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August 22, 2024

BY E-FILING

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

Re: **Docket No. 20240099-EI - Petition for rate increase by Florida Public Utilities Company**

Dear Mr. Teitzman:

Attached, for electronic filing, on behalf of Florida Public Utilities Company, please find the Testimony and Exhibit of William Haffecke.

Thank you for your assistance with this filing. As always, please don't hesitate to let me know if you have any questions whatsoever.

(Document 2 of 18)

Sincerely,

Beth Keating
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BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

Docket No. 20240099-EI: Petition for rate increase by Florida Public Utilities Company-Electric Division

Direct Testimony of William Haffecke

Date of Filing: August 22, 2024

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I. Introduction

Q. Please state your name and business address.

A. My name is William Haffecke. My business address is 208 Wildlight Ave., Yulee, FL 32097.

Q. By whom are you employed, and what is your position?

A. I am employed by Chesapeake Utilities Corporation ("CUC"or "Corporation") as the General Manager of Florida Operations.

Q. Please describe your educational background and professional experience.

A. I have over 30 years of experience in the utility business. I have a B.S degree in Business Administration as well as a B.S. in Human Resources Management.

Q. Have you ever testified before the FPSC?

A. No.

Q. Please identify the witnesses testifying on the Company's behalf and their areas of expertise.

A. In support of its request for rate relief, the Company is submitting the "Investor-owned Electric Utility Minimum Filing Requirements" ("MFRs"), as required by Commission Rule 25-6.043, Florida Administrative Code ("F.A.C."), and revised tariff sheets. I will provide an overview and testimony on operation-related issues. In addition to my testimony, we are submitting the testimony of the following witnesses:

Kim Estrada, Director of Customer Care Operations, will provide testimony regarding the Customer Care team and the improvements made in that area since the prior rate case.

Mr. John Taylor of Atrium Economics will provide testimony regarding the cost of service study, rate classification changes, projected billing determinants and rate design.

Mr. Michael Galtman, Senior Vice President and Chief Accounting Officer, will provide testimony on general accounting issues, as well as corporate and business unit allocation methods.

Mr. Nick Crowley of Christensen Associates Energy Consulting, LLC., will provide testimony on the appropriate cost of capital and return on equity for the Company.

Mr. Noah Russell, Assistant Vice President and Assistant Treasurer, will provide testimony supporting CUC's current capital structure allocation, the various components (short-term debt, long-term debt and equity) and address how FPUC has benefited from the structure, as well as testimony addressing Chesapeake's Insurance Programs.

Ms. Wraye Grimard, Pierpont & McClelland will provide testimony on the changes being made to the tariff.

Ms. Michelle Napier, Director Regulatory Distribution, will provide testimony on certain accounting adjustments made to expenses and why they were appropriate. She will also provide testimony in support of the Company's interim rate filing.

Ms. Devon Rudloff-Daffinson, Assistant Vice President Human Resources, will provide testimony on the Company's compensation plans and employee engagement activities.

Mr. Vikrant Gadgil, Vice President and Chief Information Officer, will provide testimony on the Company's Business Information Services activities and the investments made, specifically in cybersecurity, in that area in recent years that have benefitted FPUC's customers.

Q. What is the purpose of your testimony?

A. First, I provide an overview of Florida Public Utilities Company - Electric Division's ("FPUC" or "Company") request, discuss the Company's need for rate relief, and identify the key drivers behind that need, as well as the various steps taken by the Company to avoid and delay requesting a rate increase. Next, I will provide information on the drivers of the case that fall under my responsibility and tariff changes that I am supporting. Finally, I will provide an overview of certain miscellaneous topics such as rate case expense, MFR benchmarking, and future changes to the typical bill.

Q. Are you sponsoring any exhibits with your testimony?

A. Yes. A summary of those Exhibits follows:

Exhibit WH-1 is a list of Minimum Filing Requirements ("MFR") that I am sponsoring or co-sponsoring. WH-2 has been developed for informational purposes and ease of reference and identifies which Company witnesses support the respective MFR schedules. I am also providing Exhibit WH-3 which provides the temporary service cost changes that are being made in the tariff to reflect current costs and Exhibit WH-4 which provides the changes to the construction and conversion costs in the tariff which have also been updated for current costs.

II. Overview and Background

Q. Please give a general overview of the Company.

A. Florida Public Utilities Company was originally incorporated in 1924. Its official name became Florida Public Utilities Company in 1927. On October 28, 2009, FPUC was acquired by Chesapeake Utilities Corporation, a Delaware corporation. CUC also operates the Florida Public Utilities Natural Gas Division in Florida, as well as unregulated energy businesses, including Eight Flags generating station. With the acquisition of Florida Public Utilities Company in 2009, CUC expanded its energy presence throughout the State of Florida. FPUC is headquartered at 208 Wildlight Avenue in Yulee, FL 30297. The Company serves approximately 33,100 residential, commercial and industrial customers in four counties within the State of Florida.

Q. What level of rate relief is the Company seeking in this proceeding?

A. Using a projected test year ending December 31, 2025, the Company is seeking an increase in its base rates of $12,593,450. This increase is necessary to allow FPUC to earn a fair return on our investment. The request is an overall increase of approximately 12.8%. On an annual basis, the total proposed increase is below the compounded inflation rate of 34.74% (see MFR C-40) since the projected test year in FPUC's last rate case of September 30, 2015. The Company is proposing a return on equity of 11.3% that generates an overall midpoint rate of return of 6.89%. In accordance with Rule 25-6.140, F.A.C., Test Year Notification, we have notified the FPSC that we have selected the twelve-month period ending December 31, 2025, as the appropriate projected test year for our petition to increase our rates and charges.

The resulting revenue increase would allow the Company the opportunity to earn a fair return on its investments, cover its cost of service, and attract the necessary capital for system reliability improvements, customer growth, and service enhancements detailed in this proceeding.

Q. Is the Company also seeking Interim Rate Relief?

A. Yes. Using the methodology authorized by the Commission, the Company has calculated that, pending a decision on final rates, it requires an annual interim relief of $1,812,869 based on the historical test year ending December 31, 2023. The specific calculation supporting the interim rate request will be covered in the testimony of Witness Napier.

Q. Why is FPUC requesting rate relief at this time?

A. FPUC has made every effort to delay this request for as long as possible. However, our business is capital intensive and requires significant, long-term investments to enable us to continue to provide safe and reliable service to our customers. The Company has also been impacted by cost increases in excess of inflation and customer growth, as well as a need for additional staffing and programs to continue providing an appropriate level of service to our customers. Therefore, timely and sufficient revenues are critical to allow us to earn a fair rate of return, which will enhance our ability to attract capital to use for these investments, which, in turn, will ensure we are able to continue providing service to our customers at the high level they expect and deserve.

Q. When was the last rate relief requested by FPUC's Electric Division?

A. FPUC's last rate relief request was filed on April 28, 2014.[1]

Q. Is the Company currently earning a reasonable rate of rate of return?

A. No. The following chart shows the Company's achieved Rate of Return ("ROE") as of December 31, 2023, as well as the projected ROE at the end of 2025:

Entity	Current ROE	Projected 2025 ROE
FPUC-Electric	3.34%	-3.00%

Q. What are the key drivers underlying FPUC's need to seek rate relief at this time?

A. There are three primary drivers causing the Company to seek relief at this time:

1. **Investment** – The last rate case filing included plant and construction work in process of $117,072,969. Base rates were adjusted for investment of $13,520,303 in the limited proceeding Docket No. 20170150-EI and by $18,573,911 in the Hurricane Michael Docket No. 20190156-EI for a total of $149,167,183. The projected investment in this filing is $261,142,793 or an increase of $111,975,610, in its total capital spend since the last rate proceeding. The capital spend in this case excludes the amount of capital projected for the SPP docket. Therefore, the total capital FPUC is actually spending is even higher than the $261 million stated above. A significant portion of these investments are tied to improvements in reliability by way of the purchase and renovation of substations, as well as increased costs associated with safety regulations imposed by federal agencies, such as the National Electrical Safety Code ("NESC") and the North American Electric Reliability

[1] Docket No. 20140025-EI.

Corporation ("NERC"), and the investment in a new Customer Information System ("CIS"). Additional descriptions of these projects will be provided later in my testimony. These improvements are coupled with the increase in depreciation expense resulting from the additional capital installed over the period of time since the Company's last rate case. As a result, the Company has exhausted its ability to find additional cost-saving measures that would enable it to further delay a request for an increase without impacting compliance, safety, and service to our customers.

2. **Economy and Additional Costs** – Like most companies, costs for FPUC continue to trend upward in a variety of areas, in spite of our best efforts to keep expenses down. Many of these cost increases are beyond the control of the Company. This has further contributed to a significant decline in the rate of return in our electric operations. The Company believes the proposed 2025 test year will accurately reflect the economic conditions in which the Company's electric operations will be operating during the first twelve months that the new rates will be in effect. Therefore, this period is appropriate for rate-setting purposes. We have also faced unprecedented historical events, such as the COVID-19 pandemic, that have had a significant, unfavorable impact on earnings since our last rate proceeding due to supply chain shortages and increased prices. Although growth has played a smaller role in the Company's electric service territories, the construction and housing markets have grown at a historically high pace in some areas and this extraordinarily aggressive construction market has arrived at a time of 40-year high inflation. Together, these supply chain shortages and historic inflation have driven increased prices on everything from labor and fuel to materials and insurance, placing

additional downward pressure on our returns. The need for additional cyber-security to protect both customer data and Company data is also a significant driver behind the need for a rate increase. This will be discussed in more detail in Company Witness Gadgil's testimony. Additionally, as will be discussed in Witness Russell's testimony, insurance costs are increasing at a rate higher than inflation and growth. When coupled with the length of time since the last rate case, and the increased costs discussed above, it has become necessary to seek a rate increase that will provide the Company with an opportunity to earn a fair rate of return on our investments, maintain solid financial integrity, and continue to provide safe and reliable electric service to our customers.

3. **Customer Expectations** – Electric system reliability is of the utmost importance to both the Company and our customers. Additionally, customers expect to have accessibility to their data, as well as information regarding estimated and faster restoration times. In order to keep pace with customer expectations in terms of online access to their account, as well as online access to customer care, we must reinforce our system and install equipment that will allow the Company to provide the services, information and data. The Company has invested in a new CIS, as discussed in the testimony of Company witnesses Estrada and Gadgil, in order to meet our customers' higher expectations. While the new CIS will support the higher customer expectations, it also requires a significant investment and a higher level of technical and software related support costs.

Q. Are there specific increases in expenses that are contributing to the Company's request for a rate increase?

A. Yes. There are other expense increases on Schedule C-7 page 7 and 8 of the MFR's. This schedule lists the appropriate witness responsible for each of these adjustments. The expense increases I am testifying on will be described in Section III of this testimony.

Q. What steps has the Company taken to avoid or delay this request?

A. The Company has implemented several cost-containment measures that have successfully limited cost increases, thereby enabling the Company to delay seeking a rate increase for almost 10 years. Additionally, since the acquisition of FPUC by CUC, the Company has been able to take advantage of the stronger financial posture of CUC to obtain debt to fund capital additions at lower rates. Taking these interim steps for efficiency outside of a full rate proceeding has also allowed the Company to avoid pursuing multiple rate cases and thereby additional rate case expense.

Q. What other efforts have been implemented by the Company to avoid or delay a rate increase?

A. The Company has embarked on the aggressive promotion and utilization of its Commission-approved Energy Conservation programs to advance Florida's public policies regarding energy efficiency and carbon reduction, which has also helped our customers in terms of overall affordability. Additionally, the Company works with local governments within our service territories to attract new customers that will provide revenue streams that can assist with offsetting capital expenditures.

Q. What other relief is the Company requesting in this proceeding?

A. First, FPUC requests a variance from the 13-month average computation for our substantial addition in substations which I will support later in this testimony, Second, the Company is requesting a change in recovery of tree trimming and pole inspection expenses that have been removed from the SPP clause because they were in the base rates in Docket No. 20140025-EI that will be discussed by Witness Napier. Third, the Company is requesting a variation on the calculation of the cost of debt which, we believe, benefits our customers which will be discussed by Witness Russell. In addition, the Company is requesting some tariff changes. A technology rider will be discussed by Witness Napier, while I will address consolidation of Standby and GSLD1 tariffs, closing of all lighting classes, except for the Light Emitting Diode (LED) tariff, as well as closing of the Non-Firm Fuel Tariff detail later in this testimony. I am also supporting the increases in miscellaneous service charges, the forecast of the 2025 projection for GSLD customers, the new construction deposit charges, and the temporary service charges which were simply increased to reflect current costs. Other formatting tariff changes will be discussed by Witness Grimard.

III. Operation Related Topics

A. Purchase and Refurbishment of Substation Assets

Q. Is the Company planning to acquire additional substation assets?

A. Yes. The Company is planning to acquire four substations and a transmission line located in our Northwest Florida territory.

Q. Why is the Company proposing this purchase?

A. Purchasing these substation assets will allow FPUC to update aging equipment, while providing direct benefits to our customers. These updates will help improve reliability and bring these assets up to current standards. FPUC currently pays FPL fees annually in distribution charges, because the interconnection point between the Companies is located at the low voltage side of the transformers. This distribution charge will drop substantially after the interconnection point is relocated to the high side of the transformers. This reduction in costs will be passed through to FPUC's customers through reduced purchased power costs and a reduced fuel factor.

Q. What is the proposed timing of the purchase and upgrade of these assets?

A. The purchase of the assets is planned to occur in November 2024, and the upgrades of the assets will begin in early 2025 and be completed by the end of 2025.

Q. Will there be O&M costs associated with the purchase and upgrades of this equipment?

A. Yes. FPUC will need to add a technical resource (IMC Technician) to perform and coordinate O&M activities for these assets. With the addition of this resource, there will be other expenses such as equipment and tools to allow for this work. Outside contractors will also be utilized as necessary to perform maintenance activities.

Q. Are there other substation additions included in this filing?

A. Yes, in addition, the Company is replacing aging equipment and rebuilding for safety and regulatory compliance on its Northeast substations, JL Terry and AIP. These amount to approximately $9 million.

B. <u>Variance from 13-Month Average for Substation Additions</u>

Q Are you proposing changes to the traditional use of the 13-month average approach for capital installations?

A. Yes, I am supporting this proposed change.

Q. Please explain why you are proposing a change to the 13-month average approach for the capital installations.

A. The Company is making critical investments in substations for resiliency and reliability. However, these substation investments will continue into 2025. Allowing the Company to use a full-year approach would reduce the need for additional rate relief shortly after implementation of rates resulting from this rate case.

C. <u>Other Reliability and Safety Upgrades</u>

Q. Why are reliability and safety upgrades important?

A. The safety of our customers and employees is of paramount importance to the Company. To ensure that customers are not subjected to electrical hazards, the Company follows all applicable codes and regulations. Nevertheless, our employees and contractors that operate and maintain the Company's electric system are exposed to hazards on a routine basis simply by virtue of our business. We are implementing new technology and manufacturing methods that provide better safeguards compared to antiquated/obsolete equipment, which enhances the safety of our employees and our customers. The efforts to modernize our system also have the benefit of ensuring that the Company's electric system is more reliable for our customers. This is reflected in the SADI and SADI reliability numbers for both of our service areas. Combined SAFI for both service territories has improved 9.72% at the end of the 2nd quarter of 2024 when compared to 2023 and the combined SADI has improved 11.29% for this same time period. These improvements have resulted in a clear benefit to our customers and are the result of the Company's continued focus on ensuring its system is capable of providing the high level of service and safety our customers, and employees, expect and deserve. A notable example of this benefit is demonstrated by, Hurricane Debby, which recently hit the Company's Northeast region. Even with winds gusting to 50 mph on a heavily vegetated island, very few customers were impacted and those that did experience an outage were restored within a few hours, or less. In addition to the safety benefits for our employees, this system will benefit our customers with reduced outage times.

Q. Why is FPUC proposing to install a two-way communication system?

A. The installation of a two-way radio system will help improve safety for both employees and the public. This system will also help expedite outage restoration times.

Q. What is the system that this proposed two-way radio system is replacing?

A. Currently the Company does not have a two-way radio system and relies solely on cellular telephones to communicate with field personnel. This can be problematic, especially during storm restoration if cellular communication is lost when cell towers are damaged.

Q. Could you please elaborate on how the two-way radio system will expedite storage restoration?

A. Yes, a two-way radio system will allow dispatchers and/or management to guide crews directly to outages and assist with switching activities. Employees will have the ability to communicate with each other when additional help is needed or for tools/material needs. Additionally, two-way radio communication between field crews will ensure employees working on an affected circuit are in a safe position before energizing the circuit. Presently, these activities are performed by visual confirmation if cell service is not available, which requires driving out to the impacted circuit. Another added safety benefit with a two-way radio system is to broadcast messages regarding the closing of any protective device (i.e. fuse, breaker, recloser, etc.) to ensure no one is performing work on the circuit.

Q. What is the timeframe for installing the two-way radio system?

A. FPUC intends to begin the installation of this system in 2024 and complete the project in 2025.

Q. What is the estimated cost for this installation?

A. FPUC estimates the cost of this installation to be $1.3M.

Q. What are some of the other capital expenditures for reliability projected in this case?

A. The Company has several other projects that should increase the system reliability. They are installation of a new 75MVA transformer, installation of self-healing equipment that will detect which sections of the system have outages and can minimize outage times to customers, the rebuild of an existing substation and installation of substation 69KV loop and switch. Each of these will provide improved reliability for FPUC customers.

Q. Are there capital expenditures related to safety and security?

A. Yes, the Company is removing failing manholes, replacing live front equipment, and replacing unjacketed underground cable. In addition, cameras are being added at substations and offices.

Q. Could you explain what live front equipment is?

A. Yes. Typically, traditional pad-mounted dead front equipment used in underground installations uses wire and connections on the high voltage side of the equipment that are insulated. When working with this type of equipment, it is treated as non-insulated providing an extra layer of safety protection. With live front equipment, used in underground installations, the connections made on the high voltage side of the equipment are not insulated exposing workers to the un-insulated connections. Additionally, these un-insulated connections are exposed to the conditions inside the equipment creating additional vulnerabilities due to wildlife contact and contamination. Working on uninsulated live front equipment can be performed in a safe manner, but this does not provide the extra layer of safety protection that exists with pad-mounted dead front equipment. Additionally, the reliability and general safety to the public increases with dead front equipment as the potential risk of exposure to wildlife or foreign objects to un-insulated connections contained inside live front equipment is eliminated.

Q. Could you explain what unjacketed underground cable is?

A. Yes. The unjacketed underground cable referenced is used for the installation of high voltage underground cable. Although the actual high voltage cable is insulated, this cable uses a concentric neutral consisting of several bare copper conductors that are wrapped around the insulated high voltage cable. The concentric neutral on unjacketed underground cable is not insulated and exposed to the elements when installed. Over time, this exposure results in the deterioration of the concentric neutral, which is critical to the reliability of the conductor and the safe operation of the equipment to which it is connected. New jacketed underground cable provides another layer of insulation over the concentric neutral, which protects it from exposure to the elements, making the conductor more reliable and helps ensure the safe operation of the equipment to which it is connected.

Q. Why is it so critical to remove the live front equipment and unjacketed underground cable?

A. As described above, the removal of this equipment provides improved reliability, safe operation, worker safety, and reduces exposure risks to the general public. Both reliability and safety are critical fundamentals for FPUC operations.

Q. Are you asking to include costs for security cameras?

A. Yes. Security cameras provide both security and increased compliance at FPUC operations offices and electrical substations. It has become increasingly more important to have the ability to monitor conditions at offices and substations to ensure security at these locations. This will allow prompt response should conditions indicate that outside resources are attempting to cause harm to employees or equipment.

Q. Are there specific adjustments you are providing testimony on related to the Over/Under adjustments in Schedule C-7 (2025)?

A. Yes, there are. As shown on C-7 p. 7 and 8 (2025) other witnesses are also addressing some of these adjustments. I will discuss those within my zone of responsibility.

Q. Why are CUC's Supervisor of Engineering department's duties being restructured to include more time to the electric division?

A. For safety and reliability, additional duties have been added to this position related to substation maintenance, planning, additional vegetation management, transmission and distribution relay modifications, and monitoring feeder loading.

Q. Can you explain why there are additional costs related to damage prevention?

A. The CUC Damage Prevention department is spending more time on the electric division. Additional costs are being spent to provide a more active presence on the website and local activities to reinforce the need to call 811 and follow up when damages occur.

Q. Why are you adding costs for the S&P Global Platts package?

A. The electric division uses "Platts" for forecasting costs related to purchased power agreements with other generators and, therefore the costs are a necessary cost of business.

Q. Why are there adjustments to increase Fuel, Conservation and Storm Protection Plan (SPP) costs when clause costs are not included in base rates?

A. In the MFRs, all clause expenses are included on MFR Schedule C-7 and subsequently removed in MFR Schedule C-2 so they are not reflected in base rates. The adjustments simply adjusts the amounts to the recent estimates, but there is no impact on base rates.

Q. Why is the Company adding an Electric Line Operation Supervisor in both the Northeast and Northwest Territory?

A. In order to remain in compliance with the Company's O&M policies, ensure the safety of employees and customers, adequate supervision of field employees is required. The addition of a supervisor in both the NE and NW territories will allow the managers to focus more on strategic activities while the supervisors support field crews.

Q. Why are inventory costs increasing since COVID?

A. COVID not only caused price increases on goods and materials, but also resulted in an inventory shortage, which has consequently caused much longer delivery times for critical materials and components necessary for the operation and maintenance of the electric system.

Q. Is there a need for security system service and plan monitoring, as included in the Company's request?

A. Yes. The addition of security systems at FPUC's substations and Operations Centers will provide additional security for our equipment, better protect the public, and help deter theft that could lead to reliability issues on our system. As a result, we expect that it will also contribute to our ongoing compliance with the NERC CIP standards. Schedule C-7 page 8 reflects that increases in expenses for the monitoring of these added cameras.

<u>IV. Tariff Changes</u>

Q. What tariff related changes are you supporting?

A. I am supporting the elimination of Standby Rates and the Experimental Non-firm Energy Tariff. I am also supporting changes to the Hurricane Michael recovery tariff for industrial customers, the LED lighting changes, the changes in the tariff for miscellaneous service charges, new construction deposits, and temporary service charges.

Q. How were the miscellaneous service charges, new construction deposits, and temporary service charges determined?

A. The Company used the same type of costs used in the last rate case to calculate the charges in this case and simply updated the rates to recover the current costs. The resulting miscellaneous service charges are provided as an exhibit to Witness Grimard's testimony. The temporary service charges and new construction deposit amounts are provided in Exhibit WH-3 and WH-4, respectively.

Q. Why is the Company proposing elimination of Standby rates?

A. The Company is continually evaluating its business, including its tariffs to make sure they are appropriate, meet our customer's needs, consistent with current regulatory requirements, as well as effective and well-utilized in service to our customers. In that regard, the Standby tariff currently has only one customer, a large customer that switched to Standby from the GSLD1 tariff in 2012. Our experience with the customer's requests over time, however, indicate that the customer is truly more appropriately served under the GSLD1 tariff based upon routine requests for power beyond that contemplated by the Standby tariff. The Standby tariff specifically provides that customers served under this tariff must be self-generators that require service only for back-up or maintenance service, and not regular, supplemental power. Upon moving this customer to the more appropriate rate class, no customers will be taking service under the Standby tariff, and since the Company has had no other requests for Standby Service over the life of the tariff, we believe it is administratively efficient to close this tariff.

Q. Does FPUC plan to continue the Non-Firm Energy tariff going forward?

A. No. The intent of the Non-Firm Energy tariff was to provide some pricing benefits to our two industrial customers to incent them to purchase more power from the grid on a consistent basis, thereby increasing overall load factor and reducing purchased power costs for our general body of ratepayers. While both of the target customers did increase purchases somewhat, the increased purchases were not to the extent necessary to achieve the overall pricing benefits contemplated. Ultimately, since purchases under the Non-Firm Energy tariff did not reduce the peak hour of the month on which the demand portion of the bill is calculated, this cost was still included in the regular monthly purchased power billing, which is passed directly through to the general body of the rate payers. As such, the Non-Firm Energy tariff did not perform as expected and provides no notable benefit to the Company or its general body of customers. Therefore, we have concluded it should be eliminated.

Q. Why is the Company closing lighting classes other than Light Emitting Diode (LED) class?

A. The Company can no longer obtain parts for the old lighting technology and many manufacturers no longer produce the old HID lights. Therefore, it is necessary to use LED lighting moving forward which allows utilization of more energy efficient and reliable lighting.

Q. Why is the Company changing the proposal for recovery of Hurricane Michael costs for GSLD1 customers?

A. Historically, the bills for these customers have been manually generated but are going to be automated with the implementation of the new CIS system. The GSLD1 base rates are calculated using KW and KVar. Other recovery mechanisms are based on KWH. The Company is proposing to move the other mechanisms to a KW unit of measure. These changes will be presented in the Company's future clause projection dockets. The Hurricane Michael surcharge is the only remaining surcharge with a KWH unit of measure. Therefore, due to the small number of industrial customers, we are proposing a flat rate recovery methodology, as authorized in Docket No. 20190156, for industrial customers. This will have no impact on the total recovery of the surcharge.

V. Miscellaneous

Q. What is the amount of rate case expense proposed to be included in this rate proceeding?

A. On MFR Schedule C-10 which is being supported by Witness Napier, the Company is requesting a total rate case expense of $1,530,907 to be amortized over a period of four years at $382,727 annually.

Q. Has the Company prepared a benchmarking analysis as part of this filing?

A. Yes, MFR Schedule C-37 presents a benchmark analysis that shows an overall increase over benchmark of $40,887. Reasons for the increases are discussed in MFR Schedule C-41 and in the testimony Witnesses Galtman and Gadgil.

Q. Does the Company anticipate changes that will provide additional relief for customers after the implementation of any rate increase approved in this proceeding?

A. Yes, we do. Specifically, the rider for Hurricane Michael recovery will expire at the end of 2025. Therefore, the customers can expect to see a bill reduction beginning on January 1, 2026.

Also, because the Company has not filed the 2025 fuel projection at the time of this filing, the 2024 rates were used for the typical bills. These 2024 rates were based on 2024 costs and a large under-recovery due to the high fuel costs in 2021 and 2022. This under-recovery will be fully recovered in 2024 and thus, the 2025 fuel factors are expected to be lower. In addition, the Company has just entered a new purchase power agreement that should also reduce power costs in 2025. These fuel changes, coupled with the future savings from the substation changes and the eventual elimination of the Hurricane Michael surcharge, should offset a portion of the proposed rate increase.

Q. Does this conclude your testimony?

A. Yes.

Witness William Haffecke's MFRs

SCHEDULE	TITLE	WITNESS
	EXECUTIVE SUMMARY	
A-1	Full Revenue Requirements Increase Requested	Haffecke
B-1	Adjusted Rate Base	Haffecke, Galtman, Napier
B-3	13 Month Average Balance Sheet - Electric Division	Galtman, Haffecke
B-5	Detail of Changes In Rate Base	Haffecke, Napier
B-6	Jurisdictional Separation Factors-Rate Base	Haffecke, Galtman, Napier
B-7	Plant Balances By Account and Sub-Account	Galtman, Haffecke
B-8	Monthly Plant Balances Test Year-13 Months	Galtman, Haffecke
B-11	Capital Additions and Retirements	Haffecke
B-12	Net Production Plant Additions	Haffecke
B-13	Construction Work In Progress	Haffecke
B-14	Earnings Test	Haffecke
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C-43	Security Costs	Galtman, Haffecke
E-7	Development of Service Charges	Haffecke
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G-14	Interim Parent(s) Debt Information	Russell
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Exhibit: "WH-3"
Docket #20240099-EI
William Haffecke

TEMPORARY SERVICE COSTS

Florida Public Utilities Company

	overhead *		underground **	
	Service only	**Service w/ Pole**	**Service Only**	**Service w/ Pole**
material/stores	$162.41	$657.41	$0.00	$506.00
labor	$230.76	$531.76	$230.76	$691.76
trans	$20.08	$60.08	$20.08	$70.08
total	$413.25	$1,249.25	$250.84	$1,267.84

* For temp overhead services requiring more than 75' #2 triplex service from an existing secondary or transformer pole additional cost will be applied.

** For underground temporary services requiring more than tapping up to secondary at these locations additional cost will be applied.

	overhead *		underground **	
	Service only	**Service w/ Pole**	**Service Only**	**Service w/ Pole**
Calculated Cost	$413.25	$1,249.25	$250.84	$1,267.84
Rounded Amount	**$415.00**	**$1,250.00**	**$250.00**	**$1,250.00**
Service	$415.00	$415.00	$250.00	$250.00
Pole	$0.00	$835.00	$0.00	$1,000.00
Total	**$415.00**	**$1,250.00**	**$250.00**	**$1,250.00**

NEW CONSTRUCTION DEPOSITS

Per Hour Labor Cost:	$ 60.57	*Average Lineworker cost ($37.16) plus Overhead of 63%*

Engineering Rate:	15% of Total Labor Costs

Materials (OH 1 Mile - Urban Commercial) *Assumes 3PH Line Extension to Single Customer*					
Item	**Hours/Unit**	**Amount**	**Unit Type**	**Total Hours**	**Note and assumptions**
Poles and Fixtures	1.5	28	Per Pole	42	45/1 Poles and Standard Fixtures (1 pole per 200')
OH Wire and Devices	2.5	27	Per Span	52	Wire Only
Insulator	0.5	28	Per Pole	14	3 Insulators per pole
Grounding	0.5	28	Per Pole	14	Grounding and Rod
OH Transformer Bank	3	1	Per Pole	3	Assumes one 3PH customer 150 kVA Bank
		Total Hours:		125	
		Total Lineworkers:		4	
		Total Cost:		$ 30,285.00	
		Engineering:		$ 4,542.75	

Materials (OH 1 Mile - Urban Residential) *Assumes 1PH Line Extension to Single Customer*					
Item	**Hours/Unit**	**Amount**	**Unit Type**	**Total Hours**	**Note and assumptions**
Poles and Fixtures	1	28	Per Pole	28	40/1 Poles and Standard Fixtures (1 pole per 200')
OH Wire and Devices	1.5	27	Per Span	52	Wire Only
Insulator	0.1	28	Per Pole	2.8	1 Insulators per pole
Grounding	0.5	28	Per Pole	14	Grounding and Rod
OH Transformer Bank	1	1	Per Pole	1	Assumes one transformer 50kVA or less
		Total Hours:		97.8	
		Total Lineworkers:		4	
		Total Cost:		$ 23,694.98	
		Engineering:		$ 3,554.25	

Materials (OH 1 Mile - Urban Residential) *Assumes 1PH Line Extension to Single Customer*					
Item	**Hours/Unit**	**Amount**	**Unit Type**	**Total Hours**	**Note and assumptions**
Poles and Fixtures	1	23	Per Pole	23	40/1 Poles and Standard Fixtures (1 pole per 250')
OH Wire and Devices	1.5	22	Per Span	52	Wire Only
Insulator	0.1	23	Per Pole	2.3	1 Insulators per pole
Grounding	0.5	23	Per Pole	11.5	Grounding and Rod
OH Transformer Bank	1	1	Per Pole	1	Assumes one transformer 50kVA or less
		Total Hours:		89.8	
		Total Lineworkers:		4	
		Total Cost:		$ 21,756.74	
		Engineering:		$ 3,263.51	

CONVERSION DEPOSITS

Per Hour Labor Cost:	$ 60.57	*Average Lineworker cost ($37.16) plus Overhead of 63%*

Engineering Rate:	15% of Total Labor Costs

Materials (OH 1 Mile - Urban Commercial) *Assumes 3PH Line Conversion for Single Customer*					
Item	**Hours/Unit**	**Amount**	**Unit Type**	**Total Hours**	**Note and assumptions**
Poles and Fixtures	1.5	28	Per Pole	42	45/1 Poles and Standard Fixtures (1 pole per 200')
OH Wire and Devices	2.5	27	Per Span	52	Wire Only
Insulator	0.5	28	Per Pole	14	3 Insulators per pole
Grounding	0.5	28	Per Pole	14	Grounding and Rod
OH Transformer Bank	3	1	Per Pole	3	Assumes one 3PH customer 150 kVA Bank
		Total Hours:		125	
		Removal Hour		62.5	*Estimated at 1/2 the Installation Estimate
		Total Lineworkers:		4	
		Total Labor Cost:		$ 45,427.50	
		Engineering:		$ 6,814.13	

Materials (OH 1 Mile - Urban Residential) *Assumes 1PH Line Extension to Single Customer*					
Item	**Hours/Unit**	**Amount**	**Unit Type**	**Total Hours**	**Note and assumptions**
Poles and Fixtures	1	28	Per Pole	28	40/1 Poles and Standard Fixtures (1 pole per 200')
OH Wire and Devices	1.5	27	Per Span	52	Wire Only
Insulator	0.1	28	Per Pole	2.8	1 Insulators per pole
Grounding	0.5	28	Per Pole	14	Grounding and Rod
OH Transformer Bank	1	1	Per Pole	1	Assumes one transformer 50kVA or less
		Total Hours:		97.8	
		Removal Hour		48.9	*Estimated at 1/2 the Installation Estimate
		Total Lineworkers:		4	
		Total Cost:		$ 35,542.48	
		Engineering:		$ 5,331.37	

Materials (OH 1 Mile - Rural Residential) *Assumes 1PH Line Conversion for Single Customer*					
Item	**Hours/Unit**	**Amount**	**Unit Type**	**Total Hours**	**Note and assumptions**
Poles and Fixtures	1	23	Per Pole	23	40/1 Poles and Standard Fixtures (1 pole per 250')
OH Wire and Devices	1.5	22	Per Span	52	Wire Only
Insulator	0.1	23	Per Pole	2.3	1 Insulators per pole
Grounding	0.5	23	Per Pole	11.5	Grounding and Rod
OH Transformer Bank	1	1	Per Pole	1	Assumes one transformer 50kVA or less
		Total Hours:		89.8	
		Removal Hours:		44.9	*Estimated at 1/2 the Installation Estimate
		Total Lineworkers:		4	
		Total Cost:		$ 32,635.12	
		Engineering:		$ 4,895.27	

CONVERSION DEPOSITS (continued)

Low Density per Lot Estimate (assumes service to ≈ 100 Lots - 4 sevices per Transformer)					
Item	**Hours/Unit**	**Amount**	**Unit Type**	**Total Hours**	**Note and assumptions**
Poles and Fixtures	1	25	Per Pole	25	Assumes 1 40/1 pole per 4 lots
OH Wire and Devices	1.5	24	Per Span	52	Wire Only
Insulator	0.1	25	Per Pole	2.5	1 Insulators per pole
Grounding	0.5	25	Per Pole	12.5	Grounding and Rod
OH Transformer Bank	25	1	Per Service	25	Assumes one transformer 50kVA or less per lot
		Total Hours:		117	
		Removal Hour:		58.5	*Estimated at 1/2 the Installation Estimate
		Total Lineworkers:		4	
		Total Cost:		$ 42,520.14	
		Engineering:		$ 6,378.02	
		ENG PER LOT:		$ 63.78	Assuming 100 Lots

High Density per Lot Estimate (assumes service to 150 Lots - 6 services per transformer)					
Item	**Hours/Unit**	**Amount**	**Unit Type**	**Total Hours**	**Note and assumptions**
Poles and Fixtures	1	25	Per Pole	25	Assumes 1 40/1 pole per 6 lots
OH Wire and Devices	1.5	24	Per Span	52	Wire Only
Insulator	0.1	25	Per Pole	2.5	1 Insulators per pole
Grounding	0.5	25	Per Pole	12.5	Grounding and Rod
OH Transformer Bank	25	1	Per Pole	25	Assumes one transformer 50kVA or less per lot
		Total Hours:		117	
		Removal Hour:		58.5	*Estimated at 1/2 the Installation Estimate
		Total Lineworkers:		4	
		Total Cost:		$ 42,520.14	
		Engineering:		$ 6,378.02	
		ENG PER LOT:		$ 42.52	Assuming 150 Lots

Lot Calculation

One side of a 1 acre square lot ≈ 210'
Acres in one straight mile ≈ 25 (5280/210)
High Density 6 Dwellings per Acre
Low Density 4 Dwellings per Acre
Assume 1 Lot per Dwelling

Docket No. 20240099-EI
Florida Public Utilities

CERTIFICATE OF SERVICE

I hereby certify that a true and correct copy of the foregoing filing has been served by Electronic Mail this 22nd day of August, 2024, upon the following:

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