BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

In the Matter of:

DOCKET NO. 20210034-EI

Petition for rate increase by
Tampa Electric Company.
___________________________________/

DOCKET NO. 20200264-EI

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

VOLUME 3
PAGES 483 - 715

PROCEEDINGS: HEARING

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

DATE: Thursday, October 21, 2021

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

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

REPORTED BY: DEBRA R. KRICK
Court Reporter

APPEARANCES: (As heretofore noted.)

PREMIER REPORTING

I N D E X

P R O C E E D I N G S

(Transcript follows in sequence from Volume 2.)

(Whereupon, prefiled direct testimony of Lawrence J. Vogt was inserted.)

ERRATA SHEET

DIRECT TESTIMONY OF LAWRENCE J. VOGT[1]

Page and Line	Original Text	Change
25:1	58%	57%
	42%	43%
25:2	17%	72%
	83%	28%

[1] Document No. 03315, filed April 9, 2021 in Docket No. 20210034-EI.

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 20210034-EI

IN RE: PETITION FOR BASE RATES INCREASE

BY TAMPA ELECTRIC COMPANY

DIRECT TESTIMONY AND EXHIBIT

OF

LAWRENCE J. VOGT

ON BEHALF OF TAMPA ELECTRIC COMPANY

PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

LAWRENCE J. VOGT

ON BEHALF OF TAMPA ELECTRIC COMPANY

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

A. My name is Lawrence J. Vogt. My business address is 21093 Pineville Road, Long Beach, Mississippi 39560. I am the President and Principal Consultant of Vogtage Engineering Corporation.

Q. Mr. Vogt, please summarize your educational background and professional experience.

A. I am a graduate of the University of Louisville with Bachelor of Science and Master of Engineering degrees in Electrical Engineering. Over the last 45 years, I have held various positions including Distribution Engineer, Senior Industrial Marketing Engineer, and Rate Engineer at Public Service Indiana (now known as Duke Energy – Indiana) in Plainfield, IN; Senior Rate Design Engineer and Principal Engineer – Rates & Regulation at Southern Company Services

(“SCS”) in Atlanta, GA; Manager, Distribution Technologies Center at ABB Power T&D Company in Raleigh, NC; Lead Product Manager at Louisville Gas & Electric Company in Louisville, KY; and Manager, Pricing Planning and Implementation, and Director, Rates at Mississippi Power Company. In 2010, I established Vogtage Engineering Corporation. I have participated in numerous regulatory filings throughout my career in Alabama, Florida, Georgia, Indiana, Kentucky, and Mississippi and before the Federal Energy Regulatory Commission (“FERC”). This includes providing sponsored testimony and appearances as an expert witness in Commission hearings.

I have been active in a variety of industry functions throughout my career. I have conducted numerous industry lectures and workshops under the sponsorships of EUCI, the Electric League of Indiana, Inc., the University of South Alabama, and the Wisconsin Public Utility Institute. I have served as an Adjunct Professor in Pennsylvania State University’s International Power Engineering Program (1989 – 2011). I served as a representative on the Rate & Regulatory Affairs Committee of the Edison Electric Institute, where I also served as Committee Chairman (2012 – 2014). I have also served as a Principal Instructor in the Committee-sponsored E-Forum Rate College and Electric

Rate Advanced Course. I also served as a representative on the Rates & Regulation Section of the Southeastern Electric Exchange. I am a Senior Life Member of the Institute of Electrical and Electronics Engineers, and I am a Member of the Association of Energy Engineers. I am a registered Professional Engineer in several states. In addition, I am the coauthor of several technical papers and reports as well as the textbook Electrical Energy Management (Lexington Books, 1977). I am also the author of the textbook Electricity Pricing: Engineering Principles and Methodologies (CRC Press, 2009) and of the "Engineering Principles of Electricity Pricing," Chapter 21 in Power Systems, 3rd ed. of The Electric Power Engineering Handbook, CRC Press, 2012. Additional details are found in my curriculum vitae attached as Appendix 1.

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

A. No. I have not.

Q. Please state the purpose of your direct testimony.

A. The purpose of my direct testimony is to present and explain the cost-of-service study filed by Tampa Electric Company

("Tampa Electric" or "company") in this proceeding. Specifically, I present the following information:

1) The Jurisdictional Separation Study and resultant jurisdictional separation factors used for the 2020 historical period and the 2021 and 2022 projected periods that determine the portion of Tampa Electric's system rate base and operating expenses, which are subject to the jurisdiction of the Commission and form the basis for the company's proposed revenue requirement for the 2022 test year.
2) The 2022 projected period Retail Class Allocated Cost of Service and Rate of Return Studies that, for non-solar facilities, uses a 12 Coincident Peak ("CP") and $1/13^{th}$ Average Demand ("AD") production capacity cost allocation methodology, which I will refer to as 12-CP & $1/13^{th}$ AD. In addition, I will present the company's proposed cost allocation methodology for its utility-scale solar production facilities.
3) The company's proposed modifications to its Minimum Distribution System ("MDS") analysis.
4) The methods employed, facts considered, and principles upon which the Jurisdictional Separation Study and Cost-of-Service Study were prepared.
5) Conclusions regarding the adequacy of these studies and the reasonableness of the resulting costs being

used to support the rate design effort.

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

A. Yes. I am sponsoring Exhibit No. LJV-1 consisting of one document, prepared under my direction and supervision:

Document No. 1	List Of Minimum Filing Requirements Schedules Sponsored Or Co-Sponsored By Lawrence J. Vogt

Q. Are Tampa Electric's Jurisdictional Separation Study and Cost-of-Service Study provided as part of the company's Minimum Filing Requirement ("MFR") schedules?

A. Yes, they are provided within the portion of the MFR schedules designated Section E, "Rate Schedules." I have provided the Jurisdictional Separation Study and the Cost-of-Service Study as well as work papers in separate bound volumes due to their voluminous size. Volume I contains the Jurisdictional Separation Study and the Cost-of-Service Study using the MFR-required 12-CP & 1/13th AD methodology with present and proposed rates.

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

A. There are four primary goals that are reflected in the cost of service of Tampa Electric in this case. The first goal is the modification of the retail rate classes designated in the cost-of-service study to accommodate the company's proposal to develop two new commercial and industrial rate classes. The second goal is the modification and refinement of the cost classification methodology applicable to distribution system facilities. The third goal is the use of the 12-CP and 1/13th AD production capacity allocation methodology for the non-solar generation capacity. The fourth goal is the implementation of a new allocation methodology for the company's solar-based production capacity.

JURISDICTIONAL SEPARATION STUDY

Q. What is a Jurisdictional Separation Study?

A. A Jurisdictional Separation Study is an allocation of costs between the company's wholesale and retail customers or jurisdictions. While all costs are allocated, the allocation of joint costs is the focal point of the study. Joint or common costs are costs that are incurred to serve multiple customers at the same time. A common example is a generating plant that provides power to the aggregate load requirements of all customers served by the company's power system. The joint costs of the generating plant are recorded on the company's books and records in total, and the Jurisdictional Separation Study allocates the joint costs between retail and wholesale customers. Only the costs associated with retail customers are applicable in this proceeding.

The Jurisdictional Separation Study allocates revenue, rate base, and operating expense items, whether jointly or specifically assigned to a single jurisdiction, to derive the company's retail jurisdiction cost of service for the test period. Costs are first functionalized, then classified, and finally allocated between the wholesale and retail jurisdictions. These allocations utilize load and other factors that best represent each jurisdiction's cost responsibility to achieve this purpose. A detailed description of how costs are functionalized, classified, and allocated is provided below. The overall methodology is the same in both the Jurisdictional Separation Study and the Retail Cost-of-Service Studies, which I will discuss later.

Q. Why is it necessary to prepare a Jurisdictional Separation Study for Tampa Electric?

A. Since early 1991, the company has provided wholesale power sales and transmission service to some wholesale power purchasers in Florida at rates that are under the jurisdiction of the Federal Energy Regulatory Commission ("FERC"). Although the company operates in two regulatory jurisdictions, its investments, revenue, and expenses are maintained on a total company basis in accordance with the Uniform System of Accounts prescribed by the FERC and the Commission. The Jurisdictional Separation Study is designed to directly assign or allocate total system costs to each jurisdiction for reporting purposes.

Q. Is the Jurisdictional Separation Study provided in this proceeding consistent with Tampa Electric's previous Commission filings and industry practice?

A. Yes. The company provided a Jurisdictional Separation Study in its base rate proceeding in Docket No. 20080317-EI that led to an approved methodology by the Commission. That methodology has been used to produce separation factors for the annual projected surveillance reports, which are the same factors that have been used as separation factors for the 2020 and 2021 MFR schedules.

Q. What were the major steps followed in performing the Jurisdictional Separation Study?

A. There are several steps. First, the company’s accounting information provided by FERC account, shown in the MFR Schedules B, C and D, is adjusted for the 2022 test period. The accounts are then functionalized into production, transmission, distribution, and general functions. Next, they are classified into demand, energy, or customer groups. After classification, the groupings are allocated into the retail and wholesale jurisdictions using allocation factors. The allocation factors are predominantly based on demand data for the retail and wholesale jurisdictions during the time of the company’s projected system monthly peaks, although other factors are used that directly allocate certain costs to the specific jurisdiction for which the costs are incurred. In addition, other metrics such as energy sales and number of customers are used in the allocation process.

Q. Are any wholesale power sales customers included in the 2022 test year?

A. No. Currently and as forecasted for the 2022 test year, the company is not providing long-term firm requirements electric power service to any wholesale customers.

Q. Does Tampa Electric currently provide transmission service to other Open Access Transmission Tariff ("OATT") customers?

A. Yes. Tampa Electric is providing long-term firm transmission service in the test year under the company's OATT to Seminole Electric Cooperative, Inc. and Duke Energy Florida, LLC.

Q. Please summarize the results of the Jurisdictional Separation Study.

A. In 2022, the retail business represents the vast majority of the electric service provided by Tampa Electric. As the results show in Volume I, Jurisdictional Separation Study, the retail business is responsible for 100 percent of production and distribution plant and 93.32 percent of transmission plant.

COST OF SERVICE STUDY

Q. What is a Retail Class Allocated Cost-of-Service and Rate-of-Return Study ("Cost-of-Service Study" or "COSS")?

A. The retail Cost-of-Service Study is an extension of the Jurisdictional Separation Study. It starts with the retail portion of costs derived from the Jurisdictional Separation Study and further allocates and assigns these costs to individual retail rate classes. These rate classes represent relatively homogeneous groups of customers having similar service requirements and usage characteristics. Allocations of costs to each of these groups, like the Jurisdictional Separation Study, are based upon the results of a detailed cost analysis. The study provides class rates of return at present and proposed rates, class revenue surplus or deficiency from full cost of service, and functional unit cost information for use in rate design. Thus, the study serves as an important guide in determining the revenue requirement by rate class, as well as the specific charges for each rate schedule.

Q. What retail rate classes were used in the preparation of the Cost-of-Service Study?

A. Tampa Electric's current standard and time-of-day rate schedules are grouped under the major retail classifications of 1) Residential Service (RS), 2) General

Service - Non-Demand (GS), 3) General Service - Demand (GSD), 4) Interruptible Service (IS), and 5) Lighting Energy and Facilities. As discussed in Mr. Ashburn’s direct testimony, the Company proposes to restructure its demand rate services by creating two new rate schedules: a) General Service - Large Demand – Primary and b) General Service - Large Demand – Subtransmission. Qualifying customers currently served under the GSD rate would be moved to one of these new rate schedules based on their service voltages and demand levels. All of the customers currently served under the IS rate schedule would be moved to the appropriate GSLD rate. Thus, the retail rate classes used in the preparation of the 2022 test year cost-of-service study consist of 1) Residential Service (RS), 2) General Service - Non-Demand (GS), 3) General Service - Demand (GSD), 4) General Service - Large Demand Primary (GSLD-Primary), 5) General Service - Large Demand Primary (GSLD-Subtransmission), and 6) Lighting Energy and Facilities.

Q. Why are there two columns of information presented under the present and proposed rates in the Cost-of-Service Studies for lighting service: Lighting Energy and Lighting Facilities?

A. Dividing the lighting rate class into the two components, Lighting Energy (power production and delivery) and Lighting Facilities (fixtures and associated items), provides better unit cost information for designing the energy and facilities components of this rate class. The two components are distinct types of services and are not always provided as a bundled service by the company.

Q. After establishing the rate classes, what were the next steps in the Cost-of-Service Study process?

A. Similar to the Jurisdictional Separation Study, the development of a COSS consists of three major steps: 1) grouping all costs by function (cost functionalization), 2) classifying the functionalized costs by cost-causation service characteristics (cost classification), and 3) apportioning the resulting classified costs to the retail rate classes (cost allocation).

Q. How were Tampa Electric’s costs functionalized?

A. The company functionalized costs in accordance with the Uniform System of Accounts by dividing utility plant costs into the broad functions of production, transmission, distribution, and general. Operation and Maintenance

("O&M") costs and other expenses were functionalized in a comparable manner.

Q. How were Tampa Electric's costs classified after they were functionalized?

A. The company's power system operations are classified into three categories: demand, energy, and customer cost. Demand cost is a function of the capacity of plant, which in turn depends on the maximum kW for power demanded by customers. Demand cost occurs in each of the production, transmission, and distribution levels of the system. Energy cost occurs in the production level, and it is a function of the volume of kWh consumed by customers over time. Customer costs, however, are independent of customers' kW and kWh usage. Many of these costs vary with the number of customers on the system. This generally refers to the basic costs incurred by the utility to attach a customer to the distribution system, which includes metering, service lines, a portion of the system known as the Minimum Distribution System ("MDS"), along with customer billing and certain administrative costs.

Subsequently, Tampa Electric's cost of service is measured by these same three cost categories: demand, energy, and customer. The three categories are appropriately called cost causations. The assignment of costs to these cost-causation categories in the COSS is called classification.

Q. Are all of the company’s production plant facilities classified as demand–related in the cost-of-service studies?

A. No. For purposes of jurisdictional separation, all production plant facilities are classified as demand related consistent with prior jurisdictional separation practices. However, there are portions of two production facilities that are classified as energy-related for purposes of allocating the Commission jurisdictional component of these facilities on an energy basis. These facilities consist of the gasifier train equipment (“gasifier”) for Polk Unit 1 and the flue gas desulfurization, or scrubber, portion of the environmental equipment for Big Bend Unit 4.

Polk Unit 1 is an Integrated Gasified Combined Cycle (“IGCC”) plant which has two main sections – the power block, which produces the electric power through gas turbines and heat recovery steam generators, and the gasifier, which converts coal as the feedstock into a combustible gas, which then becomes the fuel used in the power block. Thus, the gasifier performs a fuel conversion function that is completely associated with the provision of fuel to the unit and not the supply of capacity. The classification of the gasifier as energy-related was applied in Tampa Electric's last three cost of service studies.

The classification of the Big Bend Unit 4 scrubber as energy-related was applied in the company's last four cost of service studies. This treatment remains appropriate because the main purpose of the plant investment is related to energy output. Since the decision to classify the scrubber investment as energy-related, additional scrubber and Selective Catalytic Reduction ("SCR") investments made by the company have been recovered through the Environmental Cost Recovery Clause ("ECRC") where they have been classified and allocated on an energy basis.

Q. How are costs classified to the customer function?

A. Costs classified to the customer function are those generally independent of kW and kWh consumption. They have traditionally included the costs of service lines, meters, meter reading, billing, and customer information. In addition, the company has employed a costing methodology in this case that is described in the industry as the MDS method. This method determines the minimum size and respective cost of distribution transformers, poles, and conductors that would be required to connect customers to the company's power grid and provide an appropriate utilization voltage. This minimum cost is also classified as customer-related, and the remaining cost of these facilities is then classified as capacity or demand related. The methodology is described in the NARUC Cost Allocation Manual and has recently been accepted by the Commission in the settlement of rate and cost of service matters in the company's 2013 retail rate case.

Q. Please describe what is meant by a Minimum Distribution System?

A. The MDS is that portion of the total costs of facilities that make up the primary voltage lines, the line transformers, and the secondary voltage lines, which is independent of customers' load requirements. An MDS study separates the costs of these distribution facilities into their respective demand-related cost components and customer-related cost components on the basis of cost causation.

MDS represents the readiness to serve a customer, not the capacity needed to meet a customer's peak demand requirements. MDS is only about providing an appropriate utilization voltage at the point at which a customer connects to the distribution system, and costs are incurred to provide a customer with such access. The readiness to serve costs is independent of how much electricity a customer consumes; thus, MDS costs are classified as customer-related cost components. MDS does not represent the costs of capacity necessary to meet a customer's peak load requirements. That portion of the total costs of facilities that make up the primary voltage lines, the line transformers, and the secondary voltage lines that provide capacity to meet customers' peak load requirements is classified as a demand-related cost component.

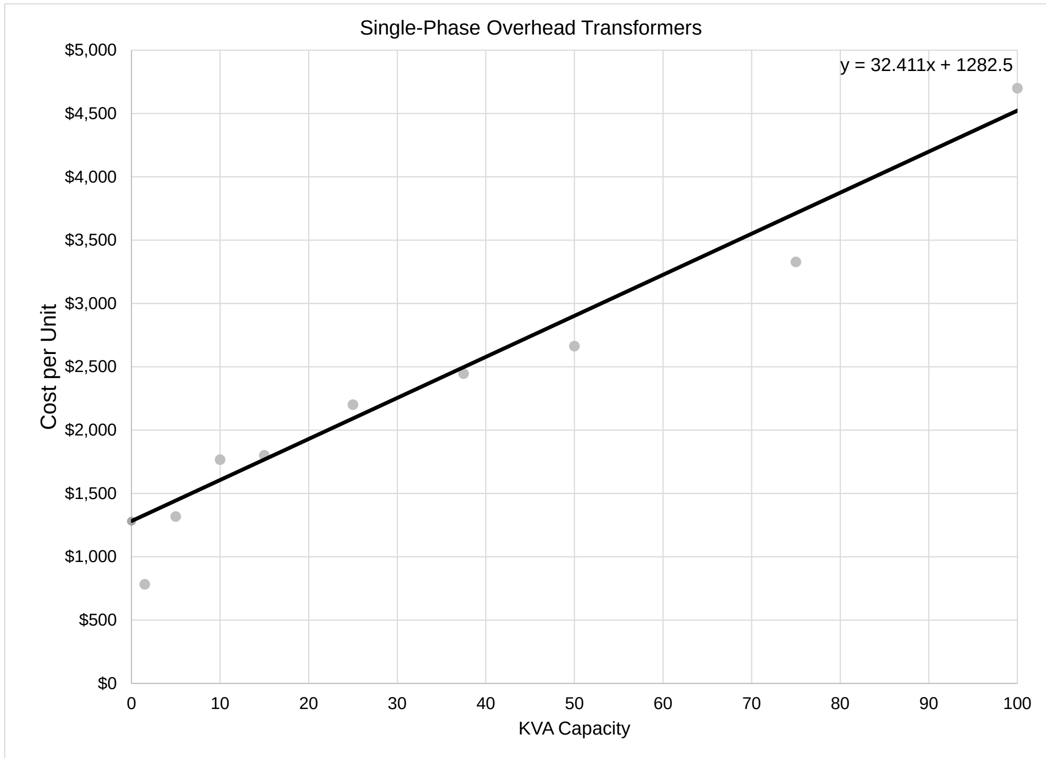
Q. How is an MDS study performed?

A. Quantifying the costs of MDS is accomplished by evaluating the cost causation aspects of all distribution system equipment and facilities, including the primary and secondary lines, line transformers, and other distribution line equipment. This approach requires an understanding of the functional application of each distribution item. In so doing, some items are found to be related directly to peak load requirements (100% demand related), some items are found to be independent of peak load requirements (100 percent customer related), and other items are found to be functionally associated with both readiness to serve and capacity.

The costs of items having attributes of both customer-related and demand-related functions must be analyzed in order to separate the total item cost into these two cost components. These items include overhead conductors and poles, underground conductors and conduit, and overhead and underground line transformers. They all provide both a readiness to serve function and a capacity function.

To accomplish this cost separation, the company applies a zero-intercept cost analysis for each of these distribution items. The zero-intercept method is a linear regression analysis that relates a distribution item’s unit costs (dependent variable) to its associated capacity values (independent variable). An example of the regression analysis results is illustrated below for single-phase overhead line transformers.

The data plots shown in the chart represent the current unit costs of transformers having standard size capacity ratings, e.g., 10, 15, 25, 37.5, 50, 75, and 100 kVA. The regression analysis was conducted using current unit costs because average unit costs calculated from the company's embedded plant account data represent a mix of transformers having a variety of input and output voltages. Some of these transformers have higher voltages, compared to the basic 120/240 volt used for small single-phase customers, and the higher voltage transformers generally have a higher unit cost. To refine the analysis to basic single-phase transformers, the company's distribution mapping system was queried to determine the number of in-service overhead single-phase transformers for each kVA size by voltage ratings. In addition, the linear regression formula includes weights (i.e., the number of transformers for each kVA size) since the count of transformers for each size is not a uniform distribution.



The resulting regression line intersects the unit cost y-axis where the value of transformer capacity is equal to zero, thus defining the per unit customer component cost, which in this example is $1,282.50. This zero-intercept value is multiplied by the total number of single-phase overhead transformers to determine that amount of the total cost of single-phase overhead transformers that is classified as customer related. The difference between the total cost of the transformers and the customer-related cost amount represents the demand-related transformer cost amount.

Since the analysis was based on current unit costs, the resulting total customer cost and total demand cost are represented as percentages, which are then applied to the embedded plant account total for overhead transformers to determine the embedded customer-related and demand-related cost components to be used in the COSS.

Separate regression analyses were also conducted for underground pad mounted transformers and for primary and secondary overhead conductors, underground conductors, and distribution poles to separate the total costs of these items into their respective customer and demand cost components.

Q. Aside from the MDS-related equipment and facilities that you discussed, how are the other distribution system equipment and facilities classified?

A. Distribution property that is classified as 100% demand-related components include voltage regulators and capacitors. This equipment is installed on the primary voltage lines and is utilized to maintain circuit voltages within an acceptable operating range during heavy loading conditions. If there was no load current flowing on the energized system, line voltage would not sag, and voltage regulation equipment would not be required. Thus, these devices are classified as demand related.

Distribution property that is independent of load and is thus classified as 100 percent customer-related components include reclosers, sectionalizers, and fused cutouts. This equipment is installed on the primary voltage lines and function together to provide distribution system protection under fault (short circuit) conditions. These devices work in a coordinated fashion to isolate a fault location and maintain a voltage connection to as many customers as possible during the fault event. Without their intended intervention during a fault, line conductors and equipment would be damaged from the fault current flows that occur and many, if not all, customers on the affected circuit could experience a major power outage. The protection equipment functions the same with or without load connected to the energized circuit because it responds to the severe overcurrent situation caused by a fault. Thus, these devices are classified as customer related.

In addition, lightning arresters are installed on the primary lines to abate damaging overvoltage conditions that occur during electrical storms. These lightning arresters function the same with or without load connected to the circuit. Thus, these devices are classified as customer related.

While cutouts and arresters are utilized for line protection, they are also applied to provide protection from overcurrent and overvoltage conditions for specific equipment, e.g., each overhead transformer. Cutouts and arresters used for this purpose are classified in the same manner as the equipment they protect was classified.

Q. Please summarize the resultant classifications of distribution facilities that you have derived under the refined MDS concept

A. The refined MDS study results are summarized by voltage level and cost component.

		Cost Component	
FERC Account	**Voltage Level**	**Customer**	**Demand**
364 Poles	Secondary	68%	32%
	Primary	60%	40%
365 OH Lines	Secondary	44%	56%
	Primary	49%	51%
366/367 UG Lines	Secondary	16%	84%
	Primary	47%	53%

368 Transformers	Secondary	57%	43%
	Primary	72%	28%

Supporting workpapers for the MDS analysis are provided in MFR Schedule E – Rate Schedules, Class Cost-of-Service Studies, Volume II.

Q. How were the MDS study results incorporated into the cost-of-service study?

A. The MDS customer and demand cost component percentages were applied to separate the costs of the plant in service for the primary and secondary voltage distribution FERC Accounts, including FERC 364, FERC 365, FERC 366, FERC 367, and FERC 368. Then an assessment was made of the subsequent Derivation of Unit Cost report that is shown on page 28 of the Cost-of-Service Study. Specifically, the monthly amounts of the customer-related costs for each rate class were evaluated in comparison to the comparable results of the cost-of-service study approved in the 2013 rate case filing. The customer-related cost component consists of MDS, meters, meter reading, billing, and customer services. The combined increases of these cost components moved the total customer cost amount materially higher than the total customer cost determined in the previous rate case filing.

While some state jurisdictions utilize the cost-of-service study as a general reference for rate design purposes, the establishment of rate components in Florida is more directly coupled with cost-of-service study results. Subsequently, the company proposes gradualism in implementation of the refined MDS analysis while consenting the full cost amounts for meters, meter reading, billing, and customer service, in order to mitigate the otherwise higher rate impact due to a full cost-based ratemaking approach.

Thus, in this filing, the company further proposes to incorporate one half of the MDS customer cost percentage results in this filing. While this proposal would then shift one half of the quantified customer-related costs to the demand-related cost component for ratemaking purposes, the refined MDS analysis stands on its own merits for full cost causation acknowledgement.

Q. After costs were functionalized and classified, how were they allocated?

A. After determining the functionalization and classification of costs based upon causation principles, the methodologies for cost apportionment to classes were determined. The resulting methodologies produce allocation factors, which are then used to apportion the demand, energy, and customer cost responsibilities to the rate classes. The derivation of the allocation factors used in the 2022 Cost of Service Study is shown in MFR Schedule E-10.

Q. What are the principal considerations when allocating demand costs?

A. The principal considerations in allocating demand costs include 1) customer demand usage characteristics and their related responsibility for system coincident and non-coincident peaks, 2) the design and configuration of production, transmission, and distribution facilities, and 3) unique customer service or reliability requirements and system operating data. These considerations provide guidance in determining what components should be used to derive the demand allocation factors for each of the functional levels of the power system. CP demands, non-coincident peak demands ("NCP"), customer peak (maximum) demands, and percentage of energy have been used to best represent those considerations.

Q. Please explain CP, NCP, and customer peak demand.

A. CP demand reflects the contribution to the total system monthly peak demand for each of the rate classes. For example, at the hour of the system peak in a particular month, the CP demand for the residential class would be that class's proportion of that hour's system peak demand.

NCP demand reflects the monthly peak demand of a rate class on its own, regardless of when the system peak occurs. For example, while the system may peak in the late afternoon, a class may peak during a nighttime hour. The class NCP would then be its demand during that nighttime hour.

For each rate class, the customer peak demand is the aggregation of all individual customers' monthly maximum demands, regardless of when they occur.

Each of these different measures of demand capture the unique load diversity characteristics of customers' usage throughout the power system. To produce a cost-causation based allocation of the cost elements at each functional level of the system, these different measurements of demand are applied objectively in accordance with the load diversity characteristics exhibited at each of those levels. The CP demand reflects a high load diversity, which is prevalent at the generators and the transmission voltage portion of the system. The NCP demand reflects a medium load diversity, which is prevalent at the primary distribution voltage level. The customer peak demand reflects a low load diversity, which is prevalent at the secondary distribution voltage level.

Q. Please describe the company's proposed cost allocation methodology for its non-solar production facilities.

A. For its non-solar production facilities, the company has proposed to allocate these costs to the retail rate classes by utilizing the 12-CP and $1/13^{th}$ AD method. With this method, 12/13ths of the production cost is allocated by means of the 12-CP demands while the remaining $1/13^{th}$ of the production cost is allocated based on the average demand. This method was utilized in the settlement of the 2013 rate case and thus is proposed in this proceeding.

Q. Please describe the company's proposed cost allocation methodology for its utility-scale solar production facilities.

A. Prior to this filing, the cost of the company's solar facilities was embedded with the costs of all of its conventional generation resources. Thus, the cost of the solar facilities was allocated to the rate classes in accord with the non-solar resources, i.e., using the 12-CP and 1/13th AD allocation. With the company's expansion of PV as a material utility-scale resource, the company believes that allocation of solar generation should be based on its unique characteristics. The company's current and planned renewable generation resources portfolio includes utility-scale, single-axis tracking PV and battery storage. These methods provide an improvement in the generation output characteristics of an otherwise static PV resource.

The daily generation output of a fixed-tilt solar PV system has a shape very much like a normal distribution curve between sunrise and sunset and which ramps up to its peak kW output at noontime and then begins ramping down shortly thereafter. The daily energy output can be increased by using a single-axis tracking system that allows the solar panels to rotate from an east facing position each morning to a west facing position each evening as the sun moves from horizon to horizon. Compared to a fixed-tilt PV panel, the annual energy output of a single-axis tracking panel may be increased by as much as 27 percent.[1] The resulting shape of the daily generation output approaches that of a

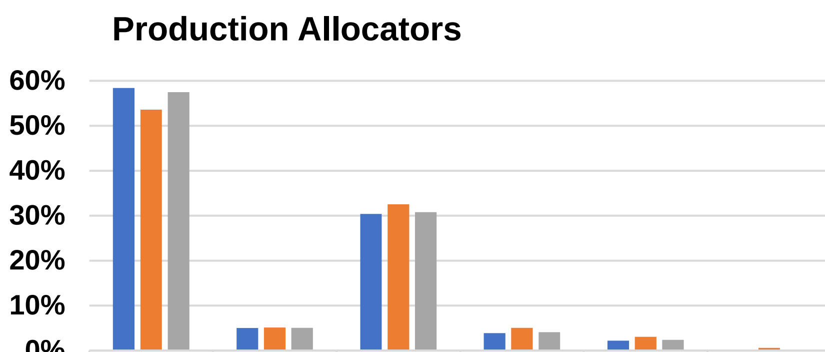
[1] "Utility-Scale Solar Photovoltaic Power Plants: A Project Developer's Guide'" International Finance Corporation, Washington, D.C., 2015, p. 34.

trapezoid with steep side legs. Thus, the panel’s peak kW output period is reached much earlier than noon and extends to well past noon. This allows the solar panel to contribute more effectively to meeting late afternoon summer loads driven by air conditioning.

“Coupling” storage batteries with PV systems has a benefit of mitigating some of the intermittency aspect of solar resources. Batteries provide a means for storing electricity from PV units as a reserve for use at times when the PV output is intermittent or even zero. For example, charged batteries could help meet the energy requirements of a pre-dawn heating load.

The company’s renewable resource expansion strategy yields both peak capacity and energy output merits. Thus, a cost allocator which encompasses both demand and energy metrics is appropriate. The company proposes to base its PV resource cost allocator on a 50 percent/50 percent weight with respect to demand and energy. The demand portion of the allocation is based on 25 percent of the average of the ten highest monthly CPs in the summer plus 25 percent of the average of the ten highest monthly CPs in the winter. The energy portion of the allocation is based on 50 percent of the annual daylight kWh.

The chart below compares the rate class allocation factors for the 12-CP and 1/13th methodology and the proposed demand and energy-weighted solar allocation methodology. The chart also illustrates the resulting total production allocation by rate class.



	RES	GS	GSD	GSLDPR	GSLDSU	LS
12-CP & 1/13th AD	58.4%	5.0%	30.4%	3.9%	2.2%	0.1%
25% Average Summer CPs + 25% Average Winter CPs + 50% Daylight Energy	53.6%	5.1%	32.5%	5.1%	3.1%	0.6%
Total	57.5%	5.0%	30.8%	4.1%	2.4%	0.2%

Q. Please explain the treatment of demand allocated transmission and distribution costs in the Cost-of-Service Study.

A. The transmission demand-classified costs are allocated on a 12-CP basis while distribution demand-classified costs are allocated on a mixture of rate class NCPs and customer maximum demands. This is the same allocation methodology as was adopted and relied on in the company’s base rate proceeding in Docket No. 20080317-EI.

SUMMARY

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

A. In line with the cost-of-service study goals stated previously, the company successfully modified the model to create two new commercial and industrial rate schedule classes for larger customers that are served at primary and subtransmission voltages, which were then incorporated in the retail cost allocation process.

The company refined its minimum distribution system methodology to analyze distribution costs at a comprehensive level of detail. The results were successfully employed in the cost-of-service study to classify the costs of the primary and secondary distribution voltage levels.

The company employed the following cost allocation factors to apportion the functional costs of capacity to the customer rate classes:

Production – Non-Solar	12-CP and 1/13th AD
Production – Solar	25 percent of the 10 highest Summer CPs plus 25 percent of the 10 highest Winter CPs plus 50 percent of Daylight Energy
Transmission	12-CP
Substations	Class NCPs
Primary Distribution	Class NCPs
Secondary Distribution	Customer Maximum Demands

Prior to this filing, solar production was allocated along with all other production.

The modifications made to the company's cost-of-service methodologies and applications, which have been employed in this filing, strive to capture and enhance cost-causation principles to the benefit of electric service customers. The cost-of-service study results are fair and equitable, and it serves as a practical resource in support of the rate design process.

Q. Does this conclude your direct testimony?

A. Yes, it does.

(Whereupon, prefiled direct testimony of Marian C. Cacciatore was inserted.)

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

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

DIRECT TESTIMONY AND EXHIBIT
OF
MARIAN C. CACCIATORE

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PREPARED DIRECT TESTIMONY AND EXHIBIT

OF

MARIAN C. CACCIATORE

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

MARIAN C. CACCIATORE

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

A. My name is Marian C. Cacciatore. My business address is 702 N. Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric company ("Tampa Electric" or "company") as Vice President of Human Resources.

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

A. I am responsible for the leadership and strategic direction of the human resources functions for Tampa Electric, including compensation, benefits, healthcare, pension and retirement savings, and payroll.

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

A. Prior to joining Tampa Electric in 2020, I served as

Vice President of Human Resources ("HR") for a satellite communications company. My background also includes HR leadership roles in manufacturing, financial services, communications, and high-tech organizations.

I hold a bachelor's degree in Business Administration from the University of South Florida and a master's degree in Human Resources Management from Rollins College.

Q. What are the purposes of your direct testimony?

A. The purposes of my direct testimony are to explain the company's employee compensation system and demonstrate that Tampa Electric's payroll and benefits costs for the 2022 test year are reasonable.

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

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

Document No. 1	List of Minimum Filing Requirement Schedules Sponsored or Co-Sponsored by Marian C. Cacciatore
Document No. 2	IBEW and OPEIU Historical Base Wage Adjustment (2012-2020)
Document No. 3	Total Annual Compensation Analysis for Exempt and Non-Covered/Non-Exempt Benchmarked Positions (2019-2020)
Document No. 4	Merit Budget History – Exempt (2012-2020)
Document No. 5	Merit Budget History – Non-Covered/Non-Exempt (2012-2020)
Document No. 6	Utility Comparison – Total Salaries and Wages as a Percent of Operations and Maintenance Expense (2019)
Document No. 7	Tampa Electric Benefits Package Description
Document No. 8	2019 BENVAL Study – Entire Benefit Program (Excludes Team Member Contributions)
Document No. 9	2019 BENVAL Study – Medical and Dental (Excludes Team Member Contributions)
Document No. 10	Mercer – Average Annual Health Benefits

	Cost Per Employee (2011-2020)
Document No. 11	2019 BENVAL Study – Defined Benefit and Defined Contribution (Excludes Team Member Contributions)

INTRODUCTION

Q. What are Tampa Electric's areas of strategic focus?

A. The company has three strategic priorities – world-class safety, improving the customer experience, and becoming cleaner and greener. Our talent philosophy, work culture, and leadership principals support these strategic priorities.

Q. What is Tampa Electric's general philosophy for its team members?

A. Tampa Electric believes that our value to our customers, communities and owners is driven by our team members, who must be focused on meeting the needs of our customers today and in the future. We want team members who are committed to world-class safety and who work relentlessly to be safe every moment of every day. The company seeks to hire and retain skilled team members who are committed to collaboration at a time when the electric industry is changing rapidly. Our team members must embrace innovations that safely and efficiently deliver clean and reliable energy to our customers. We also want team members who strive to cost-effectively deliver excellence in all aspects of our operations.

Q. What are the company's core employee values?

A. Our core employee values include safety, being healthy, a focus on customers and the environment, efficiency and cost-effectiveness, leadership, integrity, respect, collaboration, and pursuit of excellence. These values are reflected in our Employee Code of Conduct, which establishes a foundation for team member integrity and high ethical standards.

Q. What leadership competencies does Tampa Electric foster to develop in team members?

A. Tampa Electric fosters seven leadership competencies in all team members. The seven leadership competencies listed below guide the development of both people managers and team members.

1. Speaks Up on Safety, Health, and the Environment;

2. Takes Ownership and Acts with Integrity;
3. Drives Operational Excellence for Customers;
4. Builds Strong Collaborative Relationships;
5. Develops Tampa Electric and Teams;
6. Cultivates Innovation and Embraces Change; and
7. Thinks Strategically and Exercises Sound Judgment.

Q. What role do the principles of inclusion and diversity play at Tampa Electric?

A. Inclusion and diversity ("I&D") are cornerstones of our long-term success. Cultivating an inclusive work environment that fosters respect and collaboration allows us to benefit from the unique perspectives, backgrounds, and varying experiences of our team members.

Q. What has Tampa Electric done to promote I&D?

A. In 2019, the company introduced an Inclusion & Diversity ("I&D") initiative that provides an organizational blueprint for achieving sustained diversity within our employee base, our suppliers, and as part of our commitment to our communities. Last year was a foundational year, and we formed an I&D Employee Council ("council"). In partnership with our leadership team, the council created a road map of 2021 priorities including employee education and awareness that will begin with unconscious bias conversations for all team members beginning in the second quarter of 2021. In addition, HR reviewed our talent processes to increase the diversity of candidates. This review identified specific recruiting processes and strategies that resulted in removing barriers of entry for minority and underrepresented internal and external candidates.

Q. What role does I&D play in the company's overall talent strategy?

A. An inclusive and diverse workplace yields greater employee engagement. Strong employee engagement, combined with competitive compensation and benefits packages, helps the company attract and retain skilled talent. Our customers benefit when we retain, attract, reward, and respect skilled and committed team members. Taking care of our team members via competitive pay, and health and benefit packages, contributes to their safety, performance, and productivity at work, and benefits Tampa Electric's customers.

Q. How many team members are employed by Tampa Electric?

A. Tampa Electric currently employs approximately 2,400 people. These team members work toward providing a world class customer experience every day of the year, which requires a team effort.

Q. Does Tampa Electric have team members that are members of a collective bargaining unit?

A. Yes, approximately 892 members of our team are part of a collective bargaining unit. We have Collective Bargaining Agreements ("CBA") with two unions: the International Brotherhood of Electrical Workers Local Union 108 ("IBEW") and the Office and Professional Employees International Union Local 46 ("OPEIU").

Q. How is the compensation set for those team members that are members of these two collective bargaining units?

A. Their compensation is set via a CBA. A CBA is a contract between a labor union and the company that governs working conditions including wage scales, working hours, training, health and safety, overtime, grievance mechanisms, and rights to participate in workplace or company affairs. Most of our "covered" team members are non-exempt, are paid by the hour, and are eligible for overtime or shift differential pay.

Q. What other team member categories does the company have beyond those described above in the collective bargaining units?

A. Tampa Electric also has exempt, non-exempt, part-time and co-op student employees.

Q. What do "exempt" and "non-exempt" mean?

A. These terms refer to a team member's status under applicable wage and hour laws and regulations. Exempt team members are not subject to the requirements of wage and hour laws, such as provisions governing when overtime must be paid. We must follow applicable wage and hour laws and regulations for non-exempt team members.

Q. How many members of the company's team are non-exempt?

A. Approximately 304 of our team members are non-covered, non-exempt and are paid on an hourly basis.

Q. How many team members are exempt?

A. Approximately 1,179 of our team members are professionals, supervisors, managers, department directors, and officers who are non-covered, exempt, and are paid on a salaried basis.

COMPENSATION

Q. What is Tampa Electric’s overall compensation philosophy?

A. Tampa Electric recognizes that a competitive pay program is a critical component of a team member’s total compensation. We must have a reasonable and competitive compensation program to attract and retain skilled team members.

We evaluate the competitiveness of our pay program by focusing on Total Direct Compensation (“TDC”), which includes base pay (salary or hourly), short-term incentive plans (“STIP”), and long-term incentive plans (“LTIP”). All three elements are important, serve specific purposes, and work together.

Q. Please describe the company’s general system for compensating its team members.

A. Tampa Electric compensates its team members with a combination of direct compensation and benefits. The direct compensation element has three parts: base compensation, short-term incentive compensation and long-term incentive compensation. Our benefits generally include different types of health insurance plans, retirement plans and disability insurance. I will explain each of these compensation elements and our benefits program in more detail below.

All team members, whether hourly or salaried, are eligible to participate in our benefits program and participate in our short-term incentive pay program. The only exception is with our part-time and certain co-op/student employees. In general, department directors and officers are also eligible to participate in our long-term incentive program. I will describe these programs further in my testimony.

Our compensation system reflects a pay for performance model focused on total compensation that aligns the interests of our team members and customers. We have designed our compensation system to reflect market values, promote internal equity, and to be viewed as reasonable when we establish the electric rates to be paid by our customers.

Keeping our compensation packages competitive involves making an appropriate portion of a team member’s total compensation “variable” or “at risk” through incentive compensation programs that reward good performance. Our incentive compensation programs encourage our team members to focus on safety, reliability, organizational performance, and improving the customer experience.

Q. What is base compensation?

A. Base compensation (or base pay) is the pay team members receive bi-weekly and is either hourly wages or a salary.

Q. Do team members automatically get a base pay increase each year?

A. Team members who are covered by a CBA are eligible for base pay increases based on the applicable CBA. Non-covered team members do not get automatic annual base pay increases but are eligible for a merit increase.

Q. Please explain the company’s process for making merit increases.

A. We have an annual merit review process that encourages good performance by giving team members an opportunity for a TDC increase based on individual performance. Our merit review process enables the company to retain strong performers talent and remain competitive with the market.

Our merit process is closely tied to our annual talent management process by which we assess the overall performance of each team member each year. The first part of the process includes goal setting, and the second part requires assessment or performance review.

At the beginning of each year, our team members establish performance goals and reaffirm their position accountabilities with their performance coaches. Our performance coaches work with team members to ensure that an individual team member's annual goals align with the company's annual objectives as set out in the company's STIP programs. They also ensure that a team member's position accountabilities align with the team member's specific role functions.

We conduct performance reviews for team members as the end of the year approaches. Our performance coaches assess an individual's performance based on their goals and evaluate a team member's progress developing the Leadership

Competencies described above. We assess team members on a five-point scale based on expectations, i.e., Significantly Exceeds; Exceeds Many; Fully Meets; Meets Most; and Does Not Meet Job Expectations, Must Improve to Be Effective.

After the performance reviews are complete, performance coaches can recommend a merit adjustment for each eligible non-covered/non-union team member based on established guidelines. The guidelines for recommending a merit increase are based on the performance rating scale, the position of the team member's base salary within the base salary grade range, and the annual merit budget.

Merit adjustments typically are a base pay increase; however, a team member may not be eligible for a base salary increase if the individual's performance does not meet expectations or if the team member's base salary is already positioned competitively relative to the salary grade mid-point. The company's officers review and approve each proposed merit increase, and the President approves the final total annual merit amount.

Q. Are covered team members eligible for merit increases?

A. No. Team members covered by a CBA do not participate in Tampa Electric's merit process. The company negotiates with each union during each contract cycle, and an annual base wage adjustment is normally included in the final overall agreement. Document No. 2 of my exhibit summarizes the base wage adjustments for each union during the period 2012 to 2020.

Q. Please describe the company's short-term incentive plan, or STIP.

A. The company's STIP compensates team members for the achievement of annual company objectives. This variable bonus plan incentivizes individual performance and contribution to annual company goals. Achieving the STIP objectives is intended to benefit customers, directly and indirectly.

The objectives for STIP center around performance in the areas of Safety, People, Customer, Asset Management, and Financial. The company's objectives in each of these areas are as follows:

1. Safety: Achieve World Class Safety by developing a culture of safety leadership and a reduction in

serious injuries.

2. People: Develop the company’s human capabilities to shape and achieve its strategic vision by building team member commitment, standardizing work processes, and developing team members and leaders.

3. Customer Experience: Provide outstanding Customer Service in ways that result in customer loyalty and dedication by reaching high customer satisfaction levels as measured by multiple key customer service metrics.

4. Asset Management: Realize high operating performance with a continued focus on safety, compliance, and strategic growth.

5. Financial: Achieve solid financial results and effective cash flow management.

Q. Is there only one STIP applicable to all employees?

A. No, there are two plans. The first is called the Balanced Scorecard (“BSC”). The second is called the Performance Sharing Program (“PSP”).

Q. Please describe the BSC.

A. Team members compensated using the BSC are in positions with targeted at-risk pay that is tied to achievement of each objective within the BSC. The BSC is set each year with threshold, target, and stretch goals for the company to achieve during the calendar year. It is focused strategically on five areas: safety, people, customers, asset management, and financial goals. The percentage of at-risk pay based on BSC results is set by the compensation structure by grade. Grades containing management and director jobs have higher amounts of at-risk pay. This corresponds to the higher level of impact these team members should have on driving business results.

Q. Please describe the PSP.

A. The PSP applies to the remainder of the eligible team members and has a profit-sharing component based on the company's performance. There is an operations target of seven percent, which includes safety, employees, customer, operating performance, and financial goals. The profit-sharing target is up to five percent and is based on net income goals. The sum of these two targets is the maximum potential PSP payout team members may receive based on actual results and is calculated as the achieved PSP percentage multiplied by a team member's eligible annual earnings.

Q. Please describe the company's long-term incentive plan, or LTIP.

A. The company's LTIP is a compensation and retention program for team members in key senior leadership positions. The LTIP program encourages team members to focus on long-term value for customers. The purpose of the LTIP is to align the long-term incentive pay for senior leaders with corporate and shareholder goals. LTIPs like ours are commonly offered by companies that we compete with for senior leadership talent. Our LTIP is an important part of our competitive total compensation program for senior leaders. Together with our base pay and STIP programs, our LTIP allows Tampa Electric to attract and retain skilled senior leaders.

LTIP is administered through the Emera Performance Share Unit ("PSU") Plan. A PSU refers to a grant of a value of an Emera common share. Each grant has a performance, or vesting, period of three calendar years. The PSU is affected by the Emera share price and achievement of pre-determined financial objectives. At the end of the three-year performance period, the grants for that performance period are paid out. A main PSU payout factor is a comparison of Emera's performance results against the financial objectives set for that period. The purpose is to align leaders' long-term incentive pay with Emera corporate goals that focus on creating and preserving long term shareholder value, which in turn, is driven by creating long term customer value. Each year, team members at the director level or above are awarded PSUs based on a percentage of base pay.

Q. You have explained that Total Direct Compensation consists of base pay, STIP, and LTIP. What is the company's "target" for Total Direct Compensation?

A. We target the median (middle) of the market. Using the market median is a compensation best practice and is better than using the mean or average, because the median is less sensitive to outliers in market data. Targeting the median balances our desire to hire and retain quality team members and to maintain reasonable customer rates.

Q. What tools does the company use to align TDC with the market median?

A. Our skilled labor positions are covered by a CBA with the IBEW. We benchmark our TDC for these team members during each CBA negotiation against TDC paid by southeastern utilities as a comparable group.

For employees not covered by a CBA, the company assesses TDC against the market using data from the U.S. Mercer Benchmark database and the Willis Tower Watson Middle Management Professional and Support ("MMPS") Survey at least biennially.

In addition to our regular market assessments, we conducted a comprehensive compensation review in 2019 to align our compensation system for non-covered employees more closely to the market. We used reports from Mercer and Willis Tower Watson and mapped every job to an external benchmark.

Q. What changes did the company make based on the 2019 review?

A. Based on this review, we adopted a new market-based salary scale in 2020. We consolidated our 21 previous job grades into 11 grades, so each grade now contains jobs that are similar in knowledge, skills, and abilities. We used average market references for the benchmarked jobs by grade to create a mid-point salary for each grade, and then established salary ranges by grade equal to 20 percent above and below the mid-point. The resulting salary scales allow us to set a team member's salary within the applicable range based on the team member's mastery of the role, critical skills, and performance for the job. Our salary scale is now more efficient to administer, provides greater internal equity and maintains our average total annual compensation for benchmarked exempt and non-covered/non-exempt ("NC/NE") positions below the market median (50th percentile). Document No. 3 of my exhibit provides more information about the results of our review.

Q. How does Tampa Electric's total direct compensation compare to the market?

A. Tampa Electric's TDC was 98.8 percent of the market median in December 2020.

Q. What evidence do you have to support this statement?

A. As previously discussed, we perform a detailed benchmarking analysis of TDC (fixed and variable) at least biennially and completed our most recent analysis in 2019. Our periodic benchmarking analyses involve making market comparisons for a core group of jobs defined as "benchmark jobs." Benchmark jobs include exempt and NC/NE jobs that match a Tampa Electric job. This type of benchmarking analysis is standard throughout the industry when a market-based compensation system is used. Our 98.8 score in relation to the market median is reflected in Document No. 3 of my exhibit.

Q. Do you have analyses showing how Tampa Electric's salary levels compare to the market over time?

A. Yes. Document Nos. 4 and 5 of my exhibit show the overall annual percentage increase used by Tampa Electric in its annual merit pay program has averaged 0.1 percent below key market indices over the period 2012 to 2020. In addition, the percent increase for each year has consistently been at or below the average rates of key market indices.

Q. Has the company made any other comparisons that support the reasonableness of its salary and wage levels?

A. Yes. We compared Tampa Electric's total salaries and wages to 16 other utilities in the Southeastern United States as reported in the Federal Energy Regulatory Commission ("FERC") Form-1 annual report for 2019. This analysis focused on total salaries and wages as a percentage of total operations and maintenance expenses. Tampa Electric's percentage is close to the median for this benchmark group as shown on Document No. 6 of my exhibit.

Q. Are the company's compensation systems and levels reasonable considering the recent economic downturn and current unemployment levels?

A. Yes. Tampa Electric acknowledges the impact that the pandemic has had on our customers and the communities we serve, but we believe that the impact of the pandemic on compensation levels will not be significant or lasting. As we have continued to hire during the pandemic, we have had to remain competitive with our compensation levels to attract skilled candidates. Attracting and retaining a qualified work force over the long term is one of the many challenges facing the utility industry, including Tampa Electric, so our compensation system must look beyond temporary market disturbances.

A significant portion of our workforce consists of (1) technical/professional team members, many of whom are in jobs requiring a college degree, and (2) highly skilled craft team members, most of whom were trained in-house through various on-the-job and classroom training programs.

The demand for skilled trades in the state of Florida is anticipated to grow over the next decade, but the number of young people willing to work in the trades is declining. At the same time, the baby boomer generation of skilled-trade workers is continuing to retire, so we have a growing concern about the availability of talent in the skilled trades.

The competitive landscape for attracting and retaining technical/professional talent is also changing. As noted in the testimony of Tampa Electric witnesses Melissa L. Cosby, Regan B. Haines, and Karen M. Mincey, our industry is evolving and customer expectations are changing, so we are investing in digital and information technology to improve the customer experience. Consequently, we find ourselves competing for talent with high technology companies, not just other utilities. Although the pandemic has resulted in higher unemployment in some job sectors, it has also created new remote work opportunities, so we find ourselves competing with companies located far beyond our service territory for talent living in our service territory.

These changing dynamics make having a competitive compensation system for the long-term even more important. Without competitive salaries and wages, the company will lose well-qualified and talented team members and have a difficult time attracting prospective talent. Although a certain amount of employee turnover may be healthy, excessive turnover can negatively affect the level of service we provide to our customers.

BENEFITS

Q. Describe the company’s benefits package.

A. The company’s benefits package is designed to maintain a competitive position within the market so the company can attract, retain, and develop competent and qualified team members. Our benefits package includes consumer driven health plans, pharmacy plans, employee family assistance plans, dental and vision plans, flexible benefit plans (Healthcare FSA, Dependent Care FSA, and Transportation and Parking FSA), life insurance (basic, supplemental, spouse, and child), long-term care insurance, group retirement plans, long-term disability, and retiree medical. Document No. 7 of my exhibit includes a more detailed description of these plans. Additionally, team members receive paid time off, which is used for both vacation and sick time, and 10 company paid holidays.

Q. How does Tampa Electric manage the design and cost of its benefit programs?

A. Tampa Electric uses the Towers Watson BENVAL study. The BENVAL study is a nationally recognized and accepted actuarial tool that compares the relative value of a company's overall benefit plan and its various components with other companies' plans contained within the Benefits Data Source – United States database. The group used for the comparison includes 12 utility companies with revenues that range from $1,401 million to $4,200 million.

BENVAL uses consistent actuarial methods applied to a fixed population to determine a relative value index for each benefit plan component. As a result, the differences in value among employer plans are exclusively a function of differences in the plan provisions.

The BENVAL Study includes a relative value index score for each company's benefit plan components. The index score is calculated by analyzing and determining the value of each company's benefit plan component and then dividing each company's value by the average benefit plan value for each component among all the companies in the benchmark group. A relative index of 100 represents and average company value. BENVAL data is presented for both non-union (Exempt and NC/NE) and union employee groups.

Tampa Electric's BENVAL Index score for its total benefit program is 94.11 for non-union (Exempt and NC/NE) team members and 93.28 for union team members as shown in Document No. 8 of my exhibit. Both scores are below the index average of 100, which means that the cost of company's total benefit program is below the average while still providing a value that is competitive. This shows that the company's benefit package is reasonable.

HEALTHCARE BENEFITS

Q. How does the company evaluate the design and cost of its health care programs?

A. The company operates its health plans with appropriate fiduciary due diligence. In addition to regular review of vendor partners to ensure maximum cost-effectiveness, the company has implemented various cost saving programs over the past several years, reducing total health benefit costs for Tampa Electric. Examples include moving to Blue Cross Blue Shield ("BCBS") in 2019, which improved network discounts, and implementing an in-depth health management program, designed to improve both high-cost claims management and clinical outcomes. We took these actions to improve team member experiences and reduce costs. Since 2019, we have performed an annual review and renegotiation of our pharmacy discounts and rebates, which has consistently reduced our overall costs. Our projected 2022 healthcare costs reflect our active management and monitoring of our medical, pharmacy, dental, and vision benefits and are reasonable and prudent.

Q. Has the company evaluated its healthcare plan against the market?

A. Yes. Based on the results from the Towers Watson BENVAL study, Tampa Electric's relative value index score for medical and dental is 92.73 for non-union (exempt and NC/NE) team members and 90.48 for union team members. Both are below the index average of 100. This means that the company's medical and dental plans are below the average while still contributing to an overall benefits program that is competitive and reasonable. Document 9 of my exhibit contains excerpts from this study.

Q. How does the company's healthcare plan compare to industry standards?

A. Document No. 10 of my exhibit, entitled "Mercer – Average Annual Health Benefits Costs Per Employee for 2011-2020" demonstrates that Tampa Electric's costs during this period were lower than industry experience, except in 2015, 2018, and 2019. According to BCBS, in 2020 Tampa Electric was at or slightly below the health benchmark overall, and the factors that increase the company's costs were high-cost claims, inpatient services, and specialty drugs. The benchmark is based on 1.5 million patients served by BCBS.

Q. What factors are driving healthcare costs in the United States?

A. The main drivers of increased medical cost in the U.S. are inflation in unit prices, increases in the use of services (primarily due to population aging and the overall deterioration of the health of U.S. citizens), and advances in technology and treatment protocols causing a rise in the frequency and cost of high-cost claimants. The cost drivers for prescription drugs are similar, with specialty drugs representing a disproportionately higher percentage of the cost increases than non-specialty drugs. Tampa Electric is projecting an increase for its health benefit costs in 2022. The projected increase in Tampa Electric's healthcare costs is consistent with and caused by the same factors at work for healthcare costs in the United States generally.

Q. What specific actions has Tampa Electric taken to ensure its healthcare costs are reasonable?

A. In partnerships with industry experts such as Mercer and BCBS, the company has implemented initiatives to ensure its healthcare costs are reasonable, as listed below.

1. Implemented a pricing strategy to encourage cost-effective plan selections;
2. Reviewed and increased monthly team member contributions annually;
3. Promoted team member and retiree awareness and education so that they can be smart consumers of the healthcare options available in their healthcare

plans;

4. Implemented Personal Care Connections, which is a comprehensive, high touch, disease management program, including health coaching, to facilitate the effective medical treatment of plan participants with specific diseases that, if not properly managed, can generate expensive claim costs;
5. Implemented "Rally", a digital health platform which promotes overall health and wellness and offers rewards for meeting wellness goals;
6. Conducted vendor analyses and determined moving to Blue Cross Blue Shield from Aetna would result in cost containment due to BCBS network discounts, network breadth, premium holidays, and implementation and wellness credits;
7. Performed a prescription coverage collective financial review, confirming current vendor offered the most competitive pricing;
8. Restructured prescription program to require 90-day fills by using retail Smart90 pharmacy or home delivery for long-term maintenance medications; and
9. Implemented a Telehealth benefit for medical and dermatology, which is less expensive than the average office visit.

These changes have contributed to Tampa Electric healthcare costs per employee for active team members remaining competitive with the national average between 2012 and 2020. Document No. 10 of my exhibit demonstrates Tampa Electric's average healthcare cost per active team member compared to the similar-size utility companies based on Mercer survey data.

Q. How does the increase in Tampa Electric healthcare costs per team member from 2013 to 2020 compare to the average national increase for those years?

A. For 2020, Tampa Electric's medical and dental costs for active team members were $24,672,586 or $10,124 per team member. In the company's 2013 rate proceeding, the company's average medical and dental expense was $8,945 per team member. This is an average increase of two percent per year which is lower than the national average medical trend according to PricewaterhouseCoopers ("PwC"). PwC reports that the national medical cost trend between 2013 and 2020 was an average increase of seven percent per year with no plan changes.

PENSION AND RETIREMENT SAVINGS BENEFITS

Q. Please describe the pension and retirement savings plans and how they compare to industry standards?

A. Tampa Electric’s team members participate in the following TECO retirement plans:

1. TECO Energy Group Retirement Plan (a qualified defined benefit pension plan). Eligible team members become a participant on the first day of the month after completing a year of employment provided the team member is age 21 by that date. If not age 21 at that time, the team member will become a plan participant on the first day of the month after reaching age 21.

   Active participants earn a portion of the benefit each year. The benefit earned at any point in time is called an accrued benefit. Once a team member has completed three years of service or reaches age 65 (whichever occurs first) while a Tampa Electric employee, they receive this benefit even if they leave the company before retirement.

   The plan formula for determining this benefit is the employee’s final average annual earnings multiplied by the cumulative pension credits, which are based on the employee’s age and length of service. These credits increase with age and service.

The following are the formulas based on when the employee became a participant in the plan.

- Prior Plan Formula - This is the formula that was in effect on June 30, 2001. The benefit is defined as a monthly annuity, based on final average annual earnings, the employee's service up to a maximum of 35 years and covered tax base. The prior plan formula is used for grandfathered participants.

- Grandfathered Participant - If the employee was an active participant in the plan on July 1, 2001 and was age 40 or older on that date; the employee is considered a grandfathered participant. As a grandfathered participant, these special provisions apply:
  - The benefit will be determined in two ways: under the pension equity formula as if that formula had been in effect throughout the employee's career with the company and under the prior plan formula, as if that formula had remained in effect throughout the employee's career with the company. Whichever formula provides the employee with the higher benefit, is the benefit that will

be received.

- Pension Equity Formula - This is the formula that went into effect on July 1, 2001 when the retirement plan benefit formula was converted to a pension equity formula. Under this type of formula, the benefit is defined as a lump sum based on cumulative credits at retirement or termination, multiplied by final average annual earnings. Credits increase with age and service. This is the formula that is used to determine the benefit for anyone who became a participant after July 1, 2001 and for all future benefits for any participant in the plan on July 1, 2001 who was under age 40.

- IBEW CBA Employees – Benefit accruals for participants who are covered by the IBEW CBA were frozen as of October 21, 2019. This means that benefits were determined for these participants using their final average earnings and pension credits as determined as of October 21, 2019 (and for any period after October 21, 2019 that they are not covered by the IBEW CBA and are otherwise eligible to participate in the plan).

Employees who are hired on or after October 21, 2019 and are covered by the IBEW CBA will not be eligible to participate in the plan for so long as they are covered by the IBEW CBA.

2. TECO Energy Group Retirement Savings Plan (a qualified defined contribution 401(k) plan). Team members also participate in this 401k plan. New team members who do not make an enrollment election or opt out of the plan participation within 30 days of their hire date are automatically enrolled in the plan effective with the first payroll period after 30 days of employment, contributing six percent of applicable compensation on a pretax basis and invested in the Vanguard Target Retirement Fund that most closely matches their retirement date, based on an assumed retirement age of 65.

Team members can contribute on a pre-tax or after-tax basis from one percent to 50 percent of eligible compensation. Eligible compensation includes base pay, bonus, incentive, commission, and overtime earnings. Team members can make changes to their contributions at any time.

The company matches $0.75 for every $1 the employee contributes, up to the first six percent of their pay. Fixed matching contributions are made to the team member’s account each pay period and are automatically invested in the same manner as the team member’s contributions to the plan.

The company adds a performance match based upon the achievement of certain business financial goals, up to $0.25 for every $1 a team member contributes, up to the first six percent of their pay. The performance match is paid in the first quarter of the year for the previous year and is automatically invested in the same manner as the team member’s fixed matching contributions.

The fixed match and the performance match result in a potential match of $1 for every $1 contributed to the plan, up to the first six percent of the team member’s pay.

IBEW CBA Employees – Employees covered by the IBEW CBA (other than *grandfathered members) will not be eligible for the fixed match or the performance match.

Employees covered by the IBEW CBA (other than *grandfathered members) will be eligible to receive a non-elective employer contribution on a bi-weekly basis equal to a percentage of the member's compensation for that period (the IBEW member contribution). The percentage will be based on years of tenure, as follows:

Years of Tenure	% of Compensation
0.00 – 4.99 years	6%
5.00 – 10.99 years	12%
11.00 – 20.99 years	14%
21.00 – 30.99 years	18%
31.00+ years	21%

*Grandfathered members are those IBEW CBA-covered employees who were members in the TECO Energy Group Retirement Plan on July 1, 2001 and attained age 40 on or before July 1, 2001.

3. TECO Energy Group Benefit Restoration Plan (a nonqualified defined benefit pension plan). The TECO Energy Group Restoration Plan provides non-qualified benefits for team members who receive pensionable earnings over the annual pay limit, determined by IRS 417(a)(17).

Team members whose employment status is grade 11 and above and who are a member of a "select group of management” team members within the meaning of ERISA Section 201 (2) are eligible to participate in the plan.

TECO Energy Group Supplemental Executive Retirement Plan (“SERP”) (a nonqualified defined benefit pension plan):

The TECO Energy Group SERP is a closed plan with two remaining actively employed participants. The company has less than 20 retired members that are currently in pay status.

4. TECO Energy Group Postretirement Health and Welfare Plan (a retiree medical plan):

The company provides access to the retiree healthcare plans and company paid basic life insurance coverage to eligible retirees.

Employees hired prior to 04/01/2010 that elect to continue medical coverage under the terms of the TECO Energy Retiree Group Health Plan, receive a fixed-dollar amount, known as a Retiree Healthcare Defined Dollar Benefit (DDB) Credit that off-sets the monthly cost for medical coverage. This credit (no cash value) is based on age and years of service at the time of retirement.

Q. How does the company evaluate these plans for reasonableness?

A. Tampa Electric uses an independent consultant, Mercer, to evaluate the competitive positioning of these qualified pension and savings plans. Mercer's database includes detailed plan data for over 1,100 companies, including the Fortune 500 as well as smaller companies with revenues ranging from $5.0 million to $1.5 billion and is compiled solely from publicly available information. Of the 58 utilities in the database, 28 percent provide a defined benefit ("DB") plan to new hires while 72 percent provide only a defined contribution ("DC") plan. Of the plans that are offered today, the value of Tampa Electric's combined DB and DC program, is at the 50th percentile of all 58 companies in the database.

Q. How does Tampa Electric's pension plan and retirement savings plan compare to industry standards?

A. As shown in Document No. 11 of my exhibit, based on the results from the Towers Watson 2019 BENVAL study, Tampa

Electric's relative value index score for the combination of the defined benefit and defined contribution plans is 89.69 for non-union (Exempt and NC/NE) team members and 92.06 for union team members. Both are below the index average of 100. This means that the company's defined benefit and defined contribution plans are below the average relative value while still contributing to a competitive benefits program.

Q. Is it common to use an independent actuarial firm to compute pension and post-retirement benefit costs?

A. Yes. Based on the benefits provided and employee demographics, an actuary for a defined benefit plan estimates the value of employer obligations. The calculation of liabilities considers several complex variables including expected future compensation increases, asset returns, rates of retirement, disability, death, and other reasons for termination. Actuaries use historical data and future expectations to make assumptions for these variables. Actuaries for defined benefit plans also ensure the employer is following laws and regulations regarding pension plans. This includes the timely certification of minimum contributions and the funded status under The Employee Retirement Income

Security Act of 1974 ("ERISA"). As there are extensive variables and regulations to consider, it is common and often necessary, for companies to engage actuarial firms to compute pension and post-retirement benefit costs.

Q. Do the actuarial assumptions and methods provide a reasonable basis for determining the level of pension costs to be included in the company's operating cost?

A. Yes. The actuarial assumptions and methods are reasonable and consistent with FASB standards and industry practice and provide a reasonable basis for determining the level of pension cost included in Tampa Electric's cost of service studies. The company's pension costs are reflected in MFR Schedule C-17.

2022 TEST YEAR PAYROLL COSTS

Q. What is the general basis for the company's projection of its human resource needs in 2021 and 2022?

A. We determine the need for human resources after evaluating factors including customer growth, changes to our generation system, introduction of new technologies like Advanced Metering Infrastructure ("AMI"), changing expectations of our customers, and skills needed for our business requirements and practices. Tampa Electric witness David A. Pickles discusses how planned changes to our generating system will impact our need for human resources. Ms. Cosby, Mr. Haines, and Ms. Mincey discuss how the introduction of new technologies and business practices are changing the company's needs for human resources in Customer Experience, Electric Delivery, and Information Technology.

Tampa Electric is committed to serving its customers by delivering reliable electric service in a cost-effective manner. Although we operate in a capital-intensive industry, it takes people to operate our business in a way that meets customer expectations. For this reason, we remain focused on attracting and retaining team members with the right skills to meet customers' needs safely and reliably.

Q. What is Tampa Electric's projected headcount for 2022?

A. We project our average number of team members for 2022 to be 2,611, or about 175 more than in 2020. The projected O&M impact from adding team members in 2021 and 2022 is shown on MFR Schedule C-35 sponsored by company witness Jeffrey S. Chronister.

Q. What is causing the increase in team members between 2020 and 2022?

A. The 2020 average number of employees included in MFR Schedule C-35 is based on actual headcount during the year whereas the budgeted 2022 employee headcount is based on the number of authorized positions including include vacant positions that are expected to be filled during 2021 and 2022. An adjustment for vacancies was not made to the budgeted headcount as Tampa Electric does not rely on headcount to determine their budgeted expenses and the number of vacancies is not a metric that is used to operate the business. Rather, Tampa Electric's budgeting process is focused on the total dollars of expense associated with the resources that the company expects to consume.

In addition to the filling of authorized vacant positions, the increase in headcount can be attributed in part to the introduction of AMI technology, execution of the Storm Protection Plan and other emergency preparedness activities and the continued evolution to a more complex distributed computing environment in response to increasing cybersecurity and privacy demands and customer expectations.

Q. What actions has Tampa Electric taken since its last base rate case in 2013 to control headcount?

A. Staffing levels and headcount budgets are one area of constant scrutiny given the significant contribution of payroll and benefits to the company's overall costs. All department leaders are required to consider and justify the need to fill a vacancy when one occurs. To ensure the company's continued focus on managing staffing levels, officer approval is required for headcount replacements or additions.

Q. What is the projected gross average salary per active team member?

A. Tampa Electric's 2022 budgeted gross average salary per active team member is $108,860 as compared to $100,473 in 2018. This represents an increase of 8.3 percent since 2018 and an average growth rate of 2.0 percent per year. This average annual growth rate is consistent with the average of actual and forecasted CPI included in MFR Schedule C-35 for the period from 2018-2020.

Q. What is the projected average payroll and fringe cost per employee?

A. Tampa Electric's 2022 budgeted average payroll and fringe cost per active team member is $142,871 as compared to $131,971 in 2018. This represents an increase of 8.3 percent since 2018 and an average growth rate of 2.0 percent per year. This annual growth rate is consistent with the average actual and forecasted CPI included in MFR Schedule C-35 for the period from 2018-2020.

Q. You testified that the company's total direct compensation in 2020 is reasonable and explained why. What level of merit increases is the company projecting for 2021 and 2022?

A. Merit increases for 2020 to 2021 and 2021 to 2022 are projected to be three percent each year. These increases are reflected in the base pay component of projected 2020 salary and wages expenses. Based on national market sources such as Mercer, World at Work, and Gartner, increases are trending at approximately three percent.

Q. What is the company's projected STIP cost for 2022 and how does that amount compare to the the 2020 historic base year?

A. The company projects its STIP cost for the 2022 projected test year will be $21.73 million. This projected amount was calculated assuming that the target goals will be met, but not exceeded. The 2022 projected amount is less than the 2020 historic base year short-term incentive compensation expense of $33.99 million, which was higher than normal and budget because the company exceeded its target goals in 2020.

Q. What is the company's projected LTIP cost for the 2022 projected test year as compared to the 2020 historic base year?

A. The company's projected LTIP cost for the 2022 projected test year is approximately $6.83 million, which is slightly less than in 2020. The actual 2020 LTIP cost and payout of $7.15 million was slightly higher than expected, because the company exceeded its objectives for 2020. The projected amount for 2022 assumes the LTIP objectives will be met, not exceeded.

Q. Taken together, are the 2022 projected amounts for base pay, STIP and LTIP (i.e., Total Direct Compensation) reasonable?

A. Yes. As previously indicated, the market value of our TDC expense is 98.8 percent of the market median, which implies that we are paying within the market median and in support of our compensation philosophy that attracts, retains, develops, and rewards talent. In addition, we monitor our pay practices to ensure they conform with policy guidelines.

Q. What level of payroll cost increases for covered employees were included in projected payroll costs for 2022?

A. The company used the negotiated increases included in the current CBA to calculate payroll increases for covered employees. The increases reflected in CBA for IBEW Local 108 are as follows: 1.00 percent for 2019, 2.00 percent for 2020, 3.00 percent for 2021, 3.25 percent for 2022, and 3.50 percent for 2023. This CBA expires March 31, 2024.

We concluded our negotiations with the Office and Professional Employees International Union ("OPEIU") Local 46 at the end of 2020. The resulting CBA contains the following base rate increases: 3.00 percent for 2021, 2.75 percent for 2022, and 2.75 percent for 2023. This CBA expires December 31, 2023.

These increases, which were negotiated and benchmarked against other utilities in the Southeast, are reflected in salary and wages expense for 2022 and are reasonable.

Q. What is the company's gross benefits cost for the 2022 projected test year as compared to 2020?

A. Tampa Electric's total gross benefits cost is projected to be approximately $88.8 million in 2022, as compared to approximately $75.8 million in 2020. The change is primarily due to increased projected healthcare costs for active team members and increased projected post-retirement healthcare costs. The factors causing these increased costs are further described below. Despite the expected increases in healthcare related costs from 2020 through 2022, Tampa Electric's overall ability to control benefit costs has contributed to total projected Administrative & General costs in the test year falling below the benchmark, as outlined in MFR Schedule C-41.

Q. How do the gross benefits costs compare with the amounts the company has included in O&M FERC Account 926 Pension and Benefits?

A. Tampa Electric's pension and benefits costs in O&M FERC

Account 926 are projected to be approximately $52.36 million in 2022 as compared to $52.28 million in 2020. A portion of benefits costs are capitalized with labor or are clause recoverable; therefore, the amount in FERC Account 926 is lower than the gross benefits costs.

Q. What is the company’s projected healthcare cost for the 2022 test year?

A. Tampa Electric’s 2022 budgeted healthcare costs for active team members, including medical and dental expenses, is $35.56 million. The company received an actuarial estimate from Mercer that supports this level of expense. When adjusted to include medical and dental expense attributed to TECO Services Inc. (“TSI”) employees that transferred to Tampa Electric in 2020, the total adjusted medical and dental expense for years 2018 and 2019 were approximately $30.5 million and $28.1 million, respectively. Therefore, the growth in medical and dental expense from 2018 to 2022, as adjusted for TSI employee costs, is 16.4 percent and an average growth rate of 4.1 percent per year. This average growth rate per year is below the national medical cost trend of seven percent per year.

The company also provides post-retirement healthcare benefits and projects its expense levels based on actuarial calculations, similar to pension expense. The 2022 projected amount for active employees of approximately $4.6 million is based on Mercer’s actuarial projection and is reasonable. The 2020 post-retirement expense for active employees was approximately $2.83 million. The increase is the result of updated experience study performed by Mercer every four years. As a result of the 2020 experience study, assumptions were adjusted to reflect the impact of approximately 10 percent more employees participating in the TECO retirement medical plan and fewer employees opting out of medical coverage after retirement age. In addition, the 2021 forecasted expense assumes a reduction in the discount rate from 3.32 percent in 2020 to 2.40 percent in 2021. These costs are reflected on MFR Schedule C-35.

Q. Has there been any unusual activity observed in medical and dental expense from the period 2018 to 2020 and how does this compare to expectations for budgeted medical and dental expense?

A. When compared to the medical and dental expense incurred in 2018 and 2019, as adjusted for TSI employee medical and dental expenses, the medical and dental expense in 2020 was significantly lower. The decrease in medical and dental expense in 2020 as compared to the prior years is primarily related to the impact of COVID-19 on claim activity. In 2020, COVID-19 restrictions were put into place and employees remained quarantined for a significant portion of the year. Employees were reluctant to seek preventative or other non-essential medical treatments to avoid the risk of COVID-19 exposure. As a result, there were significantly fewer medical claims than what are experienced during a normal year. As supported by the opinion of Mercer and other industry experts, we expect that as pandemic conditions improve employees will begin to resume normal levels of medical care in addition to addressing any medical needs that may have been neglected during the pandemic. The ultimate impact of employee behavior on medical claims after the pandemic cannot be predicted, however we feel the assumptions used in the actuarial projections for budgeted healthcare and medical expense for 2021 and 2022 are reasonable.

Q. What is the company’s retirement expense for pension and retirement savings in the 2022 projected test year?

A. The total retirement expense for pension in the 2022 projected test year is $7.29 million. This includes $6.84

million for the Retirement Plan, $106,493 for the Supplemental Executive Retirement Plan, and $338,555 for the Restoration Plan. The total retirement expense for pension in the 2020 historical prior year is $9.94 million. This includes $9.36 million for the Retirement Plan, $246,788 for the Supplemental Executive Retirement Plan and $334,054 for the Restoration Plan. As a result of our actuarial valuation, pension expense is expected to decrease by $2.65 million from 2020 to 2022. The major reason for this cost reduction is related to interest costs. Interest costs are calculated as the annual interest on the beginning balance of the company's Projected Benefit Obligation. Due to expected reductions in actuarial assumptions over discount rates applicable in 2022, the interest costs are projected to be significantly lower.

The projected pension expenses are based on actuarial studies, are reasonable, and are included in FERC Account 926 as shown on MFR Schedule C-17.

Q. What is Tampa Electric's projected total compensation and benefits cost for 2022?

A. As outlined in MFR Schedule C-35, Tampa Electric's total compensation and benefits cost is projected to be $373,028,675 for 2022.

Q. Are Tampa Electric's total compensation and benefits costs for 2022 reasonable?

A. Yes. As noted above, the company benchmarks its total compensation and benefits costs against applicable markets using relevant utility benchmarks for both compensation and benefits and those costs come in at the median of the market. Furthermore, we have salaries that are at the median of the market and in support of our compensation philosophy that attracts, retains, develops and rewards talent. In addition, we monitor our pay practices to ensure they conform with policy guidelines.

SUMMARY

Q. Please summarize your prepared direct testimony.

A. Tampa Electric's total compensation package is reasonable and benefits customers by ensuring the company attracts and retains skilled, talented, and customer-focused team members that safely deliver reliable service for our customers. Tampa Electric's pay program is structured to be at the market median and is based on total direct compensation. Additionally, the company’s benefits and retirement programs are reasonable and competitive and allow the company to retain and attract high quality team members who are committed to safely providing excellent, reliable service to Tampa Electric’s customers.

Q. Does this conclude your prepared direct testimony?

A. Yes, it does.

(Whereupon, prefiled direct testimony of Lorraines L. Cifuentes was inserted.)

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

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

DIRECT TESTIMONY AND EXHIBIT
OF
LORRAINE L. CIFUENTES

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

LORRAINE L. CIFUENTES

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

A. My name is Lorraine L. Cifuentes. My business address is 702 North Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "company") as Director, Load Research and Forecasting in the Regulatory Affairs department.

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

A. My present responsibilities include the management of Tampa Electric's customer, peak demand, energy sales, and revenue forecasts, as well as management of Tampa Electric's Load Research program and other related activities.

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

A. In 1986, I received a Bachelor of Science degree in Management Information Systems from the University of South Florida. In 1992, I received a Master of Business Administration degree from the University of Tampa. In October 1987, I joined Tampa Electric as a Generation Planning Technician, and I have held various positions within the areas of Generation Planning, Load Forecasting, and Load Research. In November 2018, I was promoted to Director, Load Research and Forecasting.

Outside of Tampa Electric, I am also actively involved in several forecasting-related organizations. I am actively involved in the Electric Utilities Forecaster Forum ("EUFF"), which is an organization made up of electric utility forecasters from across the nation that meet twice a year to discuss forecasting issues and challenges. I held the position of President of the EUFF from 2008-2014. In addition, from 2009-2014 I was the chairperson for the Florida Reliability Coordinating Council, Inc.'s ("FRCC") Load Forecast Working Group and coordinated the review of Florida utilities' load forecasting methodologies and demand and energy forecasts that support the Peninsular Florida Load and Resource Plan and reliability assessments.

Q. What are the purposes of your direct testimony?

A. The purposes of my direct testimony are (1) to describe Tampa Electric's load forecasting process; (2) to describe the methodologies and assumptions used for the forecast; and (3) to present the load forecast used in Tampa Electric's test year budget that supports its request for a base rate increase. Additionally, I will demonstrate how the forecasts are appropriate and reasonable based on the assumptions provided.

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

A. Yes. I am sponsoring Exhibit No. LLC-1 consisting of 11 documents, prepared under my direction and supervision. The contents of my exhibit were derived from the business records of the company and are true and correct to the best of my information and belief. My exhibit consists of the following documents:

Document No. 1	List of Minimum Filing Requirement Schedules Sponsored or Co-Sponsored by Lorraine L. Cifuentes
Document No. 2	Comparison of 2013 Forecast Versus Current Forecast of Customer Growth and Energy Sales

Document No. 3	Economic Assumptions Average Annual Growth Rate
Document No. 4	Billing Cycle Based Degree Days
Document No. 5	Customer Forecast
Document No. 6	Per-Customer Energy Consumption
Document No. 7	Retail Energy Sales
Document No. 8	Per-Customer Peak Demand
Document No. 9	Peak Demand
Document No. 10	Firm Peak Demand
Document No. 11	Firm Peak Load Factor

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

A. Yes. I sponsor or co-sponsor the MFR schedules shown in Document No. 1 of my exhibit.

FORECAST RESULTS

Q. Please summarize the forecast results.

A. In my direct testimony I present forecasts that reflect the recent growth trends in the company's service territory. The company sales trends are consistent with the sales trends of other utilities in Florida.

The company expects customer growth to increase at an average annual growth rate ("AAGR") of 1.3 percent over the next ten years (2021-2030); however, we project the average customer use to decline during that period. Since 2011, per-customer consumption has declined at an AAGR of 0.9 percent, and we expect it to decline at an AAGR of 0.5 percent (0.4 percent excluding the volatile Phosphate sector) over the next ten years. Given the forecasts for 1.3 percent customer growth and 0.5 percent average per-customer use decline, the company expects retail energy sales to increase at an AAGR of 0.8 percent during the forecast horizon.

Q. Please explain the company's experience with load growth and customer growth since the last base rate proceeding was filed in 2013.

A. The company's experience over the past eight years has not been very different from the projections in the company's last base rate proceeding. Customer growth on an actual basis averaged 1.7 percent versus the projection of 1.5 percent. Consumption per-customer declined at the same rate that was projected in the last rate proceeding (-0.7 percent AAGR) for an overall annual average increase in energy sales of 1.0 percent versus the projection of 0.8 percent. During this period, the company’s annual peak demand increased from 3,892 MW to 4,255 MW, or by an average of 1.1 percent per year.

Although actual energy sales have been in line with the projections of the last base rate proceeding on average, 2020 is an exception. The unprecedented COVID-19 pandemic had a negative impact on energy sales starting in March 2020 and bottoming out around May 2020. Since then, there has been some improvement, but energy sales are still not back to normal levels. We expect conditions to continue to improve but not return to a more normal level until a vaccine is widely available. I discuss the impacts of COVID-19 in greater detail later in my direct testimony.

Document No. 2 of my exhibit shows the trends in customer growth and retail energy sales compared to the projections from the company’s last base rate proceeding and for the forecasts presented in my direct testimony.

The average annual growth rates over the forecast horizon (2021-2030) for customers and energy sales are 1.3 percent and 0.8 percent, respectively. The process Tampa Electric uses to prepare its load forecast and the steps it has taken to ensure the forecast is reasonable are discussed later in my testimony.

Q. What were the impacts of COVID-19 on energy sales in 2020?

A. Between March and December, residential energy sales volumes were approximately 2.2 percent above normal as the result of COVID-19. As more household members worked and attended school from home, there was an increased demand in appliance loads. The Shelter-In-Place order issued in April 2020 by Governor DeSantis, which mandated people to stay home and non-essential businesses to close, had adverse effects on the non-residential sectors. Between March and December, Commercial, Industrial, and Governmental/Public Authorities sector energy sales volumes decreased below normal levels by an estimated six percent, four percent, and four percent, respectively. In total, the COVID-19 impact to energy sales is a decline of approximately 1.4 percent from expectations.

TAMPA ELECTRIC’S FORECASTING PROCESS

Q. Please describe Tampa Electric’s load forecasting process.

A. Tampa Electric uses econometric models and Statistically Adjusted End-use Forecasting (“SAE”) models, which are integrated to develop projections of customer growth, energy consumption, and peak demands. The econometric models measure past relationships between economic variables, such as population, employment, and customer growth. The SAE models, which incorporate an end-use structure into an econometric model, are used for projecting average per-customer consumption. These models have consistently been used by Tampa Electric since 2003, and the modeling results have been submitted to the Commission for review and approval in past regulatory proceedings. MFR Schedule F-5, which I co-sponsor, provides a more detailed description of the forecasting process.

Q. Which assumptions were used in the base case analysis of customer growth?

A. The primary economic drivers for the customer forecast are Hillsborough County population estimates, Hillsborough County Commercial and Manufacturing employment, building permits, and time-trend variables. The population forecast is the starting point for developing the customer and energy projections. The population forecast is based upon the projections of the University of Florida’s Bureau of Economic and Business Research (“BEBR”). We supplement these sources with Moody’s Analytics projections of employment by major sectors and residential building permits. These economic growth projections drive the forecasted number of customers in each sector. For example, an increase in the number of households results in a need for additional services, restaurants, and retail establishments. Additionally, projections of residential building permits are a good indicator of expected increases or decreases in local construction activity. Similarly, commercial and industrial employment growth is a good indicator of expected activity in those respective sectors. The ten-year historical and forecasted average annual growth rates for these economic indicators are shown in Document No. 3 of my exhibit.

Q. Which assumptions were used in the base case analysis of energy sales growth?

A. Customer growth and per-customer consumption growth are the primary drivers for growth in energy sales. We base the average per-customer consumption for each revenue class on the SAE modeling approach. The SAE models have three components. The first component includes assumptions of the long-term saturation and efficiency trends in end-use equipment. The second component captures changes in economic conditions, such as increases in real household income, changes in number of persons per household, the price of electricity, and how these factors affect a residential customer’s consumption level. I provide a complete list of the critical economic assumptions used in developing these forecasts in Document No. 3 of my exhibit. The third component captures the seasonality of energy consumption. Heating and cooling degree day assumptions allocate the appropriate monthly weather impacts and are based on Monte Carlo simulations for weather patterns over the past 20 years. Historical and projected heating and cooling degree days are shown in Document No. 4 of my exhibit. MFR Schedules F-7 and F-8 provide a description and the historical and projected values of each assumption used in the development of the 2022 test year retail energy sales.

Q. Which assumptions were used in the base case analysis of peak demand growth?

A. Peak demand growth is affected by long-term appliance trends, economic conditions, and weather conditions. The end-use and economic conditions are integrated into the peak demand model from the energy sales forecast. The weather variables are heating and cooling degree days at the time of the peak, for the 24-hour period of the peak day, and the day prior to the peak day. Weather variables provide seasonality to the monthly peaks. By incorporating both temperature variables, the model accounts for cold or heat buildup that contributes to determining the peak day demand. Temperature assumptions are based on an analysis of 20 years of peak day temperatures. For the peak demand forecast, the design temperature at the time of winter and summer peaks is 31 and 92 degrees Fahrenheit, respectively.

Q. Does Tampa Electric assess the reasonableness of these base case assumptions?

A. Yes. We evaluate the base case economic assumptions by comparing the historical average annual growth rates to the projected average annual growth rates for the forecast period. In addition, we compare each economic data series to an alternate source and evaluate it for consistency. The alternate sources Tampa Electric uses for comparisons are the Office of Economic and Demographic Research, which is part of the Florida Legislature, the U.S. Energy Information Administration, and the University of Central Florida's Institute for Economic Forecasting. I found that the projections between the sources vary slightly, but the timing of the expected economic rebounds is consistent. Therefore, it is reasonable to conclude that the Moody's Analytics economic growth assumptions for Hillsborough

County are also reasonable.

Q. Were the forecasts for population growth also evaluated for reasonableness?

A. Yes. We compared county and state level projections and evaluated them for consistency. We also compared the Moody's Analytics and BEBR population forecasts and evaluated them for consistency. The BEBR 2022 population growth projections are slightly higher than Moody's. BEBR's growth rates are more aligned with Tampa Electric's recent customer growth levels.

Q. Please describe the historical accuracy of Tampa Electric's retail customer and energy sales forecasts.

A. Since the last rate proceeding in 2013, the average accuracy of the customer forecasts has been remarkable; the seven-year average accuracy is 0.1 percent below the actuals.

The average accuracy of per-customer consumption over the past seven years was 1.1 percent below the actuals, primarily due to hotter weather in recent years. However, when adjusting for weather, the average per-customer consumption forecasts have been overstated by 1.0 percent on average.

The resulting average accuracy of the retail energy sales forecasts is 1.2 percent below actual use and 0.8 percent above actual consumption when weather adjusted.

Q. Have Tampa Electric’s forecasting models used in developing the customer, demand, and energy forecasts been reviewed for reasonableness?

A. Yes. In 2009 and 2013, Itron, Inc. (“Itron”), an industry leader that provides utility forecasting software and methodologies to more than 160 utilities and energy companies, reviewed Tampa Electric’s forecasting models and assumptions. During each review, Itron concluded that the forecast models were theoretically sound with excellent model statistics and that the modeling errors were reasonable and consistent with other utilities. Since then, Tampa Electric has not made any significant changes to its forecasting models and equations.

TAMPA ELECTRIC’S FORECASTED GROWTH

Q. How many customers does Tampa Electric have?

A. Tampa Electric's current customer count is shown in Document No. 5 of my exhibit. Tampa Electric had an average of 786,048 retail accounts in 2020.

Q. What is Tampa Electric's projected customer growth?

A. Customer growth in 2020 was 1.8 percent, while projections for 2021 and 2022 are 1.7 percent and 1.6 percent, respectively. Tampa Electric projects an average annual increase of 11,013 (1.3 percent) new customers over the next ten years (2021-2030). Historical and projected customer counts are shown in Document No. 5 of my exhibit.

Q. How do Tampa Electric's projected customer growth rates compare with historical growth rates?

A. Historical ten-year AAGR for customers is 1.7 percent and projected customer growth rates are 1.3 percent. This projected growth rate represents customer growth of 1.7 percent in 2021, slowing to 1.0 percent by 2030. BEBR's population projections drive the lower projected growth rates. The moderation of growth rates over the forecast horizon is not uncommon; it is a consistent trend seen in the company's past Ten-Year Site Plans, as well as in other Florida utilities' Ten-Year Site Plans.

Q. Please describe Tampa Electric's energy sales forecast.

A. The primary driver of the increase in the energy sales forecast is customer growth. The impact of per-customer consumption, which is expected to decrease at an average annual rate of 0.5 percent over the next ten years (2021-2030), offsets some of the customer growth as shown in Document No. 6 of my exhibit. Combining the forecasted customer growth and per-customer consumption trends, we expect retail energy sales to increase at an average annual rate of 0.8 percent over the next ten years (2021-2030). I provide historical and forecasted energy sales in Document No. 7 of my exhibit.

Q. What are the primary drivers of the projected decline in average usage?

A. The primary drivers of declining average use are improvements in end-use efficiency resulting from appliance and equipment replacement; new end-use standards, such as the new lighting standards that are expected to have a significant impact on residential sales; economy-induced conservation; and demand-side management ("DSM") program activity.

Q. How do the 2022 test year projections for retail energy sales compare to the same year projections that were prepared and filed in Tampa Electric's 2013 base rate case?

A. The current 2022 projection for energy sales growth is 1.0 percent, compared to 1.1 percent in the projection for the year 2022 that was filed in the 2013 rate case.

Q. What is Tampa Electric's peak demand forecast?

A. We project summer and winter peak usage per customer will decrease at an average annual rate of 0.3 percent. Document No. 8 of my exhibit shows historical and forecasted peak usage per customer for summer and winter peaks. The increase in customers and the decrease in per-customer demand results in an average annual growth rate of 1.0 percent over the next ten years for both the winter and summer peaks, as shown in Document No. 9 of my exhibit. Summer and winter firm peak demands, which have been reduced by curtailable load such as load management and interruptible loads, are shown in Document No. 10 of my exhibit.

Q. Are conservation and demand-side management impacts accounted for in the energy sales and peak demand forecasts?

A. Yes. Tampa Electric develops energy and demand forecasts for each conservation and DSM program. The aggregated incremental energy savings and demand impact projections are then subtracted from the forecasts.

Q. Are the impacts of rooftop solar generation accounted for in the energy sales and peak demand forecasts?

A. Yes. Tampa Electric energy sales and peak demand forecasts include the impacts of rooftop solar generation.

Q. Are electric vehicle impacts accounted for in the energy sales and peak demand forecasts?

A. Yes, we included electric vehicles in the energy sales and peak demand forecasts.

Q. Does the forecast include the expected impacts of the COVID-19 pandemic? If so, what methodology was used?

A. Yes, our forecast includes the impacts of the COVID-19 pandemic in energy consumption per-customer. An out-of-model adjustment factor was used to capture the short-term behavioral changes that the economic data cannot fully explain, including customer-specific behavioral changes such as staying at home and decisions to close or open educational institutions and non-essential businesses. We applied the adjustment factors to August 2020 through December 2021 data. By the 2022 test year, these factors are no longer included, and we capture the remaining impacts of COVID-19 in the projected economic variables just as any effects from other economic upturns or downturns would be captured.

Q. Has the company performed any sensitivity analyses on its load forecast?

A. Yes. We tested the base case scenario for sensitivity to varying economic conditions and customer growth rates. The high and low peak demand and energy sales scenarios represent an alternative to the company’s base case outlook. The high scenario represents more optimistic economic conditions in the areas of customers, employment, and income. The low band represents less optimistic scenarios in the same areas. Compared to the base case, the expected customer and economic growth rates are 0.5 percent higher in the high scenario and 0.5 percent lower in the low scenario.

Q. Does Tampa Electric conclude that the forecasts of customers, energy sales, and demand are appropriate and reasonable?

A. Yes. The customer, demand, and energy sales forecasts are based on assumptions developed by industry experts and are the most recent assumptions available at the time the forecasts were prepared. We used theoretically and statistically sound methods that were previously reviewed and accepted by the Commission to develop the forecasts. In addition, we compared the average annual growth rates for per-customer demand and energy usage for consistency with historical growth rates. We reviewed summer and winter load factors to ensure proper integration of the peak and energy models. The results show that the load factors are reasonable when compared to historical years. The load factors are shown in Document No. 11 of my exhibit. The customer, energy sales, and demand forecasts are appropriate and reasonable for planning purposes.

BILLING DETERMINANTS

Q. The methodology and forecasts described in your direct testimony are on a customer class basis, so how are these forecasts converted to a tariff rate schedule basis for rate design analysis?

A. We convert the output of our customer class models to the tariff rate schedules by conversion models which use billing determinant distribution factors. The exception is the Interruptible Service rate schedules; since they are forecasted at the customer level there is no need to apply distribution factors.

Q. Please explain the term billing determinants.

A. Billing determinants are the parameters to which prices are applied to derive billed revenues. They include 1) the number of customers (*i.e.,* bills) to which the customer charges are applied, 2) the amount of energy or kilowatt-hours ("kWh") sold to which the energy charges are applied, and 3) the amount of demand or kilowatts ("kW") to which the demand charges are applied. They also include the number of units to which any additional charges, discounts, and/or penalties are applied.

Q. How are billing determinant distribution factors derived?

A. The first step is to calculate the historical distribution factors (e.g., the percentage of total residential class customers and energy that are in each residential rate schedule). Next, we analyze the trends in these percentages for each rate schedule and base the future distribution factors on the most recent trends. Similarly, we base rate schedules that have billing demand charges on historical load factors.

Q. How are these billing determinants used?

A. We apply the forecasted billing determinants to current and proposed rates to calculate the base revenues from the sale of electricity for the 2022 test year. Tampa Electric witness William R. Ashburn discusses this process in his direct testimony.

SUMMARY

Q. Please summarize your direct testimony.

A. The population of Tampa Electric’s service area will continue to grow at a steady pace over the forecast horizon. The company expects an average increase in customers of 1.3 percent a year, which is an increase of almost 112,402 by 2030. We expect per-customer demand and energy consumption to continue to decline over the next ten years. As a result, we project retail energy sales will increase at an average annual rate of 0.8 percent (0.9 percent excluding the declining Phosphate sector) over the next ten years.

We conducted reviews of actual energy sales results versus the company’s most current forecast for the period August 2020 to February 2021 and the forecast for energy sales was 0.2 percent above actual energy sales adjusted for weather. These results confirm that the company’s forecast is a reliable representation of projected sales. This forecast is the same forecast used for the 2022 test year projections. We used industry “best practice” methods and appropriate and reasonable assumptions to develop our customer, energy sales, and demand forecasts, and they are reasonable for use in this proceeding.

Q. Does this conclude your direct testimony?

A. Yes, it does.

(Whereupon, prefiled direct testimony of John C. Heisey was inserted.)

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 20210034-EI

IN RE: PETITION FOR RATE INCREASE

BY TAMPA ELECTRIC COMPANY

DIRECT TESTIMONY AND EXHIBIT

OF

JOHN C. HEISEY

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

JOHN C. HEISEY

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

A. My name is John C. Heisey. My business address is 702 North Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "company") as Manager, Gas and Power Trading.

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

A. I am responsible for natural gas and power trading activities and work closely with the company's unit commitment team to provide low cost, reliable power to customers. I am also responsible for portfolio optimization and all aspects of our Optimization Mechanism.

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

A. I graduated from Pennsylvania State University with a Bachelor of Science in Business Logistics. I have over 25 years of power and natural gas trading experience, including employment at TECO Energy Services, FPL Energy Services, El Paso Energy, and International Paper. Prior to joining Tampa Electric, I was Vice President of Asset Trading for the Entegra Power Group LLC ("Entegra"), where I was responsible for Entegra's energy trading activities. Entegra managed a large quantity of merchant capacity in bilateral and organized markets. I joined Tampa Electric in September 2016 as the Manager of Gas and Power Trading and currently hold that position.

Q. What are the purposes of your direct testimony?

A. My direct testimony describes Tampa Electric's fuel inventory planning process; the factors that influence maintaining a reliable supply and delivery of natural gas, coal, and oil; and our proposed level of fuel inventory for the 2022 test year. My direct testimony also describes the company's Optimization Mechanism and explains why it should be continued after the company's 2017 Amended and Restated Stipulation and Settlement Agreement ("2017 Agreement") expires on December 31, 2021.

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

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

Document No. 1	List of Minimum Filing Requirement Schedules Sponsored or Co-Sponsored by John C. Heisey
Document No. 2	2022 Proposed Coal Inventory
Document No. 3	2022 Proposed Total Fuel Inventory
Document No. 4	Optimization Mechanism Results

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

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

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

A. Tampa Electric witness David A. Pickles explains in his direct testimony how the transformation of our generating system has changed the mix of fuel we use to generate electricity, and I explain how those changes influence our fuel purchasing practices and reduced our inventory of solid fuel (coal). My direct testimony supports the total amount of fuel inventory we propose to include in working capital for 2022. Tampa Electric witness A. Sloan Lewis explains how our proposed level of fuel inventory factors into our revenue requirement calculation for the test year.

Q. What types of fuel does Tampa Electric use to generate electricity?

A. Tampa Electric uses natural gas, coal and petroleum coke ("coal" or "solid fuel"), and light oil to generate electricity. In 2020, Tampa Electric's generation mix was comprised of approximately 89 percent natural gas, approximately six percent solar, approximately five percent coal, and less than one percent light oil. The company's annual coal requirement is approximately 400 to

600 thousand tons and our annual natural gas requirement is about 130 million MMBtu. The company maintains a relatively small amount of light (No. 2) oil as a backup fuel for Polk Unit 2.

Q. How does Tampa Electric's fuel mix today compare to its fuel mix in 2013?

A. Being cleaner and greener is one of Tampa Electric's areas of strategic focus, and the price of natural gas has fallen dramatically in the last decade, so the company has changed its generation mix away from coal to solar and natural gas. Natural gas-fired generation has become our primary fuel for generating electricity. Consequently, although coal inventory is still needed for the company to reliably provide electric service to our customers, our total coal inventory requirement, in tons, is much lower than it has been in the past, which means lower coal-related costs for customers.

In 2013, natural gas accounted for 41 percent of our fuel mix, and coal made up the remaining 59 percent. Today, coal accounts for about five percent of our fuel mix, with natural gas at about 89 percent and solar (no fuel) at about six percent.

Q. Does the company maintain an inventory of natural gas?

A. Yes. Under normal operating conditions, the natural gas supply and pipeline infrastructure in the United States allows natural gas to be produced, transported, and consumed without a need to maintain a substantial amount in inventory. Nevertheless, Tampa Electric maintains two million MMBtu of natural gas storage capacity to provide operational flexibility and to ensure it has a reliable supply of natural gas supply during disruption events. Natural gas storage also mitigates short term price volatility for our customers during disruption events.

Q. What is the objective of Tampa Electric's fuel management plan?

A. The company seeks to maintain a reasonable level of fuel inventory that minimizes the risk of electric service interruptions from lack of fuel so we can generate power to meet instantaneous system demand, while at the same time minimizing the economic impact to customers.

Q. How does the company plan to achieve this objective?

A. The company’s overall fuel procurement planning process recognizes the operating factors that affect inventory levels, such as fuel supply availability, fuel delivery logistics, fuel consumption, storage capacity, fuel quality, and risk of extraordinary events that could disrupt supply. Experience shows that maintaining reasonable levels of fuel is less expensive than making emergency purchases of fuel or replacement power at premium prices, and also reduces the risk of interrupting electrical service to customers. Tampa Electric uses diverse supply sources and delivery methods to mitigate the risks of events that may interrupt fuel supply to the company's generating system.

Q. What fuel inventories are components of your overall system-wide fuel inventory?

A. Our fuel inventory includes natural gas, coal, and oil.

The natural gas amount included in inventory is the amount owned by Tampa Electric and stored in underground storage caverns or interstate pipelines.

Our oil inventory includes quantities stored in tanks on-site at generating stations.

Our coal inventory has historically included all coal that the company purchased and had in its control, including coal stored on-site at the power plants, coal stored off-site, and coal that was purchased and in transit to our generating sites. In 2018, however, the company began purchasing "delivered" coal, which shifted the responsibilities, costs, and logistics of transporting coal by water to our Big Bend unloading terminal to the supplier. Most of the coal we now consume arrives by water, and we use coal delivered by rail to supplement our incremental needs during peak consumption periods. The costs and responsibility for arranging coal transportation by rail remains the responsibility of Tampa Electric because our suppliers have been unwilling to accept that responsibility.

Q. Are the 2022 projected fuel inventory levels shown on MFR Schedule B-18 for natural gas, coal and oil reasonable?

A. Yes.

COAL INVENTORY

Q. What level of coal inventory does the company propose to include in working capital for 2022?

A. As shown on MFR Schedule B-18, the company proposes to include a thirteen-month average of 285,789 tons with a value of approximately $17.7 million in working capital for the 2022 test year.

Q. Was this amount adjusted using the FPSC approved thirteen-month average 98-day average daily burn methodology ("98-day average burn") approved in the company's last rate case?

A. No. The company is proposing a new coal inventory methodology because the existing 98-day average burn methodology is no longer reasonable or appropriate for evaluating the amount of coal inventory to be included in working capital for Tampa Electric.

Q. Why not?

A. The way Tampa Electric uses coal-fired generation and the role its coal plants play in the economic unit commitment and dispatch of the company's generating fleet have changed since the 98-day coal inventory level was established on February 2, 1993 in Order PSC-0165-FOF-EI, Docket 920324-EI. The 98-day coal inventory level will not provide the company enough coal to reliably operate our coal plants the way we expect to operate them in the future or allow for sufficient coal inventory levels if something unexpected were to happen to our natural gas supply, natural gas transportation, or natural gas-fired generation.

Q. Please explain.

A. Coal units like Big Bend Units 1 through 4 and Polk Unit 1 (integrated gasification combined cycle) have been the work horses in the company's generation fleet for many years. They were designed to burn coal (or to gasify coal and burn gas, in the case of Polk 1) and operated as base load units for decades. Base load units normally operate to satisfy the minimum load of a system, and consequently run continuously, burn fuel, and produce electricity at relatively constant rates. When these units ran on coal as base load units, they burned large volumes of coal almost every day at relatively constant rates; however, several things changed.

First, the Polk 2 Conversion changed the unit commitment and dispatch order of Polk Unit 2 versus our Big Bend units. Polk Unit 2, which was converted to a natural gas combined cycle unit, transitioned from primarily being a peaking facility to a baseload facility, and the role of our Big Bend units became secondary in support of our baseload facilities.

Second, the price of natural gas dropped and stayed low. Although some of our generating units (*i.e.*, Polk Unit 1 and Big Bend Unit 3) can operate on coal and natural gas, it has been more economical for them to operate on natural gas, which means we are burning less coal.

Third, as explained in the direct testimony of Mr. Pickles and Tampa Electric witness J. Brent Caldwell, we are in the process of modernizing Big Bend Unit 1 and will be retiring Big Bend Units 2 and 3. These changes have already reduced the amount of coal the company is burning and will further reduce the amount we consume in the future.

Fourth, as explained in the direct testimony of Mr. Pickles and Tampa Electric witness C. David Sweat, the company built approximately 655 MW_{ac} of solar generating capacity from 2017 to 2021 and plans to build an additional 600 MW_{ac} of solar capacity from 2021 to 2023 ("Additional Solar"). This solar capacity has and will continue to reduce the company's need to consume coal.

As a result, the role coal plays in our generation has changed from a primary fuel to a secondary fuel. We no longer need coal as a primary fuel to burn continuously in large amounts for long periods of time. Rather, we need coal for use when the economics of doing so are favorable, when system conditions change, or for use if something unexpected happens to natural gas supply, natural gas transportation, or our natural gas-fired generation is not available.

Q. How have these changes reduced the company's consumption of coal?

A. Our coal consumption has fallen from approximately four million tons in 2015 to 430,000 tons in 2020, or by about 90 percent. As our coal consumption has declined, so too has the amount of coal we need to maintain in inventory.

Q. What are the benefits of burning less coal?

A. Burning less coal means we use less water, generate less wastewater, and lower our emission of CO_2, SO_2, and NO_x, all of which makes us cleaner and greener. Burning less coal has also enabled the company to reduce its production O&M expenses. Lastly, burning less coal means we need to keep less coal in inventory, which also reduces our costs and the costs we recover from our customers.

Q. Does the company still need to maintain a reasonable level of coal inventory?

A. Yes. Even though we are burning less coal, we still must have enough coal on hand to operate our coal-fired facilities when we need them.

Q. Is the thirteen-month, 98-day daily average burn coal inventory level approved in the company's rate case still a reasonable methodology for establishing appropriate levels of coal inventory?

A. No. Due to the company's transformation to a cleaner and greener generation system, daily coal burn is so low that calculating a coal inventory level using the 98-day average daily burn methodology produces a very low coal inventory amount. More specifically, basing our coal inventory levels on the 98-day average daily amount of coal we are burning will result in a coal inventory at levels that will not allow the company to recover the amount of coal inventory required to operate its coal plants as base load units if an outage at one or more of the company’s natural gas-fired units occur or if natural gas supply or natural gas transportation becomes unavailable. Therefore, using the traditional 98-day average daily burn methodology will not allow the company to recover the cost of the coal inventory needed to maintain the reliability of our system.

Q. How has the 98-day average daily burn amount changed over time?

A. From 2013 to 2015, our 98-day average burn was 1.2 million tons. From 2019 to 2020, it was 132 thousand tons, or about ten percent of what it was from 2013-2015. We do not believe that maintaining a thirteen-month average of 132 thousand tons of coal, which can be burned at Big Bend Unit 4 in less than a month, will be adequate for us to provide reliable service to our customers. The company has been maintaining coal inventory at much higher levels, even though we cannot recover the incremental inventory under the 98-day coal inventory level.

Q. What coal inventory level is the company using to determine the system-wide coal inventory levels to support its operations?

A. For planning and operating purposes, Tampa Electric targets enough coal inventory to run its coal plants (primarily Big Bend Unit 4) at maximum burn levels for 60 days. Therefore, the company requests permission to adopt this 60-day maximum burn level for base rate making purposes.

MFR Schedule B-18 in Document No. 1 of my exhibit shows the company’s proposed level of coal inventory by station in tons and dollars for each month of the 2022 test year and supports the 13-month average amounts of coal inventory shown on page 9 of my direct testimony. Document No. 2 of my exhibit shows the overall anticipated quantities of coal in inventory by station projected for 2022.

MFR Schedule B-18 does not include any coal inventory stored off-site, because our agreement for storage at Davant, Louisiana ends in December 2021 and is not expected to be renewed.

The inventory amounts shown on MFR Schedule B-18 for the Polk Power Station (“Polk”) are zero each month, because the company does not expect to burn coal at Polk in 2022.

The other monthly amounts (Big Bend) shown on MFR Schedule B-18 vary seasonally and reflect monthly inventory amounts of between 50 to 67 days of maximum burn and a thirteen-month weighted average of 57 days maximum burn. This thirteen-month average amount is slightly below the target we use for planning and operations and is below the thirteen-month average 60-day maximum burn coal inventory level we are requesting the Florida Public Service Commission ("Commission") approve in this base rate case.

Q. How does the company's proposed amount of inventory for 2022 compare to the amount that would be allowed under the traditional 98-day average burn methodology?

A. Our proposed amount is higher on a thirteen-month average basis by about 140,000 tons or approximately $9.0 million.

Q. For how long would the company be able to run its coal plants at the maximum burn rate if it uses the 98-day average burn coal inventory level?

A. About 29 days.

Our maximum daily burn is about 5,000 tons a day and the

98-day average burn methodology would allow us to keep only about 145,000 tons of coal in inventory.

We do not believe keeping only 29 days of coal on hand to operate our coal plants at maximum burn levels is adequate, reasonable, or prudent. Our proposal to use a 60-day maximum burn target is informed by the risks, and our experiences with, factors that impact coal supply availability and deliverability, fuel use variability, and the potential for extraordinary events. It is also informed by the risks of natural gas supply and delivery interruptions that I discuss in the next section of my direct testimony. Tampa Electric targets a minimum of approximately 60 days of maximum coal burn in its operations and closely monitors these factors because of the dramatic impacts they can have on the cost and availability of fuel.

Q. Why do the amounts of inventory shown on Document No. 1 of your exhibit vary by month?

A. The amount of electricity we generate each month varies seasonally and so too must the amount of inventory we keep on hand. We generally keep more inventory in the summer months because energy usage in those months is high and the potential adverse impact of hurricanes and other named tropical storms on the deliverability of fuel is higher than in other times in the year.

Q. Why does the company need 60 days of maximum burn in inventory, rather than a fewer number of days?

A. First, we are actually keeping about that much coal inventory on hand as we operate our business. The fact that we keep that amount of inventory on hand, when cost recovery for that full level is not available under the 98-day average burn methodology, is strong proof of our need for and commitment to a 60-day maximum burn level of inventory.

Second, due to the generation fleet changes described above, we now view coal as a secondary fuel and need it primarily to operate our dual-fuel plants on coal as base load units if we experience a natural gas supply or natural gas transportation interruption or an unplanned outage at one or more of the company’s gas-fired units. A major planned or unplanned outage at one of our base load natural gas-fired plants could take up to 60 days or more, in which case we would likely need to run our coal plants as base load units for 60 days or more. Having a

60-day maximum burn amount of coal inventory on hand will allow us to maintain system reliability by burning coal on hand and provide an adequate amount of time to arrange the purchase of additional coal, as needed, if we have a major outage at one of our gas units.

Q. Why does the company need 60 days to procure additional coal?

A. The company can procure coal in less than 60 days on an emergency basis, however, emergency coal purchases are almost always more expensive than planned purchases.

In addition, unlike natural gas, which is delivered via pipelines which are ready to instantaneously deliver gas on short notice, the coal we purchase is over 1,000 miles away and must be transported by water or rail to our facilities. Even when purchase and delivery conditions are perfect, it takes up to 60 days to complete the coal purchasing cycle (identify need, order, transport, receive). Bearing in mind, conditions for purchasing and delivering coal are not always perfect. Under extreme conditions the time to procure coal can take more than 90 days.

Q. How do factors like coal supply availability and delivery risks influence the company's need to maintain coal inventories at its proposed 60-day maximum burn level?

A. Both are important considerations.

Over the years, coal supply availability and deliverability to Tampa Electric have been adversely affected by weather conditions including floods, hurricanes, extreme conditions on waterways, water route blockages, work disruptions in the coal and railroad industries, consumption variations, and transportation provider equipment breakdowns. The level of coal inventory we need to maintain must reflect the risks associated with supply availability and delivery disruptions. Our proposed 60-day maximum burn standard accounts for these risks but does not overstate our need for coal.

Q. Did changing the delivery responsibilities for waterborne coal in 2018 reduce the company's operating exposure to delivery disruptions?

A. No. The fact that we changed the delivery point of waterborne coal from the mine to our generating stations in 2018 does not mean that our operations are no longer subject to supply disruptions. Whether the company or its suppliers are responsible for transportation, the company remains subject to supply disruptions from river closings. Portions of the Mississippi and Ohio River systems must be closed periodically to repair the lock and dam mechanisms used to raise and lower barges for proper navigation. Almost every year, high or low water conditions due to rain, snow, or drought slow or stop river traffic. Fog, ice, and transportation equipment breakdowns can also delay or interrupt waterborne transportation on the rivers. Fog, hurricanes, and equipment breakdowns also affect waterborne transportation in the Gulf of Mexico as well.

Q. Is rail transportation subject to delivery interruptions?

A. Yes. The rail transportation system we rely on can be adversely affected by traffic congestion, track maintenance, rail blockings, flooding, and equipment breakdowns, resulting in slower turn times. Turn time is the time it takes a train to return to the coal mine for its next shipment. Slower turn times mean fewer deliveries.

Q. Has the company recently faced coal delivery disruptions?

A. Yes. The company recently faced coal delivery disruptions caused by the weather (Mississippi River flooding or hurricanes). Weather events can cause lingering issues that disrupt normal fuel supply and logistics for many months. We successfully managed through these disruptions by having sufficient inventory (*e.g.*, 60 days of maximum coal burn) and being able to shift our supplier choice and delivery method from waterborne to rail.

Q. Do you have examples of how weather events have affected fuel availability or deliveries?

A. Hurricanes Katrina (2005) and Isaac (2012) struck the mouth of the Mississippi River and caused significant disruptions to coal and other energy commodity deliveries.

After Hurricane Katrina, Tampa Electric's on-site inventory levels at Big Bend fell to a low of only 20 days. Tampa Electric was able to maintain adequate inventory supply on-site and manage through the disruption of deliveries, which lasted almost six months, without disrupting service to its customers.

Hurricane Isaac caused widespread flooding and disabled several bulk storage terminals at the mouth of the Mississippi River for many weeks.

Tropical Storm Debbie, which hit in June 2012, constrained shipping in Tampa Bay for an extended period of time.

In addition, Tampa Electric experienced multiple supply vessel delays due to the multiple hurricanes affecting the Gulf Coast of Florida and Louisiana in 2020.

Q. Does Tampa Electric's ability to receive coal by water and rail mitigate the risk of delivery disruptions to the company?

A. Yes. Tampa Electric's ability to receive coal by water and rail provides important optionality and reduces the risk of a solid fuel disruption to customers. It also gives us negotiating leverage with suppliers. However, it still takes as many as 60 days to purchase and receive coal, so we must keep an adequate supply on hand.

Q. Is coal supply availability a growing concern?

A. Yes. The market dynamics for domestic coal production are changing. Electric utilities all over America have retired or are planning to retire coal-fired generating plants, which has substantially reduced the demand for domestic coal. Reduced demand and increased production costs for coal have caused financial distress for many domestic coal producers and created uncertainties about the future availability and costs of coal. Force majeure events and mine issues can and have influenced and disrupted coal production. Diminished supplier performance can and has disrupted coal supplies and deliveries. Even though we are consuming less coal, our need for coal remains, and it is becoming more difficult to find suppliers that we can count on in the future. Keeping an adequate supply of coal on hand helps mitigate the risks associated with supplier failures and disruptions.

Q. How have coal mining companies performed during recent years?

A. Coal suppliers have had significant economic challenges and faced bankruptcies, acquisitions, and reorganizations, but the suppliers Tampa Electric deals with have managed to keep their supply commitments to Tampa Electric.

Q. What is “coal burn variability” and how does it affect Tampa Electric’s coal inventory planning process?

A. Coal burn variability refers to the difference between our planned coal burn and our actual coal burn. Burn variability is influenced by a variety of factors, such as the relative economics of natural gas, seasonality, weather, unit operating performance (including unit availability, heat rate, and capacity factor), and other system operating factors such as grid stability.

For the most cost-effective pricing, coal suppliers and transporters require consistent, expected sales volumes, so they can plan their monthly production and delivery schedules. Getting coal out of the ground for sale is not as simple as opening a valve on a natural gas pipeline.

As the role our coal plants play on our system has changed, our coal burn variability has increased, and our ability to find suppliers who will accommodate inconsistent or variable monthly consumption volumes has been challenging. All other things being equal, maintaining higher coal inventory levels allows us to absorb swings in supply availability during times of greater burn variability.

The extent to which burn variability affects Tampa Electric in the overall inventory planning process depends on how quickly and completely the company can respond to unexpected fuel requirements at the electric generating plants. Given where our coal suppliers are located and the distances coal must travel before we use it, our planning process must accommodate higher levels of coal burn variability. When fuel supply availability is constrained, the process of procuring solid fuel can increase from 60 days to well over 90 days from the time we identify a need for more coal to the time that coal arrives at a Tampa Electric power plant.

Q. What kind of "extraordinary events" affect coal inventory planning?

A. In addition to the "regular" supply and delivery risks discussed above, we must consider the possibility of extraordinary events. Examples from the past include the terrorist attacks on September 11, 2001, which complicated and delayed the transportation of coal due to heightened port security. Although it was less significant, the COVID-19 pandemic reduced access to labor in some areas and delayed coal shipments. The collapse of the Sunshine Skyway Bridge in the 1980s and vessels sinking in Port of Tampa Channels have blocked or delayed waterborne coal deliveries to Tampa Electric. While events like these are rare, the potential reliability impact is significant if we do not maintain an adequate level of coal inventory.

Q. Should the Commission approve the company's proposal to replace the 98-day average burn coal methodology of establishing inventory levels in working capital to establishing inventory levels using 60 days of maximum burn?

A. Yes. Based on the reasons stated above and the company's need to maintain coal inventory levels to operate the coal units prudently and reliably, the Commission should approve the proposed 60 days of maximum burn coal inventory level.

NATURAL GAS INVENTORY

Q. What amount of natural gas inventory does the company propose to include in working capital for the 2022 test year?

A. As shown on MFR Schedule B-18, the company proposes to include its projected 13-month average volume of natural gas in storage for 2022 of 336,726 MCF with a value of $0.9 million in test year working capital.

Q. Please explain the company's need for and portfolio of natural gas supply.

A. Tampa Electric has a fleet of natural gas fired generating units including combined cycle units at Bayside and Polk; dual-fuel units at Big Bend; Polk Unit 1, which can operate on natural gas or a blend of petroleum coke and coal; and natural gas fired aero-derivative combustion turbines at Bayside and Big Bend.

Q. Please describe Tampa Electric's natural gas supply plan.

A. The company's supply plan for natural gas is to maintain a portfolio of natural gas supply arrangements that have access to multiple supply basins, various receipt and delivery points, volume flexibility, and varying term lengths. We must also ensure that we have enough firm natural gas transportation to deliver the natural gas we purchase to our natural gas-fired power plants. These natural gas supply arrangements are established using industry standard contracts with creditworthy parties. This process gives us supply reliability, operating flexibility, and lower overall costs. Most of the costs for these supply arrangements are recovered through the Fuel, Purchased Power and Capacity Recovery Clause, but the amount of natural gas we keep in storage is an inventory item and is recovered through base rates.

Maintaining underground natural gas storage is another valuable part of our plan to provide reliable service to our customers. We primarily use natural gas in storage to address unexpected swings in our natural gas supply needs from unexpected increases in our use of natural gas-fired generating units and to “smooth” natural gas supplies over weekends and holidays when consumption levels may change dramatically. In addition, natural gas storage helps to mitigate reliability or cost impacts on customers when extreme conditions occur.

Tampa Electric also maintains nearly full contracted storage levels during times of greatest uncertainty. For instance, Tampa Electric fills natural gas storage capacity to approximately 80 percent before the start of each hurricane season since supply availability may be at risk while our use of natural gas is at its maximum. Similarly, Tampa Electric keeps natural gas storage at similar levels during major plant outages and extreme cold weather periods since natural gas consumption is most uncertain during those times.

Q. What factors impact the risk of natural gas supply and transportation disruptions?

A. Extreme weather conditions present the greatest risks to a reliable supply of deliverable natural gas. Natural gas production companies shut down production in the Gulf of Mexico when tropical storms and hurricanes threaten the safe operation of drilling platforms and production facilities in the Gulf. As we saw during Winter Storm Uri in February 2021 and the resulting Texas grid failure, extremely cold weather can interfere with onshore natural gas production as natural gas wells freeze, interrupting the production of natural gas. Other less likely events that could impact the transportation of natural gas supply could be severe weather (i.e., earthquakes, floods or lightning), equipment failures, accidents, or a terrorist attack on energy infrastructure. Extreme weather and high demand for natural gas in other areas of the United States, including demand for LNG exports, can also increase the price of natural gas on the spot market.

Q. Did the Winter Storm Uri impact Tampa Electric’s ability to purchase or take delivery of natural gas to operate its natural gas generating units?

A. Yes. While our ability to deliver natural gas to our power plants was not interrupted in February 2021, the storm did result in an increase in the price of natural gas on the spot market. In some cases, natural gas was not available for purchase. Because Tampa Electric has natural gas in storage, the company was able to offset the commodity shortage, avoid fuel disruptions, and mitigate price volatility for customers by using some of the low-cost natural gas it was holding in storage. The company was able to withdraw its $3/MMBtu priced natural gas from storage during this event instead of purchasing any high-priced natural gas in the $15-$25/MMBtu range. In addition, Tampa Electric lowered the overall natural gas requirements for its portfolio during the event by maximizing coal generation on Big Bend Unit 4 and having Polk Unit 2 available on oil in case further natural gas reductions were needed.

Q. What natural gas storage capacity does Tampa Electric have?

A. Because our natural gas consumption is increasing, Tampa

Electric enhanced its natural gas portfolio by adding 250,000 MMBtu of additional underground natural gas storage capacity in 2018. Tampa Electric now has a total of 2,000,000 MMBtu of long-term storage capacity to provide operational flexibility and to enhance the reliability of natural gas supply. Tampa Electric currently has contracts with Bay Gas Storage near Mobile, Alabama, and Southern Pines Energy Center in Eastern Mississippi for a combined total of 2,000,000 MMBtu of storage capacity, which gives us approximately ten days of natural gas supply at our maximum daily withdrawal quantity.

The projected 13-month average volume of natural gas in storage in 2022 is 336,726 MCF with a value of $0.9 million as shown on Document No. 1 of my exhibit. It is also shown on MFR Schedule B-18.

Q. Please explain how Tampa Electric determined the appropriate amount of natural gas inventory for the 2022 test year.

A. Tampa Electric evaluated the estimated amount of supply in its portfolio that is at risk due to high impact events. The high impact events considered were an interruption from a hurricane or other supply interruptions in the Mobile Bay area for a 10-day period. We continuously evaluate our storage needs based on market changes, expected demand and our generation plans.

Q. How does the company’s Asset Management Agreement affect natural gas inventory and fuel supply reliability?

A. The company has an Asset Management Agreement (“AMA”) for a portion of its storage capacity. The AMA has no effect on natural gas inventory and fuel supply reliability because Tampa Electric has the same rights to its storage inventory as it had prior to entering the AMA. However, any AMA natural gas in storage is not included in the projected 13-month average volume for 2022 (see Document No. 1, Note 1 under natural gas inventories).

Q. Does the company expect to incur fuel hedging expenses in the 2022 test year?

A. No. Paragraph 11(a) of the company’s 2017 Amended and Restated Stipulation and Settlement Agreement (“2017 Agreement”) states: “except as specified in this 2017 Agreement, the company will enter into no new natural gas financial hedging contracts for fuel through December 31, 2022." Consistent with this provision, the company did not make natural gas financial hedging contracts in 2020 and will not be doing so in 2021 or 2022. This position is reflected in MFR Schedule C-42.

OIL INVENTORY

Q. What amount of oil inventory does the company propose to include in working capital for the 2022 test year?

A. As shown on MFR Schedule B-18, the company has included 38,229 barrels of oil in inventory for 2022. This volume represents about 85 percent of Tampa Electric oil storage capacity and equates to a 13-month average of $3.1 million.

Q. What is the company's oil inventory planning process?

A. Oil is a backup fuel. The company's oil inventory plan is to maintain its storage tank at or near full to provide reliable backup fuel in the case of extreme demand or a natural gas pipeline interruption. We must periodically run our generating units on oil to test and ensure the reliability of the units on backup fuel, so we monitor inventory levels and replenish as needed.

TOTAL FUEL INVENTORY

Q. What is the total amount of fuel inventory that Tampa Electric proposes to be included in working capital for 2022?

A. The 2022 13-month average total fuel inventory included in working capital is $21.7 million as shown on Document No. 3 of my exhibit and on MFR Schedule B-18.

Q. How does the 2022 total fuel inventory compare to the amount proposed for 2014 during the company's last base rate case?

A. The 2022 13-month average total fuel inventory included in working capital is $84.8 million less than the 2014 13-month average included in working capital in Docket No. 20130040-EI. The transformation of the Tampa Electric generation portfolio to a cleaner, greener fleet with significantly less projected coal consumption results in an 80 percent reduction in total fuel inventory from 2014 to 2022. The reduced fuel inventory results in lower costs for customers without affecting the reliability of fuel supply.

OPTIMIZATION MECHANISM

Q. What is the Optimization Mechanism?

A. On June 30, 2016, Tampa Electric filed a petition in Docket No. 20160160-EI that asked the Commission to approve an Optimization Mechanism. In the 2017 Agreement, the parties consented to Commission approval of the program for a four-year period beginning January 1, 2018.

Q. What is the purpose of the Optimization Mechanism?

A. Under the Optimization Mechanism, gains on wholesale power transactions and optimization activities are shared between shareholders and customers. The program is designed to incentivize Tampa Electric to maximize gains to the mutual benefit of customers and the company.

Q. What portion of the gains are retained by Tampa Electric?

A. All gains up to $4.5 million are retained by customers. Gains between $4.5 million and $8.0 million are split, with 60 percent of gains allocated to the company's shareholders and 40 percent allocated to customers. Gains above $8 million are also split, with 50 percent of gains allocated to shareholders and 50 percent of gains allocated to customers.

Q. What activities are eligible to be included under the Optimization Mechanism?

A. Gains on the company's wholesale sales, short-term wholesale purchases, and optimization activities are eligible for the Program. Optimization activities include efforts such as:

- **Gas Storage Utilization** – Release of contracted storage space or sales of stored natural gas during non-critical demand seasons.

- **Delivered Gas Sales Using Existing Transport** – Sales of natural gas to Florida customers using Tampa Electric's existing natural gas transportation capacity during periods when it is not needed to serve the company's native electric load.

- **Delivered Solid Fuel and/or Transportation Capacity Sales Using Existing Transport** – Sales of coal and coal transportation using Tampa Electric's existing coal and transportation capacity during periods when it is not needed to serve Tampa Electric's native electric load.
- **Production (Upstream) Area Sales** – Sales of natural gas in the natural gas production areas using Tampa

Electric’s existing natural gas transportation capacity during periods when it is not needed to serve the company’s native electric load.

- **Capacity Release of Gas Transport** – Sales of temporarily available natural gas transportation capacity for short periods when it is not needed to serve the company’s native electric load.

- **Asset Management Agreement** – Outsourcing of optimization functions to a third party through assignment of power, transportation, and/or storage rights in exchange for a premium paid to Tampa Electric.

Q. Has Tampa Electric incurred incremental costs associated with the Program?

A. Yes. Tampa Electric incurred incremental labor costs to establish processes and manage the optimization activities. The company, however, agreed that it would not seek recovery of these costs through the Optimization Mechanism. As a result, the company does not track these costs separately.

Q. How are gains tracked and reported to the Commission?

A. Tampa Electric tracks and reports all gains achieved in the prior year on a "Total Gains Schedule" that is included as a part of the company's annual final true-up filing in the fuel and purchased power cost recovery clause ("fuel clause") docket. The company also includes a description of each activity included in the Total Gains Schedule for the prior year in the final true-up filing. The Commission reviews the amounts and activities listed in the filing to determine whether they are eligible for inclusion in the program.

Q. What mechanism does the company use to apportion gains and deliver the customers' share of those gains?

A. The Total Gains Schedule shows the customers' portion of total gains which directly benefit customers in the current period. Tampa Electric receives approval to recover its portion of the total gains through adjustments to the fuel clause factors during the following year and recovers its portion of the gains during the year after that.

Q. Has the Optimization Mechanism resulted in gains for customers since its inception in 2018?

A. Yes. In 2018, customers received a benefit of approximately $5.3 million. In 2019, customers received a benefit of approximately $5.3 million, and in 2020, customers received a benefit of approximately $5.4 million.

Q. Has the Optimization Mechanism achieved its original goals?

A. Yes. The Optimization Mechanism was designed to create additional value for Tampa Electric's customers while incenting the company to maximize gains on power transactions and optimization activities. The mechanism generated over $15.0 million in benefits to customers over its first three years, so Tampa Electric believes it was a success.

Q. Should the Commission extend the Optimization Mechanism beyond the initial four-year period approved in the 2017 Agreement?

A. Yes. Given the success of the Optimization Mechanism in generating benefits for Tampa Electric's customers, the company believes the program should continue beyond its initial four-year period and should be renewed effective January 1, 2022.

Q. Is the company proposing any modifications to the Optimization Mechanism at this time?

A. No. The Optimization Mechanism is working as intended and will continue to provide benefits to customers in its current form when authorized to continue beyond 2021.

SUMMARY

Q. Please summarize your direct testimony.

A. Tampa Electric generates energy for customer use from a diversified fuel portfolio of natural gas, coal, and oil-fired units, as well as solar generation. The company utilizes a fuel inventory plan that considers the uncertainty in availability of fuel commodity supply and transportation, fuel consumption variability, and other risk factors. The company’s fuel plan provides a consistent level of system protection and reliability. Inventory levels account for the types of fuel maintained and consumed to meet plant requirements in a cost-effective manner and reliably serve customers.

Tampa Electric's 2022 total proposed fuel inventory of $21.7 million is an appropriate value for the fuel inventory component of working capital. This level of inventory provides for continued reliable service at a cost that is less than the consequences of not having enough fuel to meet customer needs. Finally, this inventory level is consistent with the company's inventory planning process.

The Optimization Mechanism provided customer benefits of over $15.0 million in the first three years of operation. Based on that success, Tampa Electric believes the program should continue beyond the initial four-year period.

Q. Does this conclude your direct testimony?

A. Yes, it does.

(Whereupon, prefiled direct testimony of Kenneth D. McOnie was inserted.)

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 20210034-EI

IN RE: PETITION FOR RATE INCREASE

BY TAMPA ELECTRIC COMPANY

DIRECT TESTIMONY AND EXHIBIT

OF

KENNETH D. MCONIE

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

KENNETH D. MCONIE

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

A. My name is Kenneth D. McOnie. My business address is Emera Place, 5151 Terminal Road, Halifax, Nova Scotia, Canada. I am Vice President Investor Relations and Treasurer for Emera Inc. ("Emera"), which is the parent company of TECO Energy, Inc. ("TECO Energy" or "parent company"), which is the parent company of Tampa Electric Company ("Tampa Electric" or "company").

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

A. I am responsible for the treasury, investor relations and pension functions of Emera. I am also responsible for establishing and maintaining effective working relations with the investment and banking communities, and for communicating the results of our operations to investors and rating agencies.

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

A. I hold a Bachelor of Commerce degree from Saint Mary's University and an MBA with a concentration in Finance and International Business from Dalhousie University. I also hold the Chartered Professional Accountant – Certified Managerial Accountant designation (Canadian equivalent of a Certified Public Accountant in the United States). I have been working with Emera for 19 years in roles with increasing responsibility and have been in the role of Treasurer for over 10 years.

Q. What is the purpose of your direct testimony?

A. My direct testimony will discuss why it is important for Tampa Electric to maintain its financial integrity. I will describe Tampa Electric's credit ratings and the role of strong credit ratings in providing unimpeded access to capital with reasonable terms and costs. I will address the impact of the Company's infrastructure modernization on its need for capital and the importance of the requested rate relief to maintain Tampa Electric's financial integrity and credit ratings. Finally, my direct testimony will support Tampa Electric's requested capital structure and our proposed 55 percent equity ratio (investor sources).

Q. Have you prepared an exhibit for presentation in this proceeding?

A. Yes. Exhibit No. KDM-1 entitled "Exhibit of Kenneth D. McOnie" was prepared under my direction and supervision. The contents of my exhibit were derived from the business records of the company and are true and correct to the best of my information and belief. It consists of the following seven documents:

Document No. 1	List of Minimum Filing Requirement Schedules Sponsored or Co-Sponsored by Kenneth D. McOnie
Document No. 2	Tampa Electric Credit Metrics
Document No. 3	Rating Agency Conventions and Scales-Senior Unsecured Notes (Long-Term Debt)
Document No. 4	Utility Senior Unsecured Credit Ratings
Document No. 5	S&P Global Corporate Ratings Matrix
Document No. 6	Moody's Credit Rating Factors – Regulated Utilities

Document No. 7 Public Utility Commission Rankings – RRA

Q. How will Tampa Electric fund its infrastructure modernization efforts?

A. Due to the magnitude and timing of these efforts, Tampa Electric cannot generate all the required funds from operations. Without an increase in base rates, internal generation of funds averages only 81 percent of construction capital expenditures for 2013 through 2022. Even with the increased rates requested in this proceeding, internally generated funds for the period 2013 through 2022 will account for an average of only 83 percent of the estimated construction expenditures. The balance of the needed funds must be obtained from investors, primarily through the issuance of long-term debt and equity infusions from the parent company.

FINANCIAL INTEGRITY

Q. What is financial integrity?

A. Financial integrity refers to a relatively stable condition of liquidity and profitability in which the company is able to meet its financial obligations to investors while maintaining the ability to attract investor capital as needed with reasonable terms and costs.

Q. How is financial integrity measured?

A. Financial integrity is a function of financial risk which represents the risk that a company may not have adequate cash flows to meet its financial obligations. The level of cash flows and the percentage of debt, or financial leverage, in the capital structure is a key determinant of financial integrity. As such, as the percentage of debt in the capital structure increases so do the fixed obligations for the repayment of that debt. Consequently, as financial leverage increases the level of financial distress (financial risk) increases as well. Therefore, the percentage of internally generated cash flows compared to these financial obligations is a primary indicator of financial integrity and is relied upon by rating agencies in the assignment of favorable debt ratings.

Q. Why is financial integrity important to Tampa Electric and its customers?

A. As a regulated electric utility, Tampa Electric has an obligation to provide electric utility service to all customers in its defined service area at rates the Commission determines to be fair and reasonable. Fulfilling this obligation to serve requires significant investment, both planned and unplanned, in Tampa Electric's property, plant and equipment thereby making our business very capital intensive.

Customers benefit directly from Tampa Electric's infrastructure investments. For example, transmission and distribution system investments enhance service reliability by mitigating storm damage and facilitating efficient service restoration, generating fleet modernization investments improve fuel efficiency thus lowering fuel costs for customers and reducing emissions, and new technology projects improve the efficiency of the company's operations and overall customer experience. Maintaining a strong financial position allows the company to finance infrastructure investments in support of an improved system at a lower cost than would otherwise be possible.

Financial integrity is also important to ensure access to capital. As a regulated utility, Tampa Electric has a statutory obligation to serve all customers. The responsibility to serve is not contingent upon the health or the state of the financial markets. In times of constrained access to capital and depressed market conditions, only those utilities exhibiting financial integrity are able to attract capital under reasonable terms providing significant and potentially critical flexibility. This obligation to serve means Tampa Electric cannot adjust the timing and amount of their major capital expenditures to align with economic cycles or wait out market disruptions. If faced with a major storm, for example, Tampa Electric would not have that option.

Tampa Electric’s balance sheet strength and financial flexibility are important factors influencing its ability to finance major infrastructure investments as well as manage unexpected events. Financial integrity is essential to supporting these capital expenditure requirements which are necessary to serve and in times of emergency, maintain and restore power to Tampa Electric's customers. Tampa Electric competes in a global market for capital, and a strong balance sheet with appropriate rates of return attracts capital market investors. Financial strength and flexibility enable Tampa Electric to have ready access to capital with reasonable terms and costs for the long-term benefit of its customers.

Q. How will the company’s proposed base rate increase affect

Tampa Electric's financial integrity?

A. The requested base rate increase will place Tampa Electric in a prudent and responsible financial position to fund its capital program and continue providing a high level of reliable service to its customers. To raise the required capital, the company must be able to provide fair returns to investors commensurate with the risks they assume. A strong financial position ensures a reliable stream of external capital and allows the company's capital spending needs to be met in the most cost-effective and timely manner. Uninterrupted access to the financial markets provides Tampa Electric with capital on reasonable terms and costs to further reinvest in the business to continue to improve and protect the long-term interests of our customers.

Q. Please discuss the company's projected financial integrity indicators.

A. Document No. 2 of my exhibit shows Tampa Electric's credit parameters on a historical and projected basis. I have provided the information both with and without the impacts of bonus depreciation for comparability between years. It is important to recognize that the temporary tax benefits have enhanced Tampa Electric’s credit metrics in recent years, but those benefits will probably not be available in the future. The requested rate relief would maintain other key credit metrics at levels similar to the recent levels that have supported the company’s current credit ratings. Without rate relief, these metrics would substantially deteriorate in 2022, as the exhibit illustrates, and would continue to deteriorate beyond 2022 as capital spending increases and earned returns decline. Such deterioration would not support Tampa Electric’s current credit ratings and would have negative implications for the company’s credit ratings, borrowing costs, and access to capital.

CREDIT RATINGS

Q. Please describe Tampa Electric’s current credit ratings.

A. Tampa Electric’s senior unsecured debt is currently rated A3 with a Positive Outlook by Moody’s Investors Service (“Moody’s”), BBB+ with a Stable Outlook by S&P Global Ratings (“S&P”) and A with a Stable Outlook by Fitch Ratings (“Fitch”).

Q. Why is it important that Tampa Electric continue to maintain its current ratings?

A. Maintaining Tampa Electric’s current ratings is very important for two reasons. First, Tampa Electric is making capital investments to serve customers and strong debt ratings ensure Tampa Electric has adequate credit quality to raise the capital necessary to meet these requirements. Second, Tampa Electric’s current ratings provide a reasonable degree of assurance that ratings will not slip below investment grade in the event of a hurricane or other significant weather event.

Q. Why is it so important to maintain an “A” level rating on balance from all three rating agencies?

A. At present, the median rating for the utility industry is A- (Document No. 4 of my exhibit). Obtaining a consistent “A” level rating across all three rating agencies would mean Tampa Electric would be viewed positively regardless of an investor’s preference among the rating agencies.

Additionally, investors distinguish between companies with split ratings versus companies who have the same rating across all rating agencies. The lower rating in a split rated company will result in a higher cost of debt for that company. Typically, the lowest credit rating from the rating agencies becomes the more critical rating when the company seeks access to capital markets.

Obtaining, and maintaining, a consistent “A” level rating from the rating agencies has been one of the contributing factors enabling Tampa Electric to reduce its embedded cost of long-term debt from 5.4 percent in 2014 to 4.17 percent in the 2022 test year.

Q. Why are strong ratings important considering the company’s future capital needs?

A. A strong credit rating is important because it affects a company’s cost of capital and access to the capital markets. Credit ratings indicate the relative riskiness of the company's debt securities. Therefore, credit ratings are reflected in the cost of borrowed funds. All other factors being equal (*i.e.*, timing, markets, size, and terms of an offering), the higher the credit rating, the lower the cost of funds.

Additionally, companies with lower credit ratings have greater difficulty raising funds in any market, but especially in times of economic uncertainty, credit crunches, or during periods when large volumes of government and higher-grade corporate debt are being sold.

Given the capital-intensive nature of the utility industry, it is critical that utilities maintain strong credit ratings sufficiently above the investment grade threshold to retain uninterrupted access to capital. The impact of being investment grade versus non-investment grade is material. For example, a company raising debt that has non-investment grade ("speculative grade") credit ratings will be subject to occasional lapses in availability of debt capital, onerous debt covenants and higher borrowing costs. In addition, companies with non-investment grade ratings are generally unable to obtain unsecured commercial credit and must provide collateral, prepayment, or letters of credit for contractual agreements such as long-term gas transportation, fuel purchase, and fuel hedging agreements.

Given the high capital needs, obligation to serve existing and new customers, and significant requirements for unsecured commercial credit that electric utilities have, non-investment grade ratings are unacceptable. Tampa Electric's current ratings should also be strong enough to buffer against of the costs of tropical windstorm and hurricane events.

Q. Can the financial credit market be foreclosed by unforeseen events extraneous to the utility industry?

A. Yes. There have been times when financial credit markets have been closed or challenged due to unforeseen events. Market instability resulting from the sub-prime mortgage problems affected liquidity in the entire financial sector causing a financial recession, and there were periods of time in 2008 and 2009 when the debt markets were effectively closed to all but the highest rated borrowers. This is a good example of how access to the marketplace can be shut off for even creditworthy borrowers by extraneous, unforeseen events, and it emphasizes why a strong credit rating is essential to ongoing, unimpeded access to the capital markets.

More recently, the measures adopted to contain COVID-19 have pushed the global economy into recession. The utility industry continued to exhibit adequate liquidity and access to the debt markets, despite the uneven performance of the commercial paper market. This access enabled the industry to proactively manage the potential risks of lower electricity usage and increased bad debt expense by establishing additional capacity through term loans and credit facilities from banks. These actions are in contrast to the last financial recession when many utilities fully drew on their available credit lines and access to the banks or to the debt market was effectively shut down for many weeks.

Maintaining unimpeded access to the capital markets is particularly important for a utility like Tampa Electric with an obligation to its customers to finance very significant capital investments. Being unable to access funds could place the completion of critical construction in jeopardy and undermine reliability of service.

Q. How are credit ratings determined?

A. The process the rating agencies follow to determine ratings involves an assessment of both business risk and financial risk. Moody's and S&P Global each publish information on their ratings criteria. S&P Global's Corporate Ratings Matrix is shown in Document No. 5 of my exhibit. Moody's Rating Factors for Regulated Utilities are shown in Document No. 6 of my exhibit.

Q. How does regulation affect ratings?

A. The primary business risk the rating agencies focus on for utilities is regulation, and each of the rating agencies have their own views of the regulatory climate in which a utility operates. The exact assessments of the rating agencies may differ but the principles they rely upon for their independent views of the regulatory regime are similar. Essentially, the principles, or categories, that shape the views of the rating agencies as they relate to regulation are based upon the degree of transparency, predictability, and stability; timeliness of operating and capital cost recovery; regulatory independence; and financial stability.

Regulatory Research Associates ("RRA"), a firm that focuses primarily on regulation of utilities, ranks the Florida Public Service Commission ("FPSC") as "Above Average 2" on a scale that runs from Above Average 1 to Below Average 3. The RRA rankings are presented in Document No. 7 of my exhibit. According to the rating agencies the maintenance of constructive regulatory practices that support the creditworthiness of the utilities is one of the most important issues rating agencies consider when deliberating ratings.

Regulation in Florida has historically been supportive of maintaining the credit quality of the state's utilities, and that has benefited customers by allowing utilities to provide for their customers' needs consistently and at a reasonable cost. This has been one of the factors that has helped Florida utilities maintain pace with the growth in the state, which has been essential to economic development. A key test of regulatory quality is the ability of companies to earn a reasonable rate of return over time, including through varying economic cycles, and to maintain satisfactory financial ratios supported by good quality of earnings and stability of cash flows. Regulated utilities cannot materially improve or even maintain their financial condition without regulatory support. Thus, regulators have a large impact on the company, its customers, and its investors.

Q. What are recent concerns expressed by the rating agencies for the industry?

A. All the rating agencies have expressed concerns with respect to the impact of COVID-19 on the utility industry. The rapid spread of the coronavirus outbreak and the severity of its impact on the economy are creating an extensive credit shock across many sectors, regions, and markets. In April 2020, S&P Global's Outlook for the entire North American regulated utilities industry changed from stable to negative. S&P Global's expectation for the utility industry to remain a high-credit-quality investment grade industry was offset by their concern over the potential for weakening cash flow and credit metrics due to COVID-19.

All rating agencies have also highlighted that the regulatory responses to COVID-19 will be key to a utility's credit prospects. COVID-19 will test utilities' ability to maintain the liquidity and operating cash flow necessary to support credit quality. S&P Global states "Widening gaps in cost recovery could impact utilities. Regulatory jurisdictions will be tested to find creative and supportive ways to bolster the credit quality of their utilities."

CAPITAL STRUCTURE

Q. What capital structure is Tampa Electric proposing in its request for increased base rates?

A. Tampa Electric is projecting, for the 2022 test year and beyond, a 13-month average financial capital structure (over investor sources) consisting of 45 percent debt and 55 percent common equity. The 55 percent equity target referenced is based upon the 54.93 percent year-end financial equity ratio in the 2022 budgeted balance sheet. The equity balances in the budget resulted in a 2022 13-month average System Per Books financial equity ratio of

54.53 percent, as reflected on MFR Schedule D-1a. Also, as reflected on MFR Schedule D-1a, the 2022 13-month average FPSC Adjusted financial equity ratio was 54.56 percent. The 54.56 percent equity ratio was the one used to calculate the 6.67 percent rate of return used to determine the 2022 revenue requirement.

Q. Why is it important that the company's requested capital structure, consisting of 45 percent debt and 55 percent common equity, be authorized in this proceeding?

A. The proposed capital structure is important as it would ensure the long-term financial integrity of the company. This test year equity ratio of 55 percent based on investor sources (equivalent to 45.6 percent based on all sources in jurisdictional FPSC Adjusted capital structure), is appropriate and consistent with the equity ratio deemed appropriate in the Commission-approved 2017 Settlement Agreement. Further, as Tampa Electric witness Dylan W. D'Ascendis explains, the company's equity ratio of 55 percent is consistent with its peers and appropriate for ratemaking purposes as it is both typical and important for utilities to have significant proportions of common equity in their capital structures.

Tampa Electric's requirements for financial strength continue, and therefore the maintenance of the equity ratio is of key importance. If coupled with an adequate ROE and base rates that properly reflect the true cost of service, the combination of this capital structure and the resulting coverage ratios should provide adequate financial strength and credit parameters to maintain the company's credit ratings and assure continued access to capital.

Q. What is Tampa Electric's current equity ratio?

A. Tampa Electric's equity ratio as of December 31, 2020 was 53.9 percent.

Q. What are the expectations of the rating agencies with respect to Tampa Electric's regulatory environment?

A. The rating agencies are aware of the impacts of Tampa Electric's infrastructure modernization efforts and tax reform on the weakening credit metrics over the forecast period absent new rates. While acknowledging this weakening, the rating agencies have cited their support for Tampa Electric's credit profile reflecting the highly supportive Florida regulatory framework allowing for timely cost and investment recovery along with stable and predictable cash flow. Conversely, the rating agencies highlight a less credit supportive outcome as a development that may possibly lead to a negative rating action.

SUMMARY

Q. Please summarize your direct testimony.

A. Maintaining a strong, prudent, and responsible financial position, or financial integrity, is critical to allow Tampa Electric to attract capital on reasonable terms and continue to provide a safe and reliable electric system for its customers. Financial integrity helps ensure uninterrupted access to capital markets to finance required infrastructure investments as well as to manage unforeseen events.

Tampa Electric's capital spending requirements through 2024 include $7.2 billion for normal replacement and improvement of its facilities and $2.5 billion for the Big Bend Modernization and future utility-scale solar projects. The company cannot fund all of this internally and must access external capital to support its construction program.

The requested capital structure of 55 percent equity and the return on equity of 10.75 percent recommended by Mr.

D'Ascendis will provide the financial strength and credit parameters needed to maintain the company's credit ratings and assure continued unimpeded access to capital. The proposed equity ratio is consistent with Tampa Electric's actual sources of capital, with its actual equity ratio of 53.9 percent at year-end 2020, and with the 54 percent equity ratio approved in 2009 and in the company's 2013 and 2017 settlement agreements.

Tampa Electric's rate request, which includes the continued appropriate levels of ROE and equity ratio, will maintain the company's financial integrity and place Tampa Electric in an appropriate financial position to fund its infrastructure modernization efforts and continue providing the high level of reliable service to its customers.

Q. Does this conclude your direct testimony?

A. Yes, it does.

(Whereupon, prefiled direct testimony of Joseph A. Aponte was inserted.)

BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

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

DIRECT TESTIMONY AND EXHIBIT
OF
JOSE A. APONTE

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

JOSE A. APONTE

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

A. My name is Jose A. Aponte. My business address is 702 N. Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "company") as the Manager of Resource Planning.

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

A. My responsibilities include identifying the need for future resource additions and analyzing the economic and operational impacts to Tampa Electric's system.

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

A. Yes. I submitted written direct testimony in Docket Nos. 20190136-EI and 20200064-EI regarding the company's Third and Fourth SoBRA projects and have also presented to the

Commission during the Ten-Year Site Plan Workshop.

Q. How does your job impact the experience Tampa Electric provides to its customers?

A. Although I rarely have direct contact with our customers, my main responsibility in Resource Planning is to ensure that the additions we make to our electric generating portfolio are needed and are cost-effective, which in the long run helps ensure that the rates we charge our customers are fair, just, and reasonable.

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

A. I graduated from the University of South Florida with a bachelor’s degree and a master’s degree in Mechanical Engineering. I am a registered Project Management Professional (“PMP”).

I started work with Tampa Electric in 1999 as an engineer in the Inventory Management and Supply Chain Logistics department. In 2004, I became supervisor for the Materials and Quality Assurance department at the Big Bend Power Station. Since 2008, I have held several positions in the

Resource Planning department at Tampa Electric and currently serve as the Manager of Resource Planning.

I have twenty years of electric utility experience working in the areas of planning, systems integration, data analytics, revenue requirements, project economic analysis, and engineering.

Q. What are the purposes of your direct testimony?

A. The purposes of my direct testimony are to (1) generally discuss the company's plans to add an additional 600 MW of utility-scale solar generating capacity to our system ("Future Solar"), (2) demonstrate that the Future Solar projects are cost-effective, both individually and collectively, and (3) explain why the Future Solar is needed, will benefit customers, and is prudent.

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

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

Document No. 1	Demand and Energy Forecast
Document No. 2	Fuel Price Forecast
Document No. 3	Future Solar Projects Cost-Effectiveness Test (Preliminary Analysis)
Document No. 4	Future Solar Projects Revenue Requirements (Preliminary Analysis)
Document No. 5	Future Solar Individual Project Costs per kW_{ac}
Document No. 6	Future Solar Projects Cost-Effectiveness Test (Current ROE)
Document No. 7	Future Solar Projects Revenue Requirements (Current ROE)
Document No. 8	Future Solar Projects Cost-Effectiveness Test (Rate Case ROE)
Document No. 9	Future Solar Projects Revenue Requirements (Rate Case ROE)

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

A. No.

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

A. Tampa Electric witness David A. Pickles explains how the company's proposed Future Solar fits into the company's plans for its generating portfolio.

Tampa Electric witness C. David Sweat explains the details of the 11 individual projects that are underway as part of our plan to build Future Solar. He describes the location, size, timing, and projected costs of each of the projects.

My direct testimony shows that our proposed Future Solar projects are cost effective, needed, and prudent.

The investments and operation and maintenance ("O&M") expenses associated with the first 226.5 MW of additional solar are reflected in the MFR schedules for the company's proposed 2022 test year, which are jointly sponsored by Tampa Electric witness A. Sloan Lewis and Mr. Sweat.

Tampa Electric witness Jeffrey S. Chronister presents the company's proposal for recovering the investments and expenses associated with the remaining 373.5 MW of Future Solar in 2023 and 2024 in his testimony.

TAMPA ELECTRIC'S PLAN FOR FUTURE SOLAR

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

A. Tampa Electric currently owns and operates 655 MW of solar generating capacity at 13 geographically dispersed locations throughout its service territory.

Our solar portfolio includes 632.1 MW of both single axis tracking and fixed tilt PV solar at 10 sites in Hillsborough and Polk Counties, a 1.6 MW fixed tilt solar PV rooftop canopy array located at the south parking garage at Tampa International Airport, a 1.4 MW fixed tilt solar PV ground canopy array located at Lego Land Florida, and a 19.8 MW single axis tracking solar station coupled with a 12.6 MW battery storage unit located at Big Bend Station ("Big Bend").

600 MW of this capacity was installed pursuant to the company's 2017 Amended and Restated Stipulation and Settlement Agreement ("2017 Agreement"). We began deploying utility scale solar generation in 2013.

Our solar facilities now produce enough electricity to power more than 100,000 homes, and in 2020, about six percent of our energy was produced from the sun.

As noted in the direct testimony of Mr. Pickles, our first approximately 655 MW of solar is part of the transformation of our generating fleet. It also reflects our belief in the value of renewable energy and our long-standing commitment to clean energy. The Future Solar we are proposing in this case will further the transformation of our generating fleet and enable the company to be cleaner and greener, and emit less carbon, through projects that are cost-effective for all of our customers.

When we complete our Future Solar projects, nearly 14 percent of our energy will be from solar. This cost-effective long term energy solution will be enough to power more than 200,000 homes, and will promote price stability for customers, increase our fuel diversity, and reduce carbon emissions.

Q. Please generally describe the company's plans to build Future Solar.

A. Tampa Electric plans to add an additional 600 MW of utility-scale solar PV projects across its service territory by 2023. The company will build the projects in three tranches: 226.5 MW in-service by December 1, 2021, 224 MW in-service by December 1, 2022, and 149.5 MW in-service by December 1, 2023.

Our Future Solar projects will be general system resources, not dedicated to a subset of solar energy subscribers and, therefore, their benefits will inure to all of our customers.

Q. Do you have a list of the Future Solar projects by tranche and their projected cost in dollars per kW_{ac}?

A. Yes. The list of projects by tranche and projected cost in dollars per kW_{ac} is shown below in Document No. 3 of my exhibit. The projected costs, excluding Allowance for Funds Used for Construction ("AFUDC"), were provided to me by Mr. Sweat, who explains the costs and project schedules in his direct testimony. I added the AFUDC amounts to the project costs to arrive at the total project costs shown in Document No. 3 of my exhibit.

Q. How were the AFUDC amounts included in your project costs per kW_{ac} determined?

A. Mr. Sweat's capital spending was provided to the company's accounting team, who then calculated the AFUDC per project. These AFUDC costs were provided to me and included in the cost-effectiveness calculations.

Q. How do the projected costs for these Future Solar projects compare to the cost of the 600 MW of SoBRA solar approved pursuant to the 2017 Agreement?

A. The Future Solar project costs are lower than those of the SoBRA projects due to improvements in module efficiency and reduced module pricing. As modules become more efficient, the balance of system cost is also reduced on a per megawatt basis. Additionally, more efficient modules allow us to construct more solar capacity on a per acre basis, reducing overall project costs. Tampa Electric also procured inverters, tracking systems, and Generator Step-up Unit ("GSU") transformers directly from suppliers to maximize economies of scale, reduce contractor markups, and secure a full 26 percent investment tax credit for all 600 megawatts of these future solar projects.

COST-EFFECTIVENESS OF FUTURE SOLAR

Q. Are the planned solar PV projects cost-effective?

A. Yes. The Future Solar projects are cost-effective in total, by tranche, and on an individual project basis.

Q. Please describe the analyses Tampa Electric performed to evaluate the cost-effectiveness of the Future Solar projects?

A. The company prepared a preliminary analysis to ensure there was a business case for moving forward and followed that up with a second, more detailed, project-specific analysis. In both analyses, we evaluated cost-effectiveness based on whether or not the projects would lower the company's projected system cumulative present value revenue requirement ("CPVRR") as compared to such CPVRR without the solar projects. As part of the analyses, we modeled the annual revenue requirement associated with operating our system over a 30-year period with and without the proposed additions and used those annual amounts to calculate the CPVRR with and without the proposed additions.

We performed these analyses using our Integrated Resource Planning models to prepare a base case scenario without the Future Solar. We then prepared change case scenarios for the 600 MW in total, each annual tranche in total, and for each individual project, and compared the change cases to the base case. The base case and change cases used production cost modeling software to determine system CPVRR, including fuel costs and variable O&M, and then the costs associated with a change case were subtracted from the base case to determine the savings. This technique is widely used by electric utilities during the development of integrated resource plans to evaluate whether to make additions to the generating portfolio.

Q. How did the company’s detailed cost-effectiveness analysis differ from the preliminary screening analysis?

A. We prepared our preliminary analysis using an average cost of $1,385 per kW_{ac}, including AFUDC for all projects, and evaluated the Future Solar by tranche and in total. We prepared our more detailed second analysis using the forecasted project-specific costs provided by Mr. Sweat, and evaluated cost-effectiveness for the 600 MW in total, by tranche, and by project.

Our screening analysis indicated that the Future Solar was cost effective in total and by tranche, thus providing a basis for the company to continue moving forward with its efforts towards a lower carbon future. The more detailed analysis demonstrates that the Future Solar is cost-effective in total, by tranche, and by project.

Q. Please explain the assumptions underlying the company's cost-effectiveness calculations.

A. The primary assumptions for the cost-effectiveness calculations are the company's Demand and Energy Forecast, the fuel price forecast, and the projected revenue requirements of the Future Solar projects.

We prepared our cost-effectiveness analyses with the Demand and Energy Forecast used to prepare Tampa Electric's 2020 cost recovery factors and its 2020 Ten Year Site Plan. A summary of the values in the Demand and Energy Forecast is shown in Document No. 1 of my exhibit.

The company prepared the fuel forecast using the same methodology the company has used to develop its fuel price forecast each year over the last decade, and it is shown in Document No. 2 of my exhibit.

Q. How did the company calculate the annual revenue requirements used in the two analyses?

A. In our preliminary analysis, we used an average cost of

$1,385 per kW_{ac}, including AFUDC, to calculate the revenue requirement for the 600 MW of Future Solar in total and then by tranche. In our second analysis, we used project-specific projected costs to calculate a revenue requirement by project, by tranche, and in total. Document Nos. 4 and 7 of my exhibit reflect the revenue requirements used in our preliminary and second cost-effectiveness analyses.

In both analyses, we used the capital structure and return guidelines and standards in our 2017 Agreement, because those guidelines and standards were in effect when we performed our original analyses, and because it is difficult to predict the return on equity and equity ratio that will be approved in this case. Consistent with the guidelines in the 2017 Agreement, we updated the long-term debt rate to 4.8 percent to reflect the prospective long-term debt issuances during the first 12 months of operations of the projects. The investment tax credits associated with the utility-scale solar projects were normalized over the 30-year life of the assets in accordance with applicable Internal Revenue Service regulations. Our revenue requirement calculation included reasonable estimates for O&M expenses (based on our experience with our 600 MW of SoBRA solar), depreciation expense, and property taxes, including the projected impact of the property tax exemption for solar projects.

Q. Did the company consider allowance for funds used during construction ("AFUDC") and avoided carbon emission costs when calculating the revenue requirements described above?

A. Yes. We calculated the revenue requirements with and without AFUDC and with and without avoided carbon emission costs.

Q. By how much will the Future Solar projects lower the company's carbon emissions?

A. The 600 MW of Future Solar will decrease carbon dioxide ("CO_2") emissions by over 550 thousand tons per year and decrease nitrogen oxide ("NO_X") and sulfur dioxide ("SO_2") emissions by hundreds of tons.

Q. How did the company estimate the avoided cost of carbon emissions for the Future Solar projects?

A. Tampa Electric has been monitoring forecasted carbon prices since the draft Clean Power Plan was issued and contracted with a global consulting services company, ICF International, Inc., to obtain a CO_2 forecast that utilized the most current assumptions and market conditions. The consultant compared projections for various regions of the country and included low, medium, and high cost of carbon forecasts.

Q. Is it reasonable to include the value of avoided carbon emission costs in the company's cost-effectiveness tests?

A. Yes. Although our federal government and the State of Florida do not currently impose a tax or fee on carbon emissions, public policy consideration and customer expectations in the United States and around the world are trending against carbon emissions and in favor of renewable energy like solar generation. It is difficult to predict whether the company will face a carbon tax or fee in the future, but it is even more difficult to completely rule out that possibility. Accordingly, it is reasonable to consider the value of avoided carbon costs when evaluating the cost-effectiveness of generating alternatives, including our Future Solar.

Q. Did the company consider the value of deferral in its cost-effectiveness analyses?

A. Yes. The company applied the long-standing, Commission-accepted practice for including value of deferral. Specifically, we evaluated expansion plans for each project against our base expansion plan to determine if it had the ability to defer future capacity additions. Results of this evaluation showed that 10 of the projects had the ability to defer future battery storage additions, while one of the projects did not. The benefits for those projects that had value of deferral were included in the calculation of their respective total CPVRR.

Q. How much fuel expense will Future Solar allow the company's customers to avoid over the life of the projects?

A. Based on our base fuel forecast, we expect the Future Solar to save our customers approximately $739.4 million in fuel costs over the life of the projects.

Q. Please describe the results of the company's preliminary cost-effectiveness analysis.

A. Our preliminary analysis showed that Future Solar was cost effective in total and by tranche. Document No. 3 of my exhibit shows the results of our preliminary analysis in total and by tranche.

For Future Solar in total, the CPVRR differential was favorable for customers by $73.0 million before including any value for reduced emissions. Including reduced emissions benefits increased the CPVRR savings from Future Solar to $122.5 million.

The CPVRR savings for Future Solar by tranche were $22.4 million (Tranche One), $39.1 million (Tranche Two), and $11.6 million (Tranche Three) before including any value for reduced emissions. Including reduced emissions benefits increased the CPVRR savings from Future Solar to $35 million (Tranche One), $58 million (Tranche Two), and $29.5 million (Tranche Three).

Q. Please describe the results of the company's second cost-effectiveness analysis.

A. Our second analysis showed that Future Solar was cost effective in total, by tranche, and by project. Document No. 6 of my exhibit shows the results of our second analysis.

For Future Solar in total, the CPVRR differential in our second analysis was favorable for customers by $122.2 million before including any value for reduced emissions.

Including reduced emissions benefits increased the CPVRR savings from Future Solar to $171.5 million.

The CPVRR savings for Future Solar by tranche in our second analysis were $55.7 million (Tranche One), $45.1 million (Tranche Two), and $21.3 million (Tranche Three) before including any value for reduced emissions. Including reduced emissions benefits increased the CPVRR savings from Future Solar to $74.9 million (Tranche One), $63.5 million (Tranche Two), and $33.1 million (Tranche Three).

As shown on Document No. 6 of my exhibit, each individual project shows a CPVRR savings ranging from $1.5 to $30.9 million per project without carbon, including avoided emissions costs increased the CPVRR savings for each of the projects and increased the range of savings from between $3.4 and $37.3 million per project.

Q. Did the company conduct sensitivity testing on the results of its cost-effectiveness analysis?

A. Yes. Tampa Electric tested the CPVRR savings calculated in its preliminary analysis using high and low fuel price forecasts. The high and low fuel forecasts were prepared contemporaneously with the base fuel forecast. The results show that customer savings occur under the base case and high fuel forecast sensitivities.

The company also recalculated the revenue requirements for the individual Future Solar projects using a 10.75 percent return on equity and a 55 percent equity ratio as proposed by the company in this case. Using these inputs, and excluding avoided carbon costs, our proposed Future Solar yields CPVRR savings to customers in total and by tranche, with ten of the eleven individual projects showing CPVRR savings ranging from $73.0 thousand to $25.9 million, and the remaining one indicating a minimal incremental CPVRR cost. When a conservative carbon costs forecast is included, all Future Solar projects at 10.75 percent return on equity and 55 percent equity ratio are cost effective. This analysis is shown on Document No. 8 of my exhibit.

NEED FOR FUTURE SOLAR

Q. Are the solar projects needed to provide service to Tampa Electric customers?

A. Yes. Tampa Electric expects demand to increase at an average annual rate of 1.2 percent in the summer and 1.3 percent in the winter. Retail energy sales are projected to rise at a 1.1 percent annual rate. Thus, the company must plan to meet the power needs of its customers through additional resources and seeks to do so in cost-effective ways that use cleaner, greener, and lower carbon emitting assets. The company's proposed Future Solar aligns well with this goal, producing savings for customers and enhancing the company's environmental stewardship.

Q. Why does Tampa Electric need the Future Solar projects?

A. Tampa Electric needs the Future Solar projects to promote fuel diversity and price stability for our customers, and to respond to the growing demand for solar from our customers. Our proposed Future Solar does not contribute to our winter reserve margin because the projects do not provide capacity at the time of day our coincident winter peak occurs. Our Future Solar will, however, improve our summer reserve margin every year until the Future Solar projects are retired, and is part of our plan to use renewable energy resources and technology to the extent they are available, as contemplated in Section 403.519, Florida Statutes.

Q. Why is 600 MW the right amount of utility-scale solar to add to its system?

A. 600 MW of additional solar generating capacity is the amount of solar that can be added to our system without adding equipment and controls to our transmission and distribution system to accommodate the intermittent nature of solar. Adding 600 MW of zero emissions, cost-effective solar is prudent and is also the component of our generation expansion plan that allows us to maximize fuel diversity, price savings, fuel savings, and other benefits for our customers without incurring system upgrade costs.

Q. Why is it prudent for Tampa Electric to add 600 MW of utility-scale solar in the next three years?

A. Adding the Future Solar projects as planned helps to optimize our generation expansion plans and will allow our customers to enjoy the benefits of the incremental solar capacity as soon as reasonably possible. As Mr. Sweat explains further in his testimony, adding the Future Solar to our system as proposed will allow the company to maximize economies of scale in the procurement and construction of the projects.

Q. How will the Future Solar promote Tampa Electric’s fuel diversity?

A. As projected for 2021, Tampa Electric's generation mix is expected to be approximately 87 percent natural gas, about eight percent solar (no fuel), and about five percent coal.

When we complete our Future Solar projects by the end of 2023, over 14 percent of our energy will be from solar which reduces our reliance on natural gas. Tampa Electric witness John C. Heisey discusses how adding solar generating capacity to our system has reduced, and will continue to reduce, our need to maintain high inventory levels of solid fuel.

Q. How will the Future Solar projects promote price stability for Tampa Electric's customers?

A. The prices we pay for the coal, natural gas, and oil burned in our power plants vary over time. In the case of natural gas, commodity prices can become quite volatile in a short period of time.

The "fuel" for solar generation is the sun, which is free, so once installed, the cost of generating solar energy remains constant and does not vary due to fuel cost fluctuations. Future Solar will increase the percentage of our generating capacity that has no fuel cost, will effectively mitigate fossil fuel cost variability, and therefore, will help promote price stability for our customers.

Q. Is customer demand for solar energy growing?

A. Yes, we believe it is. Tampa Electric witness Melissa L. Cosby discusses this topic in her direct testimony.

Q. Can Tampa Electric use conservation measures as a substitute for the energy that will be provided by its proposed Future Solar?

A. No. These future solar projects are needed after all the Commission approved cost-effective energy efficiency measures are accounted for. As the company demonstrated in the most recent 2020-2029 Demand Side Management ("DSM") Goals proceeding, Florida Building Codes are becoming more stringent and various Federal energy efficiency and appliance standards have been enacted, which are affecting several baseline measures used for the evaluation of potential DSM measures. This reduction of potential savings as related to the baseline will further reduce the amount of energy efficiency that is available to be obtained through cost-effective DSM programs in the future. It is important to note that in this last DSM Goals proceeding, the company proposed DSM Goals that were 14.3 percent higher than what was approved for the 2015-2024 period. In addition, Tampa Electric continues to be a recognized leader in offering cost-effective DSM programs. The company offers more DSM programs than any other utility in Florida. The design of our comprehensive DSM portfolio ensures that all customers, particularly low-income customers, have opportunities to participate. Tampa Electric and its customers have realized significant savings from the DSM programs offered since the inception of DSM in Florida in 1980. These DSM programs have saved 1,722 GWh of annual energy, but additional DSM programs will not substitute for the zero-fuel cost energy to be provided from our Future Solar projects.

Q. Will Future Solar provide other benefits to Tampa Electric’s customers and the communities where they live?

A. Yes. Because it does not burn fuel or have moving parts that operate under high temperatures and pressures, solar generation is safer to operate than fossil fuel-burning generators.

Not only is solar emission-free, it doesn't use ground water nor create wastewater – better for the precious underground aquifer and Florida waterways.

As noted in the testimony of Mr. Pickles, our Future Solar projects will require fewer financial resources to operate than fossil fuel-burning plants and will substitute, in part, for operation of solid fuel generating assets that cost more to operate and maintain, which will allow the company to incur less O&M expense.

Construction of the Future Solar projects will create new construction jobs in this area, which will help our local economies.

The solar projects will also generate new property tax revenues for the local governments where they are located.

Q. Is the company's plan for Future Solar prudent?

A. Yes. As noted in the testimony of Mr. Sweat, the company has planned and will be constructing the 11 Future Solar projects at the lowest reasonable cost, and I have shown that our proposed Future Solar projects are cost-effective. We need Future Solar to promote alternative sources of energy that can be key to system reliability and resiliency, improve fuel diversity, provide price stability, and respond to growing customer demand for solar. Our planned solar additions are safe, will require fewer financial resources to operate than fossil fuel-burning plants, and will substitute, in part, for operation of solid fuel generating assets that cost more to operate and maintain, which will allow the company to incur less O&M expense.

SUMMARY

Q. Please summarize your direct testimony.

A. My testimony describes the company's plans to add additional 600 MW of utility-scale solar generating capacity to our system; demonstrates that the Future Solar projects are cost-effective, both individually and collectively; and demonstrates that the Future Solar is needed, will benefit customers, and is prudent.

The CPVRR savings for Future Solar by tranche are $55.7 million (Tranche One), $45.1 million (Tranche Two), and $21.3 (Tranche Three) before including any value for reduced emissions. Including reduced emissions benefits increased the CPVRR savings from Future Solar to $74.9 million (Tranche One), $63.5 million (Tranche Two), and

$33.1 million (Tranche Three). Taken individually, the CPVRR for each of the 11 projects was lower, with savings ranging between $1.5 and $30.9 million per project without carbon. Including avoided emissions costs increased the CPVRR savings for each of the projects and increased the range of savings to between $3.4 and $37.3 million per project.

Q. Does this conclude your direct testimony?

A. Yes, it does.

(Whereupon, prefiled direct testimony of Charles R. Beitel was inserted.)

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 20210034-EI

IN RE: PETITION FOR RATE INCREASE

BY TAMPA ELECTRIC COMPANY

DIRECT TESTIMONY AND EXHIBIT

OF

CHARLES R. BEITEL

ON BEHALF OF TAMPA ELECTRIC COMPANY

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

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

CHARLES R. BEITEL

ON BEHALF OF TAMPA ELECTRIC COMPANY

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

A. My name is Charles R. Beitel. My business address is 55 East Monroe Street, Chicago, IL 60603-5780. I am Senior Vice President & Project Director for Sargent & Lundy.

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

A. I have a Bachelor of Science degree in mechanical engineering from the University of Missouri, and I am a licensed professional engineer. In the course of my twenty-five-year career in the power industry I have served as a mechanical engineer, on-site field engineer during construction, project manager, director, and vice president for a large variety of projects in the electric power industry. This includes new construction of generating facilities (coal and gas fired), large scale environmental air quality control systems, plant services betterment and upgrades, multiple plant demolition studies and evaluations, and a large amount of project cost estimating services for the above array of projects.

Q. What are the purposes of your direct testimony in this proceeding?

A. The purposes of my prepared direct testimony are to (1) discuss the dismantlement studies Sargent & Lundy conducted for Tampa Electric and submitted to the Commission on December 30, 2020 in Docket No. 20200264-EI and (2) support the reasonableness of our dismantlement study costs included in the company's rate request in this docket.

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

A. Yes. Exhibit No. CRB-1 was prepared under my direction and supervision. My exhibit consists of two documents:

Document No. 1	Big Bend Power Station Unit 1 and 2 Dismantling Study
Document No. 2	Big Bend Power Station Unit 3 Dismantling Study

Q. What dismantlement studies did Sargent & Lundy perform for Tampa Electric?

A. We performed two dismantlement studies, one for Big Bend Power Station ("Big Bend") Units 1 and 2 and one for Big Bend Unit 3.

Q. What was the reason for performing two dismantlement studies as opposed to a single study addressing all three units?

A. At the time Tampa Electric engaged Sargent & Lundy to perform a dismantlement study for Big Bend Units 1 and 2, the company had not finalized its plans with respect to Big Bend Unit 3. After the dismantlement study for Big Bend Units 1 and 2 was nearly completed, Tampa Electric engaged Sargent & Lundy to perform the dismantlement study for Big Bend Unit 3.

Q. What were the purposes of the two dismantlement studies you performed?

A. The purposes of both studies were the same. We were asked to document the scope, strategy, costs, cash flows, and provide recommendations for execution of selective dismantlement of Big Bend Units 1 and 2 in the first study and Big Bend Unit 3 in the second study.

Q. What are the differences in the preparation of the Big Bend Unit 3 dismantlement study, compared to the Big Bend Units 1 and 2 study?

A. Apart from fundamental differences in the installed systems and equipment of the operating units, the primary difference between the two studies is that in the Units 1 and 2 study, the Unit 1 turbine equipment and auxiliaries are to remain in service since this turbine generator is being heavily modified and "repowered" with natural gas fired combined cycle technology as part of the Big Bend Modernization project.

Q. How do the two studies differ from a standard dismantlement study?

A. A "standard" dismantlement study of this type would involve wholesale demolition of an entire facility. Dismantlement of Big Bend Units 1 and 2 as well as Unit 3 are a selective demolition of certain portions of the facility, given that some equipment and operating units at this site must continue uninterrupted, safe operation during and after the demolition activities have taken place. Selective demolition requires a site-specific understanding of the overall design of the facility structure and process systems and an ability to detangle the physical infrastructure that must remain in operation from the portions that are being demolished, from a structural, mechanical, electrical, and controls perspective. An example of this is the coal tripper conveyor structure and systems which will only serve Unit 4 following dismantlement yet are structurally integral to Units 1, 2, and 3. The costs for selective demolition are substantially higher than for wholesale demolition for the reasons I previously mentioned, and given that new structural reinforcements, electrical and control feeds, and process systems are required in certain cases to provide for the aforementioned safe uninterrupted operation of the balance the facility.

Q. Did Sargent & Lundy utilize the same processes, apply the same standards and methods, and utilize the same types of data, key assumptions, and cost estimates for both the Big Bend 1 and 2 dismantlement study and the Big Bend Unit 3 dismantlement study?

A. Yes, we did.

Q. What process did you follow in preparing the Big Bend Units 1 and 2 dismantlement study and the Big Bend Unit 3 dismantlement study?

A. Sargent & Lundy has developed our process of demolition scoping and estimating over the course of over two hundred evaluations and estimates performed for power industry clients. We utilize staff that are well versed in power plant design and construction to develop a site-specific plan for the required selective dismantlement. From this plan, our teams use our firm's knowledge of the quantities of materials (concrete, steel, pipe, electrical, etc.) present to prepare detailed "bottoms up" demolition estimates of the work required, factoring in benchmarked labor rates, specialized knowledge to remove equipment containing certain materials, scrap value, and the addition of any new materials, systems, and equipment that must be installed to facilitate uninterrupted, safe operation of the balance of the facility. Our plans and estimates are checked in a "top down" manner against past similar work performed by our firm and our clients, scaled appropriately for unit size.

Q. Are there industry-standard methods used when preparing such studies?

A. Yes. Various organizations and industry committees provide guidance, recommendations, position papers, and lessons learned for the demolition planning and estimating methods that are utilized in a study of this nature. Sargent & Lundy has had continuous participation in national and international technical groups and advisory committees of this type, including the Construction Management Association of America ("CMAA"), Electric Utility and Environmental Conference ("EUEC"), American Nuclear Society ("ANS"), International Atomic Energy Association ("IAEA"), Health Physics Society ("HPS"), Organisation for Economic Cooperation Nuclear Energy Agency ("NEA"), and we include such input into our approach and procedures for performing such work.

Q. Did you apply these industry standards when preparing Tampa Electric's Big Bend Units 1 and 2 dismantlement study and the Big Bend Unit 3 dismantlement study?

A. Yes, we relied on these standards.

Q. Did Tampa Electric provide data to you for use in the Big Bend Units 1 and 2 dismantlement study and the Big Bend Unit 3 dismantlement study?

A. Yes.

Q. What data did the company provide?

A. Tampa Electric provided guidance regarding the specific areas of the facility that were to remain in safe, uninterrupted operation during and after dismantlement, as well as input regarding scope and costs for asbestos removal, disposal of consumables, and owner's costs that were factored into our estimates. Tampa Electric stakeholders also collaborated with Sargent & Lundy staff regarding the selection of an appropriate overall contingency based on the level of certainty in the study efforts.

Q. Please describe the key assumptions of the Big Bend Units 1 and 2 dismantlement study and the Big Bend Unit 3 dismantlement study.

A. Assumptions regarding scrap value, forecasted escalation, and certain labor cost parameters were made as documented. See Section L of each report, included as Document Nos. 1 and 2 of my exhibit, for a concise list of technical assumptions.

Q. How were costs estimated for purposes of the Big Bend Units 1 and 2 dismantlement study and the Big Bend Unit 3 dismantlement study?

A. As stated earlier, based on the site-specific demolition scope, our teams use our firm's knowledge of the quantities of materials (concrete, steel, pipe, electrical, etc.) present to prepare detailed "bottoms up" demolition estimates of the work required, factoring in benchmarked labor rates, scrap value, and the addition of any new materials, systems, and equipment that must be installed to facilitate uninterrupted and safe operation of the balance of the facility. Our plans and estimates are checked in a "top down" manner against past similar work performed by our firm and our clients, scaled appropriately for unit size.

Q. What are the results of the Big Bend Units 1 and 2 dismantlement study?

A. The selective dismantlement costs for Units 1 and 2 are based on the April 2020 and November 2021 retirement dates for Units 1 and 2, respectively. The total cost estimate is $81,816,224, including engineering, demolition, and pre- and post-demolition costs.

The engineering phase includes developing the scope of work, performing detailed engineering for modifications, developing the specifications, bidding the contracts, and evaluating proposals. Pre-demolition activities required to prepare for demolition include removing consumables, remediation of material containing asbestos, adding bracing, and relocating utilities. Demolition is the physical removal of the identified equipment and structures while allowing the rest of the plant to continue safe, reliable operations. Post-demolition activities are actions necessary to leave the site in a safe, usable site with proper drainage and access.

The selective dismantlement costs by unit follow, and the study is provided as Document No. 1 of my exhibit.

	(000)
Unit 1	$35,075
Unit 2	$46,740

Q. What are the results of the Big Bend Unit 3 dismantlement study?

A. The selective dismantlement costs for Unit 3 are based on its April 2023 retirement date. The total cost estimate is $50,568,243, including engineering, demolition, and preand post-demolition costs. These phases are as previously defined for the Units 1 and 2 dismantlement study. The study is provided as Document No. 2 of my exhibit.

Q. Is it your conclusion that the Big Bend Units 1 and 2 dismantlement study results and those of the Big Bend Unit 3 dismantlement study are reasonable estimates?

A. Yes, the Big Bend Units 1 and 2 dismantlement study and the Big Bend Unit 3 dismantlement study results and cost estimates are reasonable and are useful for planning purposes. It is appropriate for the company to rely on these estimates for inclusion in their dismantlement reserve needs. The subject estimates have been benchmarked against real world projects of similar scope, including past similar work performed at Tampa Electric's former Gannon Station which was converted to the Bayside Station.

Q. Please summarize your direct testimony.

A. My direct testimony describes Sargent & Lundy's work in performing two dismantlement studies for Tampa Electric, one addressing the selective dismantlement of Big Bend Units 1 and 2 and one addressing the selective dismantlement of Big Bend Unit 3. I describe Sargent & Lundy's qualifications and my experience performing dismantlement studies. I also explain the processes, industry standards and methods, data analyses, key assumptions, and cost estimates Sargent & Lundy utilized for both dismantlement studies. I conclude that the study results and cost estimates for both studies are reasonable, are useful for planning purposes, and are appropriate for Tampa Electric to rely on in determining their dismantlement reserve needs.

Q. Does this conclude your direct testimony?

A. Yes.

(Transcript continues in sequence in Volume 4.)

CERTIFICATE OF REPORTER

STATE OF FLORIDA)
COUNTY OF LEON)

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

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

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

DATED this 1st day of November, 2021.

DEBRA R. KRICK
NOTARY PUBLIC
COMMISSION #HH31926
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