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BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

In the Matter of:

DOCKET NO. 20210015-EI

Petition for rate increase by Florida Power & Light Company.
_____________________________/

VOLUME 5
PAGES 971 - 1159

PROCEEDINGS: HEARING

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

DATE: Monday, September 20, 2021

TIME: Commenced: 9:30 a.m.
Concluded: 12:00 p.m.

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

REPORTED BY: DEBRA R. KRICK
Court Reporter

APPEARANCES: (As heretofore noted.)

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I N D E X

WITNESS:	PAGE
TIFFANY C. COHEN	
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Prefiled Rebuttal Testimony inserted	1015
ROXIE MCCULLAR	
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P R O C E E D I N G S

(Transcript follows in sequence from Volume 4.)

(Whereupon, prefiled direct testimony of Tiffany C. Cohen was inserted.)

ERRATA SHEET

WITNESS: **TIFFANY C. COHEN – DIRECT TESTIMONY**

PAGE #	LINE #	CHANGE
20	21	Remove "as a new pilot available"
29	Footnote 1	Remove "two existing Storm Protection Plans and"
36	17	Remove "pilot"

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

DIRECT TESTIMONY OF TIFFANY C. COHEN

DOCKET NO. 20210015-EI

MARCH 12, 2021

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I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Tiffany C. Cohen, and my business address is Florida Power & Light Company, 700 Universe Boulevard, Juno Beach, Florida 33408.

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

A. I am employed by Florida Power & Light Company ("FPL" or the "Company") as the Senior Director, Regulatory Rates, Cost of Service & Systems.

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

A. I oversee the load research, cost of service, and rate design departments for all retail electric rates and charges for FPL and Gulf Power Company ("Gulf" or "Gulf Power"). Additionally, I am responsible for proposing and administering the tariff language needed to implement those rates and charges.

Q. Please describe your educational background and professional experience.

A. I hold a Bachelor of Science Degree in Commerce and Business Administration, with a major in Accounting from the University of Alabama. I obtained a Master of Business Administration from the University of New Orleans. I am also a Certified Public Accountant. In 2008, I joined FPL. During my tenure at the Company, I have held various regulatory positions of increasing responsibility, including overseeing the Nuclear Cost Recovery Clause and managing FPL's Rates and Tariffs department. I assumed my current role in 2017, and in 2019 I assumed responsibility for supervising Gulf Power's load research, cost of service, and rates and tariffs functions. I am a member of the Edison Electric Institute ("EEI") Rates and Regulatory Affairs Committee, and I have completed the EEI Advanced Rate Course. Prior to joining FPL, I was employed at Duke Energy for five years, where I held a variety of positions in the Rates & Regulatory Division, including managing rate cases. I also worked in the Finance, Corporate Risk Management, and Internal Audit departments. Prior to joining Duke Energy, I was employed at KPMG, LLP.

Q. Are you sponsoring or co-sponsoring any exhibits in this case?

A. Yes. I am sponsoring the following exhibits:

- TCC-1 Consolidated MFRs Sponsored or Co-sponsored by Tiffany C. Cohen
- TCC-2 Supplemental FPL and Gulf Standalone Information in MFR Format Sponsored or Co-sponsored by Tiffany C. Cohen
- TCC-3 Bills at Unified Rates (Current FPL Customers)
- TCC-4 Bills at Unified Rates (Northwest Florida Customers)
- TCC-5 National Bill Comparisons
- TCC-6 Parity of Major Rate Classes
- TCC-7 Summary of Proposed Rate Structure for Major Rate Schedules
- TCC-8 Calculation of 2022 System Differential Transition Rider and Credit

I am co-sponsoring the following exhibits:

- TCC-9 Rates for FPL and Gulf as Separate Ratemaking Entities

- REB-12 Solar Base Rate Adjustment Mechanism, filed with the direct testimony of FPL witness Barrett

Q. Are you sponsoring or co-sponsoring any consolidated Minimum Filing Requirements ("MFRs") in this case?

A. Yes. Exhibit TCC-1 lists the consolidated MFRs I am sponsoring and co-sponsoring.

Q. Are you sponsoring or co-sponsoring any schedules in "Supplement 1 – FPL Standalone Information in MFR Format" and "Supplement 2 – Gulf Standalone Information in MFR Format"?

A. Yes. Exhibit TCC-2 lists the supplemental FPL and Gulf standalone information in MFR format that I am sponsoring and co-sponsoring.

Q. How will you refer to FPL and Gulf when discussing them in testimony?

A. I use the terms "FPL" and "Gulf" throughout my testimony. Unless otherwise specifically stated or dictated by context, those references will mean the following:

- In discussing operations or time periods prior to January 1, 2019 (when NextEra Energy, Inc. acquired Gulf), "FPL" and "Gulf" will refer to their pre-acquisition status, when they were legally and operationally separate companies.
- In discussing operations or time periods between January 1, 2019 and January 1, 2022 (when operational and bookkeeping consolidation will essentially be complete), "FPL" and "Gulf" will refer to their status as

separate ratemaking entities, recognizing that they were merged legally on January 1, 2021 and consolidation proceeded throughout this period.

- In discussing operations and time periods after January 1, 2022, most references will be only to "FPL" because Gulf will be consolidated into FPL, and FPL is proposing unified rates for the consolidated company. References to "Gulf" thereafter will primarily be to address any rate differentiation between customers in the former FPL and Gulf service areas.

Q. What is the purpose of your testimony?

A. My testimony addresses the following general areas:

- Rate design principles and rate structure
- Revenue forecast by rate class
- Allocation of rate increase to rate classes
- Proposed changes to existing rates
- Service charges
- Other tariff changes
- Proposed rate adjustments for the 2024 and 2025 Solar Base Rate Adjustments ("SoBRAs")
- Proposed changes to FPL and Gulf rates, if treated as separate ratemaking entities

Q. Please summarize your testimony.

A. My testimony supports FPL's proposed base retail rates and service charges that will produce revenues sufficient to recover the Company's jurisdictional revenue requirements in the 2022 Test Year and the 2023 Subsequent Year. Because FPL and Gulf are operationally and legally combined, unified rates are the next logical step in the merger and integration process that is expected to be essentially completed by year end 2021. Due to the current difference in the cost to serve, I support FPL's proposal to implement a temporary declining transition rider ("transition rider") for customers in the former Gulf service area of Northwest Florida with an offsetting temporary declining transition credit ("transition credit") for customers in the former FPL service area. I support the methodology used to calculate the rate adjustments in 2024 and 2025 associated with the SoBRA mechanism. I also support the schedules provided for FPL and Gulf, if treated as separate ratemaking entities. They often are referred to throughout the case materials as "standalone" rates.

Q. Please provide an overview of FPL and Gulf bills over the last fifteen years.

A. Gulf Power's typical residential bill has increased 43 percent over the last fifteen years. Fifteen years ago, Gulf's typical residential bill was 15 percent lower than the national average. Today, Gulf's typical residential bill is only 3 percent lower than the national average. Additionally, Gulf's typical residential bill is currently approximately 18 percent higher than the state average. Fifteen years ago, Gulf's commercial and industrial ("CI") typical bills were approximately 20 percent lower than the national average compared to today where they are generally in line with the national average.

In contrast, FPL's typical residential bill is nearly 10 percent lower than it was fifteen years ago and is currently approximately 10 percent ***below*** the state average and approximately 30 percent ***below*** the national average. Additionally, as shown in Exhibit TCC-5, based on the 20 largest investor-owned utilities ("IOUs") in the country, ranked by number of customers, FPL has the lowest bill and is more than 40 percent below the average. Over the same period, CI typical bills also have decreased by a range of 14 percent to 19 percent. FPL's CI bills are 7 percent to 24 percent below the state average and 18 percent to 45 percent below the national average. FPL's residential, commercial, and industrial bills have been among the lowest bills in the state and the nation for over a decade. This is a significant accomplishment – one that has provided tremendous value for our customers over an extended period of time and provides important context for the discussion of rates over the proposed multi-year plan discussed in more detail by FPL witness Barrett.

Q. Can you please summarize the estimated bill impacts of FPL's proposed increases in base revenues?

A. Yes. FPL's jurisdictional revenue requirements for the test year ending December 31, 2022, reflect the need for an increase in base revenues of $1.1 billion in January 2022, and a subsequent year adjustment in base revenues of $607 million in January 2023. In unifying the rates of a consolidated utility system, rates will be designed to produce the necessary revenues and applied to all customers across the entire service area. However, to reflect an initial difference in the cost to serve, FPL proposes a temporary and declining transition rider for customers in the former Gulf service area and an offsetting declining transition credit for customers in the former FPL service area. I discuss these items later in my testimony.

FPL's filing proposes adjustments to rates and charges to more closely reflect the projected cost of service for the various rate classes, and thus address parity, while following the Florida Public Service Commission's ("FPSC" or "Commission") practice of limiting base rate increases for a specific rate class to 1.5 times the system average increase in total rate class operating revenue, as well as providing no rate decreases.

As shown in Exhibit TCC-3, under FPL's proposed four-year rate plan, the five-year compound annual growth rate ("CAGR") of the typical residential bill increase from January 1, 2021, through the end of the four-year rate proposal on December 31, 2025, is projected to be approximately 3.4 percent. As requested, and assuming other utilities experience bill increases at only their historical rates of increase, typical residential bills for customers in the FPL former service area would remain approximately 20 percent below the projected national average. Additionally, bills for typical residential customers in the former Gulf service area will decrease approximately 0.9 percent through 2025 as shown in Exhibit TCC-4. Also, even with transition rider, the typical residential bill for customers in the former Gulf service area would be approximately 15 percent lower than the projected national average at the end of the four-year rate plan in 2025, which is a significant improvement. While FPL's comparative rate standing during the four-year term obviously will be a function of state and national utility rates during that same time frame, FPL will remain well positioned as a superior value provider of electric service. The CI rate classes in the former FPL service area will experience varying increases in January 2022 depending on the current rate of return for each class as compared to the system average rate of return, *i.e.*, parity index, for each respective class. MFR E-8 shows that the 2022 total increase for CI rate classes is between 2.1 percent and 13.0 percent. Exhibit TCC-3, pages 2 through 5, shows the proposed CI typical bill increases of 3.9 percent to 4.9 percent over the four-year rate plan. These four CI rate classes (General Service, General Service Demand and General Service Large Demand 1 and 2), encompass 94 percent of FPL's CI customers. Exhibit TCC-4, pages 2 through 5, shows that CI customers in the former Gulf service area will see bills ranging from a slight decrease to a 2.5 percent increase over the same four-year rate proposal, providing excellent value for these customers as well.

As described in greater detail by FPL witnesses Ferguson and Barrett, FPL is requesting the adoption of depreciation parameters that allow for the creation and utilization of a Reserve Surplus Amortization Mechanism ("RSAM") during the 2022-2025 time period. As described by FPL witness Fuentes, the adoption of the RSAM results in a commensurately lower annual revenue requirement of approximately $203 million compared to an alternative that does not adopt FPL’s four-year rate plan with RSAM. FPL has provided MFRs and tariffs with and without the impacts of the RSAM. Allowing use of RSAM reduces the typical residential bill by approximately $1.80 per month as shown in the 2022 and 2023 MFR A-2.

II. RATE DESIGN PRINCIPLES AND RATE STRUCTURE

Q. What are the overall goals that FPL seeks to achieve through its rate design?

A. FPL’s rate design provides fair, just, and reasonable rates among customers. FPL is requesting a uniform tariff structure and will migrate all Gulf Power customers onto the applicable best-fit FPL rate schedule. Whether our customers reside in Northwest Florida or in Southeast Florida, they will be receiving service from the same company – no different than customers in Miami or Daytona Beach that for decades have been served by the same company, providing electric services in different locations throughout much of Florida from a common set of operations, a common cost of service, and unified rates. By consolidating rate schedules, the efficiencies of the consolidated system will be reflected in all customer rates, rate administration will be simplified for the Company, and future rate proceedings will become more efficient for the Commission and all parties.

Q. Please provide an overview of FPL's retail rates.

A. FPL's Electric Retail Tariff book ("Tariff") contains rate schedules for the various types of customers served by FPL. These include residential customers; small, medium, and large business and industrial customers; and lighting. Each of these customer classes is served through different rate schedules, which are designed to reflect the differences in the usage characteristics of each customer type and the cost incurred by FPL in providing service to each customer type.

Q. Please describe the various types of rate schedules.

A. Rate schedules generally contain specific prices that are applied to each customer's electric usage amount. Most rate schedules incorporate a customer charge, which is a fixed amount that recovers a portion of the fixed costs of providing service and does not vary with usage. Another price component is the energy charge, which for non-demand customers, is designed to recover the remainder of the fixed costs and the variable costs of providing service and varies with the amount of electricity consumed throughout the month. Some rate schedules also include a demand charge, which reflects the Company's cost of supplying service to meet the maximum demand the customers place on FPL's system. Finally, each rate schedule contains general terms and conditions that describe how the customer's monthly bills are determined. Exhibit TCC-7 provides a narrative explanation of the proposed rate structures of FPL's major rate schedules.

III. REVENUE FORECAST BY RATE CLASS

Q. Please describe the steps for developing the forecast of base revenues by rate class.

A. First, the billing determinant forecast for customers, kilowatt-hour ("kWh") sales, and kilowatt ("kW") demand is developed by rate schedule. Next, these billing determinants are applied to the currently applicable rates to provide the base revenue forecast at present rates. The customer, demand, and energy rates are then adjusted as discussed in Section IV, Allocation of Rate Increase to Rate Classes, and applied to the forecasted billing determinants to provide the forecasted base revenue at proposed rates.

Q. What is meant by "base revenue"?

A. Base revenue represents FPL's total revenues from the sale of electricity and other operating revenues, such as service charges, and excluding: wholesale revenue, revenues generated from adjustment clauses, applicable storm charges, gross receipts taxes, and franchise fees. This breakdown is reflected in MFR C-5.

Q. What is meant by "billing determinants"?

A. Billing determinants are the parameters used for billing customers. The applicable billing determinants reflect the rate structure established for a given rate schedule. Customer, demand, and energy charges are each associated with their own set of billing determinants. The annual customer billing determinants are expressed in terms of the number of accounts billed by month in a year.

Demand billing determinants are expressed in terms of the sum of the kW of customer monthly demand during a year, while energy billing determinants are expressed in terms of kWh. Some rate schedules are limited to customer and energy billing determinants only. For example, customers in the small general service rate schedule ("GS-1") are charged a customer charge in addition to a cents-per-kWh energy charge. GS-1 customers represent the smallest of the CI customers, whose demands are 20 kW or less, and whose rate schedule does not include a demand charge. Larger CI customers, on the other hand, are charged on the basis of their demand, *i.e.*, the maximum electric usage in a given time period, and energy consumed. Thus, the rate structure for the general service demand rate schedules ("GSD-1") includes a customer charge, a cents-per-kWh energy charge and a dollar-per-kW demand charge.

Q. How is the billing determinant forecast developed?

A. The customer and sales forecasts are provided by FPL witness Park for the appropriate time period. These forecasts are developed on a revenue class basis by FPL witness Park and must be allocated to the rate schedule level for use in the revenue forecast.

The allocation of customers and kWh sales by rate schedule is developed based on the historical relationship between the number of customers and sales by rate schedule, and customers and sales by revenue class. Historical percentages are applied to the forecast of customers and sales by revenue class. The result is an estimate of sales and customers by retail rate schedule for the appropriate time periods, which in this case are the 2022 Test Year and the 2023 Subsequent Year.

Finally, additional derivations are made to complete the estimate of customer and energy billing determinants by rate schedule. For example, the kWh sales for the residential rate schedule ("RS-1") are segmented to reflect the inverted rates described in Exhibit TCC-7. Likewise, for time-of-use ("TOU") rate schedules, total sales are segmented between on-peak and off-peak sales based on historical patterns. In addition, for demand-metered rate schedules, billing demands are developed based on the historical relationship between billing demand and billed sales by rate schedule.

Q. What is the difference between revenue classes and rate schedules?

A. Revenue classes represent general categories of customers and are used for financial reporting purposes. There are six retail revenue classes: residential, commercial, industrial, street and highway lighting, railroads and railways, and other. The revenue classes are a combination of different rate schedules, with the exception of the railroads & railways revenue class. This is the only class that is specific to a particular rate schedule, *i.e.*, the Metropolitan Transit Service ("MET") rate schedule. To provide the level of detail required in MFR E-13, the forecasts of sales and customers by revenue class were converted into forecasts of sales and customers by rate schedule.

Q. What is the difference between rate classes and rate schedules?

A. Rate classes are groups of individual rate schedules with like billing attributes (*e.g.*, customer type and load size) and rate design relationships that are treated on a combined basis for rate design purposes. As a result, one or more rate schedules may be combined into a single rate class. For example, general service, Rate Schedule GS-1, and general service TOU, Rate Schedule GST-1, are combined together into the GS(T)-1 rate class.

Q. Are there any exceptions to the process as described?

A. Yes. If a rate class is closed, or there is no projected customer growth, then the number of customers under the rate schedules within that rate class is based on their actual values during the last 12 months ending September 2020, unless customer-specific information was known. These exceptions are limited to a small number of customers (less than 0.5 percent).

Q. Which MFRs provide detail on the retail base revenue forecast described above?

A. MFR A-3 lists the currently-approved base tariff charges. MFR E-15 provides a description of how the billing determinants were developed. MFR E-13c provides the results of applying the base tariff charges to the billing determinants, and MFR E-13d provides additional detail on the base revenue forecast for the lighting rate schedules.

IV. ALLOCATION OF RATE INCREASE TO RATE CLASSES

Q. Please identify the steps necessary to transform an increased revenue requirement into rate design.

A. There are two main steps in the process. First, the total amount of the increased revenue is allocated to the various rate classes. Consideration is given to the cost of service for each rate class, as well as the Commission's guidelines for gradualism. The second step is to design the specific rate components for each rate class. In developing these components – customer charge, energy charge and demand charge – FPL considers rate stability and applies increases and changes ratably where appropriate based on the cost of providing service while taking into consideration customer acceptance and understanding, effects on conservation, and objectivity in administering rates.

Q. Please describe the first step of allocating the proposed revenue increase.

A. Revenues are allocated in order to achieve FPL's requested revenue requirement. The increase to revenue has been allocated across various rate classes as shown in MFR E-8. The cost of service study sponsored by FPL witness DuBose provides a guide for evaluating any proposed changes to the level of revenues by rate class. More specifically, the allocation of any revenue increase should be assessed in terms of its impact on the parity index for the respective rate class. FPL has set the target revenue by rate class to improve parity among the rate classes to the greatest extent possible, while following the Commission practice of gradualism, which limits the increase of each rate class to 1.5 times the system average increase in revenue, including adjustment clauses, and not allowing any class to receive a decrease.

Q. What does FPL's cost of service study show regarding the system average Rate of Return ("ROR") and the parity indices by rate class?

A. As explained by FPL witness DuBose, FPL's cost of service study shows a retail jurisdictional average earned ROR of 5.35 percent for the 2022 Test Year and 4.78 percent for the 2023 Subsequent Year. This is consistent with the retail ROR reported in MFR A-1. The cost of service study indicates that the parity indices vary by rate class, with some class indices well above parity while others fall well below parity. When a rate class is under parity, its ROR is less than the overall FPL ROR. An important goal in setting rates is that all rate classes should be as close to the FPL ROR as possible in order to minimize the cross-class subsidies.

Q. What impact would FPL's target revenues by rate class have on parity?

A. Target revenues are the revenues allocated to each rate class in order to bring each rate class towards parity. As shown in Exhibit TCC-6 and MFR E-8, under FPL's proposed target revenues by rate class, the parity of all rate classes is improved.

Q. How does FPL propose to achieve these target revenues by rate class?

A. FPL proposes to achieve these target revenues through changes to existing rates while incorporating proposed revisions to service charges. Each element of FPL's proposal is outlined below.

V. PROPOSED CHANGES TO EXISTING RATES

Q. Please explain FPL's objective for the proposed changes to existing rates.

A. The objective of the proposed changes to existing rates and charges is to achieve the target revenues by rate class previously discussed. The changes to existing rates are consistent with the objectives of providing rates that are cost-based, send appropriate price signals, and are understandable to customers.

Q. Please describe in general terms the methodology you used in developing the proposed changes to FPL's existing base rates.

A. MFR E-1 attachment 2 shows the maximum increase if all rate classes were to achieve 100 percent parity. Consideration was then placed on gradualism and each class's proposed rate of return to achieve the overall rate increase target by rate class. The resulting increase by rate class is presented in MFR E-8 and the projected revenues and billing determinants by rate schedule are presented in MFR E-13c and MFR E-13d. Current customer charges, energy charges and demand charges, where applicable, are increased by the same rate class percentage maintaining rate component relationships established in previous rate proceedings to help ensure rate stability. This methodology was applied to both increases proposed for the 2022 Test Year and 2023 Subsequent Year.

Q. How were Gulf customers migrated onto FPL rates?

A. Gulf customer accounts were moved to FPL rate schedules using available 2019 historical billing data. The first step in the process determined which revenue and rate classes were applicable to each Gulf account by reviewing the account's end-use classification (*e.g.*, residential, commercial/industrial, lighting), level of demand, meter status (metered or un-metered), and voltage level, as applicable. Accounts were migrated to rate schedules within the rate classes by on-peak usage and load factor, as applicable. The final migration results became the starting point for performing consolidated load research, cost of service, and rate design.

Q. What changes are being proposed to the residential tariff?

A. FPL proposes restoring the inverted energy rates to a one-cent differential between the first 1,000 kWh and all additional kWh. This is consistent with historical precedent from prior dockets including Docket Nos. 160021-EI, 120015-EI and 080677-EI.

FPL proposes to re-name the term "Customer Charge" to "Base Charge" for all rate schedules. FPL is not proposing to modify the type of costs to be recovered; rather, the change in terminology is simply to reflect that "Base Charge" is a more appropriate term for fixed costs required to serve customers. This charge exists to reflect the fact that a certain base level of costs is incurred by FPL to provide electricity independent of the amount of service consumed.

Q. Is FPL proposing any new residential tariffs?

A. Yes. FPL is proposing to extend Gulf Power's existing voluntary Fixed Rate (Flat-1) tariff as a new pilot available to residential and General Service FPL customers with several clarifications and modifications. The purpose of the voluntary Fixed Rate tariff is to provide customers with the option for a monthly flat electric rate that does not vary with usage. One proposed modification is the ability to remove a participating customer from the program if their actual usage exceeds their estimated usage for the program by 30 percent for three consecutive months. FPL also proposes to add language to clarify participant eligibility and applicable clauses.

We anticipate the program to go into effect once billing systems modifications are complete, which is currently estimated to be in the first half of 2023. No new Fixed Rate customers will be enrolled between the time new consolidated rates take effect on January 1, 2022, and when the new consolidated Fixed Rate tariff takes effect upon completion of the billing system changes. Existing customers on the Gulf Flat-1 tariff will be grandfathered and transitioned to the new FPL Fixed Rate tariff at their first renewal date following the effective date of the FPL Fixed Rate tariff.

Q. What changes are being proposed to existing CI rates?

A. Similar to the residential tariff, FPL proposes to change the term “Customer Charge” to “Base Charge” for all CI Rate Schedules.

FPL is also proposing to increase the threshold between the General Service (“GS”) and General Service Demand (“GSD”) rate classes from 21 kW to 25 kW, consistent with Gulf’s existing threshold. Currently, only non-residential customers who have demands less than 21 kW are eligible for service within the GS rate class. This proposed change will allow approximately 8 percent, or

2,000 current Gulf customers on three different rate schedules with a demand of less than 25 kW to remain on a non-demand rate as opposed to being transitioned to a rate with a demand schedule. Absent this proposed change, those customers must remain on a demand schedule for an entire year. Under the proposed change, these smaller customers would be eligible and have the opportunity to choose rate schedule GS, which does not have a demand component. This increased choice should further improve customer satisfaction.

FPL is proposing to add a maximum demand charge to all CI TOU distribution-level rates. Currently, most CI TOU customers on FPL rate schedules pay $0 for any demand consumed off-peak. FPL is the only IOU in Florida without a maximum demand charge that is standard for all TOU rates. Paying a maximum demand charge recognizes that there are off-peak distribution costs that should be paid by the cost-causer and corrects an intra-class annual subsidy.

FPL proposes to extend the Supplemental Power Services Rider (“OSPS”) optional pilot to December 31, 2025 coincident with the term of the proposed four-year rate plan. FPL also notes that the current SolarNow and SolarTogether programs will be limited to customers only in the former FPL service area given that the SolarNow program is being discontinued and the SolarTogether program is expected to be fully subscribed before it would be available to former Gulf customers. Future solar programs will be available to all customers.

Finally, FPL proposes to increase the Commercial Industrial Service Rider ("CISR") cap to 1000 MW or 75 contracts from the current 300 MW or 50 contracts. This proposed increase appropriately reflects that the consolidated FPL is a larger company that will serve eight additional counties in the Northwest Florida region under one unified Economic Development program.

Q. Is FPL proposing any changes to the incentive levels for Commercial/ Industrial Demand Reduction Rider ("CDR") or Commercial/ Industrial Load Control ("CILC") customers?

A. Yes. As explained by FPL witness Sim, FPL has determined the appropriate and cost-effective incentive levels for the load control programs. For CDR, the appropriate incentive is $5.80/kW. For CILC, because the credit is built into the rate schedule as a percentage reduction from the standard rate rather than a flat $/kW credit, FPL proposes to reduce the incentive level commensurate with the proposed incentive level for CDR. To determine the proposed CILC rates, FPL follows its cost of service study and allocates revenue requirements to bring the CILC customers closer to parity as shown on Exhibit TCC-8, and then applies a percentage reduction that is equivalent to the $/kW percentage reduction in CDR incentive as recommended by FPL witness Sim. MFR E-5 illustrates the respective change in the CILC and CDR credit and includes amounts for customers who subscribe to Rider Curtailable Load (Rate Schedule CL) in the former Gulf service area.

The revenues from the CILC/CDR credits are recovered through the Energy Conservation Cost Recovery ("ECCR") clause and are paid for by all customers. The annual savings associated with the reduction in the credit for CILC and CDR customers is approximately $24.2 million in 2022 and $24.6 million in 2023.

Q. Is FPL proposing any new CI rates or riders?

A. Yes. FPL is proposing a new Economic Development Rider ("EDR") tariff "Large EDR" for 1 MW of new load with a minimum of 40 jobs as a middle layer between the current EDR at 350 kW and the CISR at 2 MW. Adding one additional incentive rider will assist in attracting companies with higher demand than the regular EDR customer while encouraging job creation. The rider would be applicable for 5 years with declining discounts on base energy and demand charges each year starting at 40 percent in year 1.

Q. Please describe the methodology used to recover target revenue from the lighting rate classes.

A. The base energy charges for LED Lighting (LT-1), Street Lighting (SL-1, SL-1M), Traffic Signals (SL-2, SL-2M), Premium Lighting (PL-1), Outdoor Lighting (OL-1), and Sports Field Service (OS-2) are adjusted to achieve the target revenues of each rate class. MFR E-14, shows that the cost of installing and maintaining new lights, poles, and other lighting equipment exceeds the charges under the current tariff. Therefore, LT-1, SL-1, OL-1, and OS lights, pole and other lighting charges were adjusted to reflect the replacement costs. Maintenance charges were also adjusted to reflect current costs.

Q. Is FPL proposing any changes to the lighting rate schedules?

A. Yes. FPL is proposing to close all unmetered lighting rate schedules, except for LT-1, to new customers. Customers currently taking service under unmetered rate schedules will be grandfathered, and there will be four open tariffs to serve new customers: LT-1 for company-owned LED, street, outdoor, roadway and general lights; SL-1M for customer-owned street, roadway and general lights; SL-2M for traffic signals; and GS-1 for unmetered cable amplifiers and billboard lights. The intent of this change is to simplify and streamline lighting offerings.

LT-1 will be the primary tariff for all new LED lighting, and non-LED lighting will no longer be available to new customers. This change is important because many vendors are now only producing LEDs. Because this will be the main lighting tariff available to all customers, FPL proposes to rename the Tariff "Lighting." Under this new tariff, FPL is planning to introduce residential outdoor LED lights, to replace Outdoor Lighting (OL-1).

Q. How is FPL proposing to handle the existing Gulf lighting tariffs?

A. FPL is proposing to close the Gulf Rate Schedule OS for Outdoor Service to new customers and grandfather existing lighting customers under their existing rate schedule. The static use customers under the OS rate will be moved as follows: traffic signal customers will migrate onto FPL's closed unmetered Traffic Signal rate (SL-2); and cable amplifier and billboard customers will migrate onto FPL's General Service (GS-1) rate as unmetered. This will allow all traffic signal, cable amplifier, and billboard customers to be treated equitably.

All new lighting customers in the former Gulf service area will take service under LT-1, and new customer-owned lighting customers will be metered under SL-1M. All new traffic signals will be metered under SL-2M, and all new cable amplifiers and billboard customers will be metered under GS-1. This allows for consistency in processes in the consolidated Company and will deliver better LED rates to customers in Northwest Florida.

Q. Which MFRs provide additional information on the proposed changes to existing rates that you have outlined?

A. MFR A-2 presents the impact of the proposed rate changes to the typical bills. MFR A-3 provides a summary of those proposed rate changes. The applicable proposed tariff sheets are presented in MFR E-14, Attachment 1.

MFR E-14, starting in Attachment 2, provides work papers outlining the derivation of the proposed changes to FPL's existing rates. The revenue impact from the proposed changes to existing rates is shown in MFRs E-12, E-13a, E-13c and E-13d. The parity indices under proposed rates are shown in MFR E-

8. In addition, Exhibit TCC-7 provides a narrative explanation of the proposed rate structures and rate design.

Q. Are there any other changes to base rates?

A. As discussed by FPL witness Fuentes, FPL is requesting permission to recover minimal base revenue requirements associated with the Indiantown Cogeneration Plant through base rates and discontinue recovery through the Capacity Cost Recovery Clause ("CCRC") effective January 1, 2022. All bill impacts discussed in my testimony and exhibits reflect this adjustment.

VI. SERVICE CHARGES

Q. Is FPL proposing any changes to its service charges?

A. Yes. FPL has updated the cost basis of all the Company's service charges as shown on MFR E-7. Due to continued automation and cost reduction as explained by FPL witness Chapel, the updated cost-based service charges are significantly lower than current charges, which is consistent with FPL's value proposition for customers in delivering excellent service at low cost. The proposed service charges are shown on MFR E-13b, aligning the rates for these services with their current cost structure.

As discussed in more detail by FPL witness Chapel, FPL is proposing two changes to service charges. First, FPL proposes to increase the meter tampering fee to $500 for residential and non-demand commercial customers (*i.e.*, GS-1) and $2,500 for all other customers. Second, FPL proposes to expand the existing field collection charge to include all premise visits. Finally, FPL is proposing to update the temporary construction service rates to reflect the cost of performing this service.

Final service charge revenue is accounted for in the Company's final rates as presented in MFR E-13b.

VII. OTHER TARIFF CHANGES

Q. How has FPL recognized historic cost of service differences between the FPL and Gulf systems that have been brought together?

A. As several other FPL witnesses explain, bringing these two systems together produces approximately $2.8 billion in incremental present value savings on a combined basis. These savings will be reflected in FPL's cost of service for years to come. However, to address the initial cost to serve differential between the former FPL and Gulf systems, FPL proposes a declining transition rider to customers in Northwest Florida with an offsetting declining transition credit to customers in the former FPL service area. At the end of the transition period, there will be no meaningful distinctions among customers served by the Company.

Q. What does the transition rider represent?

A. The transition rider, which will be phased out over time, reflects initial differences in the cost to serve. FPL has designed the transition rider to represent the difference in the overall system average costs between the two companies in 2021 for base rates and all clauses including fuel, capacity, environmental, conservation, and storm protection. When base rates are combined into one cost of service, the clause structures must also be combined effective January 1, 2022. Thus, all customers will have the same base rates and the same clause rates effective January 1, 2022, as shown on Exhibit TCC-8. The only difference in the bill, based on region, will be the transition rider for a period of 5 years and storm surcharges for historical storm cost recovery expenses. In the 2021 clause proceedings, FPL will simultaneously file both standalone clauses and factors and new unified clauses and factors that, subject to the Commission's decision on unified base rates and the transition rider and credit in this proceeding, will take effect January 1, 2022.[1]

Q. How long will the transition rider be in place?

A. FPL proposes a five-year transition rider for its Northwest Florida customers with an offsetting transition credit to customers in the former FPL service area, both of which will step down ratably over the period. The proposed five-year transition rider period is a reasonable period after which no further distinctions can appropriately be drawn among customers served by the same entity on an equivalent basis, regardless of geographic location. As mentioned by other FPL witnesses, the operations of FPL and Gulf Power have been integrated.

[1] FPL will also file petitions that, subject to the Commission's decision on unified base rates and the transition rider and credit in this proceeding, request approvals to administratively consolidate the two existing Storm Protection Plans and two existing Demand Side Management plans previously approved for FPL and Gulf.

Accordingly, any rationale for allocating "historic" costs is unnecessary and any methodology would be inherently subjective, particularly as time passes. The diminishing transition rider is intended to reflect the reality that customers are receiving service from one functionally integrated company and from a common set of assets and employees, without geographical distinction (in the same way FPL customers in communities with varying degrees of cost to serve across disparate parts of the state are treated today) through payment of consolidated, equally applicable rates.

Q. Are any costs excluded from the transition rider calculation?

A. Yes. The legacy storm restoration costs associated with Hurricanes Michael and Sally will be excluded from the 5-year transition rider and retained by the customers in Northwest Florida until the costs are fully recovered. Additionally, any potential hurricane expenses incurred in 2021 during which time FPL and Gulf remain separate ratemaking entities will be retained by customers in the original service territory.

Q. How is the transition rider calculated?

A. As shown in Exhibit TCC-8, page 1, the transition rider is based on the system average rate differential in 2021, which includes merged operations before a rate structure merger. The system averages for the former FPL and Gulf service areas are calculated as the forecasted retail revenues in 2021 divided by the forecasted retail sales in 2021 excluding all clause-related true-ups and gross receipts tax. This calculation yields a system average rate. For 2021, as separate ratemaking entities, the FPL system average rate is projected to be ~

$91.36 per MWh and the Gulf system average rate is $111.32 per MWh. Under a combined system, the consolidated system average rate for 2021 is $93.12 per MWh, meaning that FPL's system average would increase $1.76 per MWh all things being equal. The potential increase of $1.76 per MWh multiplied by the forecasted 2021 sales of 110,812,880 MWh yields a revenue requirement of $197.3 million that will be charged to customers in Northwest Florida and credited to customers in the former FPL service area under a consolidated rate structure.

Q. How are the transition rider and credit allocated to the rate classes?

A. The transition rider and credit are allocated to the rate classes by using each rate class's share of 2021 total retail system revenues. See Exhibit TCC-8, page 2 for the allocation.

Q. How will the transition rider and credit be billed to customers?

A. The transition rider and credit are being designed in FPL's billing system similar to other FPL clauses and riders. FPL proposes a transition rider and credit to be applied to customer's bills in the non-fuel energy line item. The transition rider and credit will step down ratably as set forth in the tariff sheet in MFR E-14 Attachment 1 over a five-year period without the need for annual true-ups or recalculation of the transition rider and credit.

Q. Is the Company also proposing a consolidated tariff book for all customers?

A. Yes. The company is proposing a consolidated tariff book in MFR E-14 Attachment 1.

Q. How did you develop the unified tariff book proposed for the consolidated company?

A. We reviewed the existing FPL and Gulf tariffs, section by section, with the purpose to identify and adopt best practices. In most cases, language and processes for FPL were adopted in the unified tariff. In some cases, language or processes in Gulf's tariff suggested improvements that were adopted in the unified result. Finally, while reviewing the tariffs, other changes, not necessarily associated with rate unification, were adopted to improve the unified result.

Q. Please provide examples of Gulf tariff language or processes that were adopted in the unified result.

A. The following are a few examples of Gulf tariff language or processes that were adopted for use in the unified tariff: renamed the "Customer Charge" to "Base Charge"; adopted Fixed Rate (with modifications); increased the small commercial demand threshold to 25 kW; and added maximum demand charge to all CI TOU demand rates.

Q. Do you recommend retaining any existing Gulf tariff items for some period of time for existing customers while closing them to new customers, otherwise known as "Grandfathering"?

A. Yes, on a limited basis for customers who have existing contracts/agreements with Gulf. For example, lighting customers, Rider CL customers, and Flat-1 tariff customers have existing contracts, and we plan to grandfather these customers on their current tariffs. Additionally, for customers who are currently under contract on Gulf's Economic Development rate schedules, we intend to migrate the customer onto the applicable underlying FPL rate schedule but retain the discount until the term of the contract/agreement expires.

VIII. PROPOSED RATE ADJUSTMENTS FOR 2024 AND 2025 SOBRAs

Q. How does FPL propose to recover the revenue requirements of the SoBRA mechanism for years 2024 and 2025?

A. Subject to the SoBRA process discussed by FPL witness Valle in his testimony, FPL proposes to implement new rates to recover the annualized revenue requirements associated with the 2024 and 2025 SoBRAs concurrent with the in-service date of the projects as discussed by FPL witness Fuentes. The revenue requirements of the solar projects in 2024 and 2025 are approximately $140 million in 2024 and $140 million in 2025. FPL also proposes that the corresponding fuel savings associated with the SoBRAs be reflected in the fuel factors effective upon the in-service date. Implementing the fuel factors reflecting those savings concurrent with the SoBRA better aligns costs with the fuel savings benefits.

The SoBRA, once approved by the Commission, will be implemented by adjusting the customer charge, demand charge, and energy charge by an equal percentage. The calculation of this percentage is based on the ratio of jurisdictional annual revenue requirements and the forecasted retail base revenues from the sales of electricity during the first 12 months of operation. Exhibits TCC-3 and TCC-4 provide illustrative bill projections associated with the SoBRA mechanism for years 2024 and 2025, respectively, at the current projected total megawatts.

If future SoBRA filings are approved by the Commission, FPL will send a letter to advise when the unit has gone into service, at which time the tariffs reflecting the Commission-approved SoBRA adjustment can be administratively verified.

Q. Is FPL proposing a true-up mechanism for the SoBRA?

A. Yes. As discussed by FPL witness Fuentes, if the actual capital expenditures are less than the projected costs used to develop the initial revenue requirement, FPL proposes that a one-time credit be made through the CCRC. In order to determine the amount of this credit, a revised factor will be computed using the final revenue requirements described by witness Fuentes. The difference between the cumulative base revenues since the implementation of the initial adjustment and the cumulative base revenues that would have resulted if the revised adjustment had been in place during the same time period will be credited to customers through the CCRC with interest at the 30-day commercial paper rate as specified in Rule 25-6.109. In addition, on a going forward basis, base rates will be adjusted to reflect the revised factor.

Q. Is FPL's proposed method of recovering the revenue requirements of the SoBRA mechanism for the years 2024 and 2025 consistent with the methodology approved by the Commission for other Generation or Solar Base Rate Adjustments?

A. Yes. FPL's proposal is consistent with the methodology for cost recovery utilized by FPL for the Generation Base Rate Adjustments for the Riviera Beach Energy Center and Port Everglades Energy Center that were part of FPL's Commission-approved 2012 Rate Settlement, and the Okeechobee Clean Energy Center and 2017-2020 SoBRAs that were part of FPL's Commission-approved 2016 Rate Settlement.

IX. STANDALONE RATES

Q. What information has been provided for FPL and Gulf Power as separate ratemaking entities in the event the Commission does not approve unified rates for the combined system?

A. The list of MFRs for 2022 and 2023 for FPL and Gulf Power if treated as separate ratemaking entities are shown in Exhibit TCC-2. They often are referred to throughout the case materials as "standalone" rates. Additionally, the methodology used to develop standalone rates is provided in Exhibit TCC-9.

Q. Were the processes used to develop the revenue forecasts by rate class on a standalone basis the same as on a consolidated basis?

A. Yes.

Q. Were the processes used to allocate the rate increases to the rate classes on a standalone basis the same as on a consolidated basis?

A. Yes.

Q. Were the processes used to change existing base rates on a standalone basis the same as on a consolidated basis?

A. Yes.

Q. For FPL standalone, are you still proposing the same tariff changes as the consolidated case?

A. Yes. The changes requested in the consolidated case are the same as requested for FPL in the standalone case. These changes include the following:

- Restoring the one-cent energy charge differential on the standard residential rate
- Changing the name of the "Customer Charge" to "Base Charge"
- Adding a Fixed Rate pilot tariff
- Updating service charges to reflect the current cost basis
- Increasing the meter tampering charge
- Modifying the existing field collection service charge to include all premise visits

- Increasing the threshold between General Service and General Service Demand (and other optional rate schedules in the rate class) from 21 kW to 25 kW
- Adding maximum demand to the CI TOU rates
- Reducing the CILC/ CDR credit
- Adding a 1 MW minimum Large EDR tariff and increasing the CISR cap to 500 MW and 75 contracts
- Closing all unmetered lighting tariffs and modifying the LT-1 tariff
- Extending the Supplemental Power Services Rider optional pilot to December 31, 2025

Q. For Gulf standalone, what tariff changes are being requested?

A. In a standalone case, Gulf would retain the tariffs that are in place today with the requested revenue increases. Additionally, we would propose the following changes to the standalone case:

- Updating service charges to reflect the current cost basis
- Adding a late payment fee to align with FPL and all other Florida IOUs
- Adding a meter tampering charge of $500 for residential and non-demand commercial customers (i.e., GS-1) and $2,500 for all other customers as an additional deterrent for the theft of electricity to align with FPL
- Closing unmetered lighting schedules to new customers and allowing new customers access to a new LT-1 tariff that mirrors FPL's
- Modifying the Flat-1 tariff as noted earlier in my testimony

- Closing the Real Time Pricing ("RTP") rate to new customers with the plan to eliminate the rate schedule in the next base rate proceeding
- Adding the Economic Development Rider for Existing Facilities ("EFEDR") to match FPL's existing tariff
- Cancel Gulf's Rider Community Solar ("CS") which was a limited availability experimental rider and has never had any participating customers
- Adding the Supplemental Power Services Rider optional pilot to match FPL's existing tariff. Requesting the same termination date as FPL of December 31, 2025
- Extend Rider Curtailable Load ("CL") to December 31, 2023
- Adjusting on- and off-peak TOU periods to Eastern Standard Time

X. CONCLUSION

Q. Please summarize your testimony.

A. Through consolidation, FPL and Gulf will provide service as a single utility system, the natural and practical reflection of which is unified rates regardless of geographic location. Much of the work to realize customer savings began at the time Gulf was acquired. Rate consolidation is the next logical step to reflect the reality of a combined utility with a common cost of service and set of tariffs. With the transition rider methodology that FPL has proposed, all customers are treated equitably.

FPL has submitted a proposed distribution of revenue requirements by each major customer class that is reasonable and moves all customer classes towards parity. As shown on Exhibits TCC-3 and TCC-5, the FPL typical residential bill is projected to increase approximately 3.4 percent over the four-year rate plan and remain approximately 20 percent below the national average. As shown in TCC-4, a typical bill for a residential customer in Northwest Florida is projected to decline over the same period and be lower than today's bills even with a full rate increase. Once the five-year transition rider and credit are complete, all customers in FPL's service area will pay the same bills based on their class of service. FPL has a proven track record of providing customers excellent value in their electric service, and our customers in Northwest Florida will realize the same tremendous value from being served by consolidated FPL operations. For these reasons, FPL believes its rate proposals should be approved.

Q. Does this conclude your direct testimony?

A. Yes.

(Whereupon, prefiled rebuttal testimony of Tiffany C. Cohen was inserted.)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

REBUTTAL TESTIMONY OF TIFFANY C. COHEN

DOCKET NO. 20210015-EI

JULY 14, 2021

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I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Tiffany C. Cohen. My business address is Florida Power & Light Company ("FPL" or the "Company"), 700 Universe Boulevard, Juno Beach, Florida 33408.

Q. Have you previously submitted direct testimony in this proceeding?

A. Yes.

Q. Are you sponsoring any rebuttal exhibits in this case?

A. Yes. I am sponsoring the following rebuttal exhibit:

- TCC-10, Real Time Pricing Customer Response

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is to respond to the testimonies of Florida Industrial Power Users Group ("FIPUG") witness Pollock; Federal Executive Agencies ("FEA") witness Collins; Florida Retail Federation ("FRF") witness Georgis; Walmart Inc. ("Walmart") witness Chriss; Florida Rising, Inc., League of United Latin American Citizens of Florida, and the Environmental Confederation of Southwest Florida, Inc. (collectively "FR/LULAC/ECOSWF") witness Rabago; and Vote Solar and CLEO Institute (collectively "VS-CLEO") witness Whited. Specifically, I will address the Florida Public Service Commission's ("Commission") policy on gradualism and FPL's application of that policy, FPL's proposed rate design for demand-metered customers, FPL's proposal to eliminate the Real Time Pricing ("RTP") rate schedule, and FPL's benchmark of the typical residential 1,000 kWh bill.

Q. Please summarize your rebuttal testimony.

A. My testimony shows that:

- FPL has correctly applied the Commission's policy regarding gradualism;
- FPL's method for developing commercial and industrial rates for demand-metered customers is fair and reasonable and maintains the current relationship between energy and demand charges;
- FPL's proposal to eliminate the RTP tariff is fair and reasonable because the program is significantly subsidized by the general body of customers and is not working as intended because most RTP customers do not curtail their load in response to high hourly prices; and,
- FPL's benchmark of the typical residential 1,000 kWh bill is consistent with industry practice and the Commission's benchmarking practices.

II. COMMISSION POLICY ON GRADUALISM AND INTERVENOR PROPOSALS FOR ALLOCATING THE REVENUE INCREASE

Q. Witnesses Pollock, Collins and Georgis each take issue with FPL's allocation of revenue increases and the application of gradualism. Please explain the concept of gradualism as it applies to the allocation of revenue increases for rate design.

A. The Commission has made it clear that rates should be based on the fully allocated cost of service method with the objective of achieving parity among rate classes. The Commission also has expressed concerns about any rate class receiving an overly large revenue requirement increase and has created a guideline, referred to as "gradualism," to address those concerns. The concept of gradualism, as applied in Florida, limits the revenue increase for each rate class to 1.5 times the system average increase in total operating revenues, including adjustment clauses, and provides that no rate class be decreased.

In the Commission's order that first instituted the gradualism guideline, the Commission stated: "All parties in this proceeding agree that the revenue increase should be allocated between classes so as to move toward an equalized rate of return for all classes. While we embrace this concept, we feel the impact on customers' bills must be considered in allocating revenues." Order No. 10306, p. 106. The Commission articulated its guideline for addressing bill impacts stating that "[n]o customer class shall receive a revenue increase greater than 1.5 times the system average increase as a result of this proceeding." Order No. 10306, p. 107. Additionally, as I further explain below, the Commission has made it clear in subsequent orders that the calculated 1.5 times increase is based on *total* revenues. *See, e.g.*, Order No. PSC-10-0153-FOF-EI.

Q. Has FPL applied the Commission's guidelines on revenue allocation and gradualism correctly?

A. Yes.

Q. Please explain.

A. The rates FPL has proposed in this case appropriately reflect the allocated costs by rate class and move all classes closer toward an equalized rate of return (*i.e.*, parity) while limiting the increase to each class to no more than 1.5 times the system average based on total operating revenues including clause revenues. Where FPL has not had a general base rate increase since 2018, FPL has requested an 8.7% increase in total revenues for 2022. Under the gradualism guideline, any increase to a rate class is limited to 1.5 times 8.7%, or 13.0%. As shown on Minimum Filing Requirement ("MFR") E-8, under FPL's proposed rates, no class will receive an increase of more than 13.0% in total.

Q. FIPUG witnesses Pollock asserts on page 52 of his direct testimony that FPL's definition of gradualism is flawed because it is based on expressing the proposed base revenue increases as a percentage of the total revenues from each class. He also contends on page 13 of his testimony that larger customers will receive increases that violate the gradualism principle. Do you agree with his assertions?

A. No. The Commission has stated explicitly in other orders that revenues from adjustment clauses are to be included in the gradualism calculation. FIPUG raised this same issue in FPL's most recent fully litigated rate case. The Commission rejected FIPUG's position stating that "[c]onsistent with our decisions in more recent electric rate cases, we find that in this case no class shall receive an increase greater than 1.5 times the system average percentage increase in total, *i.e.*, *with adjustment clauses*, and no class should receive a decrease." Order No. PSC-10-0153-FOF-EI, p. 179 (emphasis added).

Excluding clause revenues would distort the proper application of gradualism, impede the movement of several rate classes toward parity (significantly reducing the likelihood of ever achieving parity for those classes), and continue inter-class subsidies that benefit one class of customers over another.

FIPUG witness Pollock is evaluating certain rate components and equating the increase to a violation of gradualism, which is a distortion of the gradualism guideline. FPL followed the Commission's gradualism guidelines in determining each rate class's revenue apportionment of the proposed increase. Based on the current parity of each rate class, FPL correctly applied the Commission's gradualism guideline and designed rates accordingly.

Q. Are there other Commission orders that support FPL's calculation of the gradualism guideline?

A. Yes. The Commission has consistently held that the gradualism guideline should be based on 1.5 times the system average percentage increase, in total, including adjustment clauses. *See, e.g.*, Order No. PSC-08-0327-FOF-EI, issued May 19, 2008 in Docket No. 070304-EI; Order No. PSC-09-0283-FOF-EI, issued April 30, 2009 in Docket No. 080317-EI; Order No. PSC-10-0153-FOF-EI issued March 17, 2010 in Docket No. 080677-EI; and Order No. PSC-13-0443-FOF-EI issued September 30, 2013 in Docket No. 130040-EI.

Q. FEA witness Collins proposes an alternative class revenue allocation shown on his Exhibit BCC-1 that provides increases as high as 1.65 times his calculated system average increase of 14.4%. Is his proposal an appropriate application of the gradualism guideline?

A. No. FEA witness Collins's proposal violates the Commission's well-established gradualism principle that no rate class receives an increase greater than 1.5 times the system average increase. Additionally, the 14.4% system average increase calculated by FEA witness Collins in Exhibit BCC-1 is incorrect because it excludes miscellaneous service charges and other operating revenues. Gradualism, as applied in Florida, limits the revenue increase for each rate class to 1.5 times the system average increase in total operating revenues, which includes miscellaneous service charges and other operating revenues.

Q. On page 5 of his direct testimony, FRF witness Georgis recommends that "any base revenue increase adopted by the Commission should be implemented through an equal percentage increase to all customer classes for each of the years of an approved base rate plan." Do you agree with that proposal?

A. No. Regardless of the amount of revenue increase, any increase should be spread to all customer classes based on cost of service allocations that move all customer classes closer to parity while adhering to the Commission's gradualism guidelines.

III. RATE DESIGN FOR CILC AND CDR CUSTOMERS

Q. How are CILC and CDR incentive payments treated for ratemaking purposes in MFR E-5?

A. FPL's treatment of CILC and CDR incentive payments in the MFRs are entirely consistent with prior rate cases. FPL treats the CILC and CDR incentive payments as additional base revenues (or revenue credits), directly offsetting the revenue requirements of customer classes that participate in these programs, because these incentive payments are collected from all customers as part of a Demand Side Management program recovered through the Energy Conservation Cost Recovery ("ECCR") clause. Absent this offset of revenue requirement, the customer classes that receive direct bill benefits from the CILC and CDR incentive payments would receive higher revenue allocations of the proposed increase.

Q. Starting on page 34 of his direct testimony, FIPUG witness Pollock asserts that the CILC and CDR incentive payments should be re-allocated to all customer classes. Do you agree with this proposal?

A. No. All customer classes pay the CILC and CDR incentives through the ECCR clause and customers would be adversely impacted by reallocating the incentive payments as a reduction to their present revenue in the base rate proceeding. An example of this is highlighted on FIPUG witness Pollock's Exhibit JP-6, page 2 of 2, line 11 where witness Pollock reallocates the CILC and CDR incentive payments to increase the present revenues paid by the CILC and CDR rate class and reduce the residential class present revenues by $47.68 million. This adjustment artificially reduces the residential class's present revenue resulting in residential customers receiving a larger portion of the 2022 Test Year increase, while artificially increasing the present revenues for the CILC and CDR rates classes giving them a smaller portion of the 2022 Test Year increase. This is not fair or equitable because residential customers have already paid their portion of CILC and CDR incentives through the ECCR clause. This example for residential customers illustrates that FIPUG witness Pollock is effectively proposing that the general body of customers pay twice to provide rate credits for CILC and CDR customers: once in the ECCR clause and a second time by lowering their present revenue on MFR E-5.

Q. On pages 34 and 35 of his direct testimony, FIPUG witness Pollock recalculated the CILC and CDR incentives for the 2022 Test Year. Do you agree with his recalculation?

A. No. CILC incentives are embedded in the base rate where the customer receives a lower bill as compared to the otherwise applicable standard rate. CILC rate schedules are closed to new customers, so the credit levels do not vary much year to year. CDR incentives are a flat $/kW credit to the customers' base bill.

Using CILC-1T as an example, FIPUG witness Pollock estimates a revenue adjustment of $14.41 million as shown on his Exhibit JP-3, page 1 of 4. He calculates this revenue adjustment by taking the difference in revenue for CILC-1T as compared to the revenue from the otherwise applicable rates of GSLD-3 and GSLDT-3. He then averages the revenue adjustments between GSLD-3 and GSLDT-3 to derive his $14.41 million revenue adjustment. However, in actuality, the CILC revenue adjustments (*e.g.*, incentive payments) are collected in the ECCR clause based on actual information that is calculated monthly and at the individual customer-level. FPL's approach is more accurate because it is based on customer-specific actual information.

Q. Walmart witness Chriss requested that in the event the Commission does not approve unified rates, the Commission should approve FPL's CDR for use by customers in the Gulf Power service area. Do you agree?

A. No. First, as stated in FPL's direct testimony, FPL's proposal to unify rates is beneficial to all customers and should be approved. Second, Walmart witness Chriss overlooks that customers in the Gulf Power service area already have access to the Curtailable Load Optional Rider. This is a similar load control program that offers a $/kW credit in exchange for customers curtailing their load in the event of a system emergency.

IV. RATE DESIGN FOR DEMAND-BASED CUSTOMERS

Q. Walmart witness Chriss takes issue with FPL's approach to increasing the demand and energy charges for the GSLDT-1 rate schedule. Please explain FPL's approach to rate design for demand and energy charges in this case.

A. FPL began with present demand and energy rates and increased those rates by the same percentage to maintain the current relationship between demand and energy rates. FPL then adjusted on-peak energy charges to ensure revenue neutrality to the standard, non-time of use rate. This approach is consistent with FPL's prior rate cases and was used in this case to maintain rate stability and the impact on customers with differing load factors, an issue with which the Commission has previously expressed concerns. The Commission has stated that "[i]ncreases in the demand charge impact low load factor customers to a greater extent than high load factor customers because they are less able to offset the higher demand costs with lower energy costs and are thus less able to affect their total bill." Order No. PSC-10-0153-FOF-EI, p. 189; *see also*, Order PSC-97-0074-FOF-EU, issued January 24, 1997 in Docket No. 951485.

The approach FPL used can be applied consistently across rate classes and provides rate stability, avoids significant changes in demand and energy ratios, and maintains current price signals between on- and off-peak energy charges.

Q. Please comment on Walmart witness Chriss's proposal regarding the pricing of demand and other rate schedule charges.

A. Walmart witness Chriss asserts that demand charges should be set at unit cost. Following strict unit cost in setting demand rates would distort the relationships between the general service demand classes and make it difficult to achieve target revenues while maintaining time of use ("TOU") design goals and principles. Setting demand rates closer to unit cost than as proposed by FPL would recover less cost from energy charges making it difficult to provide meaningful price signals between on- and off-peak energy charges.

Additionally, large increases in the demand rate would adversely impact low load factor customers. *See, e.g.*, Order No. 10557, issued February 1, 1982 in Docket No. 810136; Order No. 11437, issued December 22, 1982 in Docket No. 820097-EU; Order No. 11628, issued February 17, 1983 in Docket No. 820100; Order No. PSC-10-0153-FOF-EI, issued March 17, 2010 in Docket No. 080677.

Also, for energy charges, FPL began with present rates and applied the same percent increase to the off-peak energy charge to maintain the TOU price signal embedded in TOU energy rates. This is consistent with past Commission guidance. Indeed, the Commission has previously stated that "it is reasonable, as a proxy, to maintain the current differential between on- and off-peak ratios to prevent unexpected impacts on existing TOU customers who have adapted their usage to this ratio." Order No. PSC-10-0153-FOF-EI, p. 190.

The percent increase methodology that FPL utilized mitigates the impact of rate increases on low load factor customers and is a reasonable and thoughtful approach to balance the needs of all customers. I also note that FPL continues to offer high load factor time of use rates for those customers that prefer a higher demand charge coupled with a lower energy charge.

Q. Walmart witness Chriss states that FPL proposes an asymmetrical rate design for the Transition Credit/Rider for demand-metered customer classes where demand-metered customers in the FPL service area are

credited on a $/kW basis and demand-metered customers in the Gulf Power service area are charged on a $/kWh basis. Please explain.

A. FPL proposed to implement the Transition Rider for Gulf customers in the same manner in which they pay for certain charges today. Certain medium and large commercial and industrial customers today in the Gulf Power service area pay for the Capacity Clause and Conservation Clause on a $/kWh basis. As noted in my direct testimony on page 29, the clause structures will need to be combined effective January 1, 2022, if the Commission approves unified rates. Thus, a number of these customers in the Gulf Power service area will migrate to $/kW basis for the consolidated Capacity Clause and Conservation Clause. However, in an effort to help mitigate the impact on lower load factor customers, FPL proposed the Transition Rider for these customers in the Gulf Power service area on a $/kWh basis.

V. RATE DESIGN FOR RTP CUSTOMERS

Q. Please explain the background for the Gulf RTP rate.

A. Gulf's RTP rate began as a pilot in 1995 to test day-ahead hourly pricing. At that time there were 12 customers on the rate with a required minimum usage of 2 MW. In 2011, the minimum usage requirement was lowered to 500 kW and the number of customers on the rate schedule increased to approximately 120 today with wide, varying load characteristics.

Q. On pages 19-20 of his direct testimony, FEA witness Collins contends that FPL should retain the Gulf RTP rate. Please explain why FPL is proposing to cancel the RTP rate schedule and migrate those customers onto the best fit rate schedule.

A. FPL is proposing to cancel the RTP rate for several reasons.

First, the current RTP rate schedule prices are a function of the currently approved revenue requirement, which results in the actual prices for RTP customers being significantly less than the cost to serve these customers, as indicated by the 26% parity for the major accounts rate class. This also means the general body of customers is significantly subsidizing this group of 120 customers.

Second, based on FPL's experience with RTP, the Company has found that the majority of customers do not effectively respond to changes in hourly prices as the tariff was originally intended. For illustration, FPL analyzed price and resulting usage data for the month of August 2020. As shown in Exhibit TCC-10, even when faced with exponentially higher prices, the aggregate group did not curtail their load. Also, there are high load factor customers on the RTP rate schedule who are not likely to curtail their load because their rates are so low compared to other cost-based rates.

Third, while it is a separate rate class, RTP is not a "rate class" in the traditional sense where rate classes are typically made up of a relatively homogeneous group of customers that possess similar demand and usage characteristics. There currently are approximately 120 disparate customers on this rate schedule that range from 500 kW to over 2,000 kW. At FPL, these customers would span over several rate classes that are designated by their level of demand and voltage delivery. Each such rate class has standard, TOU, high load factor, seasonal, and load control offerings. A traditional TOU rate structure with fixed time periods is preferable from a cost of service /parity standpoint and improves the ability for many of these customers to plan their operations and electric usage. They can realize savings compared to the standard rate by shifting load off-peak. A TOU rate also reduces individual customer risk where large fluctuations in RTP hourly prices can create bill volatility.

Q. FEA witness Collins asserts that customers on the RTP rate schedule typically consume less electricity in response to higher prices, primarily due to lower electricity consumption during peak times on the utility's system. Do you agree?

A. No. In fact, the opposite is true. In periods of high prices, overall usage of customers on the RTP does not curtail. This is illustrated on Exhibit TCC-10.

Q. Has FPL ever offered a rate similar to the Gulf RTP rate?

A. Yes. FPL offered a similar program that was approved in February 1995. However, similar to the Gulf RTP rate schedule, program benefits did not materialize and the program was ultimately withdrawn in December 2003 by

Commission Order No. PSC-02-1634-TRF-EI. Most of the customers participating in FPL's prior RTP program did not curtail their load in response to high hourly energy prices and those that terminated service under the RTP did so for economic reasons, meaning the bill volatility created too much risk for the customer.

Q. FEA witness Collins presents the FPL system lambda data in Exhibit BCC-2 and states that FPL should develop a new RTP tariff for the consolidated company using that data. Do you agree?

A. No. FEA witness Collins overlooks that system lambda data is only one component of the RTP tariff. There are other components that include multipliers to recover the Company's embedded costs. In total, this rate is in a rate class that is at 26% parity at Gulf today. In order to bring a similar rate schedule to consolidated FPL, the price would need to be raised significantly in order to move these customers closer to parity and avoid subsidization by other customers. Additionally, there still remains a significant problem with many high load factor customers not curtailing in times of high prices, as experienced by both Gulf's RTP program and FPL's withdrawn RTP program, thereby undermining the essential goal of the program.

Q. How will current Gulf RTP accounts be migrated onto the applicable FPL rate schedule?

A. Generally speaking, we review the customer's load and usage characteristics and place them on the rate that is most advantageous to the customer based on these characteristics. I note that FPL also offers numerous options for larger customers including standard, time of use, high load factor, seasonal and load control rates and riders.

Q. Do you have any final comments on the Gulf RTP program?

A. Yes. In summary, the RTP program is not functioning as intended. Customers are not responding or curtailing load in response to higher price signals. The 120 customers on the RTP rate schedule are significantly subsidized by the general body of customers. If the RTP program were priced at full parity, I believe a significant number of customers would leave the program for economic reasons. FPL offers many alternative rate schedules that are appropriately priced for customers of various sizes and load shapes.

VI. FPL'S TYPICAL RESIDENTIAL BILL

Q. VS-CLEO witness Whited and FR/LULCAC/ECOSWF witness Rabago criticize FPL for using the typical residential 1,000 kWh bill as a benchmark to other utilities and the national average instead of the average bill. Do you agree?

A. No. FPL was very clear throughout testimony that we are using the "typical" residential 1,000 kWh bill, which is an industry-accepted benchmark. This benchmark is utilized by Edison Electric Institute and by this Commission to compare a residential bill at a certain usage level to other utilities.

Q. Why do you not benchmark the average residential bill?

A. The average residential bill is not a meaningful comparison. Average electric usage varies significantly across the country due to climate, weather, availability of gas or other alternatives to electricity, and many other characteristics. Using the industry standard typical residential 1,000 kWh bill provides a more appropriate apples-to-apples comparison of utilities' rates.

Q. FR/LULCAC/ECOSWF witness Rabago states that FPL relies on "misleading sleight of hand" to support assertions about low Company bills. Witness Rabago also claims that FPL bases assertions on "completely unrealistic and false assumption that the average customer for every utility uses an average 1,000 kWh per month". Do you agree?

A. Absolutely not. This is a total mischaracterization of our filing and my testimony. As I stated above, FPL was entirely clear throughout testimony and exhibits that we are using the typical residential bill of 1,000 kWh as a benchmark. That is a meaningful and industry-accepted benchmark. The average bill benchmark is not a meaningful comparison. Additionally, it should be noted that over 50% of FPL's residential customers use less than 1,000 kWhs per month. Finally, the Commission uses the typical residential bill for benchmarking purposes.

Q. Why is the average residential electric bill not a meaningful comparison?

A. It is not an appropriate comparison for several reasons. Using the three utilities with the lowest average bills in each of the tables presented by witnesses Whited and Rabago, I compared specific data using EIA.gov shown on Table 1 below, which is the same source used by both witnesses for their average bill comparisons.

Table 1

IOU	State	Temperature Avg	Temperature Rank	Energy Source Percentage: Natural Gas	Fuel Oil	Electricity	Propane	Other/None
Public Service Co of NM	NM	56	18	**62%**	0%	23%	6%	9%
Commonwealth Edison Co	IL	53	23	**77%**	0%	17%	4%	2%
PacifiCorp	UT	50	32	**81%**	0%	15%	2%	2%
Public Service Co of Colorado	CO	47	37	**68%**	0%	24%	5%	3%
Niagara Mohawk Power Corp.	NY	48	36	**61%**	19%	12%	4%	4%
Florida Power & Light Co	FL	73	**1**	5%	0%	**92%**	1%	2%

IOU	State	Temperature Avg	Temperature Rank	Total Energy Consumption Per Capita (MMBTU)	Rank	Total Expenditures Per Capita ($)	Rank
Public Service Co of NM	NM	56	18	336	19	$3,954	26
Commonwealth Edison Co	IL	53	23	315	25	$3,522	39
PacifiCorp	UT	50	32	265	35	$3,261	46
Public Service Co of Colorado	CO	47	37	266	34	$3,239	47
Niagara Mohawk Power Corp.	NY	48	36	197	50	$3,112	49
Florida Power & Light Co	FL	73	**1**	202	**49**	$2,941	**51**

Source: https://www.eia.gov/state/

There are a number of reasons that average electric bills should not be used for comparison purposes. First, FPL has the highest average temperature of the peer utilities and ranks first in the nation for warmest climate. Florida temperature is 43% higher than the average of the lowest 5 utilities shown in Table 1.

Second, despite having the highest temperature, Florida ranks *lowest* in total energy consumption per capita and *lowest* in total energy expenditures per capita of the comparison group in Table 1.

Third, both witnesses Whited and Rabago fail to consider that the type of fuel source needed to meet a residential customer's energy needs varies significantly depending on their geographical location. For example, witness Whited provides a chart on page 19 of her direct testimony that shows the Public Service Co. of Colorado as having the lowest average residential electric bill in the comparison of 50 investor-owned utilities; however, witness Whited fails to note that only 24% of household energy in Colorado comes from electric power as compared to 92% in Florida.

Benchmarking the *typical* residential 1,000 kWh electric bill is an industry-accepted approach and much more appropriate and meaningful for purposes of evaluating electricity rates and an overall indication of how well electric companies are managed.

Q. Do both witnesses Whited and Rabago concede in their testimony that FPL has in fact low rates?

A. Yes. Witness Whited recognizes on page 18, line 4 of her direct testimony that "FPL has relatively low electric rates." Likewise, witness Rabago acknowledges on page 10 of his direct testimony that FPL has "low rates."

Q. Do you have any additional comments regarding FPL's rate proposal and typical bills?

A. Yes. FPL's rate proposal is fair, just, and reasonable for all customers. FPL's proposal moves all customers towards parity while applying this Commission's guidelines on gradualism. As shown on Exhibits TCC-3 and TCC-5, the FPL typical residential bill is projected to increase approximately 3.4 percent over the four-year rate plan and remain approximately 20 percent below the national average. As shown in TCC-4, a typical bill for a residential customer in Northwest Florida is projected to decline over the same period and be lower than today's bills even with a full rate increase. FPL has a proven track record of providing customers excellent value in their electric service and FPL believes its rate proposals should be approved.

Q. Does this conclude your rebuttal testimony?

A. Yes.

(Whereupon, prefiled direct testimony of Roxie McCullar was inserted.)

DIRECT TESTIMONY

OF

ROXIE MCCULLAR

On Behalf of the Office of Public Counsel

Before the

Florida Public Service Commission

Docket No. 20210015-EI

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Roxie McCullar. My business address is 8625 Farmington Cemetery Road, Pleasant Plains, Illinois 62677.

Q. WHAT IS YOUR PRESENT OCCUPATION?

A. Since 1997, I have been employed as a consultant with the firm of William Dunkel and Associates and have regularly provided consulting services in regulatory proceedings throughout the country.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND.

A. I have over 20 years of experience consulting in regulatory rate cases and have addressed depreciation rate issues in numerous jurisdictions nationwide. I am a Certified Public Accountant licensed in the state of Illinois. I am a Certified Depreciation Professional through the Society of Depreciation Professionals. I received my Master of Arts degree in Accounting from the University of Illinois in Springfield.

I received my Bachelor of Science degree in Mathematics from Illinois State University in Normal.

Q. HAVE YOU PREPARED AN EXHIBIT THAT DESCRIBES YOUR QUALIFICATIONS?

A. Yes. My qualifications and previous experiences are shown on the attached Exhibit RMM-1.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING?

A. I am testifying on behalf of Florida's Office of Public Counsel ("OPC") to address certain depreciation related issues presented in Florida Power & Light Company's ("FPL" or "Company") testimony and filings in this proceeding.

II. SUMMARY

Q. WHERE ARE FPL'S PROPOSED DEPRECIATION RATES AND PARAMETERS FOUND IN THE FPL FILING?

A. FPL filed two different sets of proposed depreciation rates and parameters.

FPL Witness Allis's proposed depreciation rates and parameters are found in the FPL 2021 Depreciation Study filed as Exhibit NWA-1.

FPL Witness Ferguson's proposed a different set of depreciation rates and parameters filed in Exhibit KF-3(B). In comparison to Witness Allis, Witness Ferguson's proposed depreciation parameters use longer lives for the St. Lucie Nuclear Plant, the combined cycle generating plants, and the solar generating plants. Additionally, Witness Ferguson proposed depreciation parameters for transmission, distribution, and general mass property accounts are based on either the 2016 settlement or the 2021 Depreciation Study filed in this proceeding, which ever produces the lower depreciation rate.[1]

Q. CAN YOU SUMMARIZE YOUR RECOMMENDATIONS?

A. My recommended changes to FPL proposed depreciation parameters are based on my review of the FPL 2021 Depreciation Study filed as Exhibit NWA-1 in this proceeding, my review of other FPL witness testimonies filed in this proceeding, my review of the supporting information and workpapers provided by FPL in response to discovery, my review of recent previous Commission orders addressing FPL and Gulf Power depreciation rates in Florida, and my previous experience in depreciation rate studies.

As discussed and supported in this testimony, the reasonable adjustments to the depreciation parameters proposed in FPL 2021 Depreciation Study are the recognition of a 20-year extension for St. Lucie Nuclear Plant, the use of 45-year life for FPL's combined cycle generating plant, the use of 35-year life for FPL's solar generating plant, a -60% estimated future net salvage percent for Account 365, Overhead Conductors and Devices, and a -20% estimated future net salvage percent, for Accounts 370, Meters and 370.1, Meters-AMI.

I used the depreciation parameters and supporting data contained in Witness Allis's Exhibit NWA-1 as the starting point for my recommended adjustments. As discussed above, some of the depreciation parameters recommended by Witness Ferguson are from two different depreciation studies conducted four years apart, so I

[1] Direct Testimony of Keith Ferguson, page 14, lines 3-21.

choose not to use Witness Ferguson's proposed depreciation parameters as a starting point for my recommended adjustments.

Q. PLEASE COMPARE THE OPC'S PROPOSED DEPRECIATION RATES WITH BOTH SET OF FPL'S PROPOSED DEPRECIATION RATES.

A. The annualized accrual based on the FPL December 31, 2021 estimated investments using the OPC's proposed depreciation rates compared to Witness Allis's proposed depreciation rates from the 2021 Depreciation Study, Exhibit NWA-1, and Witness Ferguson's proposed depreciation rates from Exhibit KF-3(B), are summarized in Table 1 below:

Table 1: Comparison of Annual Depreciation Accrual Amount Using Projected December 31, 2021 Investments

Function	**12/31/21 Plant in Service**	**Current Approved Accrual Amount**	**FPL Allis NWA-1 Proposed Annual Accrual Amount**	**FPL Ferguson KF-3(B) Proposed Annual Accrual Amount**	**OPC Proposed Annual Accrual Amount**	**Difference from Allis NWA-1**	**Difference from Ferguson KF-3(B)**
(A)	(B)	(C)	(D)	(E)	(F)	(G)=(F)-(D)	(H)=(F)-(E)
Steam	1,395,998,737	48,641,086	56,657,934	55,672,882	56,657,934	0	985,0532
Nuclear	8,478,789,439	338,755,176	229,116,647	206,090,662	157,853,673	(71,262,974)	(48,236,989)
Combined Cycle	12,889,663,091	554,048,738	557,933,457	472,416,460	510,003,896	(47,929,561)	37,587,436
Peaker Plants	1,172,696,883	38,539,543	35,224,390	36,221,401	35,224,390	0	(997,011)
Solar	4,869,802,677	160,780,581	166,409,916	144,704,005	142,292,441	(24,117,475)	(2,411,564)
Energy Storage	453,716,379	45,371,638	22,610,894	22,685,819	22,610,894	0	(74,925)
Total Production	*29,260,667,205*	*1,186,136,762*	*1,067,953,238*	*937,791,229*	*924,643,228*	*(143,310,010)*	*(13,148,001)*
Transmission	8,545,268,527	191,063,604	208,410,212	189,867,388	208,410,212	0	18,542,824
Distribution	24,256,896,274	628,209,740	732,725,727	641,305,387	716,434,449	(16,291,278)	75,129,062
General	1,427,623,313	52,774,998	46,675,990	51,482,109	46,675,990	0	(4,806,119)
Total TDG	*34,229,788,115*	*872,048,342*	*987,811,929*	*882,654,884*	*971,520,651*	*(16,291,278)*	*88,865,767*
Total	**63,490,455,320**	**2,058,185,104**	**2,055,765,167**	**1,820,446,113**	**1,896,163,879**	**(159,601,288)**	**75,717,766**

The OPC's proposed remaining life depreciation rates compared to Witness Allis's proposed depreciation rates from the 2021 Depreciation Study, Exhibit NWA-

1, and Witness Ferguson’s proposed depreciation rates from Exhibit KF-3(B), are summarized in Table 2 below:

Table 2: Comparison of Proposed Annual Depreciation Rate

Function	12/31/21 Plant in Service	Current Approved Depreciation Rate	FPL Allis NWA-1 Proposed Depreciation Rate	FPL Ferguson KF-3(B) Proposed Depreciation Rate	OPC Proposed Depreciation Rate
(A)	(B)	(C)	(D)	(E)	(F)
Steam	1,395,998,737	3.48%	4.06%	3.99%	4.06%
Nuclear	8,478,789,439	4.00%	2.70%	2.43%	1.86%
Combined Cycle	12,889,663,091	4.30%	4.33%	3.67%	3.96%
Peaker Plants	1,172,696,883	3.29%	3.00%	3.09%	3.00%
Solar	4,869,802,677	3.30%	3.42%	2.97%	2.92%
Energy Storage	453,716,379	10.00%	4.98%	5.00%	4.98%
Total Production	*29,260,667,205*	*4.05%*	*3.65%*	*3.20%*	*3.16%*
Transmission	8,545,268,527	2.24%	2.44%	2.22%	2.44%
Distribution	24,256,896,274	2.59%	3.02%	2.64%	2.95%
General	1,427,623,313	3.70%	3.27%	3.61%	3.27%
Total TDG	*34,229,788,115*	*2.55%*	*2.89%*	*2.58%*	*2.84%*
Total	**63,490,455,320**	**3.24%**	**3.24%**	**2.87%**	**2.99%**

Exhibit RMM-2 support Tables 1 and 2 above.

Q. PLEASE DESCRIBE YOUR EXHIBIT RMM-2.

A. Exhibit RMM-2 contains the calculations of the OPC’s remaining life proposed depreciation rates for FPL’s Electric Plant in Florida.

Q. PLEASE DESCRIBE YOUR EXHIBIT RMM-3.

A. Exhibit RMM-3 contains the calculations of the whole life depreciation rates for FPL’s Electric Plant in Florida using OPC’s recommended depreciation parameters.

III. DEFINITION OF DEPRECIATION

Q. COULD YOU PLEASE PROVIDE THE DEFINITION OF DEPRECIATION?

A. Yes. The Federal Energy Regulatory Commission ("FERC") definitions contained in the FERC Uniform System of Accounts (18 CFR 101 ("FERC USOA")) state:

> 12. *Depreciation*, as applied to depreciable electric plant, means the loss in service value not restored by current maintenance, incurred in connection with the consumption or prospective retirement of electric plant in the course of service from causes which are known to be in current operation and against which the utility is not protected by insurance. Among the causes to be given consideration are wear and tear, decay, action of the elements, inadequacy, obsolescence, changes in the art, changes in demand and requirements of public authorities.[2]

The FERC USOA definition of "depreciation" specifically states depreciation is a "loss in service value." FERC defines service value as "the difference between original cost and net salvage value of electric plant."[3]

Since this is a utility regulation proceeding, I rely on the FERC USOA definition of "depreciation" which focuses on the "loss of service value." Determining reasonable depreciation rates is necessary for establishing the loss in service value of utility cost-based plant-in-service and incorporating it into ratemaking revenue requirement to allow for recovery of that cost.

[2] FERC Uniform System of Accounts Prescribed for Public Utilities and Licensees Subject to the Provisions of the Federal Power Act. (18 CFR 101).
[3] FERC USOA (18 CFR 101) Definition 37.

A. Overview of Depreciation Expense Impact on Revenue Requirement

Q. PLEASE PROVIDE AN OVERVIEW OF THE IMPACT OF DEPRECIATION RATES ON THE REVENUE REQUIREMENT.

A. The depreciation rate that the Commission adopts for an account is multiplied by the test year investment in that account to produce a calculated annual depreciation expense for that account. The calculated depreciation expense for all accounts are included in the revenue requirement that is to be recovered from the ratepayers.

As pointed out by the National Association of Regulatory Utility Commissioners' ("NARUC") text *Public Utility Depreciation Practices*:

> It is essential to remember that depreciation is intended only for the purpose of recording the periodic allocation of cost in a manner properly related to the useful life of the plant. It is not intended, for example, to achieve a desired financial objective or to fund modernization programs.[4]

Q. WHAT IMPACT DO THE DEPRECIATION RATES SET IN THIS PROCEEDING HAVE ON FUTURE PROCEEDINGS?

A. The depreciation rates, or any other adjustment to the accumulated depreciation reserve, decided in this proceeding will impact the level of the accumulated depreciation reserve in a future rate case.

The depreciation expense amounts, based on the approved depreciation rates, are added to the accumulated depreciation reserve, while the accumulated depreciation reserve is decreased at the time of a retirement for the book cost of the plant retired and the cost of removal, less any salvage value.[5]

[4] Page 23, *Public Utility Depreciation Practices*, published by National Association of Regulatory Commissioners (NARUC), 1996.
[5] 18 CFR 101, Account 108.

Adjustments to the accumulated depreciation reserve amount impact the allowed return on net rate base in a future rate case.

In a rate case, the calculated net rate base is multiplied by a rate of return (ROR) to calculate the shareholders' and other investors' "return on" their investment. The calculation of the allowed return on rate based included in customer rates is expressed in a simplified way here:[6]

$$\text{allowed return} = (\text{investment} - \text{reserve}) * \text{ROR}$$

The accumulated depreciation reserve is the significant amount in the "reserve" part of the formula shown above.

B. Calculation of Depreciation Rates

Q. PLEASE PROVIDE A BRIEF DISCUSSION ABOUT THE WHOLE LIFE AND REMAINING LIFE TECHNIQUES FOR CALCULATING DEPRECIATION RATES.

A. In the calculation of depreciation rates, the whole life and remaining life techniques describe two different formulas that are used to calculate the depreciation rate.

The whole life technique depreciation rate formula is:

$$\text{Depreciation Rate} = \frac{(100\% - \text{Future Net Salvage }\%)}{\text{Average Service Life}}$$

The remaining life technique depreciation rate formula is:

$$\text{Depreciation Rate} = \frac{(100\% - \text{Book Reserve }\% - \text{Future Net Salvage }\%)}{\text{Average Remaining Life}}$$

[6] Other items such as cash working capital, materials and supplies, deferred income taxes, regulatory liabilities, regulatory assets, etc. are included in the net rate base calculation.

In the formula above, the book reserve percent is the actual accumulated depreciation reserve on the Company's books divided by the actual plant-in-service investment on the Company's books at the time of the Depreciation Study.[7]

The Depreciation Study estimates the projected average service life of the assets, the retirement pattern of those assets, and the cost of removing or retiring those assets less any expected salvage from the sale, scrap, insurance, reimbursements, etc. of those assets. These estimates are referred to as depreciation parameters.

The projected average service life and retirement pattern (survivor curve) are the two parameters from the Depreciation Study that calculate the average remaining life.

The estimated future net salvage percent parameter from the Depreciation Study estimates the future cost of removing or retiring less any estimated future salvage from the sale, scrap, insurance, reimbursements, etc.

Q. WHAT IS A KEY DIFFERENCE BETWEEN THE WHOLE LIFE AND REMAINING LIFE TECHNIQUE FORMULAS?

A. A key difference is the remaining life technique formula includes an adjustment in the calculation of depreciation rates to offset any reserve imbalance, while the whole life technique does not. The whole life technique is almost identical to remaining life technique when a reserve imbalance amortization over the average remaining life is included.

NARUC's *Public Utility Depreciation Practices* states:

[7] In this proceeding, I use the FPL estimated December 31, 2021 investment and accumulated depreciation reserve amounts as shown in FPL Exhibit NWA-1.

> The desirability of using the remaining life technique is that any necessary adjustments of depreciation reserves, because of changes to the estimates of life or net salvage, are accrued automatically over the remaining life of the property.[8]

All other things being equal, in the remaining life formula, a reserve deficiency would increase the depreciation rate and a reserve excess would result in a lower depreciation rate.

Q. WHAT IS A RESERVE IMBALANCE AS ESTIMATED IN A DEPRECIATION STUDY?

A. A reserve imbalance estimated in a depreciation study is the difference between the actual book accumulated reserve at the time of the study and an estimate of what the depreciation reserve should be based on the depreciation estimates in the current depreciation study.

A reserve imbalance can be due to the prior depreciation estimates being different than the current depreciation estimates, or other causes, for example, an unanticipated event occurred in the past that impacted the book reserve balance.

Q. PLEASE EXPLAIN WHAT IS MEANT BY LIFE SPAN ACCOUNTS AND MASS PROPERTY ACCOUNTS IN THE ESTIMATION OF THE DEPRECIATION PARAMETERS.

A. Production plant accounts are considered life span accounts since all of the assets at the location are expected to retire at the same time. Transmission, Distribution, and General

[8] Page 65, *Public Utility Depreciation Practices*, published by National Association of Regulatory Commissioners (NARUC), 1996.

plant accounts are considered mass property accounts that include similar assets whose retirement are not expected to occur on the same date.

NARUC's *Public Utility Depreciation Practices* explains:

> A life span group contains units that will concurrently retire in a specific number of years after placement. For life span groups, there may be interim additions and retirements; however, all plant will be subject to a final retirement. Unlike mass property groups, life span groups often contain a small number of large units, such as an electric power generation unit or a telephone central office.[9]

Q. What are some considerations used when estimating the depreciation parameters used in the depreciation rate formulas?

A. When estimating a depreciation parameter for an account, an initial step is to analyze that utility's actual historic life and net salvage experience data for that account. In addition to considering the lives and net salvage indicated by the utility's experience data, the expectations of the management, any changes to the current industry practices, and informed judgement are part of the estimation process.

Informed judgement as explained in NARUC's *Public Utility Depreciation Practices*:

> *Informed judgment* is a term used to define the subjective portion of the depreciation study process. It is based on a combination of general experience, knowledge of the properties and a physical inspection, information gathered throughout the industry, and other factors which assist the analyst in making a knowledgeable estimate.
>
> The use of informed judgment can be a major factor in forecasting. A logical process of examining and prioritizing the usefulness of information must be employed, since there are many sources of data that must be considered and weighed by importance.[10]

[9] Page 141, *Public Utility Depreciation Practices* published by the National Association of Regulatory Utility Commissioners (NARUC), 1996.

[10] Page 128, *Public Utility Depreciation Practices* published by the National Association of Regulatory Utility Commissioners (NARUC), 1996.

IV. PRODUCTION PLANT LIFE

Q. DO YOU RECOMMEND ANY CHANGES TO THE LIFE SPAN FOR SOME PRODUCTION UNITS PROPOSED IN THE FPL 2021 DEPRECIATION STUDY, EXHIBIT NWA-1?

A. Yes. As discussed in detail below, I recommend the recognition of a 20-year extension for St. Lucie Nuclear Plant, the use of 45-year life for FPL's combined cycle generating plant, the use of 35-year life for FPL's solar generating plant based on FPL's expectation of the production plant life.

An authoritative depreciation text points out that setting "the final retirement date is the most important factor in the depreciation of a depreciation rate for life span properties."[11] That section of the depreciation text when discussing the factors to consider when estimating the life span points out that the "specific plans of management must be given consideration."[12]

A. St. Lucie Nuclear Plant Life

Q. WHAT LIFE SPAN DO YOU PROPOSE FOR ST. LUCIE NUCLEAR PLANT UNITS?

A. I recommend the recognition of a 20-year extension for St. Lucie Nuclear Plant units.

[11] Page 146, *Public Utility Depreciation Practices*, published by National Association of Regulatory Commissioners (NARUC), 1996.
[12] Page 147, *Public Utility Depreciation Practices*, published by National Association of Regulatory Commissioners (NARUC), 1996.

Witness Allis recommends a 60-year life based on the current license,[13] while Witness Ferguson recommends an 80-year life based on the expectation that FPL will receive a 20-year subsequent license renewal ("SLR").[14]

Q. DID FPL'S TESTIMONY INDICATE THAT IT IS THE COMPANY'S EXPECTATION THE ST. LUCIE WILL RECEIVE AN ADDITIONAL 20-YEAR SLR TO OPERATE FOR 80 YEARS?

A. Yes. FPL Witness Coffey states:

> Given that we have continued to deliver significant value and safe and reliable service to customers through the SLRs we obtained for Turkey Point Units 3 and 4, we have no reason to believe the NRC will not grant our request for SLRs for St. Lucie Units 1 and 2, especially given that none have been denied to date.[15]

On March 17, 2021 FPL did notify the NRC that they intended to submit a Subsequent License Renewal Application for both St. Lucie units in the third quarter of 2021. A copy of that letter is attached as Exhibit RMM-4.

Since FPL is applying for the SLR and the company's expectation is that the SLR will be approved, it is reasonable to expect an additional 20 years and use an 80-year life for St. Lucie depreciation rates. The use of the 60-year life as proposed by Witness Allis does not represent FPL's future expectations.

[13] Exhibit NWA-1, page 677.
[14] Direct Testimony of Keith Ferguson, page 15, lines 10-13.
[15] Direct Testimony of Robert Coffey page 8, lines 18-22.

B. Solar Generating Plant Life

Q. WHAT LIFE SPAN DO YOU PROPOSE FOR FPL'S SOLAR GENERATING PLANTS?

A. I recommend the use of a 35-year life span for FPL's solar generating plants. Witness Allis recommends a 30-year life for solar generating plants,[16] while Witness Ferguson recommends a 35-year life based on a recent survey.[17]

Q. DOES THE SURVEY REFERENCED IN WITNESS FERGUSON'S TESTIMONY SUPPORT A 35-YEAR LIFE FOR FPL'S SOLAR GENERATING PLANT?

A. Yes. The 35-year life is at the high end of the range in the survey, however, since most of the solar generating plant included in the 2021 depreciation study has recently been installed or will be installed soon, it is reasonable to expect that the newer solar plant technology would live at the top end of the range.

The survey referenced in Witness Ferguson's testimony is attached as Exhibit RMM-5.

C. Combined Cycle Generating Plant Life

Q. WHAT LIFE SPAN DO YOU PROPOSE FOR FPL'S COMBINED CYCLE GENERATING PLANTS?

A. I recommend the use of a 45-year life span for FPL's combined cycle generating plants.

[16] Exhibit NWA-1, page 694.
[17] Direct Testimony of Keith Ferguson, page 16, lines 8-13.

Witness Allis recommends a 40-year life for combined cycle generating plants,[18] while Witness Ferguson recommends a 50-year life. [19]

Q. DOES THE INFORMATION PROVIDED IN THIS PROCEEDING INDICATE THAT THE FPL'S COMBINED CYCLE PLANTS ARE EXPECTED TO LIVE LONGER THEN THE 40 YEARS PROPOSED BY WITNESS ALLIS?

A. Yes. In response to discovery FPL stated: "All of FPL's combined cycle plants are currently expected to have a useful life of 40 years or longer."[20]

Therefore, Witness Allis's proposed 40-year life is at the bottom of the company's expected useful life range.

Additionally, Witness Ferguson indicates that the life span may be up to 50 years. As stated in his testimony:

> However, as described by FPL witness Broad, the Company has made significant investments in these facilities in recent years that upgraded much of the primary components of the plants, and these investments can increase the useful lives of these plants. We are aware of at least one non-FPL combined cycle plant owned by Public Service of Oklahoma, the Comanche plant, that is nearing 50 years in service. Based on FPL's record of performance and its upgrades to these plants, along with the potential to convert these plants to utilize green hydrogen as a fuel source similar to the pilot described by FPL witness Valle, these plants may be able to be operated up to 50 years.[21]

The life span on FPL's combined cycle plants is expected to be longer than 40-years, however, at this time I do not believe that the use of the 50-year life at the top end of the range is supported. I recommend a 45-year life at this time which recognizes the

[18] Exhibit NWA-1, page 691.
[19] Direct Testimony of Keith Ferguson page 15, line 16 – page 16, line 2.
[20] FPL response to FIPUG Interrogatory No. 8, included in Exhibit RMM-8.
[21] Direct Testimony of Keith Ferguson page 15, line 16 – page 16, line 2.

expected longer life of FPL's combined cycle plants and uses the mid-point of the expected life range.

The use of the longer 50-year life should be examined in a future depreciation study.

V. MASS PROPERTY ESTIMATED FUTURE NET SALVAGE

Q. PLEASE EXPLAIN WHAT IS MEANT BY NET SALVAGE.

A. NARUC's *Public Utility Depreciation Practices* defines net salvage as "the gross salvage for the property retired less its cost of removal."[22] Gross salvage is defined as "the amount recorded for the property retired due to the sale, reimbursement, or reuse of the property."[23] Cost of removal is defined as "the costs incurred in connection with the retirement from service and the disposition of depreciable plant. Cost of removal may be incurred for plant that is retired in place."[24]

NARUC also explains that careful consideration should be given to the net salvage estimate stating:

> Cost of retirement, however, must be given careful thought and attention, since for certain types of plant, it can be the most critical component of the depreciation rate.[25]

NARUC's *Public Utility Depreciation Practices* later points out that:

[22] Page 322, *Public Utility Depreciation Practices*, published by National Association of Regulatory Commissioners (NARUC), 1996.
[23] Page 320, *Public Utility Depreciation Practices*, published by National Association of Regulatory Commissioners (NARUC), 1996.
[24] Page 317, *Public Utility Depreciation Practices*, published by National Association of Regulatory Commissioners (NARUC), 1996.
[25] Page 19, *Public Utility Depreciation Practices*, published by National Association of Regulatory Commissioners (NARUC), 1996.

> Determining a reasonably accurate estimate of the average or future net salvage is not an easy task; estimates can be the subject of considerable discussion and controversy between regulators and utility personnel.[26]

Q. WHAT IMPACT DOES THE ESTIMATED FUTURE NET SALVAGE PERCENT HAVE ON DEPRECIATION RATES?

A. Positive net salvage results in a lower depreciation rate, all other things being equal. Negative net salvage results in a higher depreciation rate, all other things being equal. As stated in NARUC's *Public Utility Depreciation Practices*:

> Positive net salvage occurs when gross salvage exceeds cost of retirement, and negative net salvage occurs when cost of retirement exceeds gross salvage.[27]

The estimated future net salvage is part of the annual depreciation accrual, which is credited to the depreciation reserve to cover the estimated future net salvage costs the company may incur in the future associated with plant asset retirements.

Q. DID FPL PROVIDE HISTORICAL NET SALVAGE DATA IN THE DEPRECIATION STUDY?

A. Yes. The FPL depreciation study included the historic data of the actual incurred and recorded net salvage and related retirements. Regarding historic net salvage, FPL's depreciation study states:

> The estimates of net salvage by account were based in part on the analyses of historical data compiled for the years 1986 through 2019. Cost of removal and salvage were expressed as percents of the original cost of plant retired, both on annual and three-year moving average bases. The most recent five-year average also was calculated for

[26] Page 157, *Public Utility Depreciation Practices* published by the National Association of Regulatory Utility Commissioners (NARUC), 1996.
[27] Page 18, *Public Utility Depreciation Practices*, published by National Association of Regulatory Commissioners (NARUC), 1996.

> consideration. The net salvage estimates by account are expressed as a percent of the original cost of plant retired.[28]

Q. WHAT IS A CONCERN REGARDING THE HISTORIC NET SALVAGE RATIOS CALCULATED IN THE DEPRECIATION STUDY?

A. As pointed out in Wolf and Fitch's *Depreciation Systems*:

> Salvage ratios are a function of inflation.[29]

Additionally, Wolf and Fitch's *Depreciation Systems*, points out that a historic net salvage ratio that includes inflated dollars in the numerator and historic dollars in the denominator is a ratio using different units, stating:

> One inherent characteristic of the salvage ratio is that the numerator and denominator are measured in different units; the numerator is measured in dollars at the time of retirement, while the denominator is measured in dollars at the time of installation. Inflation is an economic fact of life and although both numerator and denominator are measured in dollars, the timing of the cash flows reflects different price levels.[30]

The calculation of the historic net salvage ratio includes the impact of historic inflation rates, since the net salvage amount in the numerator is in current dollars and the cost of the plant (which may have been installed decades before) in the denominator is in historic dollars. In other words, due to inflation the amounts in numerator and denominator of the net salvage ratio are at different price levels.

Q. IS THE FACT THAT HISTORIC INFLATION IS INCLUDED IN THE NET SALVAGE RATIO RECOGNIZED IN ANOTHER AUTHORITATIVE DEPRECIATION TEXT?

A. Yes. NARUC's *Public Utility Depreciation Practices*, regarding inflation states:

[28] Exhibit NWA-1, page 43.
[29] Page 267, Wolf, Frank K. and W. Chester Fitch, *Depreciation Systems* Iowa State University Press, 1994.
[30] Page 53, Wolf, Frank K. and W. Chester Fitch, *Depreciation Systems* Iowa State University Press, 1994.

> The sensitivity of salvage and cost of retirement to the age of the property retired is also troublesome. Due to inflation and other factors, there is a tendency for costs of retirement, typically labor, to increase more rapidly than material prices.[31]

Q. HAVE OTHER JURISDICTIONS CONSIDERED THE IMPACT OF INFLATION IN THE SETTING OF THE ESTIMATED FUTURE NET SALVAGE PERCENT?

A. Yes. I am aware of several jurisdictions that have adopted estimated future net salvage percents that recognize the inflated dollars included in the historic net salvage ratio. The Commissions in Connecticut,[32] District of Columbia,[33] Maryland,[34] New Jersey,[35]

[31] Page 19, *Public Utility Depreciation Practices*, published by National Association of Regulatory Commissioners (NARUC), 1996.

[32] Connecticut Docket No. 16-06-04. In the December 14, 2016 Commission "Decision" the Commission accepted net salvage depreciation rates that produced "an annual accrual that is 1.2 times the annual incurred distribution plant net salvage costs" stating that the "distribution net salvage depreciation rates still comfortably cover the actual incurred net salvage costs." (p. 46 of the December 14, 2016 "Decision").

[33] Formal Case No. 1076, paragraph 252 of Order No. 15710. In Order No. 15710, the Public Service Commission of the District of Columbia stated: "Fairness and equity require that the Commission adopt a methodology that, to the extent possible, balances the interest of current and future ratepayers." And went on to state: "Pepco should not be allowed to charge current customers for future inflation, nor should Pepco be allowed to charge current customers in higher-value current dollars for a future cost of removal amount that is calculated in lower-value future dollars."

[34] Maryland Case No. 9092. In Order No. 81517, the Commission stated: "The Commission has carefully reviewed the record and finds that the Present Value Method should be adopted for the recovery of removal costs. The Straight Line Method recovers the same annual cost in nominal dollars from ratepayers today as it does at the time plant is removed from service. However, a dollar is worth substantially more today than it will be 20 to 40 years from now. Consequently, today's ratepayers would pay more in "real" dollars under the Straight Line Method for the recovery costs of the plant they consume than would future ratepayers when net salvage is negative, as everyone projects." (page 30 of Order No. 81517).

[35] New Jersey Docket No. ER02080506. In the May 17, 2004 Final Order, the Board found: "As a result of this data and the underlying concept of FASB 143 as discussed in this matter, the Board FINDS it appropriate to revisit the concept of including estimated future net salvage in current depreciation rates. The Board HEREBY FINDS the recommendation of the Ratepayer Advocate and Staff to exclude estimated net salvage from depreciation rates to be appropriate. The Board FURTHER FINDS that the Ratepayer Advocate and Staff's proposed utilization of a five-year average of actual salvage expense in depreciation expense is reasonable as it more closely aligns the amount recovered in base rates with the historical level of expenses incurred. The Board concurs with Staff that the ten-year window of actual experience rather than the five-year rolling average proposed by the Ratepayer Advocate is appropriate." (page 129-130 of the May 14, 2004 Final Order)

and Pennsylvania[36] have adopted methods of setting the estimated future net salvage percent that recognizes the time value of cost of removal due to inflation.

Q. WHY SHOULD INFLATION IN THE HISTORIC NET SALVAGE RATIOS BE CONSIDERED WHEN ESTIMATING THE FUTURE NET SALVAGE AMOUNTS TO BE COLLECTED FROM TODAY'S RATEPAYERS?

A. The estimated future net salvage accruals included in the revenue requirement in this proceeding are to be collected from the ratepayers in today's more valuable current dollars. Therefore, I not only reviewed the historic net salvage data as presented in the depreciation study and the underlying data provided in response to discovery, I also evaluated the impact of collecting the more valuable current dollars from the ratepayers to pay for an estimated future costs.

[36] Pennsylvania, Superior Court of Pennsylvania in Penn Sheraton Hotel v. Pennsylvania Public Utility Commission, 184 A.2d 324, 329 (Pa. Super. Ct. 1962). The court found: "Negative salvage attributed to existing plant is purely prospective; it is a cost which has not yet been incurred; it is uncertain when and if it will be incurred; and it is not a part of the original cost of construction of the facilities when first devoted to public service. To permit the recovery of prospective negative salvage is to permit the recovery of a total amount in excess of the original cost of construction prior to the actual expenditure of those costs and, in our opinion, represents the recovery of something in the nature of a future reproduction cost. The established law in this Commonwealth does not permit the recovery by annual depreciation of any such prospective excess. It is therefore the prospective nature of future negative salvage that prevents it from being considered either in accrued depreciation or in the allowance for annual depreciation; they must have a consistent basis under our law. Although prospective negative salvage is not entitled to consideration, the negative salvage actually incurred by the utility either upon the actual retirement of a property without replacement or upon the replacement of an item of property is of course entitled to consideration in a rate proceeding. It is then no longer prospective but actual. If the utility retires and removes a property without replacing it or replaces it after removal and incurs actual negative salvage in doing so, the expenditure should be capitalized and amortized by some reasonable method and for and over a reasonable length of time."

Q. BASED ON YOUR REVIEW DO YOU RECOMMEND A DIFFERENT ESTIMATE FUTURE NET SALVAGE PERCENT FOR ANY MASS PROPERTY ACCOUNTS?

A. Yes. For Account 365, Overhead Conductors and Devices, Account 370, Meters, and Account 370.10, Meters-AMI, I recommend estimated future net salvage ("FNS") percents that differ from Witness Allis's proposal and Witness Ferguson's proposal as shown in Table 3 below:

Table 3: Comparison of Distribution Plant
Estimated Future Net Salvage ("FNS") Percent Proposals

Account	Proposed by FPL Witness Allis[37]	Proposed by FPL Witness Ferguson[38]	OPC Proposed FNS%[39]
365, Overhead Conductors & Devices	-75%	-60%	-60%
370, Meters	-25%	-20%	-20%
370.01, Meters-AMI	-25%	-20%	-20%

Q. WHY IS THE ESTIMATED FUTURE NET SALVAGE SHOWN AS A PERCENT IN THE TABLE ABOVE?

A. The depreciation rates are calculated in the depreciation study based on the estimated per book amounts and experience as of December 31, 2021. The depreciation rates resulting from the depreciation study are then applied to the investment amounts as of the date of the test year in the rate proceeding. Since the depreciation study produces a depreciation rate, the estimated future net salvage is included in the depreciation rate formula as a percent of the estimated investment as of December 31, 2021.

[37] Exhibit NWA-1, page 69.
[38] Exhibit KF-3(B), page 23.
[39] Exhibit RMM-2.

Q. HAVE YOU REVIEWED THE RECOVERY OF ESTIMATED FUTURE NET SALVAGE COSTS INCLUDED IN FPL'S PROPOSED DEPRECIATION ACCRUAL AND THE ACTUAL NET SALVAGE COSTS FPL HAS INCURRED IN TODAY'S DOLLARS IN THE LAST FEW YEARS?

A. Yes. As a reasonableness check on the estimated future net salvage accrual amount to be included in the revenue requirement, I have compared the estimated future net salvage costs included in FPL's proposed depreciation accrual and the actual net salvage costs incurred by FPL on average over the recent five-year period, which is shown in Exhibit RMM-6.

Q. ARE YOUR PROPOSED ESTIMATED FUTURE NET SALVAGE PERCENTS BASED ONLY ON THE COMPARISON SHOWN IN EXHIBIT RMM-6?

A. No. This is evidenced by the fact that my proposed estimated future net salvage accrual amounts are not equal to the average annual historical amount as shown in Exhibit RMM-6. I also reviewed the historic net salvage data provided in the depreciation study and the supporting data provided in response to discovery. Exhibit RMM-6 is a reasonableness check on the estimated future net salvage accrual amount to be included in the revenue requirement. My proposed estimated future net salvage accrual amounts are in current dollars that consider FPL's historic practices, the impact of inflation, and builds a reserve for reasonable estimated future net removal costs associated with future retirements, based on the type of investments in the account, and my previous experience.

A. Account 365, Overhead Conductors and Devices Estimated Future Net Salvage

Q. PLEASE DISCUSS YOUR ADJUSTMENT TO FPL'S ESTIMATED FUTURE NET SALVAGE PERCENT FOR ACCOUNT 365, OVERHEAD CONDUCTORS AND DEVICES.

A. It is reasonable to continue the use of the current approved -60% future net salvage estimate Account 365, Overhead Conductors and Devices.

Witness Ferguson also proposes the continued use of the current approved -60% estimate future net salvage percent.

Witness Allis's proposal to accelerate the collection of the estimated future net salvage from the current ratepayer with the proposed -75% future net salvage percent is not reasonable. Even Witness Allis states that "It is, therefore, possible that costs could moderate somewhat in the future."[40]

Q. WHAT DOES WITNESS ALLIS OFFER TO SUPPORT THE CHANGE TO -75% ESTIMATED FUTURE NET SALVAGE PERCENT?

A. Witness Allis states:

> The reasons for increasing costs for overhead conductor are similar to those for poles and include permitting requirements, safety requirements and traffic control requirements. However, similar to poles, there is the possibility that storm hardening work, which has been more likely to be adjacent to major roads, could experience higher removal costs. It is, therefore, possible that costs could moderate somewhat in the future.[41]

This statement assumes that only the numerator in the historic net salvage ratio will be increased by the "permitting requirements, safety requirements and traffic control

[40] Exhibit NWA-1, page 756.
[41] Exhibit NWA-1, page 756.

requirements" costs. The cost of new plant installed that is replacing the retired plant will also be increased by the "permitting requirements, safety requirements and traffic control requirements" costs, which means when that plant retires the denominator of the historic net salvage ratio will also be impacted by these costs. The increase in both the numerator and denominator will moderate the historic net salvage ratio.

Q. DOES YOUR PROPOSAL TO KEEP THE CURRENT APPROVED -60% ESTIMATED FUTURE NET SALVAGE PERCENT RESULT IN AN UNDER-RECOVERY OF THE ESTIMATED FUTURE COSTS?

A. No. As shown in Exhibit RMM-6, for Account 365, Overhead Conductors and Devices, FPL actually incurred $34,987,796 on average per year.[42] My recommendation results in an annual accrual of $46,094,350 which is 1.3 times the average annual amount FPL has actually incurred for net salvage.[43] The annual accrual amount is an expense to be recovered from ratepayers in customer charges.[44] My recommendation, which is about 1.3 times the current average annual amount, provides recovery of the expected cost of removal in the near future and builds the reserve for future cost of removal associated with future retirements.

Witness Allis's proposal accelerates the building of the reserve for the estimate future cost. Witness Allis proposes to collect $58,087,578 which is 1.9 times the average annual amount FPL has actually incurred for net salvage.[45] However, Witness

[42] Exhibit NWA-1, page 350.
[43] I am not recommending or implying a change from the "accrual" basis to the "cash" basis for the recovery of future net salvage costs. In other words, I am not recommending or implying that the depreciation accrual no longer be credited to the Accumulated Provision for Depreciation or that the net salvage costs be "expensed."
[44] The exact amount to be recovered from ratepayers will vary depending on the actual monthly investment in the account during the rate period.
[45] FPL response to OPC Interrogatory No. 207.

Ferguson proposes to collect $44,795,487 net salvage annual accrual which is 1.3 times the average annual amount FPL has actually incurred for net salvage.[46]

B. Account 370, Meters and Account 370.1, Meters-AMI Estimated Future Net Salvage

Q. PLEASE DISCUSS YOUR ADJUSTMENT TO FPL'S ESTIMATED FUTURE NET SALVAGE PERCENT FOR ACCOUNT 370, METERS AND ACCOUNT 370.1, METERS-AMI.

A. It is reasonable to continue the use of the current approved -20% future net salvage estimate for Account 370, Meters and Account 370.1, Meters-AMI.

Witness Ferguson also proposes the continued use of the current approved -20% estimate future net salvage percent. While Witness Allis proposes a -25% estimated future net salvage percent.

Q. WHY ARE YOU DISCUSSING ACCOUNT 370, METERS AND ACCOUNT 370.1, METERS-AMI ESTIMATED FUTURE NET SALVAGE AS A COMBINED ACCOUNT?

A. The FPL depreciation study combines Account 370, Meters and Account 370.1, Meters-AMI for net salvage analysis.[47] Based on the process to retire the assets in these accounts, it is reasonable to combine the estimated future net salvage analysis for these accounts.

[46] FPL response to OPC Interrogatory No. 208.
[47] Exhibit NWA-1, page 771.

Q. WHAT DOES WITNESS ALLIS OFFER TO SUPPORT THE CHANGE TO -25% ESTIMATED FUTURE NET SALVAGE PERCENT?

A. Witness Allis relies on the recent historic net salvage ratio.[48]

The recent experience for FPL in this account has included a meter change out program from the analog meters to AMI meters. This meter program has impacted the recent historic net salvage data that does not reflect the expectations in the future. It is not expected that FPL will undertake another large meter change out program in the foreseeable future.

Q. DOES YOUR PROPOSAL TO KEEP THE CURRENT APPROVED -20% ESTIMATED FUTURE NET SALVAGE PERCENT RESULT IN AN UNDER-RECOVERY OF THE ESTIMATED FUTURE COSTS?

A. No. As shown in Exhibit RMM-6, for Account 370, Meters and Account 370.1, Meters-AMI, FPL actually incurred $3,604,070 on average per year.[49] My recommendation results in an annual accrual of $9,462,998 which is 2.6 times the average annual amount FPL has actually incurred for net salvage.[50] The annual accrual amount is an expense to be recovered from ratepayers in customer charges.[51] My recommendation, which is about 2.6 times the current average annual amount, provides recovery of the expected cost of removal in the near future and builds the reserve for future cost of removal associated with future retirements.

[48] Exhibit NWA-1, page 771-772.
[49] Exhibit NWA-1, page 364.
[50] I am not recommending or implying a change from the "accrual" basis to the "cash" basis for the recovery of future net salvage costs. In other words, I am not recommending or implying that the depreciation accrual no longer be credited to the Accumulated Provision for Depreciation or that the net salvage costs be "expensed."
[51] The exact amount to be recovered from ratepayers will vary depending on the actual monthly investment in the account during the rate period.

Witness Allis's proposal accelerates the building of the reserve for the estimate future cost even more. Witness Allis proposes to collect $12,089,970 which is 3.4 times the average annual amount FPL has actually incurred for net salvage.[52] However, Witness Ferguson proposes to collect $9,175,892 net salvage annual accrual which is 2.5 times the average annual amount FPL has actually incurred for net salvage.[53]

VI. FPL RESERVE IMBALANCE

Q. DOES THE FPL'S FILING SHOW A DEPRECIATION RESERVE IMBALANCE?

A. Yes. Both Witnesses Allis and Ferguson show a reserve imbalance using their proposed depreciation parameters.

Witness Allis shows a reserve deficiency of $436.5 million.[54] That means that the estimated December 31, 2021 book reserve is $436.5 million lower than it should be based on the assumptions in Witness Allis proposed depreciation rates.

Conversely, Witness Ferguson shows a reserve surplus of $1.48 billion.[55] That means that the estimated December 31, 2021 book reserve is $1.48 billion higher than it should be based on the assumptions in Witness Ferguson proposed depreciation rates.

For comparison, the depreciation parameters proposed by OPC result in a $639.4 million reserve surplus.

[52] FPL response to OPC Interrogatory No. 207.
[53] FPL response to OPC Interrogatory No. 208.
[54] Exhibit NWA-1, page 102.
[55] Exhibit KF-3(B), page 47.

Exhibit RMM-7 compares the reserve imbalances estimated in OPC proposed depreciation parameters and the two different FPL proposals, which is summarized in the Table 4 below.

Table 4: Estimated Reserve Imbalances

Function	12/31/21 Plant in Service	12/31/21 Book Reserve Amount	FPL Allis NWA-1 Surplus / (Deficiency)	FPL Ferguson KF-3(B) Surplus / (Deficiency)	OPC Surplus / (Deficiency)
(A)	(B)	(C)	(D)	(E)	(F)
Steam	1,395,998,737	577,123,027	30,873,368	30,873,368	30,873,368
Nuclear	8,478,789,439	3,792,211,761	776,610,604	1,434,688,952	1,434,688,952
Combined Cycle	12,889,663,091	2,186,879,047	(538,663,261)	(69,949,499)	(269,305,239)
Peaker Plants	1,172,696,883	142,604,199	15,377,251	15,377,251	15,377,251
Solar	4,869,802,677	502,678,218	(284,439)	66,331,180	66,331,180
Energy Storage	453,716,379	21,622,200	1,437,834	1,437,834	1,437,834
Total Production	*29,260,667,205*	*7,223,118,453*	*285,351,358*	*1,478,759,087*	*1,279,403,346*
Transmission	8,545,268,527	1,531,727,087	(113,351,172)	12,253,411	(113,351,172)
Distribution	24,256,896,274	5,392,129,569	(666,179,251)	(89,684,819)	(584,334,555)
General	1,427,623,313	406,235,874	57,650,209	78,875,362	57,650,209
Total TDG	*34,229,788,115*	*7,330,092,530*	*(721,880,214)*	*1,443,954*	*(640,035,519)*
Total	**63,490,455,320**	**14,553,210,983**	**(436,528,856)**	**1,480,203,041**	**639,367,828**

Q. WHY DOES FPL INCLUDE BOTH A RESERVE DEFICIENCY AND A RESERVE SURPLUS IN ITS DIRECT FILING?

A. Witness Ferguson recommended changes to the proposed depreciation parameters in Exhibit NWA-1 results in a proposed reserve surplus of $1.48 billion, as opposed to the $436.5 million reserve deficit that results from Witness Allis's proposal.

Q. PLEASE DISCUSS FPL'S PROPOSAL REGARDING WITNESS FERGUSON'S CALCULATED $1.48 BILLION RESERVE SURPLUS.

A. FPL proposes to use Witness Ferguson's calculated $1.48 billion reserve surplus to maintain their earnings within "the ROE range authorized by the Commission."[56] This is not the proper use of the accumulated depreciation reserve.

Q. PLEASE PROVIDE AN EXPLANATION AS TO WHAT THE ACCUMULATED DEPRECIATION RESERVE BALANCES REFLECTS IN A REGULATORY PROCEEDING.

A. The accumulated depreciation reserve balances reflects the portion of the initial plant-in-service investment and the estimated future net salvage costs that have been recovered by the company from ratepayers.

NARUC's *Public Utility Depreciation Practices*, regarding accumulated depreciation reserve states:

> It is intended that the depreciation reserve at the end of an accounting period be that part of the book cost of the plant in service which has been charged to depreciation expense. If depreciation rates have been accurately estimated, the depreciation reserve will reflect the investment in service capacity, utility, or service life of the surviving plant which has been used up in operations. Therefore, the unconsumed usefulness of the plant is its book cost less the depreciation reserve.[57]

[56] Direct Testimony of Robert Barrett, page 61, lines 1-9.
[57] Page 187, *Public Utility Depreciation Practices*, published by National Association of Regulatory Commissioners (NARUC), 1996.

Q. WHAT AMOUNTS ARE PROPERLY INCLUDED IN ACCOUNT 108, ACCUMULATED PROVISION FOR DEPRECIATION?

A. FERC USOA Account 108 Accumulated Provision for Depreciation of Electric Utility Plant ("accumulated depreciation reserve") states:

> A. This account shall be credited with the following:
>
> (1) Amounts charged to account 403, Depreciation Expense, or to clearing accounts for current depreciation expense for electric plant in service.
>
> …
>
> B. At the time of retirement of depreciable electric utility plant, this account shall be charged with the book cost of the property retired and the cost of removal and shall be credited with the salvage value and any other amounts recovered, such as insurance.
>
> …
>
> C. For general ledger and balance sheet purposes, this account shall be regarded and treated as a single composite provision for depreciation. <u>For purposes of analysis, however, each utility shall maintain subsidiary records in which this account is segregated according to the following functional classification for electric plant</u>: (1) Steam production, (2) Nuclear production, (3) Hydraulic production, (4) Other production, (5) Transmission, (6) Distribution, (7) Regional Transmission and Market Operation, and (8) General. <u>These subsidiary records shall reflect the current credits and debits to this account in sufficient detail to show separately for each such functional classification: (a) The amount of accrual for depreciation, (b) The book cost of property retired, (c) Cost of removal, (d) Salvage, and (e) Other items, including recoveries from insurance.</u> Separate subsidiary records shall be maintained for the amount of accrued cost of removal other than legal obligations for the retirement of plant recorded in Account 108, Accumulated provision for depreciation of electric utility plant (Major only).[58] (emphasis added)

In other words, the depreciation expense and the gross salvage go into the accumulated depreciation reserve ("credit") while the cost of removal and an amount equal to the

[58] FERC USOA 18 CFR 101, Account 108.

investment that retires are taken out of the accumulated depreciation reserve ("debit").[59]

Q. HAS THE UNITED STATES SUPREME COURT MADE FINDINGS REGARDING THE USE OF THE ACCUMULATED DEPRECIATION RESERVE TO INCREASE EARNINGS?

A. Yes. A debit or credit to accumulated depreciation reserve to achieve a certain ROE is not only contrary to the definition of the Account 108, previous Supreme Court rulings have found that the accumulated depreciation reserve "represent the consumption of capital, on a cost basis"[60] and cautions against using depreciation "to that extent, subscribers for the telephone service are required to provide, in effect, capital contributions, not to make good losses incurred by the utility in the service rendered, and thus to keep its investment unimpaired, but to secure additional plant and equipment upon which the utility expects a return."[61]

In other words, the use of the accumulated depreciation reserve for ratemaking items that are unrelated to the retirement of utility plant, or the costs related to that retirement of utility plant, results in ratepayers contributing more than their fair share of capital contributions to the utility.

The Supreme Court summarized its findings in *Federal Power Commission v. Hope Natural Gas Company*, 320 U.S. 591, 606-607 (1944):

> Moreover, this Court recognized in *Lindheimer v. Illinois Bell Tel. Co., supra,* the propriety of basing annual depreciation on cost. [Footnote 10]

[59] FERC USOA 18 CFR 101, Account 108.
[60] *Lindheimer v. Illinois Bell Tel. Co* 292 U.S. pp. 292 U. S. 168-169.
[61] *Lindheimer v. Illinois Bell Tel. Co* 292 U.S. pp. 292 U. S. 168-169.

> By such a procedure, the utility is made whole and the integrity of its investment maintained. [Footnote 11] No more is required.
>
> > [Footnote 10] Chief Justice Hughes said in that case (292 U.S. pp. 292 U. S. 168-169): "If the predictions of service life were entirely accurate and retirements were made when and as these predictions were precisely fulfilled, the depreciation reserve would represent the consumption of capital, on a cost basis, according to the method which spreads that loss over the respective service periods. But if the amounts charged to operating expenses and credited to the account for depreciation reserve are excessive, to that extent, subscribers for the telephone service are required to provide, in effect, capital contributions, not to make good losses incurred by the utility in the service rendered, and thus to keep its investment unimpaired, but to secure additional plant and equipment upon which the utility expects a return."
> >
> > [Footnote 11] *See* Mr. Justice Brandeis (dissenting) in *United Railways & Electric Co. v. West,* 280 U. S. 234, 280 U. S. 259-288, for an extended analysis of the problem.[62]

Q. WHAT ARE COMMONLY USED METHODS OF ADDRESSING AN ESTIMATED RESERVE IMBALANCE?

A. NARUC *Public Utility Depreciation Practices* states:

> The use of an annual amortization over a short period of time or the setting of depreciation rates using the remaining life technique are two of the most common options for eliminating the imbalance. The size of the plant account, the reserve ratio, the account remaining life, the technology of the plant in the account, and the account reserve imbalance in relationship to the account annual accrual all have a bearing on the chosen course of action.[63]

[62] p. 320 U.S. 606 (emphasis added).
[63] Page 189, *Public Utilities Depreciation Practices*, published by National Association of Regulatory Commissioners (NARUC), 1996.

Q. HOW DOES OPC PROPOSE TO ADDRESS THE ESTIMATED RESERVE SURPLUS?

A. OPC recommends using remaining life depreciation rates shown on Exhibit RMM-2, since the remaining life technique formula includes an adjustment to the depreciation rates to offset any reserve imbalance.

VII. OVERALL IMPACT ON THE COMPANY'S FILED REVENUE REQUIREMENT

Q. WHAT ADJUSTMENT TO FPL'S PROPOSED DEPRECIATION EXPENSE IN THE REVENUE REQUIREMENT RESULTS FROM YOUR PROPOSED CHANGES TO THE DEPRECIATION RATES?

A. I have provided my recommended depreciation rates to OPC Witness Smith.

The adjustments I made to the proposed depreciation rates, as discussed in this testimony, reduce the Company's adjustment as filed in Exhibit KF-3(A) by $154,830,(000) for the 2022 projected test year and $164,217,(000) for the 2023 projected test year.

VIII. CONCLUSION

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS.

A. For the reasons stated above, I recommend that the OPC's proposed remaining life depreciation rates shown on Exhibit RMM-2 be approved for FPL in Florida.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

(Whereupon, prefiled direct testimony of William Dunkel was inserted.)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

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

DIRECT TESTIMONY

OF

WILLIAM DUNKEL

ON BEHALF OF THE CITIZENS OF THE STATE OF FLORIDA

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I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is William Dunkel. My business address is 8625 Farmington Cemetery Road, Pleasant Plains, Illinois 62677.

Q. WHAT IS YOUR PRESENT OCCUPATION?

A. I am a consultant with and the principal of William Dunkel and Associates ("WDA"). I primarily address utility depreciation rates, which includes dismantlement.

Q. PLEASE SUMMARIZE YOUR PROFESSIONAL QUALIFICATIONS.

A. I am the principal of William Dunkel and Associates, which was established in 1980. For over 40 years since that time, I have regularly provided consulting services in utility regulatory proceedings throughout the country. I have participated in over 300 state regulatory proceedings before over one-half of the state commissions in the United States. I provide, or have provided, services in utility regulatory proceedings to the following clients:

The Public Utility Commissions or their Staffs in these States:

Arkansas	Maryland
Arizona	Mississippi
Delaware	Missouri
District of Columbia	New Mexico
Georgia	North Carolina
Guam	Utah
Illinois	Virginia
Kansas	Washington
Maine	U.S. Virgin Islands

The Office of the Public Advocate, or its equivalent, in these States:

Alaska	Maryland
California	Massachusetts
Colorado	Michigan
Connecticut	Missouri
District of Columbia	Nebraska
Florida	New Jersey
Georgia	New Mexico
Hawaii	Ohio
Illinois	Oklahoma
Indiana	Pennsylvania
Iowa	Utah
Maine	Washington

The Department of Administration in these States:

Illinois	South Dakota
Minnesota	Wisconsin

I graduated from the University of Illinois in February 1970 with a Bachelor of Science Degree in Engineering Physics, with an emphasis on economics and other business-related subjects.

Q. HAVE YOU PREPARED AN EXHIBIT THAT DESCRIBES YOUR QUALIFICATIONS?

A. Yes. My qualifications and previous experiences are shown on the attached Exhibit WWD-1.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING?

A. I am testifying on behalf of Florida's Office of Public Counsel ("OPC").

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to address one issue related to dismantlement costs in the Florida Power & Light Company's ("FPL" or "Company") testimony and filings in this proceeding.

II. DISMANTLEMENT COST

Q. FPL WITNESS FERGUSON HAS CALCULATED A $51,914,620 [1] PROPOSED ANNUAL ACCRUAL FOR THE ESTIMATED FUTURE COSTS OF DISMANTLEMENT FPL'S NON-NUCLEAR GENERATING UNITS. HOW DOES FPL WITNESS FERGUSON EXPLAIN HIS CALCULATION OF THIS ANNUAL ACCRUAL?

A. FPL witness Ferguson states:

> The resulting annual accrual is a function of the **present value** of estimated future cost to dismantle each of those units as compared to its forecasted reserve as of December 31, 2021.[2] (Emphasis added)

Q. WHAT IS "PRESENT VALUE"?

A. "Present Value" is

> Present Value (PV) is the current value given a specified rate of return of a future sum of money or cash flow. The Present Value takes the

[1] This is the "4 Year Average" as shown on page 24 of Revised Exhibit JTK-1, which Exhibit Mr. Ferguson co-sponsored (page 5, line 10 Ferguson direct testimony). (The amount FPL initially filed was $53,392,559, but FPL later revised that amount.)

[2] Page 25, lines 6-9, Direct Testimony of Keith Ferguson.

> Future value and applies a rate of discount or interest that could be earned if it is invested.[3]

Q. WHAT IS THE "FUTURE" COST IN THIS ISSUE?

A. For many production units, FPL will not incur the dismantlement costs until years, or even decades, in the future. For example, for Cape Canaveral CC Unit 5, FPL expects dismantlement costs to be incurred starting in 2053, which is over <u>three decades</u> in the future.[4]

However, starting in 2022 FPL would be collecting accruals from the ratepayers for the future Cape Canaveral CC Unit 5 dismantlement cost. FPL will collect money from ratepayers for a cost that is not expected to be incurred until more than three decades from now. For the next three decades the earliest ratepayers will not have the opportunity to earn the "rate of discount or interest that could be earned if it is invested" on this money they paid in advance to FPL. The present value calculation includes this fact in allocating the cost recovery among the different generations of ratepayers.[5]

[3] https://studyfinance.com/present-value. Visited 5/31/2021. Similarly, "Present Value" is "the sum of money which if invested now at a given rate of compound interest will accumulate exactly to a specified amount at a specified future date." https://merriam-webster.com/dictionary/present value. Visited 5/31/2021.

[4] Exhibit JTK-1, Page 22. Shown in more detail and with formulas on FPL workpaper "2020 Dismantlement-Accrual Estimate (Combined)"

[5] The full amount of the estimated future dismantlement cost is recovered from ratepayers, but the distribution among the different generations of ratepayers is affected.

Q. ARE YOU OBJECTING TO FPL USING THE "PRESENT VALUE" METHOD FOR FUTURE DISMANTLEMENT COSTS?

A. No. Present value is an accepted method for future retirement costs. As ordered in Statement of Financial Accounting Standards No. 143 (SFAS 143),[6] for financial reporting purposes[7] the Financial Accounting Standards Board requires the use of present value for the costs of future retirement activities that are virtually certain to actually occur in the future (these activities are virtually certain to occur in the future because these are the retirement activities which are "legally" required to occur in the future). Later FERC Order No. 631 adopted the same "present value" treatment of the "legal" asset retirement obligations.[8] FERC stated: "In summary, the new accounting standard requires the present value of the liability to be recorded for all assets."[9]

Q. WHAT ISSUE DID YOU OBSERVE IN THE FPL PRESENT VALUE CALCULATIONS?

A. The FPL calculations effectively assume that the annual return the ratepayers could otherwise earn on their money is only 3.39% on average. [10] I am not a cost of money witness, but I was aware that elsewhere in its filing FPL was claiming the earnings in the market were much higher than 3.39%.

[6] In June 2001 FASB issued *Accounting for Asset Retirement Obligations*, SFAS143. Later addressed in FIN 47, *Accounting for Conditional Asset Retirement Obligations*.

[7] An annual report to shareholders is an example of financial reporting.

[8] See FERC Order No. 631 and the FERC Notice of Proposed Rulemaking (NOPR) issued on October 30, 2002, Docket No. RM02-7-000 which led to Order No. 631.

[9] Paragraph 8 of FERC Notice of Proposed Rulemaking (NOPR) issued on October 30, 2002.

[10] The annual discount rate FPL used in its present value calculations varied as shown in Column AB of "Accrual" tab of FPL Excel workpaper "2020 Dismantlement -Actual Estimate (Combined)". 3.39% is the weighted average of the discount rates FPL used in its revised filing.

When presented with this issue, the OPC's Witness Kevin O'Donnell recommended that the same overall cost of money of 6.40% (investor sources only) that the OPC recommends, be used as a reasonable estimate of the amount the ratepayers' money otherwise would earn if invested.

Q. WHAT IS THE ANNUAL ACCRUAL FOR FUTURE DISMANTLEMENT IF THE PRESENT VALUE IS CALCULATED ON THE BASIS THAT THE RATEPAYERS' MONEY OTHERWISE WOULD EARN 6.40% PER YEAR?

A. The $51,914,620 annual accrual for future dismantlement that FPL Witness Ferguson filed becomes $35,891,312 when the annual discount rate of 6.40% is used. This is a difference of $16,023,308 in the annual accrual. I used 6.40% in the same present value calculation, instead of the lower discount rates that Witness Ferguson used. Other than the discount rate, all other amounts and formulas used in this calculation are identical to what Witness Ferguson used. To show the impact of just the change in the cost of money, this calculation still uses the same future production plant retirement dates used in the Witness Ferguson dismantlement calculations.

Q. IS THERE ANOTHER PROBLEM WITH THE ANNUAL ACCRUAL FOR FUTURE DISMANTLEMENT CALCULATED BY WITNESS FERGUSON?

A. Yes. FPL Witness Allis proposes a 30-year life for the solar production units. However, FPL Witness Ferguson's testimony proposes a 35-year life for the solar production units. Witness Ferguson's dismantlement calculations assume the dismantlement will commence at the end of the 30-year life <u>that Witness Allis recommends</u>, not at the end of the 35-year life that Witness Ferguson recommends.

Likewise, Witnesses Allis and Ferguson recommend different retirement dates for combined cycle production units. Instead of using the retirement dates Witness Ferguson recommends, Witness Ferguson's dismantlement calculations use the retirement dates proposed by Witness Allis.

Q. WHAT DATES DID YOU USE FOR THE COMENCMENT OF THE DISMANTLEMENT?

A. OPC Witness McCullar addresses production unit lives. My calculations assume dismantlement of a unit commences as the end of the life recommended by Witness McCullar. For example, for solar production units my calculations assume dismantlement commences at the end of the 35-year life that is recommended by Witness McCullar (FPL Witness Ferguson also recommends a 35-year life for solar production units). With the dismantlement commencement dates corrected, the annual accrual for future dismantlement is $34,881,286. [11]

The $34,881,286 annual accrual for future dismantlement, for inclusion in the revenue requirement calculations, is shown in more detail on Exhibit WWD-2.

<u>III. CONCLUSION</u>

Q. DO YOU RECOMMEND THE ADJUSTMENT DISCUSSED IN THIS TESTIMONY?

A. Yes, for the reasons discussed above.

[11] This is the "4 Year Average" annual accrual. Other OPC witnesses will flow this amount through the revenue requirement calculations to determine the base rate impact.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

(Whereupon, prefiled direct testimony of Kevin O'Donnell was inserted.)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

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

DIRECT TESTIMONY

OF

KEVIN W. O'DONNELL, CFA

ON BEHALF OF THE CITIZENS OF

THE STATE OF FLORIDA

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Appendix A – Kevin W. O'Donnell and William R. O'Donnell C.V's

Exhibits:

Exhibit KWO-1 **FPL All-Sources Requested Cap Structure Exhibit KWO-1**

Exhibit No. KWO-2 **Yield Spread 2011 through 2020**

Exhibit KWO-3 **Interest Cost Differential**

Exhibit KWO-4 **O&M Costs per MWHl**

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, POSITION, AND BUSINESS ADDRESS FOR THE RECORD.

A. My name is Kevin W. O'Donnell. I am President of Nova Energy Consultants, Inc. My business address is 1350 SE Maynard Rd., Suite 101, Cary, North Carolina 27511.

Q. ON WHOSE BEHALF ARE YOU PRESENTING TESTIMONY IN THIS PROCEEDING?

A. I am testifying on behalf of the Florida Office of Public Counsel ("OPC"). The Florida OPC represents consumers/ratepayers before the Public Service Commission of Florida ("Commission").

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND RELEVANT EMPLOYMENT EXPERIENCE.

A. I have a Bachelor of Science in Civil Engineering from North Carolina State University and a Master of Business Administration from Florida State University. I earned the designation of Chartered Financial Analyst ("CFA") in 1988. I have worked in utility regulation since September 1984, when I joined the Public Staff of the North Carolina Utilities Commission ("NCUC"). I left the NCUC Public Staff in 1991 and have worked continuously in utility consulting since that time, first with Booth & Associates, Inc. (until 1994), then as Director of Retail Rates for the North Carolina Electric Membership Corporation (1994 -1995), and since then in my own consulting firm.

I have provided testimony as a witness on rate of return, cost of capital, capital structure, cost of service, rate design, and other regulatory issues, at one time or another in general rate cases, fuel cost proceedings, and other proceedings before the North Carolina Utilities Commission, the South Carolina Public Service Commission, the Wisconsin Public Service Commission, the Virginia State Commerce Commission, the Minnesota Public Service Commission, the Colorado Public Utilities Commission, the District of Columbia Public Service Commission, and the Florida Public Service Commission. In 1996, I testified before the U.S. House of Representatives' Committee on Commerce, Subcommittee on Energy and Power, concerning competition within the electric utility industry. Additional details regarding my education and work experience are set forth in **Appendix A** to my testimony.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony in this proceeding is to present my findings and recommendations on behalf of the Florida OPC as to the proper capital structure and cost of debt to allow Florida Power & Light Company ("FPL", or "the Company") in the current proceeding. I also address some of the mythology surrounding the basis for the low rates that FPL contends separates it from other utilities and for which it seeks additional, excessive revenue recovery from customers.

Q. WHAT CAPITAL STRUCTURE IS FPL REQUESTING AS PART OF THIS PROCEEDING?

A. According to FPL's minimum filing requirement ("MFR") Schedule D-1a, FPL is seeking an investor sourced capital structure of 59.60% for common equity, 38.8% for long-term debt, and 1.6% for short-term debt as set forth in **Table 1** below. Additionally, FPL is seeking cost rates for each of these capital structure components of 11.50%, 3.61%, and 0.94%, respectively.

Table 1: FPL's Requested Cost of Capital

Component	Capital Structure Ratio (%)		Cost Rate (%)	Weighted Cost Rate (%)
	a[1]	**c = a / b**	**d**[2]	**= c * d**
Long-Term Debt	31.37%	38.93%	3.61%	1.41%
Short-Term Debt	1.18%	1.46%	0.94%	0.01%
Common Equity	48.03%	59.61%	11.50%	6.86%
Rx[3]	80.58%[4] **b**	100.00%[5]		8.28%

Q. DO YOU AGREE WITH FPL'S CAPITAL STRUCTURE REQUEST?

A. No. I disagree with FPL's requested capital structure as supported by Company Witnesses Robert E. Barrett (FPL Vice President of Finance) and James M. Coyne (Concentric Energy Advisors, Inc. Senior Vice President). In this proceeding, FPL is asking the Commission to approve a capital structure that includes an equity ratio

[1] FPL Minimum Filing Requirement ("MFR"), Schedule D-1a.
[2] *Id.*
[3] Rx refers to a "Recalculation".
[4] Represents all sources of capital.
[5] Represents only investor sources of capital.

of 59.60%. FPL's request in this case puts an unnecessarily costly burden upon the ratepayers of Florida and should not be allowed.

To be specific, FPL's requested capital structure in this case, when compared to a capital structure of 50% common equity – 50% debt, will cost FPL consumers approximately an additional $511 million per year such that the typical residential customer of FPL pays and will continue to pay approximately an extra $50 per year. Additionally, FPL's requested capital structure in this case, when compared to a capital structure of 55% common equity – 45% debt, will cost FPL consumers approximately an additional $245 million per year such that the typical residential customer of FPL pays and will continue to pay approximately an extra $24 per year. The calculations under each of the scenarios I have outlined above can be found within **Exhibit KWO-1**. Although I believe a 50% common equity ratio to be appropriate in this case, given that FPL has historically had a 59.6% common equity ratio, my recommendation in this case is a 55% common equity ratio in recognition of a more gradual adjustment to the ratio. I have further explained the rationale that has led to my ultimate 55% recommendation below.

Q. PLEASE SUMMARIZE YOUR PRIMARY RECOMMENDATIONS IN THIS CASE.

A. My recommendations in this case are as follows:

- FPL's requested capital structure is grossly excessive and improper for use in setting rates in this proceeding.

- My recommended capital structure and cost of debt is shown below within **Table 2** that shows OPC's entire cost of capital recommendation:

Table 2: Florida OPC Recommended Capital Structure

Component	Weighted Cost (%)	Cost Rate (%)	Weighted Cost
Long-Term Debt	43.37%	3.61%	1.57%
Short-Term Debt	1.63%	0.94%	0.02%
Common Equity	55.00%	8.75%[6]	4.81%
Total Capitalization	**100.00%**		**6.40%**

- FPL's claims regarding low electric rates and low O&M expenses are due to mainly excellent management is misleading given that the Company's generation mix is highly leveraged towards natural gas, which is a significant factor in FPL's low rates and low O&M expenses.

Q. HOW IS YOUR TESTIMONY STRUCTURED?

A. I have outlined my testimony in the following manner. First, I discuss the current state of the financial markets, then the economic and regulatory policy guidelines. Next, I have included discussion of capital structure, which includes an explanation of the concept of capital structure, FPL's requested capital structure, a comparison between capital structure benchmarks, and then OPC's recommended capital structure and its impact on FPL consumers. I then discuss debt and finally a response to FPL's Witness Barrett.

[6] Witness Woolridge's Direct Testimony, Exhibit JRW-1.

II. CURRENT STATE OF THE FINANCIAL MARKETS

Q. PLEASE DESCRIBE THE CORPORATE STRUCTURE OF FLORIDA POWER & LIGHT.

A. FPL is a wholly owned subsidiary of NextEra Energy, Inc ("NextEra").[7]

Q. HOW HAVE THE DEBT AND INTEREST MARKETS CHANGED FOR FPL SINCE THE COMPANY'S LATEST RATE CASE?

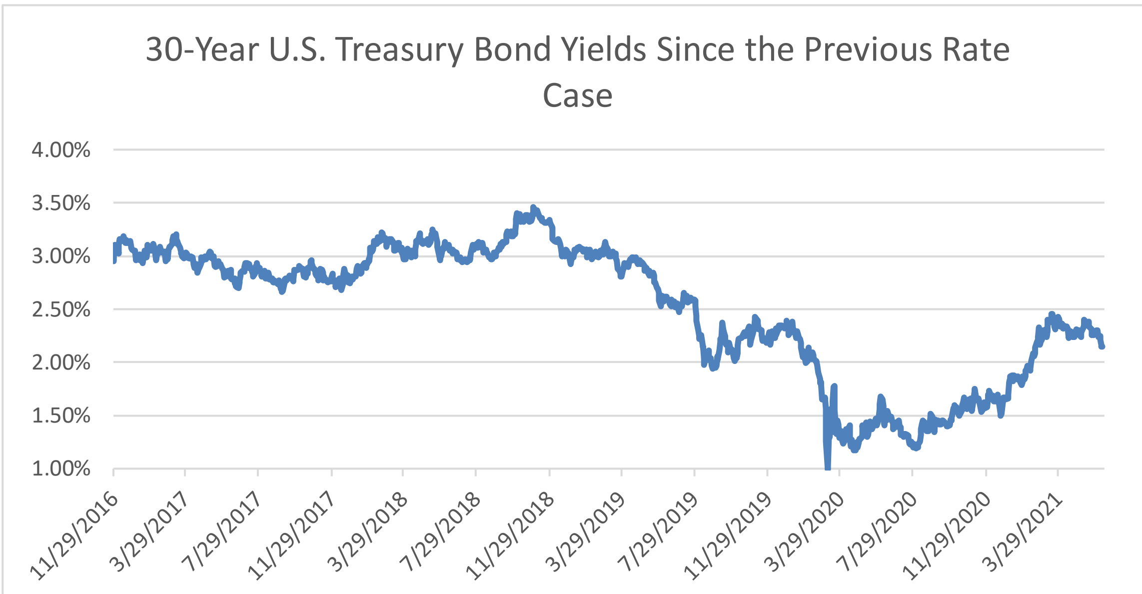
A. FPL's last rate case filing was in Docket No. 20160021-EI, on March 15, 2016 and ultimately it was resolved by a settlement which was approved on December 15, 2016.[8] In the 2016 case, FPL requested a capital structure comprised of a 59.60% equity / 40.40% long term debt capital structure[9] (based on investor sources) and cost rates consisting of 11.00% for equity[10] (before the inclusion of an ROE inflator of 50 basis points) / 4.87% for long term debt.[11] Ultimately, the only cost of capital change that was made from what was originally requested was that the authorized equity cost rate was reflected a 10.55% ROE midpoint per settlement agreement.[12]

In **Chart 1** below, I provide the change in the 30-year US Treasury bonds since the most recent previous FPL rate case (*i.e.,* November 29, 2016 – June 11,

[7] Witness Coyne's Direct Testimony, page 3: line 16.
[8] Order No. PSC-2016-0560-AS-EI, issued December 15, 2016, in Dockets Nos. 2016-0021-EI, 20160061-EI, 20160062-EI, 20160088-EI. In re: Petition for rate increase by Florida Power & Light Company, In re: Petition for approval of 2016-2018 storm hardening plan, by Florida Power & Light Company, In re: 2016 depreciation and dismantlement study by Florida Power & Light Company, In re: Petition for limited proceeding to modify and continue incentive mechanism, by Florida Power & Light Company (2016 Settlement Order).
[9] Witness Hevert's Direct Testimony, page 65: lines 17 – 18 for Docket No. 20160021-EI.
[10] Witness Hevert's Direct Testimony, page 69: line 8 for Docket No. 20160021-EI.
[11] FPL MFR Schedule D-1a for Docket No. 20160021-EI.
[12] 2016 Settlement Order.

2021). The maximum value for the 30-Year US Treasury Bonds over this period was 3.46%, the average value was 2.51%, and the minimum value was 0.99%. Refer to **Chart 1** below for further details on the yield on 30-year US Treasury Bonds subsequent to the previous rate case.

Chart 1: Yield on 30-Year US Treasury Bonds



Source: *Treasury.gov:* ***Date Accessed*** *June 14, 2021.*[13]

Q. HOW HAS THE FEDERAL RESERVE CHANGED THE FEDERAL FUNDS RATE DURING THE LAST 18 MONTHS?

A. On March 3, 2020, the Federal Reserve decreased the Federal Funds rates 50-basis points to a targeted range of between 1.00% and 1.25% in response to recent market conditions.[14] Subsequently, on March 15, 2020 in response to the COVID-19

[13]https://www.treasury.gov/resource-center/data-chart-center/interest-rates/Pages/TextView.aspx?data=yield
[14] https://www.cnbc.com/2020/03/03/heres-what-this-surprise-fed-rate-cut-means-for-you.html

outbreak and the disruptions to economic activity in this country across the globe, the Federal Reserve reduced the Federal Funds rate to 0.25%.[15]

The sharp decline in the Federal Funds Rate that occurred during March 2020 was the result of the Federal Reserve's reaction to the COVID-19 pandemic. In this circumstance, due to the drastic shift in the country's economic outlook, many individuals were looking for relative safe harbors for which to invest their money with the turbulence felt in the stock markets. Accordingly, prices for bonds were bid up, and the long-term yields and interest rates also decreased as exhibited above in **Chart 1**.

Q. DOES THIS MEAN THAT THE COST OF CAPITAL HAS DECREASED FOR COMPANIES LIKE FPL?

A. Yes. The Federal Funds Rate represents the interest rate at which commercial banks borrow and lend their short-term reserves to one another on an overnight basis. The decrease in the Federal Funds Rate over the last 18-months contributed to the sharp decline as seen within the yield on 30-year US Treasury rates over the previous 1-2 years. However, as shown in **Chart 1** above, after the 30-year US Treasury rate declined precipitously through the early onset of the COVID-19 pandemic, the economy began to improve significantly throughout the first half of 2021, and the overall 30-year US Treasury Bond Yields also increased back up over 2.00%.

[15] *See* Commission of Governors of the Federal Reserve System, *Federal Reserve Issues FOMC Statement* (Mar. 15, 2020), available at: https://www.federalreserve.gov/newsevents/pressreleases/monetary20200315a.htm

However, even though the 30-year US Treasury Bond Yields have increased during 2021, the average yield value over the period subsequent to the settlement of the Company's 2016 rate case (*i.e.,* November 29, 2016 through June 11, 2021) was 2.51%, which is still lower than the 2.95% yield at the conclusion of the Company's previous rate proceeding (*i.e.,* at November 29, 2016). Additionally, this yield as of June 11, 2021 was 2.15%. These data points indicate that the Company's cost of capital in relation to its ability to access debt markets has still been lower on average than that at the conclusion of its most recent previous rate case proceeding.

Q. IS THE COMPANY'S RISK GREATER THAN THAT OF OTHER COMPARABLE COMPANIES WHICH WOULD NECESSITATE A CAPITAL STRUCTURE AT THE CURRENT LEVEL?

A. No, it is not. Within his testimony, Mr. Coyne noted the following:

> Sufficient equity in the capital structure is an important factor for maintaining FPL's financial integrity and investment grade credit rating. . . . This capital structure represents management's decisions on how best to finance its operations. The Company's proposed equity ratio is reasonable, given the additional risk borne by FPL relative to the proxy group—i.e., the Company's projected capital expenditure requirements, risk associated with ownership of regulated nuclear generation assets, and storm-related risks.[16]

As noted above, Mr. Coyne referenced FPL's projected capital expenditure requirements, risk associated with ownership of regulated nuclear generation assets, and storm-related risks, in comparison to the risks associated with the companies included within his proxy group as part of the reason why he believes

[16] Witness Coyne Direct Testimony, page 85: lines 17 – 23, and page 86: lines 1 – 4.

that the proposed equity ratio of 59.60% is reasonable. However, he does little to expand upon why these attributes of FPL, when compared to the companies within his proxy group, would support FPL's comparatively heightened equity ratio within its capital structure.

Q. HOW HAVE THE CAPITAL MARKETS FOR UTILITIES CHANGED AS A RESULT OF THE COVID-19 PANDEMIC?

A. On April 2, 2020, *S&P Global Intelligence* published an article entitled "*US utilities demonstrate access to capital with billions in debt offerings*." This article described how utilities tapped into current credit markets to obtain low-cost debt during periods of financial turbulence as noted in the excerpt below:

> Several utilities, including Xcel Energy and NextEra Energy Inc. subsidiary Florida Power & Light Co., which issued $1.1 billion in first mortgage bonds, are "using the opportunity to take advantage of attractive borrowing costs, so there does not appear to be an inability to access capital," they said.
>
> "Utilities are reporting that recent deals have been significantly (7x) oversubscribed, highlighting that the capital markets are open for investment grade-rated utilities," the analysts wrote. "At the same time, we have also observed some utility companies that have fully drawn their bank lines as a precaution to provide them with liquidity in the event that markets seize up," such as Duke Energy Corp. and American Electric Power Co. Inc."[17]

Additionally, in the midst of the early stages of the COVID-19 pandemic on April 29, 2020, *S&P Global Market Intelligence* published an article entitled "*Utility sector 'far and away' least impacted by EPS estimate cuts*."[18] Note that this

[17] https://www.spglobal.com/marketintelligence/en/news-insights/latest-news-headlines/us-utilities-demonstrate-access-to-capital-with-billions-in-debt-offerings-57881534

[18] https://www.spglobal.com/marketintelligence/en/news-insights/latest-news-headlines/utility-sector-far-and-away-least-impacted-by-eps-estimate-cuts-58358458.

article was published April 29, 2020, when markets were at their most volatile early on during the COVID-19 pandemic. The article provided the following observation:

> The S&P 500 utility sector has "far and away" experienced the least impact from earnings revisions since Feb. 28, the corporate bond research firm found. Despite market turmoil and the ongoing economic downturn, analysts have only cut earnings per share expectations for stocks in the utility sector by an average 1% for 2020 and 2021, according to CreditSights.
>
> By comparison, consumer staples, the next least-impacted sector, saw an average 5% decrease to EPS estimates for both years. Technology followed with a 9% estimate cut for 2020 and 2021.
>
> CreditSights pulled the data to measure the consensus view that utilities provide a safe harbor to investors. "Water is wet, the sun will rise in the east and U.S. utilities are a defensive sector, but how defensive? Very defensive," CreditSights analysts Andrew DeVries and Nick Moglia wrote in an April 29 research note.[19]

The above referenced article noted the ability of utilities to continue to operate under the COVID-19 conditions impacting the debt and equity markets. This allowed many utilities to perform strongly even in the face of the COVID-19 pandemic as referenced in the December 9, 2020 article from *S&P Global Intelligence*, entitled "*Resilient Utilities Post Notable EPS Gains, Solid ROEs Despite COVID-19 Pandemic*." Within this article, the following selection was included:

> Despite the significant challenges caused by an economy that continued to be negatively impacted by COVID-19, utilities overall posted solid earnings growth and earned returns on equity during the third quarter, illustrating the tenet that utility finances hold up comparatively well in challenging economic environments.[20]

[19] *Id*.
[20] https://platform.marketintelligence.spglobal.com/web/client?auth=inherit#news/articleabstract?id=61646964

As stated within the articles referenced above, although the utility sector was impacted by the COVID-19 pandemic just like the rest of the economy, utilities were much more resilient during this period than companies across other industries. The resilient performance of utilities, as well as their ability to continue to tap into debt markets, supported that the fact that utilities were still able to access a variety of capital markets throughout 2020, which continued into the 2021 after the capital market resurgence.

Q. HOW ARE INTEREST RATES EXPECTED TO CHANGE OVER THE NEXT FEW YEARS?

A. On March 15, 2020 in response to the COVID-19 outbreak, and the disruptions to economic activity in this country across the globe, the Federal Reserve reduced the Federal Funds rate to 0.25%.[21] The Federal Reserve has since stated that they do not expect to change the Federal Funds Rate at any time in the foreseeable future. Chairman Powell reinforced this view when in January 2021 he said "[w]hen the time comes to raise interest rates, we'll certainly do that, and that time, by the way, is no time soon."[22]

Subsequently, after statements made by Chairman Powell in March 2021, the Federal Reserve explained that although they had sped up their overall

[21] *See* Commission of Governors of the Federal Reserve System, *Federal Reserve Issues FOMC Statement* (Mar. 15, 2020), available at: https://www.federalreserve.gov/newsevents/pressreleases/monetary20200315a.htm

[22] https://www.cnbc.com/2021/01/14/powell-sees-no-interest-rate-hikes-on-the-horizon-as-long-as-inflation-stays-low.html

expectation for economic growth, they continued to reinforce that they did not see any interest rate hikes likely through 2023.[23]

While changes within the market have raised certain interest rate benchmarks during the second half of 2020 and into 2021, these interest rates remain low in relation to historical interest rates. This lower interest rate environment has continued to provide a benefit to utilities from a borrowing perspective.

[23] https://www.cnbc.com/2021/03/17/fed-decision-march-2021-fed-sees-stronger-economy-higher-inflation-but-no-rate-hikes.html

III. ECONOMIC AND REGULATORY POLICY GUIDELINES

Q. PLEASE BRIEFLY DESCRIBE THE ECONOMIC AND REGULATORY POLICY CONSIDERATIONS YOU HAVE TAKEN INTO ACCOUNT IN DEVELOPING YOUR RECOMMENDATION.

A. The theory of utility regulation assumes that public utilities perform functions that are natural monopolies. Historically, it was believed or assumed that it was more efficient for a single firm to provide a particular utility service rather than multiple firms. Within the electric industry, the transmission and distribution of electricity to utilities' end-use customers is still a monopolistic business and will be regulated for the foreseeable future. On this basis, state legislatures and state utility commissions/boards established or have recognized exclusive franchise service areas for public utilities in order for these utilities to provide services more efficiently and at the lowest reasonable cost. In exchange for the protection within its monopoly service area, the utility is obligated to provide service that is adequate and non-discriminatory at fair, just and reasonable rates.

This trade-off logically leads to the question – what constitutes a fair, just and reasonable rate? The generally accepted answer is that a prudently managed utility should be allowed to charge prices that allow the utility the opportunity to recover the reasonable and prudent costs of providing utility service and the opportunity to earn a fair, just and reasonable rate of return on invested capital. The fair, just and reasonable rate of return on capital should allow the utility, under prudent management, to provide adequate service and attract capital to meet future expansion needs in its service area. Since public utilities are capital-intensive businesses, the cost of capital (which is inclusive of capital structure) is a crucial issue for utility companies, their customers, and regulators.

If any of the inputs the cost of capital (including capital structure) are set too high, then consumers are burdened with excessive costs, current investors receive a windfall, and the utility has an incentive to overinvest. If any of these inputs are set too low, then adequate service is jeopardized because the utility will not be able to raise capital on reasonable terms. As such, regulators are tasked with balancing the related interests of the affected parties (*i.e.,* the utility's equity investors, the utility itself, and the utility's customers at the varying residential, commercial, and industrial levels). This balancing act results in what regulators, analysts, and courts often refer to as setting the inputs to the cost of capital within a "zone of reasonableness." Since every equity investor faces a risk-return tradeoff, the issue of risk is an important element in determining the proper inputs to the cost of capital for a utility.

As I referenced above, FPL filed this rate case in March 2021, a time during which the country remained within a pandemic the likes of which have not been seen in this country for over a century, with employment numbers depressed from their averages for approximately one calendar year. Accordingly, what a utility may have initially deemed as fair, just and reasonable cost of capital inputs in 2020 or during prior years may simply be construed as unreasonable today given the current economic climate absent any of the other particulars of their request.

Q. PLEASE EXPLAIN THE SIGNIFICANCE OF THE SUPREME COURT'S *HOPE* AND *BLUEFIELD* DECISIONS.

A. Regulatory law and policy recognize that utilities compete with other firms in the market for investor capital. The United States Supreme Court set the guidelines for a fair, just, and reasonable rate of return in two often-cited cases: *Bluefield Water Works and Improvement Co. v. Public Service Comm'n*. 262 U.S. 679 (1923); and the *Federal Power Comm'n v. Hope Natural Gas Co*., 320 U.S. 591 (1944).

In the *Bluefield* case, the U.S. Supreme Court stated:

> A public utility is entitled to such rates as will permit it to earn a return upon the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding, risks and uncertainties; but it has no constitutional right to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures. The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties. (*Id.* at pp. 692-693)

In the above finding, the Court found that utilities are entitled to earn a return on investments of comparable risks and that a corresponding return should be sufficient enough to support credit activities and to raise funds to carry out its mission.

In *Federal Power Commission v. Hope Natural Gas Company*, 320 U.S. 591 (1944), the U.S. Supreme Court recognized that utilities compete with other firms in the market for investor capital. Historically, this case has provided legal and policy guidance concerning the return which public utilities should be allowed to earn. In *Hope Natural Gas*, the U.S. Supreme Court stated that the return to equity owners (or shareholders) of a regulated public utility should be commensurate to returns on investments in other enterprises whose risks correspond to those of the utility being examined:

> . . . the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain credit and attract capital. (*Id*. at p. 603)

Q. PLEASE EXPLAIN THE RELEVANCE OF THE SUPREME COURT'S *HOPE* AND *BLUEFIELD* DECISIONS WITHIN THE CURRENT PROCEEDING.

A. As this Commission is aware, every equity investor faces a risk-return tradeoff. The more risk the investor assumes, the higher return that the investor demands. The risks that a regulated utility incurs can be stated as a financial risk and/or a business risk. As the amount of debt relative to equity capital increases, the amount of money necessary to pay the interest on debt increases, and financial risk increases. Similarly, as the amount of debt relative to equity capital decreases, financial risk decreases. Thus, as the utility assumes more debt or less debt, the risk of repayment of the debt increases or decreases accordingly.

Business risk is a measure of a company's ability to operate at a profit within its industry. Given that FPL operates in a monopoly industry with no retail competition, its business risk is relatively small.

One of the responsibilities of the utility is to employ prudent and reasonable levels of debt and equity. Utility finance personnel will often attempt to employ different levels of debt and equity in the Company's capital structure to maximize the return allowed by state regulators. The related risk of the regulator is to assess these levels of debt and equity presented in general rate case proceedings to determine if the levels reflect the actual, corresponding financial and business risks to the utility. Further, the regulator should review the utility's capital structure and adjust the requested levels of equity and debt as necessary for rate making purposes to prevent customers from paying rates that are unreasonably high resulting in excessive compensation to shareholders for the services rendered. Moreover, the relative amounts of equity and debt in the total capital raised by the utility directly impacts the risk perceived by investors, and thus it is critical to ensure that allowed rate of return is commensurate with that risk.

IV. PROXY GROUP

Q. PLEASE DESCRIBE THE PROXY GROUP USED WITHIN YOUR TESTIMONY FOR ESTIMATING FPL'S CAPITAL STRUCTURE.

A. On Page 42 of Mr. Coyne's direct testimony, Witness Coyne indicated that he began his proxy group selection process with the 36 electric utilities followed by V*alue Line*. Witness Coyne then proceeded to outline 8 selection criteria used to screen his proxy group. This screening process resulted in Witness Coyne's proxy group being comprised of the 14 different utilities shown in **Figure 10** to his direct testimony and within **Exhibit JMC-3**.

OPC Witness Randall Woolridge has made an independent determination of an appropriate proxy group. As such, throughout this testimony I have presented results using, (1) the "OPC Proxy Group" as determined by fellow OPC Witness, Randall Woolridge, and (2) Mr. Coyne's proxy group for FPL as referenced above. As shown within Dr. Woolridge's **Exhibit JRW-3**, Dr. Woolridge has employed a proxy group within this rate case proceeding comprised of 27 different utilities based on the end result of the utility screening process outlined within his testimony.

V. CAPITAL STRUCTURE

A. Explanation of Capital Structure

Q. WHAT IS A CAPITAL STRUCTURE AND HOW DOES IT IMPACT THE REVENUES THAT FPL IS SEEKING?

A. The term "*capital structure*" refers to the relative percentage of debt, equity, and other financial components that are used to finance a company's investments. A company's capital structure typically includes some combination of three principal financing methods.

The first method is to finance an investment with common equity, which essentially represents ownership in a company and its investments. Common equity is comprised of all investments from investors, including common stock, retained earnings, and additional paid in capital. Returns on common equity, which in part take the form of dividends to stockholders, are not tax deductible which, on a pre-tax basis alone, makes this form of financing about 21% more expensive than debt financing.

The second form of corporate financing is preferred stock, which is normally used to a much smaller degree in capital structures. Dividend payments associated with preferred stock are not tax deductible. FPL does not have any preferred stock in its capital structure.

Debt is the third major form of financing used in the corporate world. There are two basic types of corporate debt: long-term and short-term. Long-term debt is generally understood to be debt that matures in a period of more than one year. Short-term debt is debt that matures in a year or less. Long-term debt and short-term debt, both of which are "above the line" costs for tax deduction and ratemaking purposes, represent liabilities on the company's books that must be repaid prior to any common stockholders or preferred stockholders receiving a return on their investment.

Q. HOW IS A UTILITY'S TOTAL RETURN CALCULATED?

A. A utility's total return is developed by multiplying the component percentages of its capital structure, represented by the percentage ratios of the various forms of capital financing relative to the total financing on the company's books, by the cost rates associated with each form of capital and then totaling the results over all of the capital components. When these percentage ratios are applied to various cost rates, a total after-tax required rate of return is developed. Because the utility must pay dividends associated with common equity and preferred stock with after-tax funds, the post-tax returns are then converted to pre-tax required returns by grossing up the common equity and preferred stock dividends to reflect the related tax costs. The final pre-tax required return is then multiplied by the company's rate base in order to develop the amount of money that customers must pay to the utility for return on investment and tax payments associated with that investment.

Q. HOW DOES CAPITAL STRUCTURE IMPACT THIS CALCULATION?

A. Costs to consumers are greater when the utility finances a higher proportion of its rate base investment with common equity and preferred stock as opposed to long-term debt. However, long-term debt, which is first in line for repayment, imposes a contractual obligation to make fixed payments on a pre-established schedule, as opposed to common equity where no similar obligations exist.

Q. WHY SHOULD THE COMMISSION BE CONCERNED ABOUT HOW THE COMPANY FINANCES ITS RATE BASE INVESTMENT?

A. There are two reasons that the Commission should be concerned about how FPL finances its rate base investment. First, FPL's cost of common equity is higher than the cost of long-term debt, meaning that a relatively higher equity percentage translates into higher costs to FPL's customers without any corresponding improvement in quality of service. Long-term debt is a financial promise made by a company and is carried as a liability on a company's books. Common stock is ownership in the company. Due to the contingent nature of an equity investment, common stockholders require higher rates of return to compensate them for the extra risk involved in owning part of the company versus having a more senior claim against the company's assets.

The second reason the Commission should be concerned about FPL's capital structure is due to the tax treatment of debt versus common equity. Public corporations, such as NextEra (*i.e.*, the parent company of FPL), can deduct payments associated with debt financing. Corporations are not, however, allowed to deduct common stock dividend payments for tax purposes. All dividend payments must be made with after-tax funds, which are more expensive than pre-tax funds. The regulatory process allows utilities to recover reasonable and prudent expenses, including taxes, within their rates.

Accordingly, if a utility is allowed to use a capital structure for ratemaking purposes that is top-heavy in common stock, customers will be forced to cover the higher income tax burden, which can result in unjust, unreasonable, and unnecessarily high rates. Setting rates through the use of a capital structure that is weighted too heavily in common equity violates the fundamental principles of utility regulation that rates must be just and reasonable and only high enough to support the utility's provision of safe, adequate, and reliable service at a fair price.

Q. HOW DOES A UTILITY'S SELECTION OF EQUITY VERSUS DEBT IMPACT RATEPAYERS?

A. Entities in more competitive markets have a profit motive that provides an incentive for such entities to select the most efficient capitalization ratio. However, utilities operating in monopoly, rate-regulated service territories have an incentive to maximize the amount of common equity in their capital structure, to increase revenues and, correspondingly, the utility's profit. Rate-regulated utilities should only be allowed to recover in rates a revenue requirement derived from a capitalization ratio that allows the utility to provide reliable service at the least cost. Therefore, finding the right balance between debt and equity is critical.

If a utility issues more common equity and less debt for a certain project, the rates could potentially be set at an unbalanced debt to equity level. This could result in the ratepayer paying higher rates to support a capital structure that is neither prudent nor reasonable to support the company's current credit rating or the company's adequate access to the capital markets. It is also important to recognize how rate levels affect economic development. The reality in today's economy is that economic development opportunities for large loads occur in places where costs are lower. A utility with unduly high rates will, all else being equal, cause its service territory to lose out on economic development opportunities.

If, on the other hand, the utility incurs too much debt, the utility's capitalization ratios present excess financial risk to the capital markets, thereby driving up the costs required by the equity markets to compensate for the added risk. In this case, the consumer would also suffer harm because the cost it must pay the utility for accessing the capital markets is higher than it would pay using a less debt-leveraged capital structure.

One role of regulation is to balance the needs of the capital markets, including utility stockholders, with the needs of ratepayers. Either too much equity or too much debt can harm both the stockholders of the corporation, as well as the consuming public.

Q. PLEASE EXPLAIN HOW ONGOING CONSTRUCTION NEEDS ARE IMPACTING UTILITIES AND THEIR CUSTOMERS?

A. As referenced above, utilities finance construction with three primary sources of capital: retained earnings; common equity issuances; and long-term debt issuances. In an ideal situation, using retained earnings would generally be the most preferred method to finance construction for a utility because using funds from ongoing operations does not dilute common equity, as would an equity issuance, nor does it add debt leverage to the utility's balance sheet. However, in most cases, financing a large asset with only retained earnings may not be possible due to the sheer size of the plant investment. As a result, utilities undergoing large construction projects often utilize a combination of common equity or long-term debt to finance these projects. Therefore, selecting the proper ratio of equity to debt is important.

Entities in unregulated, competitive markets have a profit motive that provides an incentive for such entities to select the most efficient capitalization ratio. However, franchised electric utilities operating in a regulated, noncompetitive market have an incentive to maximize the amount of common equity in their capital structure so as to increase rates and, correspondingly, the utility's profit. Franchised electric utilities should only be allowed to recover in rates a revenue requirement derived from a capitalization ratio that allows the utility to provide reliable service at the least cost. Thus, finding the right balance between debt and equity is critical, especially if the franchised electric utility is a subsidiary of a larger holding company.

Q. PLEASE EXPLAIN THE RAMIFICATIONS OF RATES BEING SET AT AN UNBALANCED DEBT/EQUITY LEVEL.

A. If a utility issues too much common equity and not enough debt for a certain project, the customer pays higher rates to support a capital structure that is neither prudent nor reasonable. It is also important to recognize how utility rate levels affect economic development. A utility with high rates will, all else being equal, cause its service territory to lose out on economic development opportunities.

If, on the other hand, the utility incurs too much debt, the utility's capitalization ratio presents excess financial risk to the capital markets, thereby driving up the costs required by the markets to compensate them for the added risk. In this case, the customer would also lose since the cost it must pay the utility for accessing the capital markets is higher than it would pay using a less debt-leveraged capital structure.

One role of regulation is to balance the needs of the capital markets, including utility stockholders, with the needs of ratepayers. Too much equity or too much debt can harm both the stockholders of the corporation, as well as the consuming public. As such, a careful and thoughtful evaluation of the risks and related costs of various potential capitalization ratios is critical.

B. FPL's Requested Capital Structure

Q. HAVE YOU REVIEWED THE CAPITAL STRUCTURE REQUESTED BY THE COMPANY IN THIS PROCEEDING?

A. Yes, I have.

Q. WHAT CAPITAL STRUCTURE IS THE COMPANY PROPOSING IN THIS CASE?

A. FPL has proposed the following capital structure:

Table 3: FPL Requested Capital Structure and Cost Rates (All Capital Sources)[24]

Source of Capital	Ratio	Cost Rate
Long-Term Debt	31.37%	3.61%
Preferred Stock	0.00%	0.00%

[24] FPL MFR, Schedule D-1a (without RSAM).

Customer Deposits	0.82%	2.03%
Short-Term Debt	1.18%	0.94%
Deferred Income Taxes	10.63%	0.00%
FAS 109 Deferred Income Tax	6.08%	0.00%
Investment Tax Credits	1.89%	8.38%
Common Equity	48.03%	11.50%
Total	**100.00%**	

However, note that the capital structure includes all sources of capital for use by FPL to finance rate base operations. When investor-only sources of capital are included, the above capital structure translates into the following:

Table 4: FPL's Requested Cost of Capital (Investor-Only Sources)

Component	Capital Structure Ratio (%)		Cost Rate (%)	Weighted Cost Rate (%)
	a[25]	**c = a / b**	**d**[26]	**= c * d**
Long-Term Debt	31.37%	38.93%	3.61%	1.41%
Short-Term Debt	1.18%	1.46%	0.94%	0.01%
Common Equity	48.03%	59.61%	11.50%	6.85%
Total Rx	80.89%[27] **b**	100.00%[28]		8.27%

Q. **DO YOU BELIEVE THAT REVENUE REQUIREMENTS IN THIS CASE SHOULD BE SET USING A 59.60% COMMON EQUITY RATIO?**

A. No. I believe that FPL's requested equity ratio is excessively high and should not be approved by the Commission for the following reasons:

1. The requested equity ratio of 59.60% is out-of-line when compared to the other electric utilities within:
    a. OPC's proxy group;
    b. Mr. Coyne's proxy group and utility operating company comparison group for FPL;

[25] *Id.*
[26] *Id.*
[27] Represents all sources of capital.
[28] Represents only investor sources of capital.

c. Allowed equity ratios from state regulators around the United States;

d. Non-regulated subsidiaries of NextEra Energy (FPL's parent company); and

e. NextEra Energy itself.

C. Capital Structure Comparison

Q. WHAT IS THE AVERAGE COMMON EQUITY RATIO OF THE COMPANIES IN OPC'S PROXY GROUP?

A. **Table 5** below shows the average common equity ratio (investor sources only) of each utility in OPC's electric comparable company proxy group as sourced from *Value Line*.

Table 5: OPC's Proxy Group's Equity Ratios[29]

Company	2019 Ratio	2020 Ratio	2021E* Ratio	2022E* Ratio	2024E* - 2026E* Ratio
Amer Elec Power	43.90%	41.50%	41.00%	41.50%	40.00%
ALLETE	61.40%	59.00%	58.00%	59.00%	57.00%
Alliant Energy	48.50%	45.70%	46.00%	46.00%	46.00%
Ameren Corp	47.10%	44.30%	45.50%	46.00%	49.00%
Avista Corp	50.60%	49.60%	52.50%	49.50%	50.50%
CMS Energy Corp	29.40%	28.60%	30.00%	32.00%	33.00%
Consol Edison	49.30%	48.00%	47.50%	48.50%	49.00%
Dominion Energy	45.00%	39.50%	39.00%	41.50%	41.00%
Duke Energy	44.10%	44.40%	44.00%	44.00%	43.50%
Edison Int'l	39.90%	39.50%	37.50%	37.00%	36.00%
Entergy Corp	37.10%	33.70%	34.00%	35.00%	35.50%
Evergy Inc.	49.40%	48.70%	49.00%	48.50%	48.50%
Eversource Energy	46.60%	47.10%	46.50%	46.00%	44.50%
Hawaiian Elec	54.60%	52.70%	55.00%	53.50%	52.50%
IDACORP Inc	58.70%	56.10%	55.50%	55.50%	51.00%
MGE Energy Inc	62.00%	64.50%	64.50%	63.50%	61.00%
NextEra Energy	49.60%	46.50%	46.50%	46.50%	47.00%
NorthWestern Corp	47.50%	47.20%	47.50%	50.00%	50.50%
OGE Energy	56.40%	51.00%	51.50%	51.50%	51.00%
Otter Tail Corp	53.10%	58.20%	55.50%	53.50%	59.50%
Pinnacle West Capital	52.90%	47.20%	44.50%	45.00%	42.00%
Portland General	48.70%	46.40%	46.50%	46.50%	47.50%
PPL Corp	38.50%	38.30%	39.50%	41.50%	41.50%
Sempra Energy	43.40%	44.80%	49.50%	49.00%	49.00%
Southern Co	39.50%	38.10%	38.00%	39.00%	39.00%
WEC Energy Group	47.40%	47.10%	45.00%	45.50%	47.00%
Xcel Energy	43.20%	42.60%	42.00%	42.50%	42.00%
AVERAGE	**47.70%**	**46.31%**	**46.35%**	**46.57%**	**46.44%**

As can be seen in the table above, the average common equity ratio for OPC's proxy group in 2019 was 47.70%, their average common equity ratio in 2020 was 46.31%, their average expected common equity ratio for 2021 is 46.35%, their average expected common equity ratio for 2022 is 46.57%, and their average expected common equity ratio from 2024 – 2026 is 46.44%, with each of these data points

[29] *The Value Line Investment Survey*: 3/12/2021 (Electric Utilities Central), 4/23/2021 (Electric Utilities West), 5/14/2021 (Electric Utilities East).

for the proxy group being *Value Line*. Notably, each of these group-average metrics is well below the Company's requested equity ratio in this case of 59.60%.

Q. WHAT IS THE AVERAGE COMMON EQUITY RATIO OF THE COMPANIES IN WITNESS COYNE'S PROXY GROUP?

A. **Table 6** below shows the average common equity ratio of each utility in Witness Coyne's electric comparable company proxy group as sourced from *Value Line*.

Table 6: Mr. Coyne's Proxy Group's Equity Ratios[30]

Company	2019 Ratio	2020 Ratio	2021E* Ratio	2022E* Ratio	2023E* - 2025E* Ratio
Amer Elec Power	43.90%	41.50%	41.00%	41.50%	40.00%
ALLETE	61.40%	59.00%	58.00%	59.00%	57.00%
Alliant Energy	48.50%	45.70%	46.00%	46.00%	46.00%
Ameren Corp	47.10%	44.30%	45.50%	46.00%	49.00%
Duke Energy	44.10%	44.40%	44.00%	44.00%	43.50%
Edison Int'l	39.90%	39.50%	37.50%	37.00%	36.00%
Entergy Corp	37.10%	33.70%	34.00%	35.00%	35.50%
Evergy Inc.	49.40%	48.70%	49.00%	48.50%	48.50%
Hawaiian Elec	54.60%	52.70%	55.00%	53.50%	52.50%
IDACORP Inc	58.70%	56.10%	55.50%	55.50%	51.00%
OGE Energy	56.40%	51.00%	51.50%	51.50%	51.00%
Pinnacle West Capital	52.90%	47.20%	44.50%	45.00%	42.00%
Portland General	48.70%	46.40%	46.50%	46.50%	47.50%
Xcel Energy	43.20%	42.60%	42.00%	42.50%	42.00%
AVERAGE	**48.99%**	**46.63%**	**46.43%**	**46.54%**	**45.82%**

As can be seen in the table above, the average common equity ratio for Mr. Coyne's proxy group in 2019 was 48.99%, their average common equity ratio in 2020 was 46.63%, their average expected common equity ratio for 2021 is 46.43%, their average expected common equity ratio for 2022 is 46.54%, and their average expected common equity ratio from 2023 – 2025 is 45.82%, with each of these

[30] *The Value Line Investment Survey*: 3/12/2021 (Electric Utilities Central), 4/23/2021 (Electric Utilities West), 5/14/2021 (Electric Utilities East).

proxy group data points provided by *Value Line*. Each of these group-average metrics is also well below the Company's requested equity ratio in this case of 59.60%.

Q. WHAT IS YOUR REASONING BEHIND UTILIZING BOTH HISTORICAL AND PROJECTED COMMON EQUITY RATIOS TO SUPPORT YOUR RECOMMENDATION?

A. Mr. Coyne utilized historical common equity ratios for both his comparable company proxy group and a group of utility operating companies, for the eight quarters ended Q3 2020 as shown in Mr. Coyne's **Exhibit JMC-11**. However, in **Table 5** and **Table 6** above, I presented both historical and forecasted common equity ratios for both OPC's proxy group and Mr. Coyne's own proxy group that includes data that would support my recommendation of a 55% common equity ratio.

I have long maintained that the most accurate projection of future common equity ratios are the current common equity ratios, which is why I included the actual common equity ratios for 2019 and 2020 within **Table 5** and **Table 6**. In my view, most projections tend to set common equity at too high a value given the inherent subjectivity and erratic nature of where common equity ratios may actually fall out in future years, especially in a period as far into the future as a 2023 – 2025 (which is presented in Mr. Coyne's testimony) or a 2024 – 2026 projection (which is presented herein). This is additionally relevant given the current economic climate where the COVID-19 pandemic has increased the uncertainty associated with projected future common equity ratios.

However, I have also included various projected common equity ratios for the numerous periods provided by *Value Line* as shown in these tables above. Additionally, in discussion below, I have included the national averages for allowed common equity ratios for electric utilities over the previous 15-year period. I have provided each of these various data points simply to show that regardless of whichever metric one uses, the 59.60% equity ratio requested by the Company in this rate case proceeding is not reasonable.

Q. DOES THE INFORMATION PROVIDED BY WITNESS COYNE IN HIS DIRECT TESTIMONY SUPPORT THE EQUITY RATIO OF 59.60% REQUESTED BY THE COMPANY FOR ITS CAPITAL STRUCTURE?

A. No, this information does not support the Company's request of 59.60%. Within Mr. Coyne's direct testimony he made the following assertion:

> I calculated the weighted average capital structures for each of the proxy group operating companies on a quarterly basis for the eight quarters through Q3 2020. Exhibit JMC-11 shows that the Company's proposed common equity ratio of approximately 59.6 percent on a financial basis (48.04 percent on a regulatory basis in the Test Year) is the upper end of the range of actual common equity ratios of 46.91 percent to 58.95 percent for the operating companies held by the proxy group over this period.[31]

I note that I sourced the actual and projected common equity ratios for OPC's proxy group and Mr. Coyne's proxy group included in **Table 5** and **Table 6** above from *Value Line*. Whereas the actual common equity ratio results for the eight quarters

[31] Witness Coyne's Direct Testimony, page 85: lines 4 – 10.

ended Q3 2020 found in Mr. Coyne's **Exhibit JMC-11** for his proxy group and his group of utility operating companies have been sourced from *SNL Financial / S&P Global*.

From a quantitative perspective, Mr. Coyne determined that the Company's equity ratio request of 59.60% was reasonable simply based on a comparison of this value to the average actual common equity ratio results for his 14-company comparable proxy group for the eight quarters ended Q3 2020 as shown Mr. Coyne's **Exhibit JMC-11**. As noted within the selection above from Mr. Coyne's direct testimony, the range of the common equity ratios included within his proxy group for the eight quarters ended Q3 2020 was 46.91% – 58.95%. In reference to this range, Mr. Coyne claimed that the Company's recommendation of 59.60% is "…the upper end of the range of actual common equity ratios of 46.91 percent to 58.95 percent for the operating companies held by the proxy group over this period."[32] However, this recommendation of 59.60% isn't simply in the "upper end" of this range, this recommendation of 59.60% exceeds the absolute high end of this range by 65-basis points.

Additionally, the only support Mr. Coyne provided for the Company's request of 59.60% per his written direct testimony is that the common equity ratio range for Mr. Coyne's chosen proxy group over the eight quarters ended Q3 2020 ranged from 46.91% – 58.95%. Upon simply inspecting Mr. Coyne's **Exhibit JMC-11**, one finds that the average of all the common equity ratios over this same time period for the entirety of Mr. Coyne's own proxy group is 52.44%.[33] However,

[32] *Id*.
[33] Witness Coyne's Exhibit JMC-11.

Mr. Coyne notably did not feel the need to mention this overall 52.44% average for his proxy group. Simply put, this 52.44% average value sourced from an exhibit to Mr. Coyne's own direct testimony exemplifies how excessive the Company's 59.60% request is in this rate case proceeding.

Additionally, within **Exhibit JMC-11**, Mr. Coyne provided the common equity ratio for a group of utility operating companies for the same eight quarters ending with the Q3 2020 time period. However, Mr. Coyne does not provide the average common equity ratio value for this group of utility operating companies that he included within his testimony and **Exhibit JMC-11**. The average value of the common equity ratios presented within the second table of Mr. Coyne's Capital Structure Analysis shown in **Exhibit JMC-11** is <u>51.65%</u>.

Mr. Coyne proceeded to note that "[b]ased on the analysis presented in Exhibit JMC-11, my conclusion is that FPL's proposed financial capital structure of 59.6 percent common equity and 40.4 percent debt is reasonable."[34] However, I simply do not believe an analyst can credibly reconcile a claim that the Company's requested common equity percentage of 59.60% is "reasonable" when it exceeds that analyst's own proxy group's average common equity percentage, over a period chosen by that same analyst, by <u>716-basis points</u> (*i.e.*, 59.60% – 52.44%), and exceeds the average common equity ratio of that analyst's group of utility operating companies by <u>795-basis points</u> (*i.e.*, 59.60% – 51.65%).

[34] Witness Coyne's Direct Testimony, page 85: lines 13 – 15.

Q. DID WITNESS COYNE PRESENT ANY ADDITIONAL INFORMATION IN SUPPORT OF THE COMPANY'S REQUESTED CAPITAL STRUCTURE INCLUSIVE OF A 59.60% EQUITY RATIO?

A. The only other piece of information that Mr. Coyne offered to support this inflated equity ratio of 59.60% was the following:

> As noted by FPL witness Barrett, the Company has maintained this same equity ratio for more than two decades, and it is an essential component of FPL's financial policies enabling access to capital on favorable terms in a variety of market circumstances. This capital structure represents management's decisions on how best to finance its operations.[35]

In reference to the above selection from Mr. Coyne's testimony, I do not find it appropriate to merely rely on the fact that the Company's equity ratio has not materially changed in over two decades as support for why its equity ratio should be deemed reasonable. Just because the equity ratio was once approved at such a level does not inherently indicate its reasonableness, especially in a time when common equity ratios have been declining as I exhibited in the tables above.

Each of the values I included in this testimony demonstrate that quantitatively, a 59.60% equity ratio request is far in excess of the average actual and average projected common equity ratios across any of the proxy groups used in this proceeding, and also far in excess of any of the national average of allowed common equity ratios across the country, as shown below. Mr. Coyne suggested that an equity ratio being set at this level "…represents management's decisions on how best to finance its operations."[36] In contrast, I would contend that the Company

[35] Witness Coyne's Direct Testimony, page 85: lines 19 – 23.
[36] *Id*.

should instead be allowed an equity ratio that does not continue to place an undue and excess amount of financial burden upon its consumers.

Q. WHAT EVIDENCE DID WITNESS BARRETT PROVIDE TO SUPPORT THE COMPANY'S REQUESTED 59.60% EQUITY RATIO?

A. Mr. Robert E. Barrett (FPL VP of Finance) provided the following statement to support FPL requested equity ratio:

> FPL has maintained its equity ratio generally around the 59-60 percent level for more than two decades, and this has been an important underpinning of the overall financial strength that has served customers well.[37]

In this portion of his testimony, Witness Barrett contends that allowing FPL an equity ratio at the continued level of 59-60 percent has provided FPL the financial strength to serve customers well.

Given the Company's position, I asked for support from the Company for this position in OPC's Third Request for Production of Documents, Request No. 73, Mr. Barrett then provided the associated response:

> <u>QUESTION</u>:
> Cost of Capitol:
> In reference to the 59.60% equity ratio requested by FPL in this case, Witness Barrett noted on page 45, lines 21-22, through page 46, lines 1-2, that "FPL has maintained its equity ratio generally around the 59-60 percent level for more than two decades, and this has been an important underpinning of the overall financial strength that has served customers well." Can Witness Barrett please provide a cost/benefit analysis showing exactly how FPL's equity ratio being set at a level in the 59-60 percent level for the last two decades has provided FPL the ability to reliably serve customers well and at the lowest cost possible to these customers.

[37] Witness Barrett's Direct Testimony, page 45: lines 21 – 22, and page 46: lines 1 – 2.

> RESPONSE:
> The question's predicate is incorrect in its express or implied assumption that service at the "lowest cost possible" is either the required or appropriate standard for service. The value of service provided is a function of more than just cost. Nevertheless, for references to FPL's achievements in cost efficiency over the last two decades while it has maintained an equity ratio around 59-60%, please refer to the testimony of FPL witnesses Reed, Barrett and Bores, among others. Mr. Barrett's statement is based on the overall value of FPL's service over this period of time based on a combination of factors including reliability, customer service, emissions reductions, and bills. FPL's performance and the value it delivers for customers has not hinged on this single factor, but rather on a number of factors and management initiatives. Accordingly, FPL has no responsive documents.[38]

I note that Mr. Barrett's response above is essentially non-responsive. As part of the Company's support for an equity ratio in the 59-60 percent range, Mr. Barrett made the assertion that setting the equity ratio at such a level in the past allowed FPL to serve its customers well. I asked the question whether the Company had performed any analysis that would show how their service levels would change should they be allowed an equity ratio beneath 59.60% and the Company was unable to provide any such analysis to support this assertion.

Q. DOES MR. BARRETT INCLUDE ANYTHING ELSE IN HIS TESTIMONY IN REFERENCE TO THE COMPANY'S REQUESTED EQUITY RATIO?

A. Somewhat. Lastly, Mr. Barrett noted the following:

> [I]nvestors expect FPL's capital structure to be relatively stable over time and to reflect the unique risk profile and underlying financial policies of the company. FPL has maintained the current equity ratio for more than twenty years, and it is foundational to FPL's current

[38] OPC's Third Request for Production of Documents, Request No. 73.

> credit rating, financial strength and flexibility to raise capital when needed and to provide customers with long-term benefits.[39]

I agree that in a hypothetical scenario, investors like to see stable capital structures over time. However, that does not inherently mean that FPL should be allowed a 59.60% equity ratio in this proceeding. A 59.60% equity ratio is out of line with each and every metric provided within this testimony and would continue to place an undue financial burden on FPL's consumers. This is especially notable in the current climate when unemployment numbers have been higher than previous annual averages given the havoc that the COVID-19 pandemic has played on financial markets over the last year. FPL has not provided any evidence that it cannot continue to thrive financially, while also providing a comparable level of service to its customers, should they be allowed an equity ratio below 59.60% in this current proceeding and more in line with national averages.

Q. WHAT IS THE AVERAGE COMMON EQUITY RATIO GRANTED BY UTILITY REGULATORS FOR ELECTRIC UTILITIES ACROSS THE UNITED STATES?

A. I have sourced the average common equity ratio values granted by utility regulators for electric utilities from across the country from *S&P Global*. In my research, I found that four states included within the overall average value of electric utilities across the country report their allowed common equity ratios on an all capital sources basis (*i.e.,* Long Term Debt, Short Term Debt, Common Equity, Preferred Stock, Customer Deposits, Deferred Income Taxes, Investment Tax Credits). As

[39] Witness Barrett's Direct Testimony, page 46: lines 13 – 18.

such, I have removed these four states (*i.e.,* Arkansas, Florida, Indiana and Michigan) from these numbers to ensure that each of the states included in this average report their allowed common equity ratio percentages only on investor-only sources of capital (*i.e.*, Long Term Debt, Short Term Debt, Common Equity). I wanted to remove these four states from the overall average to ensure that this represented an appropriate comparison given that FPL's requested equity ratio in this case of 59.60% is based solely off of investor-only sources of capital.

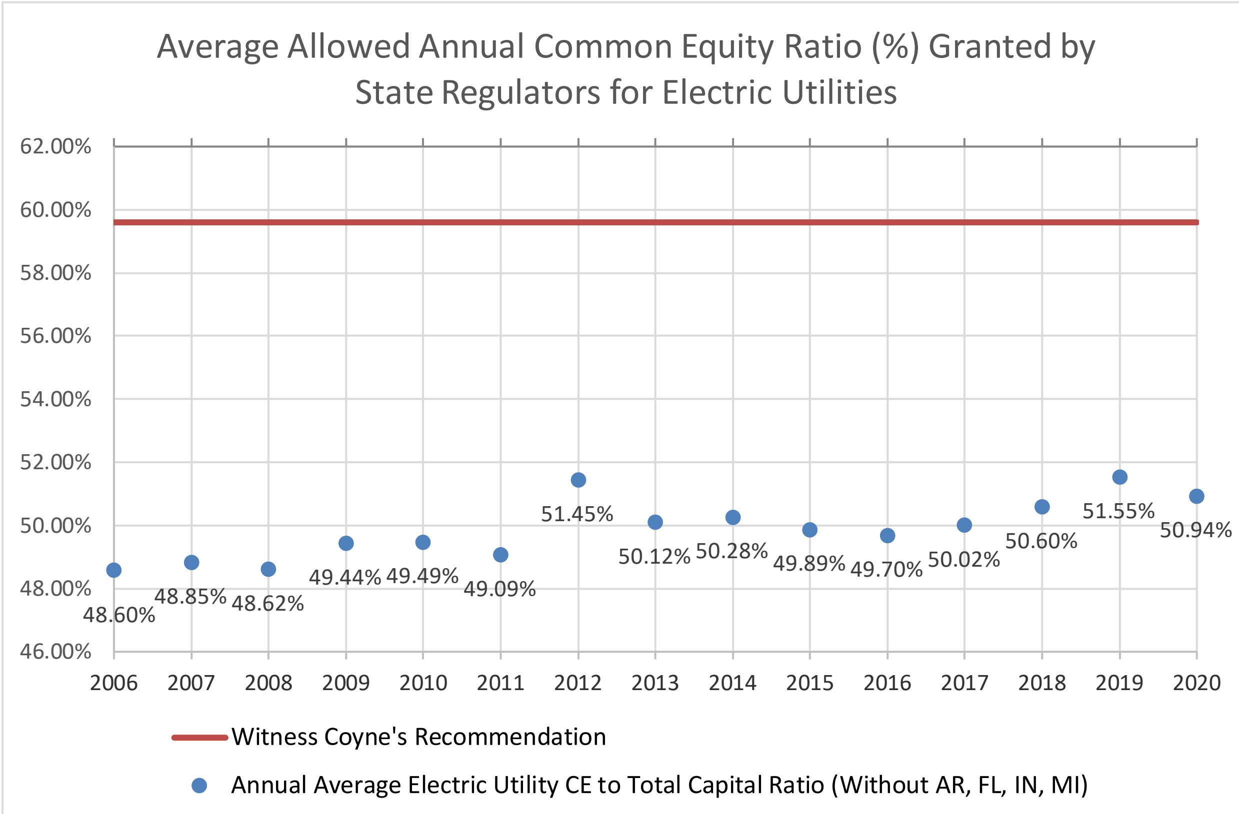
The resulting average common equity ratio granted by regulators for electric utilities for all states on an investor sources basis 2020 was 50.94%.[40]

Q. WHAT COMMON EQUITY RATIOS HAVE STATE REGULATORS ACROSS THE UNITED STATES GRANTED TO ELECTRIC UTILITIES OVER THE PAST 15 YEARS?

A. State regulators have been quite consistent in their rulings in electric cases for allowed common equity ratios based on investor sources of capital over the past 15 years. From 2006 through 2020, common equity ratios have ranged from 48.60% to 51.55%, with an average of 49.91%. If one were to evaluate this data over the previous 12 years, the average common equity ratio over this period is 50.21%, the average ratio over the previous 10 years is 51.36%, and the average ratio over the previous 8 years is 50.39%. In **Chart 4** below I have presented the average annual common equity ratio granted by state regulators for each year over the past 15 years.

[40] S&P Global Market Intelligence Rate Case Statistics; Date Range: 15 Years; Service Type: Electric; Chart Items: Common Equity to Total Capital, Return on Equity; **Date Accessed**: May 24, 2021.

Chart 4: Common Equity Ratio Granted by State Regulators (2006 – 2020)[41]



Q. HOW DOES THE 59.60% EQUITY RATIO REQUESTED BY FPL COMPARE TO THE EQUITY RATIO OF NEXTERA ENERGY'S NON-REGULATED SUBSIDIARIES?

A. Per the data included within page 2 of **Schedule D-2** of FPL's MFR's in this case, the unregulated subsidiaries/companies of NextEra Energy averaged equity ratios of 44.3% for 2019 and 39.5% for 2020 on a Non-Regulated Operations Combined basis.

[41] *Id*.

Q. HOW DOES THE 59.60% EQUITY RATIO REQUESTED BY FPL COMPARE TO THE EQUITY RATIO OF NEXTERA ENERGY?

A. Per the data included within page 2 of **Schedule D-2** of FPL's MFR's in this case, NextEra Energy had a common equity ratio that *declined* from 46.5% for 2019 to 43.2% for 2020 on an NEE Consolidated basis.

Q. WHY IS THE COMMON EQUITY RATIO OF NEXTERA'S UNREGULATED SUBSIDIARY GROUPING CONSIDERABLY LOWER THAN THE EQUITY RATIO REQUESTED BY FPL?

A. The unregulated subsidiary companies of NextEra, and sister companies of FPL, are leveraging their operations to the maximum extent possible knowing that NextEra has a strong cash flow stream from the regulated operations of FPL, which is protected from retail competition due to regulation in Florida. These strong cash flow payments go to the parent company from FPL and in turn, can support the unregulated operations of NextEra Energy.

Q. IS THE CAPITAL STRUCTURE REQUESTED BY FPL IN THIS CASE DRIVEN BY THE MARKETPLACE?

A. No, it is not. Any capital structure for a regulated utility in a parent/subsidiary structure is hypothetical because NextEra Energy has pre-determined the capital structure ratios. The Company has stated that the capital structure on which the Company wants revenue requirements to be determined in this case is one with a 59.60% equity ratio. If the marketplace was driving the capital structure of the various NextEra subsidiaries, the competition-facing non-regulated subsidiaries would have an equity ratio much higher than 39.5%, and FPL would have an equity ratio much lower than the 59.60% requested in this case.

D. OPC Recommendation and Impact on FPL Consumers

Q. PLEASE SUMMARIZE YOUR FINDINGS IN REGARD TO THE REQUESTED EQUITY RATIO IN THIS CASE RELATIVE TO THE EQUITY RATIO OF OTHER ELECTRIC UTILITIES.

A. I have provided a summary in **Table 7** below of how FPL's request in this case compares to each of the metrics previously outlined above within the **Subsection C**: "Capital Structure Comparison".

Table 7: Common Equity Ratio Comparison

FPL Eq Ratio Request per Witness Coyne	59.60%
Per **Exhibit JMC-11**:	
Q4 2018 – Q3 2020 Witness Coyne Proxy Group Actual Eq Ratio Average	52.44%
Q4 2018 – Q3 2020 Witness Coyne Utility Operating Companies Actual Eq Ratio Average	51.65%
Per **Table 5**:	
2019 OPC Proxy Group Actual Eq Ratio Average	47.70%
2020 OPC Proxy Group Actual Eq Ratio Average	46.31%
2021 OPC Proxy Group Expected Eq Ratio Average	46.35%
2022 OPC Proxy Group Expected Eq Ratio Average	46.57%
2024 – 2026 OPC Proxy Group Expected Eq Ratio Average	46.44%
Per **Table 6**:	
2019 Witness Coyne Proxy Group Actual Eq Ratio Average	48.99%
2020 Witness Coyne Proxy Group Actual Eq Ratio Average	46.63%
2021 Witness Coyne Proxy Group Expected Eq Ratio Average	46.43%
2022 Witness Coyne Proxy Group Expected Eq Ratio Average	46.54%
2023 – 2025 Witness Coyne Proxy Group Expected Eq Ratio Average	45.82%
2020 Average Annual Regulator Granted Eq Ratio (Above)	50.94%
2006 – 2020 Average Annual Regulator Granted Eq Ratio (Above)	49.91%
NextEra Non-Regulated Subsidiaries Eq Ratio (Above)	39.50%
NextEra's Eq Ratio (Above)	43.20%

As shown in the table above, each of the metrics is closer to a 50.00% equity ratio rather than the 59.60% equity ratio requested by the Company.

Q. GIVEN THAT THE MOST ELECTRIC UTILITY EQUITY RATIOS ARE CLOSER TO 50.00%, DO YOU BELIEVE THAT THE CAPITAL STRUCTURE PROPOSED BY FPL IN THIS CASE IS APPROPRIATE FOR RATEMAKING PURPOSES?

A. No, it is not. The requested capital structure for FPL is not reasonable for ratemaking purposes. Nothing in the make-up of FPL suggests that it requires a high equity ratio in the range that they are requesting than any of the companies within the comparable company proxy groups. Indeed, some of the companies included within the proxy groups are involved in a wider array of business activities that involve more business risk than a utility's production and delivery of generation and distribution of electricity within its monopoly service territory. As such, if anything, the financial risk (as represented by the equity ratio) of the comparable company proxy group should be higher, not lower, than a traditional electric utility such as FPL. Customers of FPL should not pay higher rates associated with a capital structure that consists of so much common equity which, as previously discussed, is more expensive than debt.

Q. WHO HAS THE MOST TO GAIN IF THE COMMISSION ALLOWED FPL TO USE A 59.60% EQUITY RATIO IN ITS CAPITAL STRUCTURE FOR RATEMAKING PURPOSES?

A. If a 59.60% equity ratio is allowed, the shareholders of FPL would continue to gain at the expense of consumers. If rates are set using an equity ratio of 59.60%, rather than an equity ratio of 50.00%, FPL shareholders will receive approximately an additional $511 million annually. Additionally, if rates are set using an equity ratio of 59.60%, rather than an equity ratio of 55.00%, FPL shareholders will receive approximately an additional $245 million annually. Each of these scenarios is outlined within **Exhibit KWO-1**.

Ultimately, FPL's customers will come out on the "losing" side as this the difference in rates in each of the two scenarios outlined above would result in these amounts essentially being transferred to FPL's shareholders (NextEra Energy).

Q. WHAT IS THE SIGNIFICANCE OF THE FACT THAT FPL'S REQUESTED EQUITY RATIO IS MUCH MORE EXPENSIVE THAN OTHER REGULATED UTILITIES AS OUTLINED WITHIN THIS TESTIMONY?

A. As stated previously, common equity is much more expensive than long-term debt. As such, captive ratepayers of FPL are being tasked with supporting an equity ratio that cannot be justified or explained based on any empirical data or quantitative reasoning. The ratepayers of other utilities with lower equity ratios are not being forced to support such excessively inflated equity ratios. Within pre-filed direct testimony, none of the Company witnesses attempted to demonstrate quantitatively how such an excessive equity ratio could be justified, and certainly did not present any evidence that any other utility comparable to FPL had been allowed an equity ratio above 59%.

Q. WHAT WOULD BE THE IMPACT ON RATES IF THE COMMISSION EMPLOYED A CAPITAL STRUCTURE THAT CONTAINED 50% COMMON EQUITY?

A. As mentioned above, if FPL utilized a capital structure that instead consisted of 50% common equity, the revenue requirement in this case would be approximately $511 million lower on an annual basis than the requested revenue requested in this case.

On a per customer residential basis, FPL's request amounts to an additional $50 per year of higher costs for the typical residential customer using 1,000 kWhs per year. The full details of these calculations can be seen in **Exhibit KWO-1,** but the primary calculations can be seen in **Table 8** below.

Table 8: Impact of FPL's Requested 59.60% Equity Ratio Versus a 50% Ratio

FPL Requested Pre-Tax Cost of Capital	8.73%	
OPC Recommended Pre-Tax Cost of Capital	7.81%	
Difference	0.92%	
Rate Base	$55,392,402	($000s)
Impact	$510,842	($000s)
Retail Sales (kWhs)	122,096,501,415	
Impact per kWh	$0.00418	
Annual Impact to Res Cust Using 1,000 kWhs/mo.	$50.21	

Florida also has many senior citizens that live on fixed incomes, as well as low-income customers. An additional $50 per year per year for a usage of 1000 kWh per month, for this single element of the rate case is in my view, a subsidy FPL is asking this Commission to approve from captive consumers to NextEra to support its ventures into unregulated activities.

Q. WHAT WOULD BE THE IMPACT OF A CAPITAL STRUCTURE OF 50% COMMON EQUITY TO A LARGE INDUSTRIAL CUSTOMER?

A. An industrial consumer with a load of 10 MW and an 85% load factor would spend approximately an additional $312,000 per year. The calculations for this cost increase can be seen in the table below as sourced from **Exhibit KWO-1**:

Table 9: Cost Impact for 10 MW Industrial Consumer

Load size	10,000	kW, **a**
Hours in year	8,760	**B**
Load factor	85.0%	**C**
Impact per kWh	$0.00418	**D**
Annual Impact to Ind Cust	$ 311,535	**= a * b * c * d**

Q. ARE YOU RECOMMENDING A 50% COMMON EQUITY RATIO IN THIS CASE?

A. No. I understand FPL has received a 59.6% equity ratio from this Commission for quite some time. Given that history, and given above-stated facts that show FPL's requested common equity ratio is more than excessive for Florida consumers, I am recommending the Commission employ the gradualism concept and grant FPL an equity ratio of 55% from investor-supplied sources in this case. This recommendation should not alarm the investment community as, clearly, the requested 59.6% equity ratio is considerably higher than every other comparison of regulated common equity ratios as I have demonstrated above. The movement from a 59.6% equity ratio to a 55.0% equity ratio is a gradual change that should give confidence to the investment community in that it represents a slow movement towards a more reasonable and balanced capital structure on which the Commission sets rates.

Converting the recommended 55% equity ratio to the all-sources capital structure of FPL yields the following recommendation, while continuing to use FPL's 11.50% ROE request for strict comparison purposes, as shown in **Exhibit KWO-1**.

Table 10: Capital Structure and Cost Rates Under a 55% Common Equity Ratio Scenario

Source of Capital	Ratio (%)	Cost Rate (%)	Post-Tax Cost Rate
Long-Term Debt	34.95%	3.61%	1.26%
Short-Term Debt	1.31%	0.94%	0.01%
Common Equity	44.32%	11.50%	5.10%
Preferred Stock	0.00%	0.00%	0.00%
Customer Deposits	0.82%	2.03%	0.02%
Deferred Income Taxes	10.63%	0.00%	0.00%
FAS 109 Deferred Income Tax	6.08%	0.00%	0.00%
Investment Tax Credits	1.89%	8.38%	0.16%
Total	**100.00%**		**6.55%**

Q. **WHAT IS THE IMPACT ON THE REVENUE REQUIREMENT BASED ON YOUR RECOMMENDATION TO USE A 55% EQUITY RATIO FOR INVESTOR-SOURCES OF CAPITAL FOR SETTING RATES IN THIS PROCEEDING?**

A. **Table 11** below replicates **Table 8** from above, but with the difference being that **Table 11** shows the results if the equity ratio were to be set at 55%. This calculation can also be found in **Exhibit KWO-1**.

Table 11: Impact of OPC Recommended 55% Equity Ratio

FPL Requested Pre-Tax Cost of Capital	8.73%	
OPC Recommended Pre-Tax Cost of Capital	8.29%	
Difference	0.44%	
Rate Base (without RSAM)	$55,392,402	($000s)
Impact	$244,927	($000s)
Retail Sales (kWhs)	122,096,501,415	
Impact per kWh	$0.00201	
Annual Impact to Cust Using 1,000 kWhs/mo.	$24.07	

As demonstrated in the table above, establishing FPL's equity ratio at 55% for ratemaking purposes reduces the customer's bill impact by $24.07 per year for a usage of 1000 kWh per month. As stated earlier, in the current economy every dollar saved is important to customers who are trying to get back on their feet.

Q. HOW DO YOU THINK FPL WILL RESPOND TO YOUR ARGUMENT THAT FPL'S REQUESTED EQUITY RATIO IS UNFAIR AND TOO EXPENSIVE FOR CUSTOMERS CAPTIVE TO FPL?

A. I expect FPL to argue that its bond and credit ratings will be negatively impacted by any decision to allow an equity ratio under 59.60%, or anything close to my recommendation of 55%, for calculating revenue requirements in this case.

Q. DO YOU BELIEVE FPL'S CREDIT RATING WOULD BE DOWNGRADED IF THE COMMISSION DID NOT AWARD THE UTILITY WITH ITS REQUESTED 59.60% EQUITY RATIO?

A. Credit rating agencies examine a myriad of different factors such as business risk and financial risk when determining the credit rating of a utility. It is difficult for anyone to know with any certainty if FPL would suffer a downgrade in its credit rating based solely on the Commission authorizing a capital structure with a lower equity ratio than 59.60% for ratemaking purposes. However, for the sake of argument, I have calculated the cost of a one-notch downgrade in the FPL credit rating so that we can compare the cost of such a downgrade to the higher revenue requirement sought by FPL in this case.

Q. PLEASE EXPLAIN HOW YOU CALCULATED THE COST OF A POTENTIAL DOWNGRADE IN FPL'S CREDIT RATING?

A. The higher interest costs that would accompany a downgrade are a product of the amount of debt the Company would issue in the future, multiplied by the credit spread that is accompanied by the difference in spreads between bond ratings. So, the first step in the process is determining the amount of debt FPL may issue in the future. To do so, within **Exhibit KWO-3**, I first examined FPL's year-end 2020 total asset amount and compared that total asset amount to the estimated total asset amounts from the MFR's for 2021 and 2022.

For subsequent years post-2023, I assumed an annual growth rate of 10%, which is well above the 2.3% gross domestic product ("GDP") forecast of the Congressional Budget Office ("CBO")[42] to provide estimated capital expenditures for FPL over the next 10 years. I next developed a series of possible annual debt needs for the next 10 years, assuming 50% of capital expenditure needs are financed with debt, that will be required to fund the various FPL investments (**Exhibit KWO-3**, page 1). I also developed a series of possible annual debt needs for the

[42] Congressional Budget Office, "The Budget and Economic Outlook: 2019 to 2029", page 22, available at: https://www.cbo.gov/system/files/2019-03/54918-Outlook-3.pdf.

next 10 years, assuming 45% of capital expenditure needs are financed with debt that will be required to fund the various FPL investments (**Exhibit KWO-3**, page 2).

Having taken those steps, I examined yield spreads to determine the increase in interest costs associated with the possible one-notch downgrade. The period I examined was from January 2011 through December 2020. The bond yield spread information came from the Mergent Bond Record and listed the average yields on Public Utility “A” rated bonds and Public Utility “Baa” bonds. From January 2011 through December 2020, the average yield spread between these bonds was 55-basis points (*i.e.,* 0.55%). For calendar year 2020, the yield spread was 38-basis points, which equated to 0.38% in interest rate costs. I used 46-basis points (*i.e.,* 0.46%) as a conservative estimate of the future yield spread as it was approximately the average of 55-basis points and 38-basis points. However, this spread represented a 3-notch difference, whereas any potential (unlikely) credit downgrade for FPL would be, in my opinion, a maximum downgrade of only one notch (*i.e.,* A2 to A3). As a result, for the purposes of this analysis, I assumed the yield spread change would be approximately 15-basis points (*i.e.,* 46-basis points divided by 3, rounded to 15-basis points). The details of this analysis can be seen in **Exhibit KWO-2**, attached to my testimony.

In **Exhibit KWO-3**, I provided calculations showing the effect of the higher interest costs as applied to future capital expenditures financed with debt. As can be seen in that exhibit, the first-year difference in interest costs (2021) under the 50% common equity ratio scenario and the 55% common equity recommendation are approximately $3.8 million and $3.4 million, respectively. By way of comparison, the difference in revenue requirements for consumers due to FPL's higher equity ratio, would cost consumers approximately $511 million in 2022 under the 50% common equity ratio scenario or $245 million in 2022 under the 55% common equity recommendation.

By asking for a 59.6% common equity ratio which results in higher rates than would otherwise result from using a significantly more reasonable 55% common equity, FPL is essentially seeking a subsidy from its customers that allows FPL to invest these unjustified funds from these excessive rates into FPL's non-regulated activities.

VI. <u>DEBT</u>

Q. WHAT ARE THE DEBT RATIOS TO BE USED WITHIN YOUR CAPITAL STRUCTURE RECOMMENDATION?

A. As shown in **Table 2** above, within my recommended capital structure for investor-only sources of capital, I have included a long-term debt ratio of 43.37%, a short-term debt ratio of 1.63%, and a common equity ratio of 55.00%.

With regard to the split of the remaining 45.00% of the capital structure, I have recommended a long-term debt ratio of 43.37% and a short-term debt ratio of 1.63%. This calculation was based upon the short-term and long-term debt ratios included within **Table 1** above. If one were to take the total debt percentage and then calculate the respective long-term and short-term debt component ratios out of the total debt percentage, the associated percentages are a long-term debt ratio of 43.37% and a short-term debt ratio of 1.63%. This calculation is also shown in **Exhibit KWO-1**.

Q. WHAT IS THE COMPANY'S COST OF DEBT USED IN THIS PROCEEDING?

A. As shown in **Schedule D-1a** to the Company's MFR's, the long-term debt cost rate is 3.61% and the short-term debt cost rate is 0.94%.

The short-term cost of debt is developed based upon **Schedule D-3** within the Company's MFR's. Per Mr. Barrett's testimony, the short-term debt cost rate was developed based upon the "…forward Intercontinental London Interbank

Exchange Offered Rate ("LIBOR") curve for its short-term debt cost projections."[43] The long-term cost of debt is developed based upon **Schedule D-4a** within the Company's MFR's.

Q. DO YOU AGREE WITH THE COMPANY'S PROPOSED 3.61% LONG-TERM COST OF DEBT AND 0.94% SHORT-TERM COST OF DEBT?

A. Yes, I do. Based on my evaluation of the cost of debt supporting documents provided by the Company, I agree with the Company's proposed long-term debt cost rate of 3.61% and short-term debt cost rate of 0.94%.

[43] Witness Barrett's Direct Testimony, page 47: lines 2 – 3.

VII. FPL INCENTIVE MECHANISM

Q. WHAT IS THE INCENTIVE MECHANISM THAT FPL IS PROPOSING?

A. As described in FPL Witness Forrest's Direct Testimony, FPL proposes to continue the Economy Sales, Economy Purchase Savings, Natural Gas Optimization, and Other Incentive Mechanisms. In addition, FPL proposes to update the asset optimization incentive mechanism by reducing the number of thresholds from four threshold levels to three threshold levels and update the variable power plant O&M.[44] FPL also is asking to expand the asset optimization incentive mechanism to include all fuel sources and monetize Renewable Energy Credits ("RECs").[45]

Q. DO YOU RECOMMEND THAT THE COMMISSION APPROVE FPL'S PROPOSED INCENTIVE MECHANISM?

A. No, I cannot recommend wholesale approval of FPL's proposed incentive mechanism at this time. While we have been able to examine activities approved by the Commission in the original pilot program, and have fairly good understanding of how they would work in the future, there is not sufficient information to understanding how the requested expansions of the incentive mechanism would work or if it would benefit customers.

[44] Witness Forrest's Direct Testimony, page 17: lines 5-6.
[45] Witness Forrest's Direct Testimony, page 16: lines 17-18.

VIII. RESPONSE TO COMPANY WITNESS BARRETT

Q. DO YOU AGREE WITH MR. BARRETT'S CLAIM THAT THE RECENT MARKET VOLATILITY HAS MADE IT IMPERATIVE THAT FPL MAINTAIN ITS INCREDIBLY HIGH EQUITY RATIO IN ITS PROPOSED CAPITAL STRUCTURE?

A. I disagree with Mr. Barrett's claim that utilities with only very high credit ratings were able to access the credit markets during the COVID-19 crisis. Specifically, Mr. Barrett stated:

> The three leading credit rating agencies, S&P Global Ratings ("S&P"), Moody's Investors Service ("Moody's"), and Fitch Ratings ("Fitch"), each issue short-term CP ratings. Those CP ratings, in order of credit quality from high to low are tier-1, tier-2 and tier-3. During periods of extreme volatility and market uncertainty, generally only the tier-1 rated CP issuers such as FPL are able to maintain access, and when lower rated issuers are able to issue CP, those issuances are at significantly elevated rates as illustrated below.[46]

Mr. Barrett went on to state:

> However, even for strong tier-1 issuers like FPL, liquidity was extremely limited. While FPL typically issues CP to meet liquidity for a minimum of thirty days, during this extremely constrained period FPL often was only able to issue CP overnight, meaning each day brought concerns about liquidity for the next day. Only FPL's strong financial position, particularly its strong capital structure and credit ratings, enabled it to have continued access to CP markets while other lesser credits were completely essentially shut out of the market.[47]

[46] Witness Barrett's Direct Testimony, page 16.
[47] *Id.*, page 17.

There are two fundamental problems with Mr. Barrett's testimony on this matter. First, his conclusions are contradicted by an *S&P Global* article, "*US Utilities Access to Capital with Billions in Debt Offerings,"* [48] published April 2, 2020, that discussed how utilities across the country were able to raise capital with relative ease during the COVID-19 crisis that I previously cited in this testimony in **Section II**: Current State of the Financial Markets. The article noted FPL when it stated:

> Several utilities, including Xcel Energy and NextEra Energy Inc. subsidiary Florida Power & Light Co., which issued $1.1 billion in first mortgage bonds,are "using the opportunity to take advantage of attractive borrowing costs, so there does not appear to be an inability to access capital," they said.
>
> "Utilities are reporting that recent deals have been significantly (7x) oversubscribed, highlighting that the capital markets are open for investment grade-rated utilities," the analysts wrote. "At the same time, we have also observed some utility companies that have fully drawn their bank lines as a precaution to provide them with liquidity in the event that marketsseize up," such as Duke Energy Corp. and American Electric Power Co. Inc.[49]

The strength of utilities did not limited access to the credit markets. On February 3, 2021, *S&P Global* also stated:

> The S&P 500 utility sector has "far and away" experienced the least impact from earnings revisions since Feb. 28, the corporate bond research firm found. Despite market turmoil and the ongoing economic downturn, analysts have only cut earnings per share expectations for stocks in the utility sector by an average 1% for 2020 and 2021, according to CreditSights.[50]

Furthermore, in regard to FPL, itself, *Moody's* stated the following in regard to the Company's exposure to risk with relation to the COVID-19 pandemic:

[48] *S&P Global Market Intelligence*, April 20, 2020 "US Utilities Demonstrated Access to Capital with Billions in Debt Offerings."
[49] *Id*.
[50] *S&P Global Market Intelligence*, February 3, 2021, "Utility Sector "Far and Away" least impacted by EPS Estimate Cuts."

> We expect FPL to be relatively resilient to recessionary pressures related to the coronavirus because of its rate regulated business model, very large residential customer base, and timely cost recovery mechanisms. Nevertheless, we are watching for electricity usage declines, utility bill payment delinquency, and the regulatory response to counter these effects on earnings and cash flow. As events related to the coronavirus continue, we are taking into consideration a wider range of potential outcomes, including more severe downside scenarios. The effects of the pandemic could result in financial metrics that are weaker than expected; however, we see these issues as temporary and not reflective of the long-term financial profile or credit quality of FPL.[51]

The above statement shows that Mr. Barrett's concerns about utilities not being able to access the capital markets during COVID-19 is simply not an accurate one.

Q. DO YOU HAVE ANY CONCERNS ABOUT MR. BARRETT'S POSITION THAT THERE IS NO "SOUND REASON" THE COMPANY'S REQUESTED EQUITY RATIO OF 59.6% SHOULD NOT BE APPROVED?[52]

A. Yes, I do. As I discussed previously, I have provided several "sound reasons" for denying the Company's requested equity ratio of 59.60% based on quantifiable historical data and associated forecasted projections. Specifically, FPL's 59.60% requested equity ratio results in higher rates for the typical FPL customer and these customers are not receiving any benefit from the unnecessarily high equity ratio. As I have shown above, the high equity ratio was not needed to access the capital markets during the COVID-19 pandemic.

[51] *Moody's* Credit Opinion, Florida Power & Light, August 25, 2020, page 1.
[52] Witness Barrett's Direct Testimony, pages 11 – 12.

In his testimony, Mr. Barrett claims that there is no “sound reason” for adopting any capital structure other than the one that he was recommending in this case. However, FPL has the burden of proving the need for their excessive 59.60% equity ratio request. As I previously referenced, Mr. Barrett essentially provided a non-response answer when he was asked to provide a cost/benefit analysis showing how FPL’s equity ratio being set a level in the 59-60 percent level for the last two decades provided FPL the ability to reliably serve customers well and at the lowest cost possible to these customers.[53]

Unless there is any evidence to the contrary that the Company has declined to provide, the Company has not performed any type of study that would help them to determine its optimal or appropriate capital structure. Instead, in comparison to a more reasonable 55% equity ratio, the Company is simply continuing to ask Florida ratepayers to pay approximately $245 million per year in higher rates (refer to **Table 11** above) to support a regulatory capital structure that is grossly excessive by any standard. I do not believe the Florida Public Service Commission should allow the Company to arbitrarily set a high equity ratio that punishes consumers $245 million per year without the Company providing any evidence to support its continued request of this 59.60% equity ratio.

[53] OPC’s Third Request for Production of Documents, Request No. 73.

Q. DO YOU AGREE WITH WITNESS BARRETT THAT FPL'S RATES ARE LOWER THAN THE NATIONAL AVERAGE?

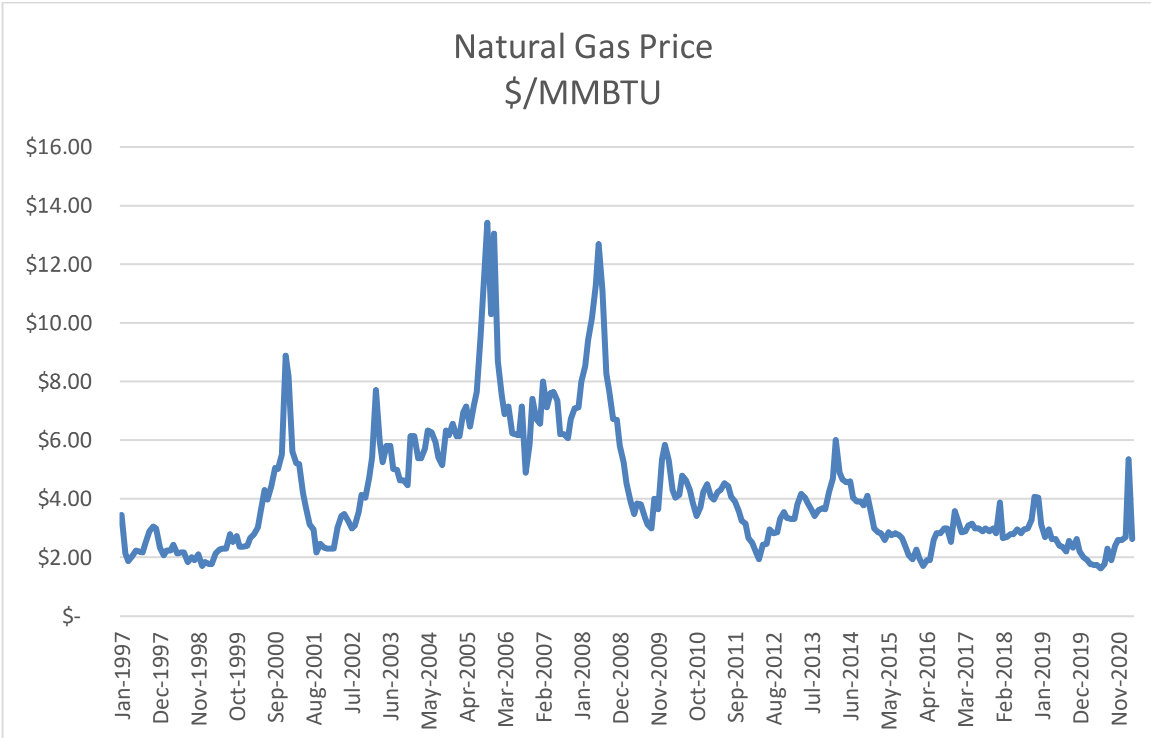
A. Yes, I agree that FPL's rates are lower than the national average. However, I believe Mr. Barrett should have examined this topic more deeply and explained exactly why FPL's rates are below the national average.

FPL's electric rates have not always been lower than the national average. As can be seen in **Chart 3** below, prior to the development of natural gas fracking, FPL's rates were higher than the national average. However, in the 2008/2009 timeframe, fracking was implemented on more of a widespread basis, and FPL's rates began to fall soon thereafter relative to the national average. I believe the primary reason for FPL's relatively low rates is because fracking has driven down the price of natural gas and the United States now has an abundance of natural gas which has driven down the price of the fuel.

Q. PLEASE DESCRIBE HOW FRACKING HAS LED TO LOWER ELECTRIC RATES FOR FPL.

A. FPL, as well as the state's two other investor-owned electric utilities, Duke Energy Florida ("DEF") and Tampa Electric Company ("TECO"), obtain a large amount of their generation output from natural gas-fired electric generators. As such, FPL, DEF, and TECO are all heavily dependent upon pricing as found in the natural gas markets. Prior to 2008, most of the natural gas that served electric utilities in the southeast was obtained in the Gulf of Mexico and transported up the eastern seaboard by various interstate pipelines. However, in response to the high natural gas prices from 2000 to early 2008, the "shale revolution", which was driven by hydraulic fracturing ("fracking"), drove natural gas prices downward tremendously.[54] **Chart 2** below shows the price of natural gas dating back to 1997.

Chart 2: Historical Natural Gas Prices



As can be seen above, natural gas was seemingly abundant and cheap in the late 1990s through 2000. However, in the winter of 2000/2001, gas prices went up to over $8 per MMBTU and, essentially, provided a foreshadowing of the volatility that was to come in the natural gas markets.

In 2008 and 2009, fracking was more widely implemented and, as shown above, prices fell as the new supplies were brought into the marketplace. One of the greatest beneficiaries of the lower cost natural gas were electric utilities with a

[54] https://www.api.org/news-policy-and-issues/blog/2016/03/29/americas-fracking-energy-progress

heavy reliance on natural gas. **Table 12** below shows the percentage of natural gas generation for the Florida investor-owned electric utilities as compared to the national average.

Table 12: Percentage of Electric Energy Produced Using Natural Gas

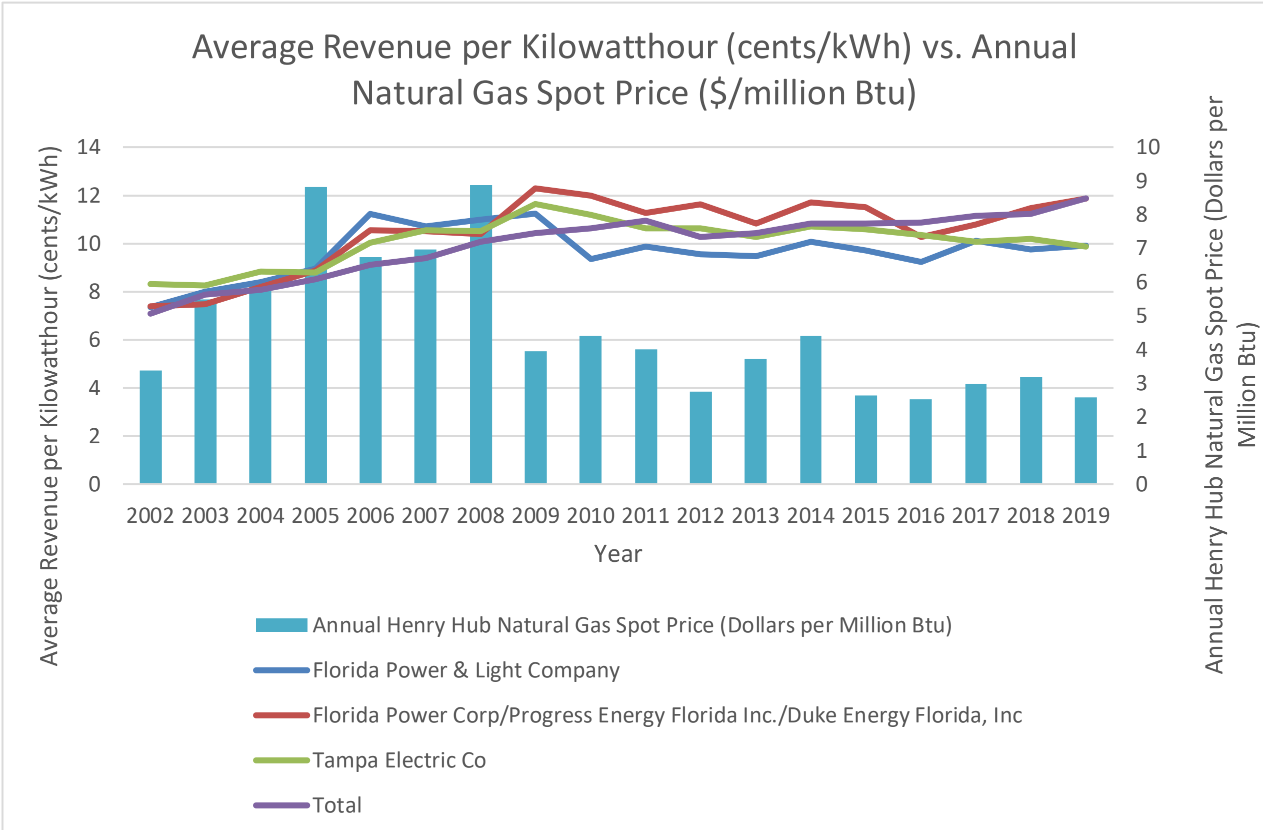
Utility	Natural Gas Generation as a Percentage of Total Generation
FPL	71.8%[55]
Duke Florida	87.9%[56]
Tampa Electric	76.6%[57]
National Average	39.0%[58]

As can be seen in the above table, all the Florida utilities rely quite heavily on natural gas, particularly in comparison to the national average. As such, any change in the price of natural gas will have a dramatic impact on prices for electricity produced by any of the three major Florida utilities.

The evolution of fracking and lower natural gas prices can be seen vividly for the Florida utilities in **Chart 3** below. This chart is a double y-axis chart that shows historical electric prices for the Florida utilities and the national average on the right y-axis and historical natural gas prices on the left y-axis.

[55] Raw data sourced from *S&P Global*.
[56] *Id*.
[57] *Id*.
[58] https://www.eia.gov/energyexplained/natural-gas/use-of-natural-gas.php#:~:text=Natural%20gas%20accounted%20for%2038,by%20all%20sectors%20in%202019

Chart 3: Florida Electric Costs Compared to National Average and Natural Gas Prices[59]



FPL's cost line is in blue in the above chart. As can be seen in this chart, the average cost of service from FPL fell sharply in 2009 as the effect of lower natural gas prices began to show up in the electric rates offered by the utility. Specifically, the average electric cost of FPL, as compared to the national average from the period of 2006 through 2010, can be seen in the table below.

[59] https://www.eia.gov/dnav/ng/hist/rngwhhdm.htm - Annual data from the Energy Information Association

Table 13: Average Revenue per MWH

Year	Avg. Rev per MWH[60]	Annual Gas Price at Henry Hub[61]
2006	$11.22	$6.75
2007	$10.70	$6.98
2008	$10.99	$8.86
2009	$11.24	$3.95
2010	$9.37	$4.39

The table above provides the numerical data that was shown in **Chart 3** and show that FPL's electric rates fell dramatically when the price of natural gas fell due to fracking and an abundant new supply of natural gas hitting the United States market.

Q. ARE THERE REASONS WHY THE COSTS FOR FPL COULD BE LOWER THAN DUKE ENERGY FLORIDA AND TAMPA ELECTRIC, ALTHOUGH BOTH UTILITIES HAVE A HIGHER AMOUNT OF NATURAL GAS GENERATION?

A. Yes. One possible explanation may simply be a function of timing. The current regulated utility model is comprised of historical fixed costs and current variable costs. Historical fixed costs are, generally, for assets such as electric generating plants as well as transmission and distribution lines. Recovery of these costs take place over time – 30 years in many cases. As a result, some utilities will, generically, have higher/lower costs than other utilities based on decisions made at the time the assets were constructed and put into service. Without knowing the

[60] https://www.eia.gov/electricity/sales_revenue_price/
[61] https://www.eia.gov/dnav/ng/hist/rngwhhdm.htm

exact timing of each major plant investment on the Duke Energy Florida, Tampa Electric, and FPL systems, it is possible that timing of the plant investments had a lot to do with current rates. This possibility cannot be discounted in the rush to make claims about superior performance.

Q. WHY DO YOU BELIEVE THE LINK BETWEEN NATURAL GAS AND FPL'S RATES ARE IMPORTANT FOR THIS COMMISSION TO UNDERSTAND?

A. I have two reasons for bringing this information to the Commission's attention.

First, Mr. Barrett seemingly wants to credit himself and his employer, FPL, for the fact that its rates are below the national average. However, I believe that natural gas prices, over which FPL has no control, has been a significant driver to lower electric prices for FPL. As such, it would appear as though FPL and its customers simply were fortunate with the dramatic turn in natural gas prices. If natural gas prices had remained as high as $8.86 per MMBTU, I do not believe FPL's rates would now be below the national average.

Secondly, while natural gas prices moving forward appear to be relatively stable, one should also recognize the risk inherent in such forecasts. With the government's new administration advocating for cleaner energy, a federally mandated carbon tax is certainly possible in the next two to four years. Such a tax would disproportionately impact Florida due to the prevalence of natural gas generation in the generation portfolios of the State's utilities.

In addition, with the movement away from coal to natural gas-fired generation and permitting for new interstate pipelines facing mounting legal obstacles, capacity on interstate pipelines continues to tighten. Such supply/demand imbalances may drive up the price of natural gas thereby also driving up the price of electricity in the State.

If the price of natural gas reverses course and increases, FPL's rates may, once again, be above the national average.

Q. HOW DO YOU RESPOND TO MR. BARRETT'S COMMENTS ABOUT FPL'S LOW NON-FUEL O&M COSTS?

A. As was the case with Mr. Barrett's claim of low FPL rates, I believe he should have provided more of an explanation as to exactly <u>why</u> FPL's non-fuel O&M costs are lower than comparable utilities. In **Exhibit KWO-4**, I have provided a table that compares non-fuel O&M costs per MWH for companies for which I could obtain the necessary data from *S&P Global*. There are a total of 46 companies for which the data was available.

Exhibit KWO-4 shows that companies with a high portion of natural gas in the total portfolio mix generally have lower non-fuel O&M costs. One potential explanation is that natural gas plants require fewer employees, for example, than do coal plants. *The Wall Street Journal* noticed how fewer employees were needed at natural gas plants when it stated the following in its January 16, 2018 edition:

> "Natural gas, solar and wind are all less job intensive for ongoing operations," says Philip Jordan, a vice president at the Carlsbad, Calif., based group, which has analyzed worker data for the U.S. Energy Department.

> Coal plants require people and machines to unload the combustible rocks, sort them into piles and prepare them to be pulverized into a fine mist, which is then blown into boilers. Once the coal is burned, the resulting ash needs to be collected and disposed.
>
> Natural gas is typically delivered straight to power plants by pipeline—no unloading required. It combusts completely, so it doesn't need people or machines to handle the residue.[62]

So, while Mr. Barrett is correct in that FPL does have low non-fuel O&M costs, he has not mentioned that FPL's generation mix is a major reason for the lower costs.

[62] *The Wall Street Journal*, Jan. 16, 2018.

IX. SUMMARY

Q. MR. O'DONNELL, PLEASE SUMMARIZE YOUR TESTIMONY.

A. FPL's requested rate increase in this case is excessive, unnecessary, and burdensome on the ratepayers of Florida. My specific recommendations in this case are as follows:

- FPL's requested capital structure is unnecessarily expensive to consumers in Florida. Relative to a 50% common equity ratio, Florida consumers are being asked to pay an additional $511 million per year for the excessive capital structure requested by FPL in this case. This $511 million cost equates to an annual average cost increase of approximately $50 to the typical residential consumer and $312,000 (**Exhibit KWO-1** page 1) for a typical industrial consumer;
- Relative to the OPC recommendation of a 55% common equity ratio, Florida consumers are being asked to pay an additional $245 million per year for the excessive capital structure requested by FPL in this case. This $245 million cost equates to an annual average cost increase of approximately $24 to the typical residential consumer and $149,000 (**Exhibit KWO-1** page 2) for a typical industrial consumer;
- The proper capital structure using investor-only sources of capital in this proceeding is 43.37% long-term debt, 1.63% short-term debt, and 55.00% common equity; and
- Mr. Barrett's remarks regarding FPL's relatively low electric rates and low O&M expenses can be misleading as to the underlying cause for the lower

costs. The reality of the situation is that FPL's low costs can, largely, be explained by the fact that the Company sources a very large amount of its generation mix from natural gas fired electric plants that, due to the advent of fracking and lower gas prices, have allowed the Company to offer rates below the national average, have allowed the Company to operate at relatively low O&M costs per MWH produced.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

Kevin W. O'Donnell, CFA

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Kevin W. O'Donnell, is the founder of Nova Energy Consultants, Inc. in Cary, NC. Mr. O'Donnell's academic credentials include a B.S. in Civil Engineering - Construction Option from North Carolina State University as well as a MBA in Finance from Florida State University. Mr. O'Donnell is also a Chartered Financial Analyst (CFA).

Mr. O'Donnell has over thirty-four years of experience working in the electric, natural gas, and water/sewer industries. He is very active in municipal power projects and has assisted numerous southeastern U.S. municipalities cut their wholesale cost of power by as much as 67%. On Dec. 12, 1998, ***The Wilson Daily Times*** made the following statement about O'Donnell.

> **Although we were skeptical of O'Donnell's efforts at first, he has shown that he can deliver on promises to cut electrical rates.**

Mr. O'Donnell has completed close to 30 wholesale power projects for municipal and university-owned electric systems throughout North and South Carolina. In May of 1996 Mr. O'Donnell testified before the U.S. House of Representatives, Committee on Commerce, Subcommittee on Energy and Power regarding the restructuring of the electric utility industry.

Mr. O'Donnell has appeared as an expert witness in over 110 regulatory proceedings before the North Carolina Utilities Commission, the South Carolina Public Service Commission, the Virginia Corporation Commission, the Minnesota Public Service Commission, the New Jersey Board of Public Utilities, the Colorado Public Service Commission, the Wisconsin Public Service Commission, the Maryland Public Service Commission, the District of Columbia Public Service Commission, the Pennsylvania Public Utility Commission, the Indiana Public Utility Commission, the California Public Service Commission, and the Florida Public Service Commission. His area of expertise has included rate design, cost of service, rate of return, capital structure, asset valuation analyses, fuel adjustments, merger transactions, holding company applications, as well as numerous other accounting, financial, and utility rate-related issues.

Mr. O'Donnell is the author of the following two articles: "Aggregating Municipal Loads: The Future is Today" which was published in the Oct. 1, 1995 edition of *Public Utilities Fortnightly;* and "Worth the Wait, But Still at Risk" which was published in the May 1, 2000 edition of *Public Utilities Fortnightly*. Mr. O'Donnell is also the co-author of "Small Towns, Big Rate Cuts" which was published in the January, 1997 edition of *Energy Buyers Guide*. All of these articles discuss how rural electric systems can use the wholesale power markets to procure wholesale power supplies.

Regulatory Cases of Kevin W. O'Donnell, CFA
Nova Energy Consultants, Inc.

Year	Name of Applicant	State Jusrisdiction	Docket No.	Client/ Employer	Case Issues
1985	Public Service Company of NC	NC	G-5, Sub 200	Public Staff of NCUC	Return on equity, capital structure
1985	Piedmont Natural Gas Company	NC	G-9, Sub 251	Public Staff of NCUC	Return on equity, capital structure
1986	General Telephone of the South	NC	P-19, Sub 207	Public Staff of NCUC	Return on equity, capital structure
1987	Public Service Company of NC	NC	G-5, Sub 207	Public Staff of NCUC	Return on equity, capital structure
1988	Piedmont Natural Gas Company	NC	G-9, Sub 278	Public Staff of NCUC	Return on equity, capital structure
1989	Public Service Company of NC	NC	G-5, Sub 246	Public Staff of NCUC	Return on equity, capital structure
1990	North Carolina Power	NC	E-22, Sub 314	Public Staff of NCUC	Return on equity, capital structure
1991	Duke Energy	NC	E-7, Sub 487	Public Staff of NCUC	Return on equity, capital structure
1991	North Carolina Natural Gas	NC	G-21, Sub 306	Public Staff of NCUC	Natural gas expansion fund
1991	North Carolina Natural Gas	NC	G-21, Sub 307	Public Staff of NCUC	Natural gas expansion fund
1991	Penn & Southern Gas Company	NC	G-3, Sub 186	Public Staff of NCUC	Return on equity, capital structure
1995	North Carolina Natural Gas	NC	G-21, Sub 334	Carolina Utility Customers Assoc.	Return on equity, capital structure, rate design, cost of service
1995	Carolina Power & Light Company	NC	E-2, Sub 680	Carolina Utility Customers Assoc.	Fuel adjustment proceeding
1995	Duke Power	NC	E-7, Sub 559	Carolina Utility Customers Assoc.	Fuel adjustment proceeding
1996	Piedmont Natural Gas Company	NC	G-9, Sub 378	Carolina Utility Customers Assoc.	Return on equity, capital structure, rate design, cost of service
1996	Piedmont Natural Gas Company	NC	G-9, Sub 382	Carolina Utility Customers Assoc.	Return on equity, capital structure, rate design, cost of service
1996	Public Service Company of NC	NC	G-5, Sub 356	Carolina Utility Customers Assoc.	Return on equity, capital structure, rate design, cost of service
1996	Cardinal Extension Company	NC	G-39, Sub 0	Carolina Utility Customers Assoc.	Capital structure, cost of capital
1997	Public Service Company of NC	NC	G-5, Sub 327	Carolina Utility Customers Assoc.	Return on equity, capital structure, rate design, cost of service
1998	Public Service Company of NC	NC	G-5, Sub 386	Carolina Utility Customers Assoc.	Return on equity, capital structure, rate design, cost of service
1998	Public Service Company of NC	NC	G-5, Sub 386	Carolina Utility Customers Assoc.	Natural gas transporation rates
1999	Public Service Company of NC/SCANA Corp	NC	G-5, Sub 400	Carolina Utility Customers Assoc.	Merger case
1999	Public Service Company of NC/SCANA Corp	NC	G-43	Carolina Utility Customers Assoc.	Merger Case
1999	Carolina Power & Light Company	NC	E-2, Sub 753	Carolina Utility Customers Assoc.	Holding company application
1999	Carolina Power & Light Company	NC	G-21, Sub 387	Carolina Utility Customers Assoc.	Holding company application
1999	Carolina Power & Light Company	NC	P-708, Sub 5	Carolina Utility Customers Assoc.	Holding company application
2000	Piedmont Natural Gas Company	NC	G-9, Sub 428	Carolina Utility Customers Assoc.	Return on equity, capital structure, rate design, cost of service
2000	NUI Corporation	NC	G-3, Sub 224	Carolina Utility Customers Assoc.	Holding company application
2000	NUI Corporation/Virginia Gas Company	NC	G-3, Sub 232	Carolina Utility Customers Assoc.	Merger application
2001	Duke Power	NC	E-7, Sub 685	Carolina Utility Customers Assoc.	Emission allowances and environmental compliance costs
2001	NUI Corporation	NC	G-3, Sub 235	Carolina Utility Customers Assoc.	Tariff change request.
2001	Carolina Power & Light Company/Progress E	NC	E-2, Sub 778	Carolina Utility Customers Assoc.	Asset transfer case
2001	Duke Power	NC	E-7, Sub 694	Carolina Utility Customers Assoc.	Restructuring application
2002	Piedmont Natural Gas Company	NC	G-9, Sub 461	Carolina Utility Customers Assoc.	Return on equity, capital structure, rate design, cost of service
2002	Cardinal Pipeline Company	NC	G-39, Sub 4	Carolina Utility Customers Assoc.	Cost of capital, capital structure
2002	South Carolina Public Service Commission	SC	2002-63-G	South Carolina Energy Users Committee	Rate of return, accounting, rate design, cost of service
2003	Piedmont Natural Gas/North Carolina Natura	NC	G-9, Sub 470	Carolina Utility Customers Assoc.	Merger application
2003	Piedmont Natural Gas/North Carolina Natura	NC	G-9, Sub 430	Carolina Utility Customers Assoc.	Merger application
2003	Piedmont Natural Gas/North Carolina Natura	NC	E-2, Sub 825	Carolina Utility Customers Assoc.	Merger application
2003	Carolina Power & Light Company	NC	E-2, Sub 833	Carolina Utility Customers Assoc.	Fuel case
2004	South Carolina Electric & Gas	SC	2004-178-E	South Carolina Energy Users Committee	Return on equity, capital structure, rate design, cost of service
2005	Carolina Power & Light Company	NC	E-2, Sub 868	Carolina Utility Customers Assoc.	Fuel case
2005	Piedmont Natural Gas Company	NC	G-9, Sub 499	Carolina Utility Customers Assoc.	Return on equity, capital structure, rate design, cost of service
2005	South Carolina Electric & Gas	SC	2005-2-E	South Carolina Energy Users Committee	Fuel application
2005	Carolina Power & Light Company	SC	2006-1-E	South Carolina Energy Users Committee	Fuel application
2006	IRP in North Carolina	NC	E-100, Sub 103	Carolina Utility Customers Assoc.	Submitted rebuttal testimony in investigation of IRP in NC.
2006	Piedmont Natural Gas Company	NC	G-9, Sub 519	Carolina Utility Customers Assoc.	Creditworthiness issue
2006	Public Service Company of NC	NC	G-5, Sub 481	Carolina Utility Customers Assoc.	Return on equity, capital structure, rate design, cost of service
2006	Duke Power	NC	E-7, 751	Carolina Utility Customers Assoc.	App to share net revenues from certain wholesale pwr trans

Regulatory Cases of Kevin W. O'Donnell, CFA
Nova Energy Consultants, Inc.

Year	Name of Applicant	State Jusrisdiction	Docket No.	Client/ Employer	Case Issues
2006	South Carolina Electric & Gas	SC	2006-192-E	South Carolina Energy Users Committee	Fuel application
2007	Duke Power	NC	E-7, Sub 790	Carolina Utility Customers Assoc.	Application to construct generation
2007	South Carolina Electric & Gas	SC	2007-229-E	South Carolina Energy Users Committee	Rate of return, accounting, rate design, cost of service
2008	South Carolina Electric & Gas	SC	2008-196-E	South Carolina Energy Users Committee	Base load review act proceeding
2009	Western Carolina University	NC	E-35, Sub 37	Western Carolina University	Rate of return, accounting, rate design, cost of service
2009	Duke Power	NC	E-7, Sub 909	Carolina Utility Customers Assoc.	Cost of service, rate design, return on equity, capital structure
2009	South Carolina Electric & Gas	SC	2009-261-E	South Carolina Energy Users Committee	DSM/EE rate filing
2009	Duke Power	SC	2009-226-E	South Carolina Energy Users Committee	Return on equity, capital structure, rate design, cost of service
2009	Tampa Electric	FL	080317-EI	Florida Retail Federation	Return on equity, capital structure
2010	Duke Power	SC	2010-3-E	South Carolina Energy Users Committee	Fuel application - assisted in settlement
2010	South Carolina Electric & Gas	SC	2009-489-E	South Carolina Energy Users Committee	Return on equity, capital structure, rate design, cost of service
2010	Virginia Power	VA	PUE-2010-00006	Mead Westvaco	Rate design
2011	Duke Energy	SC	2011-20-E	South Carolina Energy Users Committee	Nuclear construction financing
2011	Northern States Power	MN	E002/GR-10-971	Xcel Large Industrials	Return on equity, capital structure
2011	Virginia Power	VA	PUE-2011-0027	Mead Westvaco	Capital structure, revenue requirement
2011	Duke Energy	NC	E-7, Sub 989	Carolina Utility Customers Assoc.	Accounting, cost of service, rate design, ROE, capital structure
2011	Duke Energy	SC	2011-271-E	South Carolina Energy Users Committee	Accounting, cost of service, rate design, ROE, capital structure
2011	Dominion Virginia Power	VA	PUE-2011-00073	Mead Westvaco	Rate design
2012	Town of Smithfield/Partners Equity Group	NC	ES-160, Sub 0	Partners Equity Group	Rate design, asset valuation
2012	Florida Power & Light	FL	120015-EI	Florida Office of Public Counsel	Capital structure
2012	South Carolina Electric & Gas	SC	2012-218-E	South Carolina Energy Users Committee	Accounting, cost of service, rate design, ROE, capital structure
2013	Progress Energy Carolinas	NC	E-2, Sub 1023	Carolina Utility Customers Assoc.	Accounting, cost of service, rate design, ROE, capital structure
2013	Duke Energy Carolinas	NC	E-7, Sub 1026	Carolina Utility Customers Assoc.	Rate design
2013	Jersey Central Power & Light	NJ	BPU ER12111052	Gerdau Ameristeel	Return on equity, capital structure
2013	Duke Energy Carolinas	SC	2013-59-E	South Carolina Energy Users Committee	Accounting, cost of service, rate design, ROE, capital structure
2013	Tampa Electric	FL	130040-EI	Florida Office of Public Counsel	Capital structure and financial integrity
2013	Piedmont Natural Gas	NC	G-9, Sub 631	Carolina Utility Customers Assoc.	Accounting, cost of service, rate design, ROE, capital structure
2014	Dominion Virginia Power	VA	PUE-2014-00033	Mead Westvaco	Recoverable fuel costs, hedging strategies
2014	Public Service Company of Colorado	CO	14AL-0660E	Colorado Healthcare Electric Coordinating Council	Return on equity, capital structure
2015	WEC Acquisition of Integrys	WI	9400-YO-100	Staff of Wisconsin Public Service Commission	Merger analysis
2015	Dominion Virginia Power	VA	PUE-2015-00027	Federal Executive Agencies	Return on equity
2015	South Carolina Electric & Gas	SC	2015-103-E	South Carolina Energy Users Committee	Return on equity
2015	Western Carolina University	NC	E-35, Sub 45	Western Carolina University	Accounting, cost of service, rate design, ROE, capital structure
2016	Sandpiper Energy	MD	9410	Maryland Office of People's Counsel	Return on equity, capital structure
2016	Washington Gas Light	DC	FC 1137	Washington, DC Office of People's Counsel	Return on equity, capital structure
2016	Florida Power & Light	FL	160021-EI	Florida Office of Public Counsel	Capital Structure
2016	Jersey Central Power & Light	NJ	EM15060733	NJ Division of Rate Counsel	Asset valuation
2016	Rockland Electric Company	NJ	ER16050428	NJ Division of Rate Counsel	Rate design
2016	Dominon NC Power	NC	E-22, Sub 532	Carolina Utility Customers Assoc.	Accounting, cost of service, rate design, ROE, capital structure
2017	Potomac Electric Power	DC	FC 1139	Healthcare Council of the National Capitol Area (HCNCA)	ROE and capital structure
2017	Columbia Gas of Maryland	MD	FC 9447	Maryland Office of People's Counsel	ROE and capital structure
2017	Washington Gas Light	DC	FC 1142	Washington, DC Office of People's Counsel	Merger analysis
2017	Duke Energy Progress	NC	E-2, Sub 1142	Carolina Utility Customers Assoc.	Accounting, cost of service, rate design, ROE, capital structure
2018	Public Service Electric & Gas	NJ	GR17070776	NJ Division of Rate Counsel	ROE and capital structure
2018	Duke Energy Carolinas	NC	E-7, Sub 1146	Carolina Utility Customers Assoc.	Accounting, cost of service, rate design, ROE, capital structure
2018	Elkton Gas/SJI	MD	FC 9475	Maryland Office of People's Counsel	Merger analysis
2018	Entergy Texas	TX	PUC 48371	Entergy Texas Cities	ROE
2018	Duke Energy Carolinas	SC	2018-3-E	South Carolina Energy Users Committee	Fuel case

Regulatory Cases of Kevin W. O'Donnell, CFA
Nova Energy Consultants, Inc.

Year	Name of Applicant	State Jusrisdiction	Docket No.	Client/ Employer	Case Issues
2018	Elkton Gas Company	MD	FC 9488	Maryland Office of People's Counsel	Accounting, ROE, capital structure
2018	Baltimore Gas & Electric	MD	FC9484	Maryland Office of People's Counsel	ROE, capital structure
2018	South Carolina Electric & Gas	SC	2017-370-E	South Carolina Energy Users Committee	Creditworthiness issue
2018	Jersey Central Power & Light	NJ	EO18070728	NJ Division of Rate Counsel	ROE and capital structure
2019	Duke Energy Carolinas	SC	2018-319-E	South Carolina Energy Users Committee	Accounting, rate design
2019	Duke Energy Progress	SC	2018-318-E	South Carolina Energy Users Committee	Accounting, rate design
2019	Public Service Electric and Gas	NJ	EO18060629	NJ Division of Rate Counsel	ROE and capital structure
2019	Potomac Electric Power	MD	FC 9602	Maryland Office of People's Counsel	ROE, capital structure
2019	Oklahoma Gas and Electric	OK	PUD 201800140	Sierra Club	Creditworthiness issue
2019	Peoples Natural Gas	PA	R-2018-3006818	Pennsylvania Office of Consumer Advocate	ROE, capital structure
2019	UGI Natural Gas	PA	R-2018-3006814	Pennsylvania Office of Consumer Advocate	ROE, capital structure
2019	Dominion Virginia Power	VA	PUR-2019-00050	Federal Executive Agencies	Return on Equity
2019	Piedmont Natural Gas	NC	G-9, Sub 743	Carolina Utility Customers Assoc.	Accounting, cost of service, rate design, ROE
2019	Pacific Gas & Electric, Southern California Edison, San Diego Gas & Electric	CA	A-1904014, et al	Federal Executive Agencies	ROE, capital structure
2019	Duke Energy Indiana	IN	Cause 45253	Federal Executive Agencies	ROE, capital structure
2020	Duke Energy Carolinas	NC	E-7 Sub 1214	Carolina Utility Customers Assoc.	Accounting, cost of service, rate design, ROE
2020	Duke Energy Progress	NC	E-2 Sub 1219	Carolina Utility Customers Assoc.	Accounting, cost of service, rate design, ROE
2020	Dominion Virginia Power	VA	PUR-2019-00154	Southern Environmental Law Center	Financial analysis of plant investment
2020	Southwest Electric Power Company	LA	U-35324	Alliance for Affordable Energy	Financial analysis of plant investment
2020	Texas Gas Company	TX	PUC 10928	Texas Gas Cities	ROE, capital structure
2020	Potomac Electric Power	DC	FC 1156	District of Columbia Office of Peoples Counsel	ROE, capital structure
2020	UGI Gas	PA	R-2019-3015162	Pennsylvania Office of Consumer Advocate	ROE, capital structure, creditworthiness
2020	Columbia Gas of Maryland	MD	FC 9644	Maryland Office of People's Counsel	ROE, capital structure
2020	Columbia Gas of Pennsylvania	PA	R-2020-3018835	Pennsylvania Office of Consumer Advocate	ROE, capital structure
2020	New Mexico Gas Company	NM	19-00317-UT	Federal Executive Agencies	ROE, capital structure, accounting, rate design, cost of service
2020	Washington Gas Light	DC	FC 1162	District of Columbia Office of Peoples Counsel	ROE, capital structure
2020	Dominion Energy South Carolina	SC	2020-125-E	South Carolina Energy Users Committee	Accounting, rate design
2021	Suez Water Company	NJ	BPU WR2011	NJ Division of Rate Counsel	ROE, capital structure, rate design

(Transcript continues in sequence in Volume 6.)

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 21st day of September, 2021.

Debbie R Krick

DEBRA R. KRICK
NOTARY PUBLIC
COMMISSION #HH31926
EXPIRES AUGUST 13, 2024