club, and Ms. Glick's recommendations regarding Big Bend Unit 4 and Polk Unit 1. I will also respond to the proposed issues raised by Sierra Club based on Ms. Glick's testimony.

Q. Have you prepared an exhibit supporting your rebuttal testimony?

A. Yes. Rebuttal Exhibit No. CA-2, entitled "Rebuttal Exhibit of Carlos Aldazabal," was prepared by me or under

my direction and supervision. The contents of this rebuttal exhibit were derived from the business records of the company and are true and correct to the best of my information and belief. My rebuttal exhibit consists of the following two documents:

Document No. 1	Tampa Electric's Answer to OPC's First Set of Interrogatories No. 7
Document No. 2	2022 Fuel Savings Associated with Using Coal

I. NORMALIZATION OF PLANNED GENERATION MAINTENANCE EXPENSE

Q. On page 11 of his testimony, Mr. Kollen asserts that Tampa Electric deferred planned maintenance and "bunched the outages" in the projected test year to inflate test year planned generation maintenance expense. Is this accurate?

A. No. Outages are scheduled based on planned maintenance schedules and to accommodate resource and parts availability. Major planned outage work occurs in uneven cycles. The uneven nature of planned outage work is reflected in the information contained in the company's answer to OPC's First Set of Interrogatories No. 37, which I have included as Document No. 1 in my rebuttal exhibit.

Q. Do you agree with Mr. Kollen's recommendation for normalization of planned generation expenses in the company's test year?

A. No. Mr. Kollen's normalization proposal is flawed in that he recommends normalization of historical average costs rather than the costs the company expects to incur in the test year. On page 11 of his testimony, he proposes using an average of expenses starting in the year 2019. Historical costs are not indicative of needed generation expenses in the test year.

Q. OPC's witness, Mr. Kollen provides an alternative solution to defer what he calls "abnormally high expense" more than his calculated level of normalized expense and amortize that deferral over an extended period. He opines that this approach would "attempt to allocate the benefits" of the planned maintenance to the periods benefitting from the planned maintenance scope of work and expenses. Please comment on that alternative approach.

A. If the Commission decides to adjust the company's test year outage expense, then I believe it is appropriate to defer the costs above the annual allowed or "normalized"

amount for recovery in future years. Further, I believe that such an adjustment, if applied, should be made using the approach described in the rebuttal testimony of Tampa Electric witness Jeff Chronister.

II. TAMPA ELECTRIC PERFORMED A FULL COST-BENEFIT ANALYSIS FOR THE CORPORATE HEADQUARTERS

Q. On page 51 of his testimony, Mr. Rábago asserts that the Commission should disallow rate recovery for the company's Corporate Headquarters "until TECO produces a comprehensive BCA that fully considers alternatives to new building construction." Did Tampa Electric perform a benefit-cost analysis for the project that included alternatives?

A. Yes. As I explained in my direct testimony, Tampa Electric performed a net present value revenue requirement ("NPVRR") calculation for the new Corporate Headquarters and compared it to two alternatives. This analysis was included in Document No. 9 of my Exhibit CA-1. That analysis shows that there is less than a $1 million net present value ("NPV") differential between continuing to lease the existing corporate headquarters and purchasing the Midtown location. The company then compared this quantitative assessment against the resilience and

qualitative benefits that the new Midtown location provides.

Q. Did the company consider alternatives other than construction of a new headquarters in Midtown?

A. Yes. As stated in my direct testimony, Tampa Electric partnered with Colliers International, a global commercial real estate company, to explore various lease or own locations throughout our service area. Some of these options are listed on Document No. 8 of my Exhibit CA-1. The company also evaluated extending the lease of TECO Plaza or purchasing the existing building, as shown in Document No. 9 of my Exhibit CA-1.

Q. What qualitative benefits did the company identify for the Midtown location?

A. As I explained in my direct testimony, the company created an internal team of 18 director-level employees to evaluate several criteria, which are listed on Document No. 8 of my Exhibit CA-1. This team identified Midtown as the option that provided the highest level of these qualitative benefits. Additionally, as I explained in my direct testimony, the company also identified several

qualitative drawbacks to remaining in TECO Plaza, including flooding and storm surge risk, available capacity limits, and lack of dedicated parking.

Q. How did the company weigh the expected costs of the TECO Plaza and the Midtown options against the identified benefits?

A. After careful consideration, the company determined that the Midtown location was the best alternative from a value, resilience, and employee retention and satisfaction perspective. Furthermore, as the analysis proceeded, the need to locate the company's headquarters away from potential flooding became a more important priority, especially since the economics of the options being considered were about the same. The company weighed the identified qualitative benefits of the Midtown location against the approximately $1 million difference in NPVRR cost and concluded that the benefits outweighed the $1 million difference in cost.

III. TAMPA ELECTRIC'S POLK FUEL FLEXIBILITY PROJECT IS NECESSARY, PRUDENT, AND WILL BENEFIT OUR CUSTOMERS

Q. Mr. Rábago recommends that the Commission should disallow the Polk Fuel Diversity Project because the company has

not demonstrated the cost-effectiveness of the project. Do you agree with this recommendation?

A. No. The decision to invest in a backup oil project of this nature was based upon the need to mitigate risk. Even with the growth in the company's solar generation, Tampa Electric projects over 80 percent of its electricity for customers will come from natural gas fired generation. Florida's peninsular geography means that the state and Tampa Electric can face challenges importing fuel or power when one or more of the current sources is constrained or fully subscribed. The fact that surrounding interconnection options are limited by geography makes on-site fuel diversity even more important than for utilities with interconnection options all around them.

The Polk Fuel Diversity Project mitigates the risk of service interruptions to customers due to a disruption or deficiency in natural gas supply or delivery. The Polk Fuel Diversity Project combines existing facilities, capabilities, and expertise at the Polk Power Station to expand the backup fuel oil capacity at Polk Power Station. This is a very effective and low-cost alternative for mitigating natural gas supply risk.

As I explained in my direct testimony, the company also considered several alternatives including purchases of capacity, storage, liquified natural gas ("LNG") storage, incremental firm gas transportation, solid fuel generation, purchased power, transmission, and renewable generation. The company determined that this project was the most feasible and logical option to add fuel diversity. In short, the company did not develop a quantitative cost-effectiveness analysis for the Polk Fuel Diversity Project because it is not needed. This project will be completed to mitigate fuel supply risk, which enhances reliability, and it is clearly the right option for Polk Power Station.

IV. TAMPA ELECTRIC'S SOUTH TAMPA RESILIENCE PROJECT IS NECESSARY, PRUDENT, AND WILL BENEFIT OUR CUSTOMERS

Q. On page 50 of his testimony, Mr. Rábago asserts that Tampa Electric did not provide a cost-benefit analysis for the South Tampa Resilience Project. Do you agree with this assertion?

A. No. Tampa Electric performed a comprehensive cost-benefit analysis which showed that the South Tampa Resilience Project has a projected net benefit to customers of approximately $10 million CPVRR, excluding any benefit

from the value of reduced emissions. This net benefit includes projected fuel savings to customers of $137.9 million, and is shown in Document No. 5 in Exhibit No. JA-1, which is attached to the direct testimony of Jose Aponte. This project was also scrutinized by the company's capital leadership team and reviewed and approved by the Board of Directors.

Q. Mr. Rábago also asserts that the project will have "new highly-pollution [sic] fossil fuel generation." Is this an accurate characterization of the project?

A. No. As stated in my direct testimony the South Tampa Resilience Project is expected to produce $137.9 million of cumulative projected fuel savings for customers. These engines are highly efficient, and, because of their efficiency, they operate using less fuel, which will also result in reduced CO_2 emissions on our system over their operating life.

Q. How will these natural gas burning engines result in reduced CO_2 emissions?

A. These reciprocating engines complement Tampa Electric's portfolio of four large, efficient natural gas combined

cycle units. Because the reciprocating engines can dispatch very quickly (and turn off quickly, ramp up and down rapidly, and be cycled on and off repeatedly), they will allow Tampa Electric to dispatch its generating assets more efficiently. Large combustion turbines ("CT") have a limited number of starts, must be started early to warm up, must be blended into the combined cycle, and then must run for several hours to meet minimum run times. By contrast, the company can dispatch the South Tampa reciprocating engines on and off to meet the load exactly when it is needed. Keeping the combined cycle steady while dispatching reciprocating engines to precisely match changing load demands uses less fuel and reduces emissions compared using large, combined cycle units to follow load.

Additionally, the quick start nature of the reciprocating engines allows them to cover spinning reserves without even turning on. Without the reciprocating engines, spinning reserves may have to be covered by keeping extra MW spinning in combined cycle mode which causes extra fuel to be used without serving more load. This more efficient and effective use of the combined cycle units will likely extend the life of those assets.

Q. Also on page 50, Mr. Rábago criticizes the project on the

grounds that it will not receive "direct funding support from the U.S. Department of Defense." Do you agree with this criticism?

A. No. Although the government provided no "cash" funding support for the project, the lease agreement between the government and Tampa Electric allows "rent" to be paid in the form of in-kind consideration or "in-kind rent" which takes the form of Electrically Islanded Operations on MacDill Air Force Base ("MAFB") in the event of a very rare, declared emergency.

Q. Why was this rent-free land beneficial for the project?

A. Available land in South Tampa is very limited. Securing an available parcel that could both accommodate these reciprocating engines and be permitted for their use would have been difficult, if not impossible, in this load congested area. This arrangement is a great solution that addresses a capacity need for the company and solves a resilience need for MAFB.

V. TAMPA ELECTRIC'S PLANS FOR POLK UNIT 1 AND BIG BEND UNIT 4 ARE PRUDENT AND WILL PROVIDE BENEFITS TO OUR CUSTOMERS

Q. In her direct testimony, Ms. Glick asserts that Polk Unit

1 cannot mitigate the impacts of natural gas price volatility because the Integrated Coal Gasification Combined Cycle ("IGCC") equipment is in reserve standby, because environmental regulations restrict potential IGCC operation, and because Polk Unit 1 has been unreliable. Do you agree with this analysis?

A. No. Due to limited interconnects with other states, the amount of renewable power or replacement power that can be imported into the state is limited. Therefore, any renewable power or any replacement power must be generated within the state to meet reliability needs. Retaining the existing solid fuel assets of Polk Unit 1 is important to provide fuel diversity options and help mitigate the potential volatility of natural gas prices. With some necessary maintenance, Polk Unit 1 could return to IGCC operation within a year and help protect customers from high natural gas prices if the forward price curve shows petcoke prices will be lower than natural gas prices. Additionally, if Polk Unit 1 were to return to IGCC operation but retire before 2032, it would not be subject to any Greenhouse Gas ("GHG") emission standards. If Polk Unit 1 ceased operation after January 1, 2032, but before 2039, co-firing a minimum of 40 percent natural gas would be required, or a Carbon Capture and Storage ("CCS")

system with a 90 percent CO_2 capture rate could be used. Finally, Polk Unit 1 has been a very reliable generating asset on our system, and it is expected to be even more reliable once converted to simple cycle operation in the Polk 1 Flexibility Project.

Q. On page 33, Ms. Glick presents the net equivalent forced outage rate and argues that Polk Unit 1 has been "relatively unreliable." Do you agree with her characterization of that information?

A. No. As noted in Ms. Glick's testimony, Polk Unit 1 had unusually high net equivalent forced outage rates ("NEFOR") in the years 2020, 2021, and 2022; however, I do not view these anomaly years as an accurate predictor of future performance. There were two unexpected major forced outage events that caused significant down time during this period. However, several primary components of the combustion turbine and generator were refurbished to "like new" condition during the outage work. These refurbishments, along with the combustion system upgrades associated with the planned simple cycle conversion, incorporate robust, advanced combustion turbine technology and will position the unit for high reliability for its remaining useful life.

Q. On page 26 of her testimony, Ms. Glick also asserts that the Polk Unit 1 IGCC assets are no longer used and useful, and that the only reason that the company has not retired those assets is to keep them in rate base. Do you agree with this characterization of the company's decision-making?

A. No. The IGCC assets on Polk Unit 1 are a unique, proven technology and have been in a designed layup configuration for the past several years. With certain evaluation, inspection, maintenance, and testing, the unit can be returned to service operating as an IGCC within a year. The primary equipment and systems within the IGCC have been maintained in a used and useful state and remain an integral component to mitigate risk related to volatile natural gas prices.

Q. On page 27, Ms. Glick suggests that the Commission should order retirement of the Polk Unit 1 IGCC assets and create a regulatory asset to allow the company to recover some or all the undepreciated balance of the assets. Do you agree with this proposed treatment of the IGCC equipment?

A. No. It is not appropriate to order the retirement of these assets since they are potentially useful and could benefit

customers in the future. However, I do agree that if the Commission orders the retirement of the IGCC equipment, then the remaining value of the assets should be transferred to a regulatory asset and recovered from customers. Of course recovery of the regulatory asset over a shorter period than the remaining life of the assets would increase customer bills. In addition, since a regulatory asset balance recovered over the remaining life of the assets would have the same impact on customer bills as keeping the assets in rate base for future use, I do not see the benefit in forcing retirement of the assets. In either scenario, customers would lose the fuel diversity benefits of retaining the IGCC components in service.

Q. Ms. Glick asserts that Tampa Electric did not provide an analysis demonstrating that converting Polk Unit 1 to simple cycle operation is more economic than alternatives, including retirement. She also asserts that the converted unit will be only "marginally economic." Do you agree with her assessment?

A. No. First, Tampa Electric did compare the economics of converting Polk Unit 1 to simple cycle operation to alternatives, including early retirement of the combined

cycle components of Polk Unit 1. Second, this analysis showed that the conversion to simple cycle operation resulted in the most cost savings for customers when compared to a reference case with Polk Unit 1 continuing to operate as a natural gas combined cycle unit.

The company evaluated two additional options besides the conversion of Polk Unit 1 to simple cycle operation. In one of the options, the company analyzed retirement of the combined cycle components for Polk Unit 1 early in the year 2028. The second option evaluated an optionality case, in which Polk Unit 1 could operate in combined and simple cycle modes. Ultimately, the analysis showed that conversion of Polk Unit 1 to simple cycle mode is the most favorable option for customers, with an estimated CPVRR savings of $166.9 million, compared to an estimated $24.6 million savings for the early retirement option, and $39.1 million savings for the optionality case.

The Polk Unit 1 conversion is not only the most economic option for customers; it also provides additional dispatch flexibility to our system. Operating Polk Unit 1 as a simple cycle combustion turbine will allow for faster starts, shorter up/down times, and lower turndowns, enabling Tampa Electric to better optimize

dispatch of the other assets in the generation portfolio.

Q. On pages 42 to 44 of her direct testimony, Ms. Glick asserts that Big Bend Unit 4 was uneconomic to operate in 2019, 2020, and 2023. Is this statement accurate?

A. No. As Ms. Glick admits in her testimony on page 44, the approach of including long-term capital investments as a lump sum in a single year can give false uneconomic signals. Tampa Electric had large capital investments in the years 2019, 2020, and 2023 that resulted in false economic signals in Ms. Glick's Table 6.

Q. Why did Tampa Electric operate Big Bend Unit 4 using coal during the years referenced by Ms. Glick?

A. Big Bend Unit 4 burned coal for a variety of reasons over the last five years. From 2019 through 2021, the unit operated on coal when the capacity was needed. The coal-fired capacity was more than double the capability on natural gas and the additional capacity was needed to serve load and reserves. The unit also operated on coal for environmental reasons related to the Manatee Protection Plan or managing water levels at the plant.

Big Bend Unit 4 was also committed on coal during a Gulfstream Natural Gas System ("GNGS") pipeline outage for about two weeks in March 2021. This was a significant pipeline outage for Tampa Electric and the state of Florida, in which Big Bend Unit 4's dual fuel capability was critical to meet the demand of Tampa Electric customers.

Other than the GNGS outage or environmental reasons, the unit was committed only when it was economic relative to the purchased power market or when constraints such as inbound transmission, availability of power supply, or system conditions prevented economic purchased power from displacing Big Bend Unit 4.

During Winter Storm Uri in February 2021, Big Bend Unit 4 was committed on coal at maximum capacity to reduce natural gas requirements. Tampa Electric experienced a significant loss of natural gas supply during the event, and Big Bend Unit 4's coal capability reduced system natural gas requirements. As natural gas prices spiked during the event, operating Big Bend Unit 4 on coal provided fuel savings for customers and mitigated natural gas pipeline penalties as pipeline alert days were posted every day. Penalties on pipeline alert days can be three

times the gas price when actual gas burns exceed scheduled burns.

In late 2021, the capability of Big Bend Unit 4 on natural gas was increased to a level like its coal-fired capacity. In 2022, with natural gas prices at their highest levels in years, Tampa Electric used coal in Big Bend Unit 4 because it was more economic than natural gas. The estimated fuel savings for customers was over $32 million in 2022, as demonstrated in Document No. 2 of my rebuttal exhibit CA-2 titled, "2022 Fuel Savings Associated with Using Coal". These savings are a direct result of Big Bend Unit 4 being dual fuel capable.

Although Ms. Glick claims on page 43 of her testimony that the market conditions in 2022 are rare and not expected to continue going forward, Tampa Electric prepares to be resilient and reliable in any number of unexpected scenarios. We have experienced extreme events (weather and other) recently and prepare for uncertain conditions going forward.

Q. Are there other examples showing the benefits of dual fuel capability at Big Bend Unit 4?

A. Yes. In December 2022, Big Bend Unit 4 operated on coal to reduce portfolio natural gas requirements during Winter Storm Elliott. In 2023, Big Bend Unit 4 coal burn was at an all-time low. During 2023, the unit operated on coal early in the year to support environmental constraints. In August 2023, Tampa Electric experienced extreme heat and set a new summer peak record almost five percent greater than its previous summer peak. Gas pipeline alert days were issued daily throughout the summer, and there was very little delivered gas available in the Florida market. Again, Big Bend Unit 4 operated on coal to reduce system natural gas needs and to mitigate natural gas pipeline penalties.

In 2024, Big Bend Unit 4 has burned little coal year to date. The only coal burn took place on January 13, 2024, through January 16, 2024, as a winter storm drove natural gas prices to $12/MMBtu at the Henry Hub. The estimated fuel savings for customers was approximately $600,000 during the event. Based on the extreme weather experienced during May 2024, we expect to commit Big Bend Unit 4 on coal this summer as needed to reduce system natural gas requirements and mitigate natural gas pipeline penalties.

Q. On pages 45 and 46 of her direct testimony, Ms. Glick

projects that Big Bend Unit 4 will remain uneconomic to operate going forward. Do you agree with her analysis?

A. No. Tampa Electric expects to operate Big Bend Unit 4 mostly on natural gas. However, it is important that we maintain the coal capability on Big Bend Unit 4 for fuel diversity, resilience, and to minimize fuel expense for our customers.

Dual fuel capability on Big Bend Unit 4 allows Tampa Electric to avoid buying additional firm gas transportation. The available gas transportation in Florida is limited and expensive. Given the limited availability of transportation, transportation is typically only available for the entire year, rather than seasonally, and for 10 to 15-year minimum terms. To serve a similar-sized 400 MW combined-cycle natural gas unit, the cost of incremental firm natural gas pipeline transportation would exceed $25 million annually. If this avoided cost of pipeline transportation was added to Ms. Glick's Table 7, the projected net value of Big Bend Unit 4 would be positive in all years.

The dual fuel capability of Big Bend Unit 4 allows Tampa Electric to put the unit on coal for short periods of

time during periods of extreme demand and avoid the significant fuel expense of buying additional long term firm gas pipeline transportation.

Q. How does fuel switching capability at Big Bend Unit 4 benefit customers?

A. The fuel switching capability at Big Bend Unit 4 is important and can result in fuel savings for customers, help avoid pipeline penalties, reduce gas requirements during periods of extreme demand, and avoid the expense of long-term firm gas pipeline transportation. During extreme events or a pipeline disruption, onsite solid fuel for Big Bend Unit 4 could mitigate potential electric service interruptions for our customers. Big Bend Unit 4 is the only dual fuel unit in the company's portfolio capable of quickly switching from one fuel to another and remaining on that onsite fuel during an extended fuel interruption such as a cyber-attack similar to the Colonial pipeline incident in 2021, a terrorist attack on energy infrastructure, an operational pipeline failure, extreme winter weather such as Winter Storms Uri or Elliott, a hurricane in the Gulf Coast damaging natural gas infrastructure, or the Piney Point reservoir incident near a Gulfstream pipeline compressor in 2021.

Q. On page 47 of her testimony, Ms. Glick claims that Tampa Electric did not evaluate whether continued operation of Big Bend Unit 4 is in the best interest of the company's customers. Is this statement correct?

A. No. Tampa Electric evaluated continued operation of Big Bend Unit 4 and considers the continued operation of that unit to be in the best interest of the company's customers. Big Bend Unit 4 currently has dual fuel capability and can operate using natural gas or coal. Considering the recent volatility of natural gas prices, the scarcity of available firm natural gas pipeline transportation and amount of pipeline alert days in Florida, and supply constraints on the natural gas pipelines during periods of extreme demand, keeping Big Bend Unit 4 in operation to provide fuel diversity and system reliability is crucial for our customers.

Q. Do you agree with Ms. Glick's assumptions on the costs for Big Bend Unit 4 to comply with EPA's Effluent Limitation Guidelines ("ELG") rule?

A. No. Ms. Glick's environmental assessments are based on incorrect assumptions. Tampa Electric has already achieved compliance with the ELG rule through its deep

injection well ("DIW") system. The discharge of flue gas desulfurization ("FGD") wastewater to the DIW system is now permitted and regulated through the Florida Department of Environmental Protection's ("FDEP") Underground Injection Control ("UIC") Program. Tampa Electric has already incurred the cost to comply with the ELG rule as part of its design and construction of the DIW system.

I do not know the exact source of the $129 million compliance cost estimate included in the EPA report cited in Ms. Glick's testimony. It is possible that EPA made an erroneous assumption due to the fact that Big Bend's National Pollutant Discharge Elimination System ("NPDES") permit has been delayed. The EPA is not privy to additional information that has been provided to FDEP but has not yet reached EPA as a part of the formal review process. It appears that the EPA's projections assume that Tampa Electric will design and build a zero-discharge system for FGD wastewater (and Bottom Ash and Fly Ash Transport Water). For plants that have no alternative to surface water discharge and no basis for exemption, the zero-discharge system is the only compliance option. However, Big Bend does have an alternative to continued surface water discharge, through its DIW system. Since a

zero-discharge system is not required at Big Bend Unit 4, EPA's projected cost estimate is not applicable.

Q. Do you agree with Ms. Glick's assumptions about Big Bend Unit 4 compliance with EPA's Mercury and Air Toxics Standards ("MATS") regulations?

A. No. Big Bend Unit 4 is already compliant with the MATS regulations and will continue to be compliant in the future. No additional costs will be incurred to continue operating the unit under MATS.

Q. What is the basis for Ms. Glick's apparent misunderstanding?

A. The lowest achievable filterable particulate matter ("FPM") rate of 0.00953 lb/MMBtu referenced by the Sierra Club is incorrect. The Sierra Club referenced this rate based on the EPA MATS Technical Analysis, suggesting the Big Bend Unit 4 may not be able to comply with the new 0.01 lb/MMBtu and may need controls to meet the compliance deadline by 2027. Tampa Electric was able to recalculate the lowest achievable filterable FPM rate of 0.00974 lb/MMBtu using the same FPM hourly database data referenced by EPA, which is close to the FPM rate of

0.00953 lb/MMBtu referenced by Sierra Club. However, this is not the rate that would be used to determine compliance. The FPM rate must be recalculated using the 30-boiler operating day data to make an appropriate compliance assessment with the new limit of 0.010 lb/MMBtu based on a 30-boiler operating day average. Tampa Electric recalculated the quarterly lowest achieved FPM rate using the actual 30-boiler operating day data. The average FPM rate on Big Bend Unit 4 was 0.0035 lb/MMBtu on a 30-boiler operating day average from January 1, 2023, through December 31, 2023. This FPM monitoring data shows that Big Bend Unit 4 will continue to demonstrate compliance with the new MATS Rule Revisions, including the FPM limit of 0.010 lb/MMBtu based on a 30-boiler operating day average.

Q. On page 51 of her testimony, Ms. Glick suggests that the company could convert Big Bend Unit 4 to seasonal operation during winter peak months. Have you evaluated this alternative?

A. No. The company needs Big Bend Unit 4 to be dual fuel operational during the entire year. Specifically, Tampa Electric customers benefit from Big Bend Unit 4's coal capability during extreme events (weather or other) in

the summer and winter months to reduce portfolio gas requirements and to avoid having to acquire long-term firm natural gas pipeline transportation. Outside of the summer and winter periods, Big Bend Unit 4's coal capability provides fuel resilience in the event of a gas pipeline interruption.

Q. Ms. Glick also suggests the unit could be converted to operation solely on natural gas ahead of its retirement. Have you evaluated this alternative?

A. No. As I previously stated, the dual fuel functionality of Big Bend Unit 4 provides needed fuel diversity and resilience that helps to mitigate risk associated with a natural gas supply interruption as well as mitigating the impacts of volatile natural gas prices. Without Big Bend Unit 4's dual fuel functionality, Tampa Electric would be required to purchase incremental long-term gas transportation, and it would be detrimental to fuel resilience as it would increase the impact of a natural gas supply disruption for customers.

Q. On pages 52 through 57 of her testimony, Ms. Glick argues that the company should retire all its coal-fired generation because it exposes customers to volatile fuel

prices and high environmental compliance costs. Do you agree with this conclusion?

A. No. Tampa Electric does not rely on coal and petcoke as Ms. Glick suggests on page 54. Going forward, Tampa Electric projects coal as a percentage of generation mix to be less than one percent annually. Maintaining the dual fuel capability of Big Bend Unit 4 and Polk Unit 1 will help our customers mitigate the risk of volatile natural gas prices as those dual fuel units provide an alternate fuel to natural gas during periods of price volatility. Specific examples of coal-fired generation mitigating natural gas price volatility are Winter Storm Uri, the high natural gas prices in 2022, and most recently, the four days of natural gas price spikes in January 2024, which I previously described.

Q. On page 57 of her testimony, Ms. Glick asserts that Tampa Electric should replace its coal-fired assets with solar generation, energy storage, energy efficiency, and demand response. Do you agree that these resources could provide a substitute for the company's coal-fired generation?

A. No. While transitioning to solar generation, energy storage, energy efficiency, and demand response

technologies reduce carbon emissions, there are certain challenges associated with these technologies. For example, solar generation is not available to meet customer's needs during early morning winter peaks. Solar generation requires significant amounts of land that simply may not be available in a compact, urban service territory like Tampa Electric's. Solar generation, energy storage, energy efficiency, and demand response technologies are important tools that Tampa Electric supports to complement our generation resources. However, these alternative energy resources outlined in Ms. Glick's testimony are not a viable option to replace Tampa Electric's coal units at this time.

Q. On pages 58 through 63 of her testimony, Ms. Glick describes the Energy Infrastructure Reinvestment ("EIR") program and recommends that the company should set an early retirement date for Big Bend Unit 4 and apply for EIR funding. Have you evaluated this program and considered Ms. Glick's recommendation?

A. Although Tampa Electric is aware of the EIR program, we have not evaluated its use as an early retirement mechanism for Big Bend Unit 4. As I previously stated, the continued operation of Big Bend Unit 4 as a dual fuel

unit is in the best interest of customers, and it provides added fuel resilience and helps mitigate volatile natural gas prices. Tampa Electric does not believe the EIR program is an economic alternative to accelerate the retirement of these assets, nor does the company believe they should be retired at this time.

VI. TAMPA ELECTRIC'S POSITIONS ON SIERRA CLUB'S OTHER ISSUES

Q. Should Tampa Electric recover Operating and Maintenance ("O&M") costs associated with keeping integrated gasification, steam turbine, and/or heat recovery steam generator components at Polk Unit 1 in long-term standby, and what adjustments should be made?

A. Yes. As I previously explained, the IGCC, steam turbine, and heat recovery steam generator components of Polk Unit 1 should remain in service because they allow the unit to burn solid fuel. This provides fuel diversity and reliability benefits to the company's customers. Consequently, the company should be able to recover the O&M costs associated with those components, and no adjustments should be made.

Q. Should Tampa Electric recover O&M costs associated with injecting wastewater into deep wells at Polk Unit 1 and

Big Bend Unit 4, and what adjustments should be made?

A. Yes. These wells are necessary to maintain compliance with applicable environmental regulations at those units. Again, maintaining the capability to operate Polk Unit 1 and Big Bend Unit 4 on solid fuel provides fuel diversity and reliability benefits to Tampa Electric's customers. As a result, the company should be able to recover O&M costs associated with the wastewater injection wells, and no adjustments should be made.

Q. Should Tampa Electric recover any O&M costs associated with coal or petcoke combustion at Polk Unit 1 and/or Big Bend Unit 4, and what adjustments should be made?

A. Yes. Maintaining the ability to burn solid fuel in Polk Unit 1 and Big Bend Unit 4 provides fuel diversity and reliability benefits to the company's customers. As a result, the company should be able to recover O&M costs associated with coal or petcoke combustion at Big Bend Unit 4 and/or Polk Unit 1, and no adjustments should be made.

Q. Should Tampa Electric be required to conduct an alternative analysis for retiring Polk Unit 1 and/or Big

Bend Unit 4 before their current retirement dates?

A. No. Tampa Electric should not be required to conduct alternative analyses for retiring Polk Unit 1 or Big Bend Unit 4. As I stated earlier in my testimony, Tampa Electric performed an analysis of early retirement of the combined cycle components of Polk Unit 1 which demonstrated the conversion to simple cycle resulted in the greatest cost savings for customers. Tampa Electric did not evaluate retirement of Big Bend Unit 4 because, as previously stated, the dual fuel functionality of Big Bend Unit 4 provides needed fuel diversity and resiliency that helps to mitigate risk associated with a natural gas supply interruption or volatile natural gas prices.

Q. Should Tampa Electric be required to conduct an analysis for retiring Polk Unit 1 and/or Big Bend Unit 4 earlier to avoid environmental compliance costs associated with EPA coal rules finalized in April 2024?

A. No. As I previously explained, Tampa Electric has already evaluated whether these units will comply with these environmental regulations and determined that the company will not incur any incremental expense to comply with those regulations.

Q. Should Tampa Electric be required to evaluate procurement of additional solar and energy storage projects to facilitate the earlier retirements of Polk Unit 1 and Big Bend Unit 4.

A. No. The company evaluated the level of cost-effective solar generation and energy storage it could implement in the near term and is seeking cost recovery for projects totaling approximately 490 MW of additional solar generation and 115 MW of energy storage capacity in this rate case. Furthermore, as I previously explained, these resources are not a viable option to replace Tampa Electric's coal units at this time.

Q. Should Tampa Electric be required to apply for the U.S. Department of Energy's Energy Infrastructure Reinvestment Program for Polk Unit 1 and/or Big Bend Unit 4?

A. No. Again, Tampa Electric's solid fuel units provide fuel diversity and reliability benefits that cannot be cost-effectively replaced by solar and energy storage at this time, and those units should not be retired.

Q. Should Tampa Electric be required to cease all coal combustion at Polk Unit 1 by 2024 and Big Bend Unit 4 by

2025?

A. No. For all the reasons I have already discussed in my testimony, these units should remain in-service and retain the equipment necessary to combust solid fuel.

VII. SUMMARY

Q. Please summarize your rebuttal testimony.

A. My rebuttal testimony addressed statements made in the direct testimony of OPC's witness Kollen, LULAC's witness Rábago, and Sierra Club witness Glick. I explained why the Commission should reject witness Kollen's proposal to reduce the company's 2025 test year outage expense, and I recommended that if the Commission decided to adjust outage expense, then it should adopt the approach described in Mr. Chronister's rebuttal testimony.

I addressed the assertions of Mr. Rábago, filed on behalf of LULAC, that the Corporate Headquarters, Polk Fuel Diversity, and South Tampa Resilience Projects should be disallowed. I explained that his arguments are unfounded, that these projects are prudent, and that Mr. Rábago's recommendations should not be followed.

I responded to the direct testimony of Ms. Glick, filed on behalf of the Sierra Club, and Ms. Glick's recommendations regarding Big Bend Unit 4 and Polk Unit 1. I explained that these units are useful, provide benefits to customers, and contrary to Ms. Glick's recommendations, should not be retired or replaced at this time. I also explained that the costs of operating and maintaining the units should continue to be recovered in base rates.

Q. Does this conclude your rebuttal testimony?

A. Yes.

TAMPA ELECTRIC COMPANY
DOCKET NO. 20240026-EI
WITNESS: ALDAZABAL

REBUTTAL EXHIBIT

OF

CARLOS ALDAZABAL

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37. **Planned Maintenance**. For Tampa Electric Company, please provide for each of the years 2019 through 2023 and for 2024 year to date the actual and budgeted planned generation maintenance by unit with explanations for any variances of more than 15%. Provide a comparable summary for the requested generation maintenance, by unit, for intermediate projected year 2024, and projected test year December 31, 2025.

ANSWER: The tables attached provide the actual and budgeted planned generation maintenance by unit with explanations for any variances of more than 15 percent for the years 2019 through 2023 and for 2024 year to date. Additionally, this table includes a comparative summary for the requested generation maintenance, by unit for the intermediate projected test year 2024 and projected test year December 31, 2025.

Planned Outage
Operations & Mainteance

2019		**Actual**	**Budget**	**Variance**	**%**	**Explanation**
Station	**Unit**					
Big Bend	BB1	204.9	489.0	284.1	58%	Scope reductions with units approaching retirement.
Big Bend	BB2	363.3	489.0	125.7	26%	Scope reductions with units approaching retirement.
Big Bend	BB3	2,863.0	2,674.3	(188.7)	-7%	
Big Bend	BB4	2,356.8	1,700.0	(656.8)	-39%	Upon inspection, additional motor and backpass maintenance required.
Big Bend	BB Aero	75.7	100.0	24.3	24%	Upon inspection, less maintenance required than budgeted.
Big Bend	BBCT5	-	-	-	-	
Big Bend	BBCT6	-	-	-	-	
Big Bend	BBST	-	-	-	-	
Bayside	BS1	1,744.2	900.0	(844.2)	-94%	Upon inspections, additional repairs on the 1A, B & C HRSG high pressure steam section, and 1C intermediate pressure steam section; and condenser\tunnel cleaning
Bayside	BS2	1,780.0	900.0	(880.0)	-98%	Upon inspections, additional repairs for control systems; Phase Bus; HRSG reheat section piping\drain values, outlet headers; and condenser inlet tunnel, waterbox & debris filter
Bayside	BS Aero	297.5	320.0	22.5	7%	
Polk	PK1	1,013.0	1,075.0	62.0	6%	
Polk	PK2	237.1	187.5	(49.6)	-26%	Upon inspection, additional HRSG drums, breakers and valves maintenance needed.
Polk	PK3	178.9	187.5	8.6	5%	
Polk	PK4	182.0	187.5	5.5	3%	
Polk	PK5	178.5	187.5	9.0	5%	
	Total	11,474.9	9,397.3	(2,077.6)		

2020		**Actual**	**Budget**	**Variance**	**%**	**Explanation**
Station	**Unit**					
Big Bend	BB1	4.8	-	(4.8)	0%	
Big Bend	BB2	184.6	400.0	215.4	54%	Scope reductions with units approaching retirement.
Big Bend	BB3	488.5	400.0	(88.5)	-22%	Upon inspection, additional boiler feed pump and bearing maintenance required.
Big Bend	BB4	6,778.7	6,166.8	(611.9)	-10%	
Big Bend	BB Aero	117.1	95.0	(22.1)	-23%	Upon inspection, additional battery load testing required.
Big Bend	BBCT5	-	-	-	-	
Big Bend	BBCT6	-	-	-	-	
Big Bend	BBST	-	-	-	-	
Bayside	BS1	1,270.5	1,055.0	(215.5)	-20%	upon inspection, found steam turbine had water induction for hotwell, additional costs to clean and inspect oils systems and equipment
Bayside	BS2	1,656.8	1,060.0	(596.8)	-56%	Upon inspection, repairs to high energy piping including insulation lagging and scaffolding
Bayside	BS Aero	211.3	275.0	63.7	23%	annual unit audits and bore scope inspections

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Polk	PK1	308.6	600.0	291.4	49%	Covid related delayed outages, lead times
Polk	PK2	328.1	400.0	71.9	18%	Covid related delayed outages, lead times
Polk	PK3	75.7	148.7	73.0	49%	Covid related delayed outages, lead times
Polk	PK4	99.1	155.7	56.6	36%	Covid related delayed outages, lead times
Polk	PK5	225.7	400.0	174.3	44%	Covid related delayed outages, lead times
	Total	11,749.6	11,156.2	(593.4)		

2021		Actual	Budget	Variance	%	Explanation
Station	Unit					
Big Bend	BB1	-	-	-	0%	
Big Bend	BB2	0.0	200.0	200.0	100%	Scope reductions with units approaching retirement.
Big Bend	BB3	42.3	400.0	357.7	89%	Scope reductions with unit approaching retirement.
Big Bend	BB4	4,960.0	800.0	(4,160.0)	-520%	Scope increase after budget due to natural gas conversion. (1)
Big Bend	BB Aero	30.3	150.0	119.7	80%	Upon inspection, less maintenance required than budgeted.
Big Bend	BBCT5	-	-	-	-	
Big Bend	BBCT6	-	-	-	-	
Big Bend	BBST	-	-	-	-	
Bayside	BS1	1,505.1	930.0	(575.1)	-62%	upon inspection, additional repairs for electrical equipment ; control systems; steam header; and condenser inlet tunnel, waterbox & debris filter
Bayside	BS2	1,841.0	935.0	(906.0)	-97%	upon inspection, additional repairs for electrical equipment ; control systems; air inlet systems; exhaust systems; steam header, piping & drains; and condenser inlet tunnel, waterbox & traveling screens
Bayside	BS Aero	236.1	275.0	38.9	14%	
Polk	PK1	262.3	500.0	237.7	48%	Upon inspection, LP economizers needed replacing not maintenance.
Polk	PK2	300.3	165.0	(135.3)	-82%	Upon inspection, additional HRH steam bypass valve, scc dampers, and port consolidation oil maintenance needed.
Polk	PK3	568.7	400.0	(168.7)	-42%	Upon inspection, additional Hot gas path, and APE electrical equipment maintenance needed.
Polk	PK4	371.2	400.0	28.8	7%	
Polk	PK5	176.7	165.0	(11.7)	-7%	
	Total	10,294.0	5,320.0	(4,974.0)		

2022		Actual	Budget	Variance	%	Explanation
Station	Unit					
Big Bend	BB1	-	-	-	0%	
Big Bend	BB2	-	-	-	0%	
Big Bend	BB3	60.3	100.0	39.7	40%	Scope reductions with unit approaching retirement.
Big Bend	BB4	513.7	900.0	386.3	43%	Scope reductions due to strong unit performance and past work.
Big Bend	BB Aero	103.0	154.5	51.5	33%	Upon inspection, less maintenance required than budgeted.
Big Bend	BBCT5	-	-	-	0%	
Big Bend	BBCT6	-	-	-	0%	

Big Bend	BBST	-	-	-	0%	
Bayside	BS1	7,833.4	6,380.1	(1,453.3)	-23%	Outage work scope estimate increase due to higher labor rates, material costs due to supply chain issues, overtime due to schedule constraints, and higher planning and outage support costs. Inspection also resulted in additional work scope for steam turbine auxiliaries; condenser inlet tunnel, waterbox & debris filters; HRSG and blow down tanks inspections\repairs; and boiler feed pump motor overhauls.
Bayside	BS2	2,145.6	1,785.1	(360.5)	-20%	upon inspection, additional repairs for HRSG steam headers, drums & piping; circulating water pumps & motors; and condensers. Also, there was higher labor rates and material costs due to supply chain issues.
Bayside	BS Aero	64.5	275.0	210.5	77%	The amount listed ($64.5k) for 2022 Aero outages is not correct. Actual 2022 Aero outage was $355.6k, or $80.6k higher than then $275K budget. The actual spend was for inspections and Unit alignments.
Polk	PK1	517.9	1,000.0	482.1	48%	Due to run hour reductions, less maintenance was needed during planned outages.
Polk	PK2	414.0	190.0	(224.0)	-118%	Upon inspection, additional switchgear, dampers and verticle pole switch needed.
Polk	PK3	128.7	190.0	61.3	32%	Upon inspection, less equipment maintenance required after 2021 Outages.
Polk	PK4	94.9	190.0	95.1	50%	Upon inspection, less equipment maintenance required after 2021 Outages.
Polk	PK5	201.4	190.0	(11.4)	-6%	
	Total	12,077.3	11,354.6	(722.7)		

2023 Station	Unit	Actual	Budget	Variance	%	Explanation
Big Bend	BB1	-	-	-	0%	
Big Bend	BB2	-	-	-	0%	
Big Bend	BB3	-	-	-	0%	
Big Bend	BB4	3,564.9	2,379.8	(1,185.1)	-50%	Upon inspection, additional precipitator, boiler and stack maintenance required.
Big Bend	BB Aero	323.2	177.0	(146.2)	-83%	Unbudgeted maintenance to meet unexpected new environmental regulations (Formaldehyde).
Big Bend	BBCT5	118.5	102.5	(16.0)	-16%	First year of commercial operations, discovery led to additional fire alarm maintenance.
Big Bend	BBCT6	148.0	102.5	(45.5)	-44%	First year of commercial operations, discovery led to additional transformer maintenance.
Big Bend	BBST	316.3	127.5	(188.8)	-148%	First year of commercial operations, discovery led to additional HRSG matinenance.
Bayside	BS1	613.7	1,800.0	1,186.3	66%	reduced scope due to prior year's extensive outage
Bayside	BS2	2,299.0	9,000.0	6,701.0	74%	reduced O&M work due to physical work area inferences with large capital project actives - 2023 fall outage was heavy with capital projects and O&M actives were deferred to a second 2024 spring major outage
Bayside	BS Aero	464.3	450.0	(14.3)	-3%	
Polk	PK1	179.5	280.9	101.4	36%	Maintenance needed during planned outages.
Polk	PK2	476.3	302.8	(173.5)	-57%	Upon inspection, additional switchgear, attemperator valve, NH3 tank repair and HRSG maintenance needed.
Polk	PK3	188.7	302.8	114.1	38%	Maintenance needed during planned outages.
Polk	PK4	507.7	354.7	(153.1)	-43%	Upon inspection, additional switchgear, transformer and motor maintenance needed.
Polk	PK5	284.3	354.7	70.3	20%	Maintenance needed during planned outages.

	Total	9,484.3	15,735.1	6,250.7

		2024 YTD	2024 FY	2025 FY
Station	**Unit**			
Big Bend	BB1	-	-	-
Big Bend	BB2	-	-	-
Big Bend	BB3	-	-	-
Big Bend	BB4	-	800.0	2,000.0
Big Bend	BB Aero	-	250.0	262.5
Big Bend	BBCT5	-	100.0	105.0
Big Bend	BBCT6	-	100.0	105.0
Big Bend	BBST	-	150.0	157.5
Bayside	BS1		1,800.0	7,200.0
Bayside	BS2		8,200.0	2,200.0
Bayside	BS Aero		600.0	600.0
Polk	PK1	-	200.0	-
Polk	PK2	-	446.0	9,500.0
Polk	PK3	-	223.0	1,025.0
Polk	PK4	-	223.0	1,025.0
Polk	PK5	-	223.0	1,025.0
	Total	-	13,315.0	25,205.0

2022 FUEL SAVINGS ASSOCIATED WITH USING COAL

Table 1

2022	
Coal Generation (MWh)	1,319,238
Coal Generated Fuel Cost per KWh (cents/KWh)	3.77
Natural Gas Generated Fuel Cost per KWh (cents/KWh)	6.25
Coal Generated Fuel Cost per MWh ($/MWh)	37.7
Natural Gas Generated Fuel Cost per KWh ($/MWh)	62.5
Est Fuel Savings from burning Coal vs Natural Gas	$ 32,717,102

Source: Tampa Electric Schedule A3 filed on 1/25/23 (December Period to Date Actual)

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that copies of the foregoing rebuttal testimony and exhibit have been served by posting on a shared document site, hand delivery of a USB drive or by electronic mail on this 2nd day of July, 2024 to the following:

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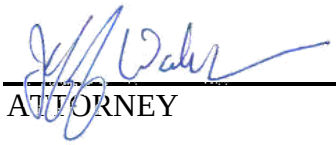

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