BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition by Florida Power & Light Company for Rate Unification and for Base Rate Increase	DOCKET NO.: 20210015-EI FILED: June 21, 2021

DIRECT TESTIMONY AND EXHIBITS OF BRIAN C. COLLINS ON BEHALF OF FEDERAL EXECUTIVE AGENCIES

Attached for filing is the Direct Testimony and Exhibits of Brian C. Collins on behalf of Federal Executive Agencies in the above referenced docket.

Respectfully Submitted,

Attorney for Federal Executive Agencies

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CERTIFICATE OF SERVICE
Docket No. 20210015-EI

I HEREBY CERTIFY that a true and correct copy of the foregoing has been furnished by electronic mail this 21st day of June, 2021 to the following:

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s/ Arnold Braxton
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BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

IN RE: PETITION FOR RATE INCREASE BY FLORIDA POWER & LIGHT COMPANY	)))))	**DOCKET NO. 20210015-EI**

Direct Testimony and Exhibits of

Brian C. Collins

On behalf of

Federal Executive Agencies

June 21, 2021

BRUBAKER & ASSOCIATES, INC.

Project 11121

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BEFORE THE

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IN RE: PETITION FOR RATE INCREASE BY FLORIDA POWER & LIGHT COMPANY	)))))	**DOCKET NO. 20210015-EI**

<u>Direct Testimony of Brian C. Collins</u>

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Brian C. Collins. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017.

Q WHAT IS YOUR OCCUPATION?

A I am a consultant in the field of public utility regulation and a Principal of Brubaker & Associates, Inc. ("BAI"), energy, economic and regulatory consultants.

Q PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A This information is included in Appendix A to my testimony.

Q ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?

A I am appearing in this proceeding on behalf of the Federal Executive Agencies ("FEA").

Q WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A My testimony addresses FPL's proposed class cost of service, class revenue allocation and rate design proposals.

Q DOES THE FACT THAT YOU DID NOT ADDRESS EVERY ISSUE RAISED IN FPL'S TESTIMONY MEAN THAT YOU AGREE WITH FPL'S TESTIMONY ON THOSE ISSUES?

A No. It merely reflects that I chose not to address all those issues in my testimony. It should not be read as an endorsement of, or agreement with, FPL's position on such issues.

I. INTRODUCTION AND SUMMARY

Q HOW IS YOUR TESTIMONY ORGANIZED?

A First, I present an overview of cost of service principles and concepts. This is followed by a discussion of the typical classification and allocation of distribution related costs. Next, I discuss the results of FPL's cost of service study implementing a Minimum Distribution System ("MDS") that takes into account cost-causation principles. This cost study indicates how individual customer class revenues compare to the costs incurred in providing distribution service to them. This discussion is then followed by recommendations with respect to the class revenue allocation and rate design.

Q PLEASE SUMMARIZE YOUR RECOMMENDATIONS AND CONCLUSIONS.

A My specific recommendations and conclusions are as follows:

1. Class cost of service is the starting point and most important guideline for establishing the level and design of rates charged to customers.

2. The primary purpose of the distribution system is to deliver power from the transmission grid to the customer. Certain distribution investments must be made to connect a customer to the system. Therefore, these investments are considered customer-related.

3. The consolidated Class Cost of Service Study ("CCOSS") with an MDS has been provided on an informational basis by FPL. However, this CCOSS best reflects cost causation on the Company's system. The classification and allocation of certain distribution plant accounts in FPL's CCOSS have been modified to classify a portion of those costs as customer-related consistent with the recognition of an MDS.

4. The results of the CCOSS with an MDS, which takes into account actual cost utilization principles, should be used to allocate any distribution revenue increase in this proceeding as well as the design of distribution rates.

5. With respect to Class Revenue Allocation, I recommend that revenues be allocated to classes under FEA's proposed class allocation shown on Exhibit BCC-1. This revenue allocation is guided by FPL's CCOSS with an MDS.

6. With respect to Rate Design, I recommend that FPL should retain the existing Gulf Power ("GP") Real-Time Pricing ("RTP") rate for customers and expand it to be offered for customers in the combined FPL and GP systems.

II. COST OF SERVICE OVERVIEW

Q WHAT INFORMATION IS CONTAINED IN A CCOSS?

A A CCOSS compares the cost that each customer class imposes on the system to the revenues each class contributes. This relationship is generally presented by comparing the rate of return that a class is providing with the utility's overall jurisdictional rate of return.

For example, when a customer class produces the same rate of return as the total jurisdictional utility rate of return, the customer class is paying revenue to the utility just sufficient to cover the costs that the utility incurs to serve that class. If a class produces a below-average rate of return, it may be concluded that the revenue provided by the class is insufficient to cover all relevant costs to serve that class. On the other hand, if a class produces a rate of return above the system average, it is not only paying revenues sufficient to cover the cost attributable to it, but in addition, it is paying part of the cost attributable to other classes who produce below system average rates of return.

Q WHY IS A CCOSS OF IMPORTANCE?

A A CCOSS shows the costs that a utility incurs to serve each customer class. It is a widely held principle that costs should be allocated among customer classes on the basis of cost causation. That principle is perhaps the most universally accepted principle of allocating cost that cannot be directly assigned to a particular customer class. The costs should be allocated to those classes on the basis of cost causation. The results of such studies are used in assigning cost responsibilities to various customer classes in regulatory proceedings.

Q DO YOU SUPPORT THAT PREMISE?

A Yes. Rates that are based on consistently applied cost-causation principles are not only fair and reasonable, but further the cause of stability, conservation and efficiency. When consumers are presented with price signals that convey the consequences of their consumption decisions, i.e., how much energy to consume, at what rate, and when, they tend to take actions which not only minimize their own costs, but those of the utility as well.

Although factors such as simplicity, gradualism, economic development and ease of administration may also be taken into consideration when determining the final spread of the revenue requirement among classes, the fundamental starting point and guideline should be the cost of serving each customer class produced by the CCOSS.

Q HOW IS THE COST OF SERVING EACH CUSTOMER CLASS DETERMINED?

A The appropriate mechanism to determine the cost of serving each customer class is a fully allocated embedded CCOSS. It follows, however, that the objective of cost-based rates cannot be attained unless the CCOSS is developed using cost-causation principles.

Q WHAT ARE THE MAJOR STEPS IN A CCOSS?

A The first step in a CCOSS is known as <u>functionalization</u>. This simply refers to the process by which the utility's investments and expenses are reviewed and put into different categories of cost. The primary functions utilized are production, transmission and distribution. Of course, each broad function may have several subcategories to provide for a more refined determination of cost of service.

The second major step is known as <u>classification</u>. In the classification step, the functionalized costs are separated into the categories of demand-related, energy-related, and customer-related costs in order to facilitate the allocation of costs applying the cost-causation principles.

Demand or capacity-related costs are those costs that are incurred by the utility to serve the amount of demand that each customer class places on the system. A traditional example of capacity-related costs is the investment associated with generating stations, transmission lines, and a portion of the distribution system. Once the utility makes an investment in these facilities, the costs continue to be incurred, irrespective of the number of kilowatthours generated and sold or the number of customers taking service from the utility.

Energy-related costs are those costs that are incurred by the utility to provide the energy required by its customers. Thus, the fuel expense is almost directly proportional to the amount of kilowatthours supplied by the utility system to meet its customers' energy requirements.

Customer-related costs are those costs that are incurred to connect customers to the system and are independent of the customer's demand and energy requirements. Primary examples of customer-related costs are investments in meters, services, and the portion of the distribution system that is necessary to connect customers to the system. In addition, such accounting functions as meter reading, bill preparation, and revenue accounting are considered customer-related costs.

The final step in the CCOSS is the <u>allocation</u> of each category of the functionalized and classified costs to the various customer classes using the cost-causation principles. Demand-related costs are allocated on the basis that gives recognition to each class's responsibility for the Company's need to build plant to serve demands imposed on the system. Energy-related costs are allocated on the basis of energy use by each customer class. Customer-related costs are allocated based upon the number of customers in each class, weighted to account for the complexity of servicing the needs of the different classes of customers.

III. COST OF SERVICE AND REVENUE ALLOCATION/RATE DESIGN PRINCIPLES

Q WHY IS IT IMPORTANT TO ADHERE TO COST OF SERVICE PRINCIPLES IN THE REVENUE ALLOCATION/RATE DESIGN PROCESS?

A The basic reasons for using cost of service as the primary factor in the revenue allocation/rate design process are equity, cost causation, appropriate price signals, conservation and revenue stability.

Q HOW IS THE EQUITY PRINCIPLE ACHIEVED BY BASING RATES ON COSTS?

A To the extent practical, when rates are based on cost, each customer pays what it costs the utility to serve the customer, no more and no less. If rates are not based on cost of service, then some customers contribute disproportionately to the utility's revenue requirement and provide contributions to the cost to serve other customers. This is inherently inequitable.

Q HOW DO COST-BASED RATES PROVIDE APPROPRIATE PRICE SIGNALS TO CUSTOMERS?

A Rate design is the step that follows the allocation of costs to classes, so it is important that the proper amounts and types of costs be allocated to the customer classes so that they may ultimately be reflected in the rates.

When the rates are designed so that the energy costs, demand costs, and customer costs are properly reflected in the energy, demand and customer components of the rate schedules, respectively, customers are provided with the proper incentives to manage their loads appropriately. This, in turn, provides the correct signal to the utility (and other competitive power suppliers) about the need for new investment. When customers impose a certain level of demand on the system, they should pay for the prudent cost that the utility incurs to supply that demand and the energy charge that they pay should reflect the cost of providing that energy.

Q HOW DO COST-BASED RATES FURTHER THE GOAL OF CONSERVATION?

A Conservation occurs when wasteful or inefficient uses of electricity are discouraged or minimized. Only when rates are based on actual costs do customers receive an accurate and appropriate price signal against which to make their consumption decisions. If rates are not based on costs, then customers may be induced to use electricity inefficiently in response to the distorted price signals.

Q PLEASE DISCUSS THE REVENUE STABILITY CONSIDERATION.

A When rates are closely tied to costs, the impact on the utility's earnings due to changes in customer use patterns will be minimized. Rates that are designed to track changes in the level of costs result in revenue changes that mirror cost changes. Thus, cost-based rates provide an important enhancement to a utility's earnings stability, reducing its need to file for rate increases.

From the perspective of the customer, cost-based rates provide a more reliable means of determining future levels of power costs. If rates are based on factors other than the cost to serve, it becomes much more difficult for customers to translate expected utility-wide cost changes, such as expected increases in overall revenue requirements, into changes in the rates charged to particular customer classes and to customers within the class. This situation reduces the attractiveness of expansion, as well as continued operations, in the utility's service territory because of the limited ability to plan and budget for future power cost.

IV. FPL'S CLASS COST OF SERVICE STUDY

Q HAVE YOU REVIEWED THE CONSOLIDATED CCOSS FILED BY FPL THAT UTILIZES AN MDS IN THIS PROCEEDING?

A Yes. In its CCOSS with an MDS, FPL has partially classified and allocated costs on a customer basis for the following Distribution Plant Accounts: 364 (Poles, Towers and Fixtures); 365 (Overhead Conductors and Devices); 366 (Underground Conduit);

367 (Underground Conductors and Devices); and 368 (Line Transformers). The results of FPL's CCOSS with an MDS are shown on Exhibit BCC-1.

Q SHOULD THE CCOSS WITH AN MDS BE USED FOR THE BASIS OF THE CLASS REVENUE ALLOCATION ?

A Yes. Because FPL's CCOSS with an MDS better reflects class cost causation, I recommend that it be used to guide class revenue allocation.

Q WHY SHOULD THE COSTS ASSOCIATED WITH DISTRIBUTION PLANT ACCOUNTS 364 THROUGH 368 BE CLASSIFIED AND ALLOCATED ON BOTH A DEMAND AND CUSTOMER BASIS AS OPPOSED TO JUST A DEMAND BASIS AS PERFORMED IN FPL'S CCOSS WITHOUT AN MDS?

A Classifying and allocating the costs associated with Distribution Plant Accounts 364 through 368 entirely on a demand basis is inconsistent with cost causation and generally accepted costing methodology. The primary purpose of the distribution system is to deliver power from the transmission grid to the customer in various geographical locations with service at different voltage levels. Certain distribution investments must be made just to connect a customer to the system. Also, many equipment manufacturers have only minimum sized equipment available. Safety concerns and construction practices often require minimum sized equipment which is not determined by demand. These investments are properly considered to be customer-related.

Q IS THIS A NEW COST OF SERVICE CONCEPT?

A No. The concept is known as the Minimum Distribution System ("MDS"), and has been accepted for decades as a valid consideration by numerous state public utility commissions. It has also been presented in the National Association of Regulatory Utility Commissioners' Electrical Utility Cost Allocation Manual ("NARUC Manual") and the Gas Distribution Rate Design Manual published by NARUC.

The central idea behind the MDS concept is that there is a minimum cost incurred by any utility when it extends its primary and secondary distribution systems and connects an additional customer to them. By definition, the MDS comprises every distribution component necessary to provide service, i.e., meters, services, secondary and primary wires, poles, substations, etc. The cost of the MDS, however, is only that portion of the total distribution cost the utility must incur to provide service to customers. It does not include costs specifically incurred to meet the peak demand of the customers.

Q PLEASE ELABORATE FURTHER ON THE MDS CONCEPT AND THE DISTINCTION BETWEEN CUSTOMER-RELATED COSTS AND DEMAND-RELATED COSTS IN THE CONTEXT OF A CCOSS.

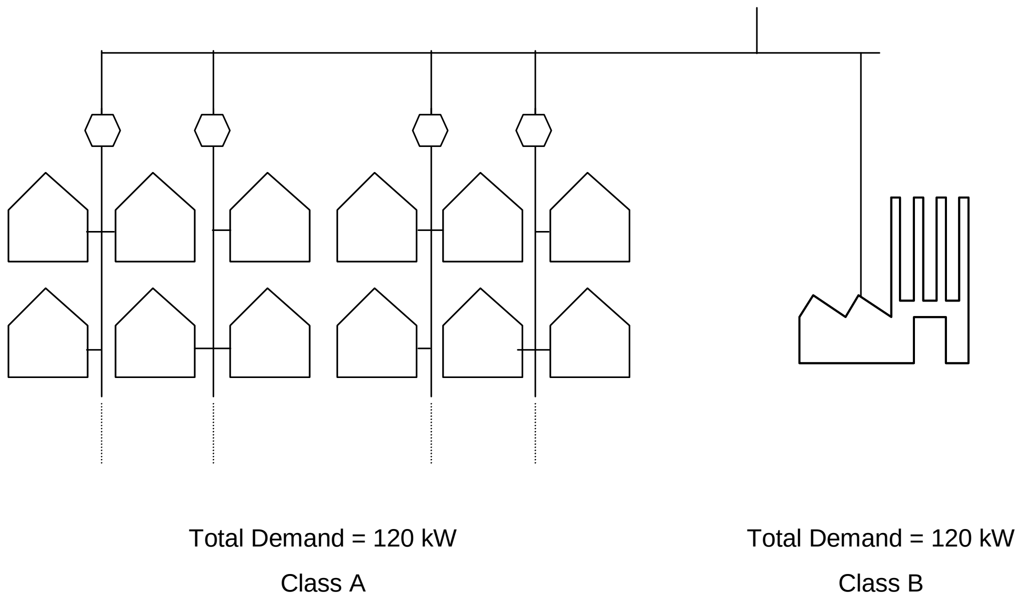
A A certain portion of the cost of the distribution system associated with poles, wires and transformers is required just to attach customers to the system in different geographical locations, regardless of their demand or energy requirements. This minimum or "skeleton" distribution system may also be considered as customer-related cost because it depends primarily on the number of customers, rather than on demand or energy usage.

Figure 1, as an example, shows the distribution network for a utility with two customer classes, A and B. The physical distribution network necessary to attach Class A is designed to serve 12 customers, each with a 10-kilowatt ("kW") load, having a total demand of 120 kW. This is the same total demand as is imposed by Class B, which consists of a single customer. Clearly, a much more extensive distribution system is required to attach the multitude of small customers (Class A), than to attach the single larger customer (Class B), despite the fact that the total demand of each customer class is the same.

Even though some additional customers can be attached without additional investment in some areas of the system, it is obvious that attaching a large number of customers in different geographical locations requires investment in facilities, not only initially but on a continuing basis as a result of the need for maintenance and repair. Thus, a large part of the distribution system is classified as customer-related in order to recognize this area coverage requirement.

Figure 1

Classification of Distribution Investment



Q IN ADDITION TO THE AREA COVERAGE FACTOR YOU NOTED ABOVE, ARE THERE OTHER REASONS FOR CLASSIFYING PART OF THE DISTRIBUTION SYSTEM AS CUSTOMER-RELATED?

A Yes, there are. Safety and reliability are the best examples of these. A properly conducted CCOSS must consider all cost-causing factors.

Q PLEASE EXPLAIN.

A When distribution engineers design the enhancement, upgrade, or extension of an electric system, they must be constantly aware of the operating parameters of the system. It is in the construction of the distribution system, however, that the *true* *cause* of many distribution costs is clearly seen. Surprisingly, that cause is frequently *not* demand.

An illustration helps make this point clear. Consider a customer who intends to build a home on a new lot, one that does not already have electrical service. This customer is cost and energy conscious and, thus, chooses to employ as many energy efficiency and conservation techniques and appliances as the customer can. After considerable research and consultation with experts, the customer calls the utility and advises that service will be required capable of providing a maximum peak demand of 2,000 watts (2 kW).

During the installation of the primary and secondary distribution extension to the customer's home, the customer notices that the linemen are using conductors, poles, cross-arms, and components identical to those serving the much larger, and less efficient, houses down the street. After more investigation, the customer learns that the distribution extension to the home is capable of carrying far greater demand than the home was designed to use. When the customer informs the utility of this "error," the utility explains that because of reliability and safety concerns it cannot install wires smaller than a certain size or hang them below a certain height. In short, there are specified minimum standards that the utility must meet that are wholly unrelated to the new home's reduced demand.

This illustration demonstrates that, although utilities design and install distribution equipment to satisfy their customers' need for electricity, there are factors other than electrical demand that force them to incur costs. Safety and reliability are as critical to every phase of design and construction as demand. Further, many equipment manufacturers have only minimum sized equipment available for installation. As one reviews the cost of the distribution system nearest the customer (i.e., that portion from the primary radial lines through the line transformers and secondary system), the cost incurred to comply with safety and reliability standards, as well as minimum sized equipment available, begins to outweigh the cost of meeting electrical demand.

Q CAN YOU CITE ANY AUTHORITATIVE PUBLICATIONS THAT SUPPORT ALLOCATING PART OR ALL OF DISTRIBUTION PLANT ACCOUNTS 364 THROUGH 368 ON THE BASIS OF A CUSTOMER COMPONENT?

A Yes. In 1992, NARUC published the NARUC Manual which states:

> Distribution Plant Accounts 364 through 370 involve demand and customer costs. The customer component of distribution facilities is that portion of costs which varies with the number of customers. Thus, the number of poles, conductors, transformers, services, and meters are directly related to the number of customers on the utility's system. As shown in Table 6-1, each primary plant account can be separately classified into a demand and customer component. Two methods are used to determine the demand and customer components of distribution facilities. They are, the minimum-size-of-facilities method, and the minimum-intercept cost (zero-intercept or positive-intercept cost, as applicable) of facilities. (NARUC Manual, page 90)

Table 6-1 from the NARUC Manual is included as Figure 2. It shows that Distribution Plant Accounts 364 through 368, which include conductors, support structures and line transformers, have both a demand component and a customer component.

Figure 2

TABLE 6-1

CLASSIFICATION OF DISTRIBUTION PLANT[1]

FERC Uniform System of Accounts No.	Description	Demand Related	Customer Related
	Distribution Plant[2]		
360	Land & Land Rights	X	X
361	Structures & Improvements	X	X
362	Station Equipment	X	-
363	Storage Battery Equipment	X	-
364	Poles, Towers, & Fixtures	X	X
365	Overhead Conductors & Devices	X	X
366	Underground Conduit	X	X
367	Underground Conductors & Devices	X	X
368	Line Transformers	X	X
369	Services	-	X
370	Meters	-	X
371	Installations on Customer Premises	-	X
372	Leased Property on Customer Premises	-	X
373	Street Lighting & Signal Systems[1]	-	-

[1]Assignment or "exclusive use" costs are assigned directly to the customer class or group which exclusively uses such facilities. The remaining costs are then classified to the respective cost components.

[2]The amounts between classification may vary considerably. A study of the minimum intercept method or other appropriate methods should be made to determine the relationships between the demand and customer components.

Q HAVE UTILITY COMMISSIONS ADOPTED ALLOCATION METHODS FOR CLASSIFYING AND ALLOCATING A PORTION OF DISTRIBUTION PLANT AS CUSTOMER-RELATED?

A Yes. For example, the Connecticut, Colorado, Hawaii, Indiana, Kansas, Maine, Missouri, New York, North Carolina, Oregon, Pennsylvania, Texas and Wisconsin commissions have classified a portion of distribution plant on a customer- and demand-related basis for cost of service purposes.

Q HAS ANY UTILITY COMMISSION STAFF OPINED ON THE CLASSIFICATION AND ALLOCATION OF A PORTION OF DISTRIBUTION PLANT AS CUSTOMER-RELATED USING A MINIMUM SYSTEM METHODOLOGY?

A Yes. The Public Staff of the North Carolina Utilities Commission stated the following in a recent report from March 2019:

> After our review, the Public Staff believe that the use of MSM [Minimum System Methodology] by electric utilities for the purpose of classifying and allocating distribution costs is reasonable for establishing the maximum amount to be recovered in the fixed or basic customer charge.[1]

Q WHAT IS YOUR RECOMMENDATION WITH RESPECT TO THE CLASSIFICATION AND ALLOCATION OF DISTRIBUTION PLANT COSTS ASSOCIATED WITH ACCOUNTS 364 THROUGH 368?

A I recommend that the Commission use the results of FPL'S CCOSS with an MDS that classifies and allocates a portion of distribution plant costs associated with Accounts 364 through 368 on a customer basis. This approach is consistent with general ratemaking policy objectives, such as customer equity, conservation and revenue stability. The CCOSS with a MDS should be used as a guideline in revenue allocation and rate design in this proceeding.

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[1]Report of the Public Staff on the Minimum System Methodology of North Carolina Electric Public Utilities, Docket No. E-100, Sub 162, March 28, 2019, pp. 16-17.

V. CLASS REVENUE ALLOCATION

Q HAS FPL ALLOCATED ITS REQUESTED LEVEL OF DISTRIBUTION INCREASE TO CLASSES IN THIS CASE RECOGNIZING THE RESULTS OF ITS CCOSS WITHOUT AN MDS?

A Yes. I have summarized FPL's proposed class revenue allocation using this study on Exhibit BCC-1.

Q HAVE YOU DEVELOPED A RECOMMENDED SPREAD OF THE INCREASE TO CLASSES, ASSUMING FULL REVENUE RELIEF FOR THE COMPANY, AND USING THE FPL CCOSS WITH MDS?

A Yes. Because the FPL CCOSS with MDS better reflects class cost causation, I recommend the CCOSS with an MDS be used as a guide for class revenue allocation.

Q HAVE YOU PREPARED AN ALTERNATIVE CLASS REVENUE ALLOCATION?

A Yes. FEA's proposed alternative class revenue allocation is also shown on Exhibit BCC-1. Under my class revenue allocation, classes have been limited to an increase no greater than 1.65 times the system average increase of 14.4%. I have also held classes at current rates when the CCOSS indicates those classes should receive a rate decrease.

Q WHAT IS YOUR RECOMMENDATION WITH RESPECT TO CLASS REVENUE ALLOCATION?

A I recommend that the Commission set rates using FEA's proposed class revenue allocation shown on Exhibit BCC-1. This exhibit assumes the full revenue increase requested by FPL for class revenue allocation. To the extent the Commission approves a revenue requirement that differs from FPL's request, FEA's proposed class revenue allocation would be adjusted.

VI. RATE DESIGN

Q DOES GULF POWER ("GP") CURRENTLY OFFER AN RTP RATE TO ITS CUSTOMERS?

A Yes, it does. Under the current GP tariff, the RTP hourly energy prices are derived using the day ahead projection of Southern System Lambda adjusted to recognize embedded costs.

Q DOES FPL CURRENTLY OFFER AN RTP RATE TO ITS CUSTOMERS?

A No, it does not.

Q PLEASE DESCRIBE RTP TARIFFS IN GENERAL.

A During periods of high electricity use by customers that have the potential to strain a utility's grid, the incentive for electricity customers to conserve energy is reduced when those customers pay a fixed price per kilowatt hour of electricity. Under an RTP tariff, the tariff reflects the cost of electricity that varies throughout the day. As a result, a utility charges customers different prices for electricity through the day typically based on fluctuating wholesale costs. Customers charged according to RTP typically consume less electricity in response to higher prices, primarily due to lower electricity consumption during peak times on the utility's system.

Q DOES FPL PROPOSE TO ELIMINATE THE GP RTP TARIFF?

A Yes, it does. According to the testimony of FPL witness Tiffany C. Cohen at page 38, she indicates that FPL plans to close the RTP rate to new customers and eliminate the rate schedule in the next base rate proceeding.

Q HOW DO YOU RESPOND TO FPL'S PROPOSAL TO ELIMINATE THE RTP RATE?

A The GP RTP rate should not be eliminated until a comparable RTP rate is established for FPL. RTP tariffs offer customers the ability to make energy asset investments or modify operations to alter hourly demands based on the price signals produced in an RTP rate. GP's customers that take service on its RTP rate stand to lose the conservation benefits of these load modifications if the RTP rate is eliminated before FPL develops and offers a comparable RTP rate.

The RTP tariff is another tool available to customers to manage their power costs and consumption during peak periods on the utility's system, provides price incentives to pursue economic renewable and green power investments that reduce carbon emissions and encourage enhanced utilization of the utility's infrastructure investments (e.g., improve load factor). These conservation/clean energy efforts by GP customers benefit both utility customers and the utility.

Q DOES FEA CURRENTLY TAKE SERVICE UNDER THE GP RTP RATE?

A Yes, it does. FEA has considerable load that takes service under the current RTP rate.

Q HAS FPL INDICATED TO FEA WHICH FPL RATE WOULD BE OPTIMAL FOR THE FEA ACCOUNTS CURRENTLY TAKING SERVICE UNDER THE RTP TARIFF?

A No, it has not. This makes it difficult for FEA to forecast its projected electricity costs as well as plan investments for its military installations.

Q WHAT IS YOUR RECOMMENDATION WITH RESPECT TO THE EXISTING GP RTP RATE?

A I recommend that FPL retain the GP RTP rate and investigate expanding the RTP rate into the combined footprint of GP and FPL.

Q DO YOU HAVE SOME COMMENTS ON HOW FPL SHOULD REVISE ITS RATES TO REFLECT REAL-TIME COST DIFFERENTIALS?

A Yes. FPL should either develop a separate RTP rate for eligible customers that reflect real-time cost differentials, or it could possibly add an RTP option to an existing tariff rate that reflects FPL's real-time cost differentials.

Q DOES FPL's SYSTEM LAMBDA VARY BY SEASON AS WELL AS DURING FPL'S TARIFF DEFINED ON-PEAK AND OFF-PEAK PERIODS?

A Yes. I have examined FPL's FERC Form 714 Lambda data. This data is shown in Exhibit BCC-2.

As shown in the exhibit, FPL's system lambda does vary by season and by time period. As a result, an RTP tariff could likely be developed that would provide all eligible customers in the combined GP and FPL footprint a tool to assist them in making investments and/or modifying operations to alter hourly demands based on the price signals produced in an RTP rate tariff.

An FPL RTP tariff rate would provide the opportunity for all eligible customers in the combined GP and FPL footprint to help manage their power costs and consumption during peak periods on the utility's system and provide price incentives for all such customers to pursue economic renewable and green power investments that reduce carbon emissions and encourage enhanced utilization of the utility's infrastructure investments.

Q DO YOU HAVE ANY OTHER RECOMMENDATIONS WITH RESPECT TO AN RTP TARIFF RATE FOR FPL?

A I recommend a workshop be held between the Company and its customers in order to explore an FPL RTP tariff rate option prior to FPL's next rate case.

Q DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A Yes, it does.

Qualifications of Brian C. Collins

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Brian C. Collins. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017.

Q WHAT IS YOUR OCCUPATION AND BY WHOM ARE YOU EMPLOYED?

A I am a consultant in the field of public utility regulation and a Principal with the firm of Brubaker & Associates, Inc. ("BAI"), energy, economic and regulatory consultants.

Q PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND WORK EXPERIENCE.

A I graduated from Southern Illinois University Carbondale with a Bachelor of Science degree in Electrical Engineering. I also graduated from the University of Illinois at Springfield with a Master of Business Administration degree. Prior to joining BAI, I was employed by the Illinois Commerce Commission and City Water Light & Power ("CWLP") in Springfield, Illinois.

My responsibilities at the Illinois Commerce Commission included the review of the prudence of utilities' fuel costs in fuel adjustment reconciliation cases before the Commission as well as the review of utilities' requests for certificates of public convenience and necessity for new electric transmission lines. My responsibilities at CWLP included generation and transmission system planning. While at CWLP, I completed several thermal and voltage studies in support of CWLP's operating and planning decisions. I also performed duties for CWLP's Operations Department, including calculating CWLP's monthly cost of production. I also determined CWLP's allocation of wholesale purchased power costs to retail and wholesale customers for use in the monthly fuel adjustment.

In June 2001, I joined BAI as a Consultant. Since that time, I have participated in the analysis of various utility rate and other matters in several states and before the Federal Energy Regulatory Commission ("FERC"). I have filed or presented testimony before the Arkansas Public Service Commission, the California Public Utilities Commission, the Delaware Public Service Commission, the Public Service Commission of the District of Columbia, the Florida Public Service Commission, the Georgia Public Service Commission, the Idaho Public Utilities Commission, the Illinois Commerce Commission, the Indiana Utility Regulatory Commission, the Kentucky Public Service Commission, the Public Utilities Board of Manitoba, the Minnesota Public Utilities Commission, the Mississippi Public Service Commission, the Missouri Public Service Commission, the Montana Public Service Commission, the North Dakota Public Service Commission, the Public Utilities Commission of Ohio, the Oregon Public Utility Commission, the Rhode Island Public Utilities Commission, the Public Service Commission of Utah, the Virginia State Corporation Commission, the Public Service Commission of Wisconsin, the Washington Utilities and Transportation Commission, and the Wyoming Public Service Commission. I have also assisted in the analysis of transmission line routes proposed in certificate of convenience and necessity proceedings before the Public Utility Commission of Texas.

In 2009, I completed the University of Wisconsin – Madison High Voltage Direct Current ("HVDC") Transmission Course for Planners that was sponsored by the Midwest Independent Transmission System Operator, Inc. ("MISO").

BAI was formed in April 1995. BAI and its predecessor firm has participated in more than 700 regulatory proceedings in forty states and Canada.

BAI provides consulting services in the economic, technical, accounting, and financial aspects of public utility rates and in the acquisition of utility and energy services through RFPs and negotiations, in both regulated and unregulated markets. Our clients include large industrial and institutional customers, some utilities and, on occasion, state regulatory agencies. We also prepare special studies and reports, forecasts, surveys and siting studies, and present seminars on utility-related issues.

In general, we are engaged in energy and regulatory consulting, economic analysis and contract negotiation. In addition to our main office in St. Louis, the firm also has branch offices in Phoenix, Arizona and Corpus Christi, Texas.

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

IN RE: PETITION FOR RATE INCREASE BY FLORIDA POWER & LIGHT COMPANY	)))))	**DOCKET NO. 20210015-EI**

STATE OF MISSOURI	)	
	)	**SS**
COUNTY OF ST. LOUIS	)	

Affidavit of Brian C. Collins

Brian C. Collins, being first duly sworn, on his oath states:

1. My name is Brian C. Collins. I am a consultant with Brubaker & Associates, Inc., having its principal place of business at 16690 Swingley Ridge Road, Suite 140, Chesterfield, Missouri 63017. We have been retained by the Federal Executive Agencies in this proceeding on their behalf.

2. Attached hereto and made a part hereof for all purposes are my direct testimony and exhibits which were prepared in written form for introduction into evidence in the Florida Public Service Commission Docket No. 20210015-EI.

3. I hereby swear and affirm that the testimony and exhibits are true and correct and that they show the matters and things that they purport to show.

Brian C. Collins

Brian C. Collins

Subscribed and sworn to before me this 21st day of June, 2021.

SALLY D. WILHELMS
Notary Public - Notary Seal
STATE OF MISSOURI
St. Louis County
My Commission Expires: Aug. 5, 2024
Commission # 20078050

Sally D Wilhelms

Notary Public

Florida Power & Light Company

Consolidated Comparison of Proposed Target Revenue Requirements by Rate Class with and without MDS

For the Test Year 2022

($ Millions)

		Cost of Service Without MDS			Cost of Service With MDS			FPL Proposed Revenue Allocation			FEA Proposed Revenue Allocation		
		Without MDS	Increase over Present Revenues		With MDS	Increase over Present Revenues			Increase over Present Revenues			Increase over Present Revenues	
Rate Class	Present Revenues [3]	Target Revenue Requirements [1]	Amount	Percent	Target Revenue Requirements [2]	Amount	Percent	Company Proposed Revenues [3]	Amount	Percent	FEA Proposed Revenues	Amount	Percent
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
CILC-1D	$ 106.2	$ 127.6	$ 21.4	20.1%	$ 113.3	$ 7.1	6.7%	$ 128.4	$ 22.2	20.9%	$ 113.3	$ 7.1	6.7%
CILC-1G	5.1	6.1	1.0	19.2%	5.4	0.3	5.2%	6.1	1.0	20.0%	5.4	$ 0.3	5.2%
CILC-1T	41.8	52.1	10.3	24.7%	52.1	10.3	24.7%	52.6	10.7	25.7%	51.7	$ 9.9	23.7%
GS(T)-1	580.0	652.1	72.2	12.4%	677.0	97.0	16.7%	659.8	79.8	13.8%	677.0	$ 97.0	16.7%
GSCU-1	4.3	4.2	(0.1)	-2.4%	5.7	1.4	31.8%	4.5	0.2	3.7%	5.4	$ 1.0	23.7%
GSD(T)-1	1,420.2	1,755.0	334.8	23.6%	1,556.3	136.2	9.6%	1,752.8	332.6	23.4%	1,573.0	$ 152.8	10.8%
GSLD(T)-1	455.8	643.4	187.6	41.2%	562.5	106.7	23.4%	569.0	113.2	24.8%	562.5	$ 106.7	23.4%
GSLD(T)-2	135.1	200.7	65.6	48.5%	178.0	42.9	31.7%	172.1	36.9	27.3%	167.2	$ 32.0	23.7%
GSLD(T)-3	24.5	36.0	11.6	47.2%	36.0	11.6	47.2%	32.4	8.0	32.6%	30.3	$ 5.8	23.7%
MET	4.1	4.9	0.7	17.9%	4.3	0.2	3.6%	4.9	0.8	18.8%	4.3	$ 0.2	3.6%
OL-1	14.7	14.3	(0.4)	-2.5%	20.9	6.3	42.6%	15.1	0.4	2.6%	18.1	$ 3.5	23.7%
OS-2	1.1	1.3	0.3	24.1%	0.8	(0.3)	-28.8%	1.3	0.2	18.2%	1.1	$ -	0.0%
RS(T)-1	4,786.4	5,183.2	396.8	8.3%	5,474.7	688.3	14.4%	5,277.4	491.0	10.3%	5,474.7	$ 688.3	14.4%
SL-1	122.6	131.9	9.3	7.6%	126.8	4.2	3.4%	133.3	10.7	8.7%	126.8	$ 4.2	3.4%
SL-1M	0.9	1.0	0.1	7.4%	0.8	(0.1)	-12.8%	1.0	0.1	10.3%	0.9	$ -	0.0%
SL-2	1.9	2.1	0.2	8.9%	1.8	(0.1)	-5.3%	2.1	0.2	11.1%	1.9	$ -	0.0%
SL-2M	0.2	0.2	(0.0)	-8.0%	0.3	0.1	55.1%	0.2	0.0	11.0%	0.3	$ 0.0	23.7%
SST-DST	1.5	1.4	(0.2)	-12.2%	1.5	-	0.0%	0.5	(1.1)	-69.5%	1.5	$ -	0.0%
SST-TST	6.0	3.4	(2.6)	-44.0%	3.4	(2.6)	-44.0%	7.4	1.4	23.2%	6.0	$ -	0.0%
Total Revenue from Sales	**$ 7,712.4**	**$ 8,820.8**	1,108.4	14.4%	**$ 8,821.6**	$1,109.2	14.4%	**$ 8,820.8**	$1,108.4	14.4%	**$ 8,821.3**	$1,108.9	14.4%
Misc. Service Charges	100.1	100.1			100.1			100.1			100.1		
Other Operating Revenues	126.2	126.2			126.2			126.2			126.2		
Total Operating Revenues	**$ 7,938.7**	**$ 9,047.2**			**$ 9,048.0**			**$ 9,047.2**			**$ 9,047.6**		

Notes:

(1) Provided on MFR E-1, Attachment 2, Equalized at Proposed Rates,w/ RSAM

(2) Provided on Informational MDS MFR E-1, Attachment 2, Equalized at Proposed Rates,w/ RSAM and MDS

(3) Provided on MFR E-1, Cost of Service Study (With RSAM), Attachment No. 3 of 3.

Totals may not add due to rounding.

Florida Power & Light Company

Summary of 2019 FPL System Lambda

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
On-Peak	19.67	17.69	19.23	18.72	21.19	20.95	18.86	16.66	22.68	19.40	17.65	15.49
Off-Peak	19.23	17.86	18.18	16.77	17.34	16.41	15.69	14.67	18.03	15.24	16.66	14.62

Source: FERC Form 714

Note: FPL's On-Peak hours are defined as November 1 through March 31 during the hours from 6 am to 10 am and 6 pm to 10 pm on Monday through Friday excluding Thanksgiving Day, Christmas Day, and New Year's Day. Additionally they are defined as from April 1 through October 31, Monday through Friday from 12 noon to 9 pm, excluding Memorial Day, Independence Day, and Labor Day. All other hours are considered Off-Peak.