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BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for rate increase by Florida Power & Light Company	**DOCKET NO. 160021-EI** **Filed: July 7, 2016**

DIRECT TESTIMONY AND EXHIBITS OF JEFFRY POLLOCK

ON BEHALF OF
THE FLORIDA INDUSTRIAL POWER USERS GROUP

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LIST OF EXHIBITS

GLOSSARY OF ACRONYMS

Term	Definition
12CP+1/13th AD	Twelve Coincident Peak and 1/13th Average Demand
12CP+25% AD	Twelve Coincident Peak and 25% Average Demand
AFUDC	Allowance for Funds Used During Construction
Capacity	Capacity Payment Recovery
CCGT	Combined Cycle Gas Turbine
CCOSS	Class Cost-of-Service Study
CDR	Commercial/Industrial Demand Reduction
CILC	Commercial/Industrial Load Control
Conservation	Energy Conservation Cost Recovery
CT	Combustion Turbine
CWIP	Construction Work in Progress
Duke Energy Florida	Duke
Environmental	Environmental Cost Recovery
FIPUG	Florida Industrial Power Users Group
FPL	Florida Power & Light Company
GPIF	Generation Performance Incentive Factor
Gulf	Gulf Power Company
HRSG	Heat Recovery Steam Generator
IOU	Investor Owned Utility
kW	Kilowatt
kWh	Kilowatt Hour
MW	Megawatt
MFR	Minimum Filing Requirement
MYRP	Multi-Year Rate Plan
O&M	Operation and Maintenance
OCEC	Okeechobee Clean Energy Center
ROE	Return on Equity
SYA	Subsequent Year Adjustment
TECO	Tampa Electric Company
TOU	Time-Of-Use

Direct Testimony of Jeffry Pollock

1. INTRODUCTION, QUALIFICATIONS AND SUMMARY

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. Jeffry Pollock; 12647 Olive Blvd., Suite 585, St. Louis, MO 63141.

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

A. I am an energy advisor and President of J. Pollock, Incorporated.

Q. PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A. I have a Bachelor of Science Degree in Electrical Engineering and a Master's Degree in Business Administration from Washington University. Since graduation in 1975, I have been engaged in a variety of consulting assignments, including energy procurement and regulatory matters in both the United States and several Canadian provinces. My qualifications are documented in **Appendix A.** A partial list of my appearances is provided in **Appendix B** to this testimony.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?

A. I am testifying on behalf of the Florida Industrial Power Users Group (FIPUG). FIPUG members purchase electricity from Florida Power & Light Company (FPL). They consume significant quantities of electricity, often around-the-clock, and require a reliable affordably-priced supply of electricity to power their operations. Therefore, FIPUG members have a direct and significant interest in the outcome of this proceeding.

Q. WHAT ISSUES DO YOU ADDRESS?

A. I am addressing the following issues:

- FPL's multi-year rate plan;
- Performance incentive;
- Construction work in progress;
- Cost of capital (long-term debt, cost of equity and capital structure);
- Class revenue allocation;
- Class cost-of-service study; and
- GSLD/CILC rate design.

Q. ARE YOU SPONSORING ANY EXHIBITS WITH YOUR TESTIMONY?

A. Yes. I am sponsoring **Exhibits ___(JP-1) through ___(JP-16).**

Q. THROUGHOUT YOUR TESTIMONY AND EXHIBITS YOU REFER TO FPL'S PROPOSED REVENUE REQUIREMENTS, CLASS COST-OF-SERVICE STUDY AND OTHER PROPOSALS. SHOULD THIS BE INTERPRETED AS AN ENDORSEMENT OF FPL'S PROPOSALS?

A. No. Any reference to FPL's proposals is strictly for illustrative purposes. It should not be interpreted as endorsing FPL's proposals both on the issues addressed as well as the issues not addressed in my testimony.

<u>Summary</u>

Q. PLEASE SUMMARIZE YOUR FINDINGS AND RECOMMENDATIONS.

A. My findings and recommendations are as follows:

<u>Multi-Year Rate Plan</u>

- The proposal would raise base revenues by approximately $1.31 billion over four years, including a 2017 increase effective on January 1, 2017, a subsequent year adjustment effective on January 1, 2018 and a limited scope increase to recognize the Okeechobee Clean Energy Center shortly after its commercial in-service date, which is projected to occur in June 2019.

- From a factual perspective, the request for a subsequent year adjustment is an objectionable pancaking of two separate rate cases in a single proceeding. Pancaked rate increases are bad policy because they fail to properly balance the utility's needs with the needs of its customers, they rely on speculation rather than known and reasonably predictable revenues and costs to set base rates, and they would unnecessarily bind a future commission by prematurely setting rates now for 2018.

- Multi-year rate plans are not a common practice, and they are unnecessary in jurisdictions like Florida where 45% of a utility's costs are separately recovered outside of a rate case in various cost recovery clauses.

- The 2017 test year and subsequent year adjustment revenue requirements are based on budgets that were developed and approved in October 2015, which is 14 to 26 months prior to the effective dates of the proposed 2017 and 2018 rates. Though sales, revenues and costs are likely to change between October 2015 and the time the Board approves FPL's official corporate budgets for 2017 and 2018, FPL is not proposing to adjust the assumptions underlying the subsequent year adjustment in this proceeding.

- FPL's sales assumptions, which are a key component in determining its revenue needs and rate design, show negative growth in 2017 and only 0.3% per growth over the period 2016-2018. These are in stark contrast to the 1% per year growth that FPL has experienced since 2011 and the much higher growth rates in prior years. Accordingly, the Commission should be highly skeptical of such modest and self-serving growth projections.

- Further, given that many of the 2017 assumptions also carry-over to 2018, there may not be any need for a subsequent year adjustment even if the projections could be relied upon to set rates.

- The subsequent year adjustment should be rejected because it is speculative, inappropriate and unnecessary.

Performance Incentive

- FPL's proposed 50 basis point return on equity performance incentive alone would account for about $120 million of the proposed $829.7 million 2017 base revenue increase.

- A performance incentive should only be necessary for service provided above and beyond reasonable expectations. FPL's many cost-savings investments, which retail customers have paid and are paying for, are neither above nor beyond its obligation to provide reliable service at the lowest reasonable cost. Customers should not be forced to pay for these investments twice in the form of higher rates. Further, it is improper to ignore the $3.2 billion of hedging losses that FPL has incurred from 2002-2014, for which customers have paid higher fuel charges.

- FPL has consistently earned the maximum allowed return on equity without the addition of a performance adder due to its very liberal use of surplus depreciation and fossil fuel dismantlement balances. This practice has more than adequately rewarded executives and shareholders while leaving retail customers saddled with a $99 million depreciation deficiency.

- FPL is already subject to a Generation Performance Incentive Factor that encourages the investment in improvements as well as operational efficiency in each base load unit that results in net savings to customers.

- Accordingly, no further performance incentive is either necessary or deserved.

<u>Construction Work in Progress</u>

- FPL is seeking recovery of $748 million of construction work in progress (CWIP) in rate base consisting of projects on which FPL says it cannot capitalize allowance for funds used during construction. This accounts for only 2% of FPL's proposed 2017 test-year rate base.

- CWIP is plant that is not used and useful in providing electricity service.

- FPL has not demonstrated that current recovery of the financing costs on CWIP is either extraordinary or necessary to maintain its financial integrity and its current credit ratings.

- Pursuant to Rule 25-6.0141 F.A.C., the Commission *may* include non-interest bearing CWIP, but it also can remove CWIP from rate base to mitigate the impact on rates. Given that FPL's proposed four-year multi-year rate plan would cause rate shock, CWIP should be removed from rate base to help mitigate the impact on rates.

<u>Cost of Capital</u>

- FPL's projected cost of long-term debt is overstated because it fails to recognize that interest rates are less likely to increase due to recent changes in global economic and financial markets in part due to Brexit.

- The Commission should find that FPL's cost of long-term debt in 2017 is not greater than 4.5489%.

- FPL's proposed 11% cost of equity (before any performance incentive) is excessive relative to the returns authorized by this Commission as well as by other state regulatory commissions nationwide in rate case decisions since 2012 for vertically integrated electric investor-owned utilities. Authorized returns have averaged below 10% since 2013.

- An 11% cost of equity is especially inappropriate given that equity would comprise nearly 60% of FPL's "financial" capital structure. Accordingly, FPL's return on equity should be set below the electric utility average.

- A 60% financial equity ratio is clearly excessive in this case because FPL's proposed 11% cost of equity is 645 basis points more expensive than long-term debt. This excessive equity ratio results in a higher cost of capital and higher rates than a utility with a more leveraged capital structure.

- On average, other vertically integrated electric investor-owned utilities collectively have an average 51.1% financial equity ratio, which is 890 basis points lower than FPL is proposing in this case.

- For ratemaking purposes, FPL's capital structure should be more in line with the average of other vertically integrated electric investor-owned utilities.

<u>Class Revenue Allocation</u>

- Base revenues should reflect the actual cost of providing service to each customer class, as closely as practicable, using a class cost-of-service study that appropriately reflects cost causation. Cost-based rates are equitable, send proper price signals, encourage cost-effective conservation and provide more stability.

- Cost-based rates are also consistent with this Commission's long-standing practice.

- The only exceptions to setting rates to cost are rate administration and gradualism.

- FPL's proposed class revenue allocation ignores the impact of reducing the CILC/CDR credits by $23 million or 37%. A 37% reduction would result in CILD and CDR customers experiencing substantial rate shock. It is also not consistent with the proper application of gradualism, which limits the increase to 1.5 times the system average increase, irrespective of whether gradualism is measured relative to revenues including or excluding the cost recovery clauses.

- FPL's proposed class revenue allocation should be rejected because it would result in increases that exceed 1.5 times the system average increase for the CILC/CDR customers.

- Because the cost recovery clauses are not being changed for ratemaking purposes in this case, it is proper to measure gradualism relative to base revenues (*i.e.,* excluding the clauses).

Class Cost-of-Service Study

- FPL's class cost-of-service study fails to reflect cost causation for three reasons.

- First, FPL is proposing to change the way it allocates production plant-related costs by increasing the energy weighting from 7.6% (*i.e.,* 1/13th average demand) to 25% without providing any study or analysis supporting said change. In fact, FPL has not changed the way it either plans or operates its system since its last rate case, when it supported the 12CP+1/13th AD method.

- FPL would be the only major electric utility in Florida not using 12CP+1/13th AD. Duke Energy Florida, Gulf Power Company and Tampa Electric Company all use 12CP+1/13th AD.

- The capacity additions that are purportedly a major cost driver of the proposed base revenue increases were justified on the basis of meeting FPL's capacity needs based on its projections of firm peak demand.

- Further, FPL has chosen to install capacity that is highly flexible; that is, it can be cycled more cost-efficiently than FPL's older steam turbines to meet changes in system loads and integrate increasing amounts of renewable generation. This enhanced load following capability provides a significant reliability benefit, which supports a heavier demand weighting.

- Accordingly, 12CP+1/13th AD should be retained.

- Second, FPL failed to classify any of its distribution "network" as a customer-related cost. As with production plant, FPL is clearly an outlier. Both Gulf and TECO classify about 26% of their distribution network costs as customer-related. Further, many other utilities also follow this practice.

- The distribution network provides a connection to the grid, and it includes facilities that also provide the voltage support needed before any power or energy can be delivered to and consumed by the customer. These prerequisites (*i.e.*, a grid connection and voltage support) are clearly related to the existence of the customer.

- Classifying these costs entirely to demand would have the practical effect of allocating less than 1 pole, less than 20 feet of overhead conductors and less than 5 feet of underground conductors to serve each Residential and General Service Non-Demand customer, which is clearly contrary to reality.

- FPL's investments to "harden" the distribution system are driven by the need to maintain a connection and the voltage support during major storm events. Based on its projections, FPL will have invested over $2 billion in distribution storm hardening for the period 2014 through 2018. Thus, distribution storm hardening costs are a major driver of FPL's proposed rate increase and further support a significant customer component.

- Approximately 26% of FPL's distribution network costs should be classified as a customer-related cost.

- Third, FPL fails to recognize that it provides distribution service to customers that take service directly at an FPL-owned distribution substation. Distribution Substation service is less costly to provide than Primary Distribution service because the customer, not FPL, provides the necessary equipment to distribute electricity to and within the customer's facilities. The only difference between Transmission and Distribution Substation services is that FPL must provide the step-down transformer and related equipment to serve the latter.

- Accordingly, FPL should be ordered to file a cost-based tariff for Distribution Substation service within 90 days after a final order is issued in this proceeding.

<u>GSLD/CILC Rate Design</u>

- FPL's proposed GSLD/CILC rate design features Energy charges that would recover substantially more than energy-related costs, thereby resulting in intra-class subsidies. Accordingly, consistent with cost-based ratemaking (*i.e.,* setting rates that reflect cost subject to gradualism concerns), the Energy charges should not be increased by more than 50% of the corresponding increase in the Demand charges.

- FPL is proposing to reduce the incentive payments to CILC/CDR customers by $23 million or 37%. Notwithstanding the obvious impact on CILC/CDR customers, which FPL ignored in applying gradualism, the CILC/CDR credits cannot and should not be "reset" as FPL is proposing.

- FPL has provided no explanation and no study supporting a 37% reduction in the CILC/CDR incentive payments.
- The Commission has previously determined in FPL's 2015 Demand Side Management case that CILC/CDR were cost-effective at the *current* level of incentive payments. Accordingly, by FPL's own admission, no further change can be made in this case.
- Prior to the 2012 FPL rate case, the CDR credits had not been changed since 2004. The CILC incentive payments had not been revised prior to FPL's 2008 rate case. The increase in the incentive payments in the 2012 rate case, thus, reflected inflationary factors, coupled with strong load growth that has prompted FPL to add new capacity to maintain reliability.
- Further, the CILC/CDR credits should not be changed because FPL can use CILC/CDR load to defer or avoid installing new generation capacity, such as peaking units. Thus, FPL is able to maintain reliable service to its firm customers with less installed capacity while incurring less costs because non-firm load is not included in FPL's peak demand projections that are used to assess resource adequacy when planning to meet its firm load.
- Accordingly, the Commission should reject FPL's proposal to reduce the CILC/CDR credits.

2. MULTI-YEAR RATE PLAN

Q. WHAT BASE RATE INCREASES IS FPL SEEKING IN THIS PROCEEDING?

A. In its Application, FPL was seeking to increase base revenues by approximately $1.34 billion. It has since identified adjustments that would reduce the proposed increase to about $1.31 billion.[1]

Q. HOW IS FPL PROPOSING TO IMPLEMENT ITS PROPOSED $1.31 BILLION BASE REVENUE INCREASE IN THIS PROCEEDING?

A. FPL is proposing a forward-looking multi-year rate plan (MYRP). Each step increase was derived using fully projected periods. Under the proposed MYRP, the base revenue increases would be implemented as follows:

FPL's Proposed MYRP
($ in Millions)[2]

Description	Effective Date	Projection Period	Amount
Test Year	1/1/2017	CY 2017	$829.7
Subsequent Year Adjustment (SYA)	1/1/2018	CY 2018	$266.8
Okeechobee Clean Energy Center Limited Scope Adjustment	6/1/2019	6/19 - 5/20	$209.2
Cumulative Increases			$1,305.7

1 FPL's Notice of Identified Adjustments filed on May 3, June 16, and June 30.

2 Initial proposal adjusted as follows:

- Test Year: $866.4 Million per MFR Schedule A-1 less $36.6 Million of identified adjustments;
- SYA: $262.3 Million per MFR Schedule A-1 2018 Subsequent Year Adjustment less $32.3 Million plus $36.8 Million ($36.6 Million growth adjusted) of identified adjustments;
- OCEC: MFR Schedule A-1 OCEC Limited Scope 2019 plus $0.2 Million. The OCEC increase would be implemented after the plant is placed in commercial operation.

Further, FPL asserts that it would not adjust base rates in 2020. Thus, its proposed MYRP would be a four-year commitment.

Q. IS FPL SEEKING COMMISSION APPROVAL OF MULTIPLE BASE RATE INCREASES AT THIS TIME?

A. Yes. In addition to implementing an increase in 2017, FPL is also seeking Commission approval of what it has characterized as a “subsequent year adjustment” (SYA) to raise base rates in 2018. In addition, FPL is proposing an Okeechobee Clean Energy Center (OCEC) Limited Scope increase. However, the amount and impact of the OCEC increase would not be finalized until the plant is placed in commercial operation, which is expected to occur on June 1, 2019.

Q. SHOULD THE COMMISSION GRANT A SUBSEQUENT YEAR ADJUSTMENT RATE INCREASE?

A. No. As a preliminary matter, please note that I do not address the Commission’s authority to grant a SYA rate increase. This is a legal issue.

From a factual perspective, the request for an additional increase in 2018 is an objectionable pancaking of two separate rate cases in a single proceeding. The reasons for not allowing pancaked rate increases are discussed below.

More importantly, the requested SYA is especially objectionable because the 2018 revenue requirements FPL attempts to rely upon are based on projections that were approved in October 2015.[3] These projections will be 26 months old when the

[3] FPL’s Response to FIPUG’s Interrogatory No. 1. Energy sales were derived from an updated forecast that was prepared in early 2016.

proposed SYA rates would become effective. Also, FPL is not proposing to update any of the SYA assumptions.[4] Further, the SYA sales, revenues and costs do not reflect FPLs “official” 2018 corporate budget. In fact, FPL’s official 2017 corporate budget will not be approved by the Board of Directors until December 2016.[5] This is after the record in this case will be closed. Thus, the official 2018 corporate budget will not be known until 30-days prior to the effective date of the proposed SYA rates.

Finally, considering the various cost recovery clauses, the ability to implement a limited scope proceeding for a major new investment, and adjustments to FPL’s projected sales, revenues, rate base, cost of capital and expenses that various parties are likely to propose, a SYA may simply be unnecessary.

Q. HOW WOULD YOU CHARACTERIZE THE SUBSEQUENT YEAR ADJUSTMENT PROPOSAL?

A. The phrase “subsequent year adjustment” is really a misnomer and a thinly-disguised attempt to package a second proposed base rate increase filed at the same time as the first base rate increase as something other than what it is — a full scale 2018 base rate case and attendant rate increase. This takes the concept of pancaking rate increases – filing increases one after another in close order — to the ultimate extreme, in my view.

[4] FPL’s Response to FIPUG’s Interrogatory No. 89.

[5] FPL’s Response to FIPUG’s Interrogatory No. 4.

Q. WHY DO YOU CONCLUDE THAT THE SUBSEQUENT YEAR ADJUSTMENT IS AN ATTEMPT TO PROSECUTE TWO RATE CASES AT ONCE?

A. The SYA is a filing that looks, feels and smells like a full rate case. First, the SYA is not a proposal to adjust rates based on a specific occurrence or event, such as what might be addressed in a limited scope proceeding. Rather, it is a second rate filing in which FPL seeks to have increased rates put into effect to cover all manner of cost increases ranging from an increase in the overall cost of capital from 6.6% to 6.7%, operation and maintenance (O&M), depreciation, tax expenses, adjustments to billing determinants, capital additions and even inflation-related adjustments, all based on speculative costs projected for 2018. These are not specific SYAs, but rather the full set of pro-forma adjustments that are seen as part of a full rate increase filing. Second, FPL has filed a full set of minimum filing requirements (MFRs) for the SYA. These are the same MFRs that were filed with its 2017 test year request.

Q. IS IT A REASONABLE REGULATORY POLICY TO ALLOW ELECTRIC UTILITIES TO PROSECUTE TWO BACK-TO-BACK RATE INCREASES IN THE SAME PROCEEDING, AS FPL PROPOSES?

A. No. Such back-to-back rate increases fail to properly balance the utility's needs with the needs of its customers. Assuming its 2018 assumptions are accurate (which FIPUG disputes), FPL is really asking the Commission to guarantee that it will achieve the authorized return. Providing such a guarantee is contrary to accepted regulatory practice, which is to provide an *opportunity* to earn the authorized return.

Further, as previously discussed, the 2018 test year is based on a budget that was approved in October 2015. FPL will not formally approve its "official" 2018 budget until December 2017, which is well after this rate case will be decided. Thus, setting rates for 2018 is highly speculative. Rates should not be set based on speculation about the future. Additionally, this Commission should not bind a future Commission by setting rates now for 2018.

And finally, the proposed 2018 increase may be unnecessary depending on the Commission's findings on FPL's 2017 revenue requirements. The need for further relief can only be evaluated in the context of the rates that this Commission determines to be appropriate for the 2017 test year.

Q. IS IT A COMMON PRACTICE TO ALLOW UTILITIES TO PROPOSE MULTI-YEAR RATE PLANS?

A. No. This practice is not widely used. The only exceptions are in states, like Minnesota and Mississippi, which have statutes specifically authorizing Commission approval of a MYRP.

Q ARE THERE OTHER TOOLS THAT ALLOW FPL TO REMAIN WHOLE BETWEEN RATE CASES?

A Yes. This Commission has authorized limited scope increases to recognize major asset additions, such as OCEC, or to implement special riders to recover restoration costs following a major storm event. FPL also has many separate cost recovery clauses, such as Fuel and Purchased Power (Fuel), Capacity Payment Recovery (Capacity), Environmental Cost Recovery (Environmental), and Energy Conservation

Cost Recovery (Conservation). Together, these clauses recover 45% of FPL's revenue requirement. Finally, if FPL's earnings fall below the low end of the authorized range, or are unacceptably low, FPL always reserves the right to file a rate case.

Q. WHAT IS SIGNIFICANT ABOUT THE USE OF PROJECTED REVENUES AND COSTS CALCULATED IN THE FALL OF 2015 TO SET RATES FOR 2018?

A. The use of projections calculated more than two years prior to when the 2018 rate would be implemented will result in rates that are based on highly speculative information that could change significantly in the future. The farther out in time projections are, the less likely they are to be accurate.

In Florida, no doubt due in part to the numerous recovery clauses, many years can elapse between rate cases. If the Commission were to base 2018 rates on speculative data from 2015 – which will undoubtedly change as 2018 gets closer – these inaccurate rates may be in effect for a long time and ratepayers may be paying more than necessary. This is a risk to which ratepayers should not be exposed.

If FPL can support a case for rate relief in 2018, it can file a rate case when projections and budgets will be more accurate.

Q. IS THERE A BASIS TO ASSUME THAT ANY OF FPL'S 2018 PROJECTIONS MAY BE QUESTIONABLE?

A. Yes. **Exhibit ___ (JP-1)** provides an analysis of FPL's historical and projected weather-normalized retail sales and average customer forecasts. Specifically, FPL's historical 2011-2015 sales and customers are shown on lines 1-5, while the corresponding 2016-2018 projections are shown on lines 7-9. Historically, FPL has experienced 1% per year average weather-normalized sales growth and 1.2% average customer growth (line 6). These are in stark contrast to FPL's projections, which reveal a rather anemic sales growth rate of only 0.3% per year for the period 2016 through 2018 despite projected customer growth of 1.5% per year for the same period (line 10).

Q. WHAT DO THESE CHANGES SUGGEST WITH REGARD TO THE 2018 SUBSEQUENT YEAR ADJUSTMENT?

A. Sales and customer projections are key to quantifying FPL's annual revenue needs and essential to accurately designing future rates. If projected sales are understated, FPL's revenue needs and the resulting rates would be overstated. Using questionable assumptions to set rates would give FPL the opportunity to earn more than its authorized midpoint return if FPL were to experience sales growth that is more consistent with past experience.

The substantial changes highlighted above raise serious questions as to whether the 2018 SYA sales and revenues are sufficiently known and measurable so as to form an appropriate and sufficient basis for determining the SYA base rate increases and rate designs. In effect, FPL is asking the Commission to accept that a sales forecast produced in early 2016 is sufficiently accurate to measure FPL's net income at current rates and to design rates. This is simply a forecast, a look beyond the horizon, and not an official budget. At best, FPL's 2018 revenue needs are a preliminary estimate. Thus, although my analysis demonstrates that FPL's 2017 sales and revenue projections should be thoroughly reviewed, it would clearly be premature to use its 2018 forecast to set 2018 rates at this time.

Q. WILL CHANGES MADE TO FPL'S 2017 REVENUE REQUIREMENTS OBVIATE THE NEED FOR A SECOND RATE CASE?

A. Yes. FPL's originally proposed second rate increase is $262.3 million. It is based on the same assumptions (*e.g.,* cost of capital, depreciation rates) as the first rate increase scheduled to take effect in 2017. For example, if the Commission reduces FPL's 2017 cost of capital, FPL's 2018 revenue needs may be minimal or non-existent. Similarly, if 2017 sales grow at a rate more consistent with recent experience, FPL may earn in excess of the Commission-authorized mid-point return. This outcome would not be in the public interest.

Q. SHOULD THE COMMISSION CONSIDER THE AVAILABILITY OF THE VARIOUS COST RECOVERY CLAUSES AND FPL'S ABILITY TO SEEK A LIMITED PROCEEDING, IF CIRCUMSTANCES SUPPORT IT, WHEN CONSIDERING THE SUBSEQUENT YEAR ADJUSTMENT FPL SEEKS?

A. Yes. Taken as a whole, the Florida regulatory scheme provides utilities with more than ample opportunity to timely recover legitimate costs and expenses. The overall effect of the cost recovery clauses (which currently account for 45% of FPL's total revenues) is to limit substantially the need for full rate cases. The annual clauses also serve to substantially reduce the risk of under-recovery. When reaching a decision regarding the "subsequent year" concept – pancaked rate increases in this case – the Commission must also be mindful of the existence of, use of, and benefits that already accrue to utilities in the state of Florida from the numerous cost recovery clauses.

Q. WHY SHOULD PANCAKED RATE INCREASES BE AVOIDED?

A. Pancaked rate increases are not consistent with good public policy. This is especially true under the current circumstances, where base rates are set using a completely forward-looking test year, regulatory lag is minimal, 45% of FPL's costs are recoverable outside of base rate cases through cost recovery clauses, and inflation is minimal. On average, rate case decisions in Florida occur within five months of the filing date. This is the second shortest regulatory lag of any state regulatory commission.

Q. WHAT DO YOU RECOMMEND?

A. The Commission should reject FPL's SYA because it is speculative, inappropriate and unnecessary.

3. PERFORMANCE INCENTIVE

Q. WHAT IS THE PERFORMANCE INCENTIVE ADDER THAT FPL IS REQUESTING?

A. FPL is requesting a 50 basis point adder to its requested cost on equity of 11.0% "to reflect what FPL has already accomplished in its efforts to deliver superior value to its customers and as an incentive to promote further efforts to improve the customer value proposition."[6] This would set its authorized return on equity (ROE) at 11.50%.

Q. WHAT IS THE REVENUE IMPACT OF A 50 BASIS POINT PERFORMANCE INCENTIVE?

A. The proposed 50 basis point performance incentive comprises about $120 million of the 2017 revenue requirement. Thus, it would account for about 14% of FPL's proposed 2017 base revenue increase.

Q. SHOULD FPL BE REWARDED WITH A 50 BASIS POINT PERFORMANCE ADDER?

A. No. FPL is requesting the adder to reward and incent the company for providing reliable service at the lowest reasonable cost, exactly what a regulated utility is expected to do, regardless of any incentives. It does not need any additional financial incentive to do this. As stated by FPL witness, Moray P. Dewhurst, customer bills are 30% below the national average and 20% below the state average.[7] This result is a combination of dramatically lower natural gas prices and

[6] Direct Testimony of Moray P. Dewhurst at 27.

[7] *Id*. at 11.

investments in more efficient generation capacity. It has been accomplished without any performance adder. A performance adder should not be the determining factor as to whether a utility will pursue superior customer value or whether it will be able to provide reliable and affordable electric service. FPL shouldn't be rewarded for providing the required service and the performance adder should be denied.

Q. ARE FPL'S AVERAGE RATES LOWER THAN THOSE FOR OTHER UTILITIES ACROSS THE COUNTRY AND ACROSS FLORIDA?

A. Yes, according to FPL. However, FPL has lower costs because it has invested in cost savings measures, such as installing lower heat rate generation capacity and smart grid meters. Retail customers are paying for these cost savings measures, and they are entitled to benefit from their investments, not pay a higher rate to reward FPL. FPL wants customers to pay for cost saving investments while it reaps the rewards of those cost saving investments.

Q. WHAT COST SAVING MEASURES HAS FPL (AND ITS CUSTOMERS) INVESTED IN THAT HAVE RESULTED IN COST SAVINGS?

A. FPL states that it has transformed its fossil generating fleet, which has resulted in cost reductions and performance improvements achieved by FPL's generating fleet that provide substantial benefits to its customers. These include reducing heat rate by 25%, reducing EFOR by 60%, reducing air emissions by 33% for CO_2, 94% for NO_x and 99% for SO_2, and reducing total non-fuel O&M per kW by 39%. Combined these have resulted in $8 billion cumulatively in fuel cost avoidance for customers.[8]

[8] Direct Testimony of Roxane R. Kennedy at 6.

This $8 billion of savings required $7.1 billion of capital which will be recovered in rates.[9] Again, the customers have paid for these cost savings investments and should not be forced to pay for them twice in the form of higher rates.

Q. MR. DEWHURST STATES THAT IT IS INCONSISTENT WITH SOUND REGULATORY POLICY FOR A COMPANY WITH A SUPERIOR RECORD OF DELIVERING VALUE TO ITS CUSTOMERS TO EMERGE FROM A KEY REGULATORY PROCEEDING WITHOUT ANY REFLECTION OF THAT PERFORMANCE IN ITS ALLOWED ROE[10]. DO YOU AGREE?

A. No, I do not. To the contrary, it would be *inconsistent* with sound regulatory policy to impose an additional fee on customers for receiving the expected reliable and affordable service for which they have already paid.

Q. WHY ELSE WOULD A PERFORMANCE INCENTIVE BE UNNECESSARY?

A. For the past six years FPL has consistently earned high ROEs without the addition of a performance adder, as shown in the table below.

Earned Return on Equity[11]	
Year	**Amount**
2010	11.00%
2011	11.00%
2012	11.00%
2013	10.96%
2014	11.50%
2015	11.50%

9 FPL's Response to SFHHA Interrogatory No. 151.

10 Direct Testimony of Moray P. Dewhurst at 30.

11 FPL's Response to AARP's Interrogatory No. 10.

As can be seen, over the last several years FPL has enjoyed generous ROEs at the top end rather than the mid-point of its authorized ROE range (9.50%-11.50%) *without* a performance adder.

Q HOW WAS FPL ABLE TO EARN SUCH HIGH RETURNS ON EQUITY IN THE RECENT PAST?

A FPL was able to maintain such high ROEs, in part, by amortizing a $894.6 billion depreciation reserve imbalance and a portion of its fossil fuel dismantlement surplus (*i.e.,* Reserve Amount). The amortization commenced in 2010 following FPL's 2009 rate case, and it was continued in 2013 following the Settlement Agreement in FPL's last rate case.[12]

Q WILL FPL CONTINUE TO USE THE RESERVE AMORTIZATION TO EARN HIGHER RETURNS ON EQUITY?

A Yes. FPL projects that by amortizing all of the remaining $263 million of the Reserve Amount it will earn an 11.5% ROE in 2016.[13] However, this will deplete the Reserve Amount, and FPL now asserts that it has a $99 million depreciation deficiency.[14]

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[12] *In Re: Petition for Increase in Rates by Florida Power & Light Company* and *In re: 2009 depreciation and dismantlement study by Florida Power & Light Company,* Docket Nos. 080677-EI and 090130-EI, Order No. PSC-IO-0153-FOF-EI at 81 (Mar. 17, 2010)*; In Re: Petition for Increase in Rates by Florida Power & Light Company*, Docket No. 120015-EI, Order Approving Revised Stipulation and Settlement at 4 (Jan. 14, 2013).

[13] FPL's Response to AARP's Interrogatory No. 54.

[14] Direct Testimony of Ned W. Allis at 53.

Q. WAS FPL OBLIGATED TO AMORTIZE THE RESERVE AMOUNT TO EARN AT THE HIGH END OF ITS AUTHORIZED ROE RANGE?

A. No. FPL was required to amortize an amount that would allow it to achieve a minimum 9.5% ROE (and not to exceed a maximum 11.5% ROE). FPL used its discretion to use the Reserve Amount to earn at the maximum 11.5% ROE, thereby handsomely rewarding its executives and benefiting shareholders.

Q. HOW DOES FPL'S CHOICE TO DEPLETE THE RESERVE AMOUNT AUTHORIZED BY THE COMMISSION RELATE TO ITS REQUEST FOR A PERFORMANCE INCENTIVE?

A. FPL has taken advantage of the 2010 Rate Case Order and the 2012 Settlement to earn the maximum possible returns for the benefit of its executives and shareholders. As a result, FPL's customers may now be saddled with a $99 million depreciation reserve deficiency. Accordingly, FPL has been more than compensated for its superior performance. No further incentive is necessary or appropriate.

Q. DOES FPL ALREADY HAVE INCENTIVE MECHANISMS TO REWARD SUPERIOR PERFORMANCE?

A. Yes. FPL is subject to a Generation Performance Incentive Factor (GPIF) that encourages the investment in improvements as well as operational efficiency in each base load unit that results in net savings to customers.[15] On several occasions, FPL has received GPIF rewards.

[15] Eduardo Balbis, P.E. (Commissioner Florida Public Service Commission), *Role of Incentives – A Florida Prospective*.

Q. ARE THERE ANY ASPECTS OF FPL'S OPERATIONS THAT ARE NOT DESERVING OF A PERFORMANCE INCENTIVE?

A. Yes. FPL has incurred $3.2 billion of hedging losses for the period 2002 through 2014.[16] These hedging losses have directly increased the fuel costs charged to FPL's customers. The magnitude of these losses is not consistent with rewarding a utility for superior performance.

Q. WHAT DO YOU RECOMMEND?

A. The Commission should reject FPL's proposed 50 basis point performance incentive because it is unnecessary and not deserved.

[16] *In re: Fuel and Purchased Power Cost Recovery Clause with Generating Performance Incentive Factor,* Docket No. 150001-EI, Order No. PSC-15-0586-FOF-EI at 5 (Dec. 23, 2015).

4. CONSTRUCTION WORK IN PROGRESS

Q. IS FPL SEEKING TO INCLUDE CONSTRUCTION WORK IN PROGRESS IN RATE BASE?

A. Yes. For the 2017 test year, FPL is proposing to include $748 million of construction work in progress (CWIP) in rate base. The $748 million consists of projects on which FPL says it cannot capitalize allowance for funds used during construction (AFUDC).[17] Accordingly FPL is seeking a current cash return on this CWIP.

Q. IS THE RECOVERY OF CWIP IN RATE BASE CONSISTENT WITH TRADITIONAL RATEMAKING?

A. No. CWIP is the investment in facilities that are in construction and are not providing service. In other words, this investment is not "used and useful." Under traditional ratemaking, investment that is not used and useful is excluded from rate base.

Q IS ALLOWING A CASH RETURN ON CONSTRUCTION WORK IN PROGRESS A NORMAL REGULATORY PRACTICE?

A No. For example, the Public Utility Commission of Texas (PUCT) regards CWIP as an "exceptional form of rate relief." Under the PUCT's rules:

> Under ordinary circumstances the rate base shall consist only of those items which are used and useful in providing service to the public. Under exceptional circumstances, the commission will include construction work in progress in rate base to the extent that:
>
> (i.) the electric utility has proven that:

[17] FPL's Response to FIPUG No. 92.

> (I.) the inclusion is necessary to the financial integrity of the electric utility; and
>
> (II.) major projects under construction have been efficiently and prudently planned and managed. However, construction work in progress shall not be allowed for any portion of a major project which the electric utility has failed to prove was efficiently and prudently planned and managed; or
>
> (ii.) for a project ordered by the Commission under §25.199 of this title (relating to Transmission Planning, Licensing and Costs-recovery for Utilities within the Electric Reliability Council of Texas), if the commission determines that conditions warrant the inclusion of CWIP in rate base, the project is being efficiently and prudently planned and managed, and there will be a significant delay between initial investment and the initial cost recovery for a transmission project.[18]

Q UNDER WHAT CIRCUMSTANCES CAN UTILITIES BE ALLOWED TO BEGIN RECOVERING A CASH RETURN ON CONSTRUCTION COSTS?

A Because of its extraordinary nature, the recovery of a cash return on CWIP from retail customers is generally limited to extraordinary circumstances. Such circumstances would occur when a utility is engaged in a very large construction program relative to its existing rate base and where the utility requires substantial external financing. Under these circumstances, a utility may experience lower earnings quality; that is, its cash earnings may not provide ample interest coverage, and its reported earnings would include a substantial amount of non-cash AFUDC earnings. These non-cash AFUDC earnings cannot be used to pay the interest and repay the principal on outstanding long-term debt.

[18] P.U.C. SUBST. R. 25.231(c)(2)(D).

The lower earnings quality could possibly trigger a reassessment of the utility's outstanding debt by the major credit rating agencies. Absent prospects for improvement over time, the credit rating agencies could consider whether to downgrade the utility's bonds. All other things equal, a lower bond rating would increase the cost of the debt issued to finance the utility's construction program. This could increase the utility's cost of capital and may result in higher rates.

Q. IS THERE ANY CONCERN THAT FPL'S CREDIT RATINGS MAY DETERIORATE IF IT IS NOT ALLOWED TO HAVE CWIP IN RATE BASE?

A. No. CWIP accounts for only 2% of FPL's proposed 2017 test-year rate base. This is not a sufficient amount to have any impact on FPL's cash earnings or the financial indicators used by the major credit rating agencies to evaluate FPL's bond ratings.

Q. WHY ELSE SHOULD CWIP BE EXCLUDED FROM RATE BASE IN THIS CASE?

A. FPL's proposed $1.31 billion of base revenue increases over the next four years is very substantial and, as discussed later, will result in rate shock for customers. Thus, the Commission should take all necessary steps to mitigate rate increases of this magnitude on FPL's retail customers consistent with the intent of Rule 25-6.0141 F.A.C., which states:

> (g) On a prospective basis, the Commission, upon its own motion, may determine that the potential impact on rates may require the exclusion of an amount of CWIP from a utility's rate base that does not qualify for AFUDC treatment per paragraph (1)(a) and to allow the utility to accrue AFUDC on that excluded amount.

Q. WHAT DO YOU RECOMMEND?

A. The Commission should reject FPL's proposal to include CWIP in rate base.

5. COST OF CAPITAL

Q. HAS YOU REVIEWED FPL'S PROPOSED COST OF CAPITAL?

A. Yes. FPL's proposed 2017 cost of capital is summarized in the table below.

FPL's Proposed Cost of Capital Test Year Ending December 31, 2017			
Description	**Percent of Capital**	**Cost**	**Weighted Cost**
	(1)	(2)	(3)
Long-Term Debt	28.763%	4.617%	1.328%
Customer Deposits	1.252%	2.045%	0.026%
Common Equity	45.127%	11.500%	5.190%
Short-Term Debt	1.884%	1.850%	0.035%
Deferred Income Tax	22.647%	0.000%	0.000%
Investment Tax Credits	0.327%	8.821%	0.029%
Total	100.000%		6.607%

As the table demonstrates, FPL is seeking an 11.5% ROE including the proposed 50 basis point incentive. Ignoring customer deposits, deferred income taxes, and investment tax credits, FPL's "financial" capital structure would consist of approximately 40% (short and long-term) debt and 60% equity.

Q. DO YOU HAVE ANY CONCERNS WITH FPL'S PROPOSED COST OF CAPITAL?

A. Yes. My primary concerns are:

- The projected cost of long-term debt is overstated.
- Even without the 50 basis point performance incentive, the proposed ROE is excessive relative to the ROEs authorized by this Commission and by other state regulatory commissions for electric investor-owned electric utilities (IOUs) operating in the Southeast.
- FPL's equity ratio is excessive.

Long-Term Debt

Q. WHAT LONG-TERM INTEREST RATE COST DID FPL ORIGINALLY PROJECT FOR 2017 AND 2018?

A. For 2017, FPL projected a 6.16% cost for long-term debt issues in March and November 2017 and 6.50% for debt issues in February and November 2018.[19] These projections are based on the December 2014 Blue Chip Financial Forecast's interpolated data for Corporate Aaa and Baa rated debt.[20] Thus, this forecast was made 24 and 36 months prior to the beginning of 2017 and 2018.

Q. ARE THESE RATES REASONABLE?

A. No. The forecast used by FPL to project the interest rate for 2017 and 2018 debt issues is dated. Further, FPL could have used more current information because these forecasts are published monthly and long range consensus forecasts are provided semi-annually. FPL itself stated that the "Corporate Aaa & Baa bond yields that are used in FPL's forecasted assumptions have decreased 20 basis points and 10 basis points, respectively, based on a 5-year average, compared to December 2015."[21] This further demonstrates that FPL's forecast rates are too high.

Further, it is more difficult to forecast debt rates this far out, especially in times of uncertain market conditions when the Federal Reserve has indicated that it

[19] MFR Schedule D-8.

[20] FPL's Response to SFHHA No. 88.

[21] FPL's Response to AARP's Interrogatory No. 46.

will raise rates gradually and cautiously, without a set timetable.[22] The odds that the Federal Reserve will raise interest rates by the end of the year have dropped substantially, from 60% on June 22, 2016 to less than 5% on June 25th.[23] This is mainly due to the fall-out from the recent British vote to exit from the European Union. Due to the latest economic news, it makes it even more difficult to forecast long-term interest rates.

Q HAS FPL UPDATED ITS FORECAST OF LONG-TERM DEBT COSTS?

A Yes. It is now projecting long-term debt costs of 5.66% for debt issued in 2017 and 6.13% for debt issued in 2018.[24] These are based on the latest forecast information from the most recent issue of Blue Chip Financial Forecasts. As can be seen, there has been a drop of 50 basis points for 2017 long-term debt costs and 37 basis points for 2018 long-term costs.

Q. WHAT DO YOU RECOMMEND?

A. As a conservative estimate, using FPL's updated forecast, I believe that FPL has overstated the cost of long-term debt issues planned for 2017 and 2018 by *at least* 10 basis points. Lowering the debt costs by 10 basis points would reduce FPL's 2017 cost of long-term debt to 4.5489%. The calculation of FPL's 2017 cost of long-term debt is provided in **Exhibit ___ (JP-2)**.

[22] Hilsenrath, Jon "Yellen: Recession Unlikely, but Long-Run Growth Could Be Slow" *The Wall Street Journal*, June 21, 2016.

[23] Lahart, Justin "What Brexit means for U.S. Investors" *The Wall Street Journal*, June 26, 2016.

[24] FPL's Response to Staff No. 254, Att. 1.

Cost of Equity

Q. HOW DOES FPL'S REQUESTED RETURN ON EQUITY COMPARE WITH OTHER ELECTRIC INVESTOR-OWNED UTILITIES?

A. FPL's proposed 11% ROE is clearly excessive. This is shown in **Exhibit __ (JP-3)**, which is a summary of the authorized ROEs by other state regulatory commissions for vertically integrated electric IOUs for the period 2012 through the first quarter of 2016. Page 1 summarizes the authorized ROEs by year. Pages 2-4 list the 111 rate case decisions referenced on page 1. As can be seen:

- For rate cases decided since FPL's last rate case, the average authorized ROEs have steadily declined.
- Beginning in 2014, the average authorized ROE is *below* 10%.

Q. HOW DOES FPL'S REQUESTED RETURN ON EQUITY COMPARE WITH OTHER ELECTRIC INVESTOR-OWNED UTILITIES IN FLORIDA?

A. The currently authorized ROEs for other Florida IOUs is shown in the table below.

Authorized Returns on Equity by The Florida Public Service Commission			
Utility	**Docket No.**	**Decision Date**	**ROE**
Duke Energy Florida	090079-EI	3/5/10	10.50%
Gulf Power Company	130140-EI	12/3/13	10.25%
Tampa Electric Company	130040-EI	9/11/13	10.25%

As the table demonstrates, FPL's requested ROE is 50 to 75 basis points higher than the ROEs authorized for Duke Energy Florida (Duke), Gulf Power Company (Gulf) and Tampa Electric Company (TECO). A 50 to 75 basis point change in FPL's authorized ROE would reduce FPL's requested 2017 base revenue increase by between $120 and $180 million, thereby resulting in considerable savings benefitting FPL's retail customers.

Q. WHAT DO YOU RECOMMEND?

A. I am not recommending a specific ROE at this time. FPL's proposed 11% ROE is excessive particularly with a 60% equity ratio. Accordingly, I recommend that the Commission set FPL's ROE below the average of the authorized ROEs by other state regulatory commissions. This would recognize the much lower risk associated with a 60% equity ratio.

Capital Structure

Q. WHAT IS THE BASIS FOR YOUR STATEMENT THAT FPL'S PROPOSED EQUITY RATIO IS EXCESSIVE?

A. **Exhibit ___ (JP-4)** summarizes the average financial equity ratio of each vertically integrated electric IOU in the most recent rate case decided during the period 2012 through March 2016. A financial capital structure is comprised of debt and equity. This is in contrast to a "regulatory" capital structure, which may also include deferred taxes, customer deposits and deferred investment tax credits.

Page 1 shows the financial equity ratio. Page 2 plots both the authorized ROEs and financial equity ratios. Referring to page 1, the average electric IOU financial equity ratio has ranged from 45% to 53%. FPL's proposed ROE and financial equity ratio are specifically identified on page 2. As can be seen, relatively few electric IOUs have financial equity ratios comparable to FPL. However, even in these instances, the authorized ROE is well below FPL's proposed 11.5% (including the performance incentive).

Exhibit ___ (JP-4), pages 3-4 list each of the 63 rate case decisions depicted on pages 1 and 2. The average financial common equity ratio is 51.10%. Thus, FPL's proposed financial common equity ratio is 890 basis points higher than the electric IOU average.

Q ARE THERE ANY CONSEQUENCES OF USING MORE EQUITY AND LESS DEBT TO FINANCE THE UTILITY'S RATE BASE?

A Yes. FPL's higher percentage of equity and lower percentage of debt in its capital structure lowers its financial risk. Furthermore, common equity is more expensive than debt. In this case, FPL is proposing an 11% cost of equity, but the proposed cost of debt would be only 4.6%, which is 640 basis points lower. A utility with too much equity in its capital structure has a higher cost of capital than a utility with a more balanced common equity ratio. All else being equal, the higher the overall common equity ratio, the greater the benefits to FPL's shareholders and executives and the higher the rates all FPL retail customers will bear. FPL should not be rewarded for its overly conservative use of debt and high equity ratio.

Q. WHAT DO YOU RECOMMEND?

A. FPL can use whatever capital structure it chooses. However, for ratemaking purposes, FPL's capital structure should be more in line with the average of electric IOUs. Accordingly, I recommend that FPL's equity ratio not exceed 51.10%.

6. CLASS REVENUE ALLOCATION

Q. WHAT IS CLASS REVENUE ALLOCATION?

A. Class revenue allocation is the process of determining how any base revenue change the Commission approves should be apportioned to each customer class the utility serves.

Q. HOW SHOULD ANY CHANGE IN BASE REVENUES APPROVED IN THIS DOCKET BE APPORTIONED AMONG THE VARIOUS CUSTOMER CLASSES FPL SERVES?

A. Base revenues should reflect the actual cost of providing service to each customer class as closely as practicable. Regulators sometimes limit the immediate movement to cost based on principles of gradualism and rate administration.

Q. WHAT IS THE PRINCIPLE OF GRADUALISM?

A. Gradualism is a concept that is applied to prevent a class from receiving an overly-large rate increase. That is, the movement to cost should be made gradually rather than all at once because it would result in rate shock to the affected customers.

Q. HOW IS RATE ADMINISTRATION RELATED TO CLASS REVENUE ALLOCATION?

A. Rate administration is a concept that applies when the design of a rate may be tied to the design of other rates to minimize revenue losses when customers migrate from a more expensive to a less expensive rate. FPL applies this concept in designing the GSLD and derivative rates (*e.g.,* SDTR, HLFT).

Q. SHOULD THE RESULTS OF THE COST-OF-SERVICE STUDY BE THE PRIMARY FACTOR IN DETERMINING HOW ANY BASE REVENUE CHANGE SHOULD BE ALLOCATED?

A. Yes. Cost-based rates will send the proper price signals to customers. This will allow customers to make rational consumption decisions.

Q. ARE THERE OTHER REASONS TO APPLY COST-OF-SERVICE PRINCIPLES WHEN CHANGING RATES?

A. Yes. The other reasons to adhere to cost-of-service principles are equity, engineering efficiency (cost-minimization), stability and conservation.

Q. WHY ARE COST-BASED RATES EQUITABLE?

A. Rates which primarily reflect cost-of-service considerations are equitable because each customer pays what it actually costs the utility to serve the customer – no more and no less. If rates are not based on cost, then some customers must pay part of the cost of providing service to other customers, which is inequitable.

Q. HOW DO COST-BASED RATES PROMOTE ENGINEERING EFFICIENCY?

A. With respect to engineering efficiency, when rates are designed so that demand and energy charges are properly reflected in the rate structure, customers are provided with the proper incentive to minimize their costs, which will, in turn, minimize the costs to the utility.

Q. HOW CAN COST-BASED RATES PROVIDE STABILITY?

A. When rates are closely tied to cost, the utility's earnings are stabilized because changes in customer use patterns result in parallel changes in revenues and expenses.

Q. HOW DO COST-BASED RATES ENCOURAGE CONSERVATION?

A. By providing balanced price signals against which to make consumption decisions, cost-based rates encourage conservation (of both peak day and total usage), which is properly defined as the avoidance of wasteful or inefficient use (not just less use). If rates are not based on an appropriate class cost-of-service study, then consumption choices are distorted.

Q. DOES COMMISSION POLICY SUPPORT THE MOVEMENT OF UTILITY RATES TOWARD ACTUAL COST?

A. Yes. The Commission's support for cost-based rates is longstanding and unequivocal. The Commission reiterated this principle in the most recent fully litigated Tampa Electric Company rate case:

> It has been our long-standing practice in rate cases that ***the appropriate allocation of any change in revenue requirements, after recognizing any additional revenues realized in other operating revenues, should track, to the extent practical, each class's revenue deficiency as determined from the approved cost of service study, and move the classes as close to parity as practicable.*** The appropriate allocation compares present revenue for each class to the class cost of service requirement and then distributes the change in revenue requirements to the classes. No class should receive an increase greater than 1.5 times the system average percentage increase in total, and no class should receive a decrease.[25]

[25] *In Re: Petition for Rate Increase by Tampa Electric Company*, Docket No. 080317-EI, Order No. PSC-09-0283-FOF-EI at 86-87 (Apr. 30, 2009). Footnote omitted and emphasis added.

Therefore, a more gradual movement of FPL's rates closer to cost would be consistent with Commission policy rather than what FPL has proposed.

<u>FPL's Proposal</u>

Q. HOW IS FPL PROPOSING TO ALLOCATE THE PROPOSED BASE REVENUE INCREASE IN THIS PROCEEDING?

A. FPL states that it set the target revenue by rate class to move all rates closer to cost to the greatest extent possible, while recognizing gradualism.[26] I will discuss FPL's application of gradualism later. FPL's proposed base revenue increase is shown in **Exhibit ___ (JP-5)**. Page 1 shows the allocation of the proposed 2017 increase, while page 2 shows the cumulative base revenue increases based on FPL's proposed SYA.

Referring to page 1, the 2017 increase would be a 15.8% base rate increase (line 21). The increases by class would range from 0.7% for OL-1 to 77.6% for CILC-1T. The other CILC rates would see similarly large increases (28.1% for CILC-1G and 57.0% for CILC-1D).

Referring to page 2, the cumulative 2017 and SYA base revenue increase would be 20.4% (line 21). The proposed cumulative increases would range from 0.7% for OL-1 to over 80% for CILC-1T. The corresponding cumulative base rate increases to the other CILC rates would be 33.7% for CILC-1G and 69.6% for CILC-1D.

[26] Direct Testimony of Tiffany C. Cohen at 14.

Q. WOULD THE BASE RATE INCREASES PROPOSED BY FPL FOR CERTAIN CUSTOMER CLASSES CONSTITUTE RATE SHOCK?

A. Yes. FPL's proposed 38% and 72% cumulative base rate increases for the GSLD and CILC rates, respectively, would constitute rate shock. A more in-depth analysis of how FPL's proposed class revenue allocation is inconsistent with accepted gradualism principles is provided later.

Q. WHY IS FPL PROPOSING SUCH LARGE BASE RATE INCREASES IN THE CILC RATES?

A. The very large CILC base rate increases can be attributed to two factors. First, FPL is proposing to "reset" the credits paid to CILC customers as well as the GSD and GSLD customers that take non-firm service under Rider CDR. This accounts for a significant portion of the proposed base rate increases to CILC and CDR customers, as shown in the table below.

Impact of "Resetting" the CDR/CILC Credits[27]

Customer Class	Amount ($000)	Percent Of Total Increase
CILC-1D	$9,943	27%
CILC-1D	370	24%
CILC-1T	5,234	33%
GSD-1	2,201	0%
GSLD-1	4,152	3%
GSLD-2	1,069	3%
Total	$22,969	1%

[27] MFR No. E-14 Attachment 2 of 6 at 30.

Thus, resetting the CILC/CDR credits would result in a $23 million additional base revenue increase and would account for up to one-third of the proposed CILC-1T base revenue increase. As discussed later, this rate case is not an appropriate venue for changing the CILC/CDR credits.

Second, FPL's class cost-of-service study (CCOSS) purportedly shows that the CILC classes are paying rates well below their allocated costs. As discussed later, FPL's CCOSS is flawed and cannot be used to set rates in this proceeding.

Q. WHAT DOES RESETTING THE CILC/CDR CREDITS MEAN?

A. FPL is proposing to restate the CILC/CDR credits to the levels that existed prior to the Settlement in its 2012 rate case, adjusted for the subsequent generation base rate adjustments (GBRAs) that have been implemented since 2012.

Q. IS FPL'S PROPOSED 2017 CLASS REVENUE ALLOCATION REASONABLE?

A. No. FPL's proposed class revenue allocation would violate this Commission's long-standing principle of gradualism.

Gradualism

Q. HOW HAS FPL APPLIED GRADUALISM?

A. FPL states that it followed the Commission practice of limiting 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.[28] FPL's application of gradualism is shown in **Exhibit ___ (JP-6)**.

[28] Direct Testimony of Tiffany C. Cohen at 14.

Q. PLEASE EXPLAIN EXHIBIT ___ (JP-6).

A. **Exhibit ___ (JP-6)** is a reproduction of a portion of MFR Schedule E-14 Attachment 2. Column 1 shows the present operating revenues including the clauses. Operating revenues include:

- Base rate revenues.
- Clause revenues (*i.e.,* Fuel, Conservation, Capacity, Environmental).
- Other revenues (*i.e.,* late payment charges, pole attachments, connect/reconnect charges, returned check charges).

Columns 2 and 3 show FPL's proposed base revenue increase (in dollars and expressed as a percent of operating revenues) as shown in MFR Schedule E-13a. Column 4 shows the impact of reversing the CILC/CDR credits.

In measuring the impact of gradualism, FPL removed the CILC/CDR credits from the proposed base revenue increases (column 4). The net revenue increase shown in column 5 matches the increases shown in MFR Schedule E-8. The percentage change in base revenues (column 6) measures the net revenue increase (ignoring the CILC/CDR credits) as a percent of present total operating revenues. When measured on this basis, the system average increase is 8.3%. Thus, applying a 150% gradualism constraint would result in a maximum increase of 12.4%. As can be seen, none of the proposed increases, including clauses, would exceed 12.4%.

Q. IS THIS A PROPER APPLICATION OF GRADUALISM?

A. No, for three reasons. First, FPL included other operating revenue in the calculation. Gradualism is typically measured on the revenues generated from electricity sales, not revenues from other sources, such as pole attachment and late payment charges. Second, FPL has ignored the impact of resetting the CILC/CDR credits in measuring the impact of its proposed base revenue increase. In other words, FPL has assumed that the CILC/CDR customers would not be affected by reducing their credits by $23 million. This is clearly wrong as resetting the credits clearly impacts the CILC/CDR customers. Third, gradualism should not be measured by including the clause revenues because the clauses are not at issue in a base rate case.

Q. ARE THERE ANY POLICY REASONS WHY GRADUALISM SHOULD BE APPLIED TO ONLY BASE RATES?

A. Yes. From a policy perspective, cost recovery clauses should not be included in this analysis because they change on an annual basis whereas base rates generally remain in place for a much longer period of time. And, as we have seen over the past eight years, fuel prices, for example, may experience great fluctuation in one year and then dramatically change again in the next year. Thus, it would be inappropriate to include and rely on projections of clause revenues for just one year (the test year) in setting base rates.

Q. HOW SHOULD GRADUALISM BE APPLIED?

A. FPL is seeking an increase in base rates. The cost recovery clauses are not at issue in this case. In other words, the increase FPL is now seeking has nothing to do with increases or decreases in fuel, energy conservation, environmental, or capacity costs. For this reason, gradualism should be applied to that portion of the rate that is subject to change in this proceeding—*the base rate*.

Further, gradualism is not a consideration in setting the cost recovery clauses. Thus, a sudden increase or decrease in natural gas prices will not affect how base rates are determined in this case.

The Commission should apply the principle of gradualism to any base revenue increase that may be approved in this case, notwithstanding any predictions about subsequent changes in cost recovery clauses.

Given that the cost recovery clauses are separate ratemaking mechanisms and can have positive or negative impacts on customers depending on the circumstances, any projected short-term clause changes should not be considered in setting base rates.

Q. ASSUMING THAT GRADUALISM IS APPLIED TO OVERALL RATES AND NOT TO BASE RATES, WOULD FPL'S PROPOSED CLASS REVENUE ALLOCATION BE CONSISTENT?

A. No. **Exhibit ___ (JP-7)** is the same as **Exhibit ___ (JP-6)** except that:

- Other revenues have been removed from column 1.
- The CILC/CDR reset was not removed from the proposed base revenue increase.

Focusing on the base revenue impact, base revenues would increase by $893.1 million or 8.7%, including clauses. Applying a 150% gradualism constraint, no customer class should receive an increase higher than 13%. However, FPL's proposal would result in increases higher than 13% for the GSLD-1, GSLD-2, CILC-1D and CILC-1T classes.

Thus, FPL's proposed class revenue allocation would clearly violate gradualism if it is applied on total revenues, including the clauses.

Q. HAVE YOU DEVELOPED AN ALTERNATIVE CLASS REVENUE ALLOCATION APPLYING REASONABLE GRADUALISM PRINCIPLES?

A. Yes. **Exhibit ___ (JP-8)** is an alternative class revenue allocation that applies gradualism on a total revenue basis, including the clauses. Applying a 150% gradualism constraint, the maximum increase cannot exceed 12.7%. As can be seen, no class would receive an increase higher than 12.7% measured on total sales revenues, including the clauses. It also differs from FPL's proposal because:

- The CILC/CDR credits were retained.
- Any revenue shortfall was used to move the remaining classes (not affected by applying gradualism) equally closer to cost.

As can be seen in **Exhibit ___ (JP-9)**, applying this class revenue allocation to FPL's CCOSS study would move rates about 44% closer to cost for those classes not affected by gradualism.

Q. PLEASE EXPLAIN HOW THE CLASS COST-OF-SERVICE STUDY RESULTS ARE MEASURED.

A. The results presented in **Exhibit ___ (JP-9)** are measured in three ways: (1) rate of return; (2) parity index; and (3) interclass subsidies.

Rate of return is the ratio of net operating income (revenues less allocated operating expenses) to the allocated rate base. Net operating income is the difference between operating revenues and allocated operating expenses. If a class is presently providing revenues sufficient to recover its cost of service (at the current system rate of return), it will have a rate of return equal to or greater than the Florida retail jurisdictional return of 4.97% at present rates.

The ***parity index*** is the ratio of each class's rate of return to the Florida retail average rate of return. A parity index above 100 means that a class is providing a rate of return higher than the system average, while a parity index below 100 indicates that a class is providing a below-system average rate of return.

The ***interclass subsidy*** measures the difference between the revenues required from each class to achieve the system rate of return and the revenues actually being recovered. A negative amount indicates that a class is being subsidized each year (*i.e.*, revenues are below cost at the system rate of return), while a positive amount indicates that a class is providing a subsidy each year (*i.e.*, revenues are above cost).

Q. WHAT DO YOU RECOMMEND?

A. First, the Commission should reject FPL's proposed class revenue allocation because it violates gradualism principles. Second, gradualism should be applied on a base revenue basis because the cost recovery clauses are not being changed in this case (except possibly the allocation factors if FPL's proposed CCOSS is adopted).

Finally, the Commission should use a more appropriate CCOSS to determine a class revenue allocation. Later in my testimony I discuss two adjustments to FPL's CCOSS that reflect cost causation. The results of this revised study should be used to determine the spread of any base revenue increase approved for 2017. Specifically, all customer classes should be moved equally closer to cost, provided that no class receives an increase exceeding 150% of the system average base rate increase. Finally, as discussed later, the CILC/CDR credits should be maintained and not reset.

Q. IF THE COMMISSION APPROVES A LOWER REVENUE REQUIREMENT THAN FPL HAS PROPOSED, HOW SHOULD ANY CHANGE IN BASE REVENUES BE ALLOCATED?

A. If the Commission approves more than 33% (but less than 100%) of FPL's proposed base revenue increase, I recommend reducing the amounts shown in **Exhibit ___ (JP-8)**, column 2, proportionally if FPL's CCOSS is adopted. Should the Commission adopt the changes to FPL's CCOSS as discussed later, the increase should be reduced in proportion to the amounts shown in **Exhibit ___ (JP-14)**, column 2.

If however, the Commission approves less than 33% of FPL's proposed base revenue increase or a decrease, it should be spread equally to all customer classes.

7. CLASS COST-OF-SERVICE STUDY

Q. WHAT IS A CLASS COST-OF-SERVICE STUDY?

A. A CCOSS is an analysis used to determine each class' responsibility for the utility's costs. Thus, it determines whether the revenues a class generates cover the class's cost of service. A CCOSS separates the utility's total costs into portions incurred on behalf of the various customer groups. Most of a utility's costs are incurred to jointly serve many customers. For purposes of rate design and revenue allocation, customers are grouped into homogeneous classes according to their usage patterns and service characteristics. The procedures used to conduct a CCOSS are described in **Appendix C**.

<u>FPL's Class Cost-of-Service Study</u>

Q. HAVE YOU REVIEWED THE CLASS COST-OF-SERVICE STUDY FPL FILED IN THIS PROCEEDING?

A. Yes.

Q. DOES FPL'S CLASS COST-OF-SERVICE STUDY COMPORT WITH ACCEPTED INDUSTRY PRACTICES?

A. Yes, in many respects. FPL's CCOSS generally recognizes the different types of costs as well as the different ways electricity is used by various customers. However, there are several significant flaws that must be corrected before the study can be used to design rates in this proceeding. The flaws include:

- Use of the Twelve Coincident Peak and 25% Average Demand (12CP+25% AD) method to allocate production plant and related costs;

- The failure to recognize that a portion of the costs incurred to provide a distribution network (*i.e.,* investments booked to FERC Account Nos. 364 through 368) is customer-related; and
- Over-allocating distribution plant and related expenses due to the failure to recognize that some customers take service directly from an FPL-owned distribution substation.

Each of the above flaws is discussed below.

<u>Allocation of Production Plant-Related Costs</u>

Q. WHAT IS THE 12CP+25% AD METHOD?

A. The 12CP+25% AD method allocates production plant costs using both 12CP (which is also used to allocation transmission plant related costs) and energy (or average demand). Specifically, the 12CP+25% AD allocation factors are derived as follows:

$$\mathbf{12}\boldsymbol{CP}+\mathbf{25}\%\boldsymbol{AD}=\mathbf{12}\boldsymbol{CP}\%\ \boldsymbol{X}\ \mathbf{75}\%+\boldsymbol{AD}\%\ \boldsymbol{X}\ \mathbf{25}\%$$

Where: 12CP = Twelve Coincident Peak Demand
AD = Average Demand

Average Demand is the same as energy. Thus, 12CP+25% AD weights energy by 25%,

Q. HAS FPL EVER PROPOSED THE 12CP+25% AD METHOD?

A. No.

Q. WHAT METHODOLOGY IS FPL CURRENTLY USING?

A. FPL is currently using the 12CP+1/13th AD method. In contrast to 12CP+25% AD, 12CP+1/13th AD weights energy by 7.6% This method has been used by FPL in rate cases filed since 1982.

Q. WHY DID FPL SUPPORT THE 12CP+1/13TH AD METHOD IN PAST CASES?

A In its last rate case, FPL supported 12CP+1/13th AD stating that:

> ***The 12 CP and 1/13th methodology recognizes that the decision to add generating capacity is driven primarily by peak demands on the system.*** This methodology classifies 12/13ths, or approximately 92% of costs on the basis of coincident peak demand and 1/13th, or approximately 8%, of costs on the basis of energy. That portion classified to demand is allocated to the individual rate classes based on their 12 CP contributions, adjusted for losses, while the portion classified to energy is allocated based on their kWh sales, adjusted for losses. ***Under the 12 CP and 1/13th methodology, all generating units are treated consistently based on their function (i.e. production), their classification (12/13th demand and 1/13th energy), and their allocation (contribution to the system peak and kWh of energy).*** The 12 CP and 1/13th methodology has a significant history of regulatory acceptance in Florida. The 12 CP and 1/13th methodology was used in Docket No. 830465-EI and Docket No. 080677-EI. Furthermore, the FPSC has approved the 12 CP and 1/13th methodology in rate cases involving other investor-owned utilities.[29i] (Emphasis added)

Q. WHAT METHODOLOGY IS CURRENTLY BEING USED BY OTHER FLORIDA INVESTOR-OWNED ELECTRIC UTILITIES?

A. Like FPL, Duke, Gulf and TECO currently use 12CP+1/13th AD. Thus, FPL would be the only Florida IOU not to use the 12CP+1/13th AD method if its proposal is adopted.

Q. WOULD FPL'S DECISION TO CHANGE THE ALLOCATION METHOD AFFECT ONLY THE BASE RATES DETERMINED IN THIS PROCEEDING?

A. No. If the Commission approves FPL's proposal to increase the energy weighting from 7.6% to 25%, it will also change how costs are allocated to, and recovered from

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[29] *In Re: Petition for Rate Increase by Florida Power & Light Company*, Docket No. 120015- EI, Testimony and Exhibits of Joseph A. Ender at 21.

customer classes in the Capacity, Conservation and Environmental clauses. Thus, it would have a more significant impact beyond this base rate case. Not only would adopting 12CP+25% AD shift base rate costs, it will also shift Capacity, Conservation and Environmental costs from residential to non-residential customers.

Q. WHY IS FPL PROPOSING TO CHANGE THE ALLOCATION METHODOLOGY?

A. FPL asserts that 12CP+25% AD is more appropriate because it considers how FPL plans and operates its power plants in response to customer energy and demand needs. FPL also cites how it has installed a significant amount of generation capacity that costs more to construct but is less costly to operate over time than peaking generation. This type of generation improves system heat rate and lowers fuel costs.[30]

Q. DO ANY OF THESE EXPLANATIONS SUPPORT CHANGING THE CURRENTLY USED 12CP+1/13TH AD METHOD?

A. No. First, FPL has not changed the way it plans and operates its system since the last rate case, when it supported 12CP+1/13th AD.[31] Second, FPL does not plan or operate its system any differently than any other Florida utility. Duke, Gulf and TECO are among the other Florida utilities that plan and operate generating systems in Florida. Further, these utilities have had regulatory proceedings before the Commission in recent years. In these cases, Duke and TECO ultimately agreed to use the 12CP+1/13th AD method, and Gulf continued to support the 12CP+1/13th AD

[30] Direct Testimony of Renae B. Deaton at 21.

[31] FPL's Response to FIPUG's Interrogatory No.84.

method. The Commission approved these settlements finding that they were in the public interest. Finally, because FPL is a predominantly summer-peaking utility using 12CP as the demand allocator implicitly recognizes many of the factors cited by Ms. Deaton that purportedly support a higher energy weighting.

Q. WHAT DOES MS. DEATON MEAN BY THE TERM INTERMEDIATE LOAD GENERATION?

A. I presume Ms. Deaton is referring to the combined cycle power plants that FPL has been adding to its system. Specifically, FPL has added over 9,000 MW of combined cycle gas turbine (CCGT) plants over the past ten years.

Q. WHAT IS A COMBINED CYCLE POWER PLANT?

A. A combined-cycle power plant uses both a gas and a steam turbine together to produce up to 50% more electricity from the same fuel than a traditional simple-cycle plant. The waste heat from the gas turbine is routed to the nearby steam turbine, which generates extra power. They are comprised of an array of combustion turbine (CT) peaking units and steam turbines. In a combined-cycle power plant, the exhaust heat from the CTs is captured in a heat recovery steam generator (HRSG), which create steam and deliver that steam to a steam turbine generator, which produces additional electricity.[32]

Q. WHY DO UTILITIES INSTALL COMBINED CYCLE POWER PLANTS?

A. Combined-cycle power plants provide flexible operating capacity. They can be

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[32] https://powergen.gepower.com/resources/knowledge-base/combined-cycle-power-plant-how-it-works.html.

started up more quickly than older steam units and have considerable load-following capability. Load following means that generator output can be automatically adjusted from moment-to-moment so that the available supply always matches the utility's loads in real time. Flexible capacity is especially important for systems having substantial amounts of intermittent resources (*i.e.,* solar, hydro, wind).

With more flexible capacity, CCGTs can also be used to supply Contingency Reserves, which consist of generation and interruptible loads available within 15 minutes. Contingency Reserves are necessary to assure that sufficient capability exists to meet the NERC Disturbance Control Standard and to reestablish resource and demand balance following a Reportable Disturbance.[33] These functions are clearly necessary to maintain system reliability.

Thus, it is a misnomer to characterize CCGTs as "intermediate" capacity. The reality is that CCGTs can provide both base load and load following (*i.e., peaking)* capacity.

Q. ARE COMBINED-CYCLE POWER PLANTS INSTALLED SOLEY TO SAVE FUEL COSTS?

A. No. Ms. Deaton's assertion that any *extra* investment that may be incurred to install CCGTs is driven by fuel savings is an oversimplification, and it confuses cost causation with benefits.

[33] Florida Reliability Coordinating Council, Inc. FRCC Handbook, FRCC Contingency (Operating Reserve) Policy (July 7, 2011) at 1.

Q. PLEASE EXPLAIN.

A. Every CCGT that FPL has installed has received a determination of need. A determination of need means that FPL has demonstrated that the capacity is needed in order to meet its planning reserve requirements. For example, in the OCEC Unit 1 Determination of Need case, FPL asserted that:

> ….the OCEC Unit 1 will enable the Company to meet a projected need for additional generation resources that begins in 2019, continues into 2020, and increases each year thereafter.[34]

The Commission agreed, stating:

> We find that FPL demonstrates a need for additional generation, beginning in 2019***, in order to maintain electric system reliability and integrity based on a reasonable load forecast and a 20% reserve margin criterion as discussed below***.[35]

Thus, the factor driving the need for new capacity is the growth in projected peak demand and the need to maintain an appropriate reserve margin. In other words, peak demand is the cost causer, while fuel savings is the outcome of installing more efficient generation capacity. Ms. Deaton would have us believe that the opposite is true (*i.e.* fuel savings drive plant investment) which is clearly contradicted by the facts.

Having determined that capacity is needed, FPL has chosen the generation technology that would result in the lowest overall cost. CCGTs are the most efficient generating technology and thus are also the lowest cost source of capacity.

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[34] *In re*: *Petition For Determination Of Need For Okeechobee Clean Energy Center Unit 1, by Florida Power & Light Company*, Docket No. 150196-EI, Order No. PSC-16-0032-FOF-EI at 2 (Jan. 19, 2016)

[35] *Id.* at 4.

Q. ARE CCGTS THE ONLY TYPE OF CAPACITY THAT FPL HAS INVESTED IN OVER THE PAST TEN YEARS?

A. No. First, FPL is upgrading the "Compressor" section and improving the "Combustor" section of 26 of its GE 7FA CTs. Second, FPL is also replacing approximately 1,700 MW of peaking capacity. These investments are projected to be completed by the end of 2017.[36] These investments demonstrate FPL's continuing need for peaking capacity to meet both system and local area needs.

Q. ARE THERE OTHER FACTORS, BESIDES THE CAPITAL COST-FUEL COST TRADE-OFF, THAT CAN AFFECT UTILITY INVESTMENT DECISIONS?

A. Yes. A generating unit represents a 30 to 60-year investment. The long life-cycle makes it difficult for a utility to anticipate every contingency, such as new regulations that require utilities to cease using certain types of fuels, limit operations or install costly equipment to meet prevailing emissions standards or changes in public policy. These contingencies could transform what is otherwise an economical resource under today's circumstances into an uneconomical resource under different circumstances. Thus, it behooves a utility to manage these risks by installing a diversified portfolio of generating resources.

Q. HAS FPL ADEQUATELY SUPPORTED ITS PROPOSAL TO CHANGE THE COST ALLOCATION METHODOLOGY FROM 12CP+1/13TH AD TO 12CP+25% AD?

A. No. FPL has provided no study to support changing the energy weighting from 7.6%

[36] Direct Testimony of Roxane R. Kennedy at 16-17.

to 25%.[37] Further, FPL's decision to install CCGTs is no different from any other growing utility that requires new and more efficient capacity to meet the projected increase in peak demand, provide an appropriate reserve margin and replace older less efficient capacity. Finally, given that FPL's new CCGTs and new/modernized CTs enhance the utility's load following capabilities, which provide significant reliability benefits, it is particularly inappropriate to increase the energy weighting for the entirety of FPL's entire generation fleet.

Q. WHAT DO YOU RECOMMEND?

A. The Commission should reject FPL's proposal to use 12CP+25% AD and retain 12CP+1/13th AD.

Distribution Cost Classification

Q. HOW HAS FPL CLASSIFIED DISTRIBUTION INVESTMENT?

A. FPL has classified all of its distribution network investment as demand-related costs.

Q. WHAT DO YOU MEAN BY THE DISTRIBUTION NETWORK?

A. The distribution "network" consists of FPL's investment in poles, towers, fixtures, overhead lines and line transformers. These investments are booked to FERC Account Nos. 364, 365, 366, 367, and 368.

Q. IS FPL'S PROPOSAL CONSISTENT WITH COST CAUSATION?

A. No. The purpose of the distribution network is to deliver power from the transmission grid to the customer, where it is eventually consumed. Certain investments (*e.g.,*

[37] FPL's Response to FIPUG's Production of Documents Request No. 33.

meters, service drops) must be made just to attach a customer to the system. These investments are clearly customer-related. However, each utility must also invest in a distribution network, which provides the necessary voltage support to allow power to flow to the customer. Thus, a portion of the distribution network should also be classified as a customer-related cost. Classifying these costs entirely to demand is unreasonable.

Q HOW IS FPL'S PROPOSAL TO CLASSIFY ALL DISTRIBUTION NETWORK COSTS TO DEMAND UNREASONABLE?

A FPL's proposal would result in allocating far too few poles, overhead conductors and underground conductors to Residential and General Service customers and far too many poles, overhead conductors and underground conductors to GSLD and CILC customers. This conclusion is demonstrated in the table below. To arrive at this conclusion, I allocated the number of poles, overhead conductors and underground conductors using FPL's distribution demand allocation factor. I then divided the results by the number of customers to derive the number of primary poles and the lengths of overhead and underground conductors per customer.

Effect of FPL's Proposal to Classify All Distribution Network Facilities As Demand-Related Costs			
Customer Class	**Distribution Poles (No. Per Customer)**	**Overhead Conductors (1000 ft. Per Customer)**	**Underground Conductors (1000 ft. Per Customer)**
Residential	0.2	0.02	0.00
General Service	0.2	0.02	0.00
GS Demand	2.3	0.45	0.10
GS LD	37.3	57.94	49.56
CILC	60.1	386.37	356.88
MET	32.7	557.29	522.31
Standby	0.7	0.26	0.16

As the table demonstrates, FPL's proposed 100% demand allocation results in over 37 poles, 58,000 feet of overhead conductors and 50,000 feet of underground conductors being allocated to each GSLD customer. Similarly, over 60 poles, 386,000 feet of overhead conductors and 357,000 feet of underground conductors are allocated to each CILC customer.

In stark contrast, less than 1 pole, less than 20 feet of overhead conductors and less than 5 feet of underground conductors are allocated to each Residential and GS customer and only 2.3 poles, 450 feet of overhead conductors and 100 feet of underground conductors per GSD customer.

These results are not only highly unlikely, it demonstrates how FPL's proposal is not consistent with either cost causation or the physical realities of the distribution system.

Q. WHY ELSE IS IT APPROPRIATE TO CLASSIFY A PORTION OF THE DISTRIBUTION NETWORK INVESTMENTS AS A CUSTOMER-RELATED COST?

A. Classifying a portion of the distribution network as a customer-related cost recognizes the reality that every utility must provide a path through which electricity can be delivered to each and every customer, regardless of the peak demand or energy consumed. Further, that path must be in place if the utility is to meet its obligation to provide service upon demand.

Absent a connection to the system, a customer cannot take power. Further, the connecting facilities must provide voltage support before any power or energy can be consumed. These prerequisites (*i.e.,* a grid connection with facilities sized to provide voltage support) are clearly related to the existence of the customer.

Q. DO ANY OTHER FACTORS JUSTIFY CLASSIFYING A PORTION OF THE DISTRIBUTION NETWORK AS CUSTOMER-RELATED?

A. Yes. The distribution network must comply with this Commission's standards of construction. Specifically, Rule 25-6.034 F.A.C. requires that:

> (1) The facilities of each utility shall be constructed, installed, maintained and operated in accordance with generally accepted engineering practices to assure, as far as is reasonably possible, continuity of service and uniformity in the quality of service furnished.
>
> (2) Each utility shall, at a minimum, comply with the National Electrical Safety Code [ANSI C-2) [NESC], incorporated by reference in Rule 25-6.0345, F.A.C.

Rule 25-6.0342 F.A.C. was more recently enacted. It requires utilities to cost-effectively strengthen critical electric infrastructure to increase the ability of transmission and distribution facilities to withstand extreme weather conditions and reduce restoration costs and outage times to end-use customers associated with extreme weather conditions.

Q. IS DISTRIBUTION STORM HARDENING A SIGNIFICANT COST DRIVER IN THIS CASE?

A. Yes. Based on its projections, FPL will have invested over $2 billion in distribution storm hardening for the period 2014 through 2018.[38] Thus, distribution storm hardening costs are a major driver of FPL's proposed rate increase.

Q. ARE DISTRIBUTION STORM HARDENING INVESTMENTS NEEDED FOR FPL TO MEET PEAK DEMAND?

A. No. Distribution storm hardening investments are not required because of the amount of electric power and energy demanded. They are required because of the existence of each customer and FPL's obligation to provide a reliable connection to the grid. Thus, there is no question that a significant portion of the distribution network is a customer-related cost.

Q. IS IT A RECOGNIZED PRACTICE TO CLASSIFY A PORTION OF THE DISTRIBUTION NETWORK AS CUSTOMER-RELATED?

A. Yes. For example, the NARUC Electric Utility Cost Allocation Manual states that:

> Distribution plant Accounts 364 through 370 involve demand and customer costs. The customer component of distribution facilities is that portion of costs which varies with the number of customers. Thus, the number of poles, conductors, transformers, services, and

[38] FPL's Response to SFHHA's Interrogatory No. 99.

> meters are directly related to the number of customers on the utility's system.[39]

An excerpt from the Manual pertaining to distribution cost classification is provided in **Exhibit ___ (JP-10)**.

Q. IS THIS PRACTICE FOLLOWED BY OTHER ELECTRIC UTILITIES?

A. Yes. **Exhibit ___ (JP-11)** is a partial list of the utilities that classify some portion of their distribution network investment as customer-related. As can be seen, the list includes both Gulf and TECO. Thus, this practice has been previously accepted by the Commission.

Q. WHAT DO YOU RECOMMEND?

A. I recommend that approximately 26% of FPL's distribution network costs should be classified as customer-related. As shown in **Exhibit ___ (JP-11)**, both Gulf and TECO classify approximately the same portion of their investments in FERC Account Nos. 364 through 368, respectively, as a customer-related cost. Since FPL has not conducted its own study, I recommend that the specific customer cost determinations by Gulf and TECO be applied to FPL.

Distribution Substation Service

Q. DOES FPL PROVIDE DISTRIBUTION SUBSTATION SERVICE?

A. Yes.[40]

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[39] NARUC, *Electric Utility Cost Allocation Manual* at 90 (Jan. 1992).

[40] FPL's Response to FIPUG's Interrogatory No. 17.

Q. WHAT IS DISTRIBUTION SUBSTATION SERVICE?

A. Distribution substation service is provided when a customer takes service directly from a utility-owned distribution substation. Under these circumstances, the customer does not require the utility to install any other distribution facilities to provide service.

Q. HOW IS DISTRIBUTION SUBSTATION SERVICE DIFFERENT FROM OTHER TYPES OF DELIVERY SERVICES?

A. Examples of other types of electric delivery services are provided in **Exhibit ___ (JP-12)**

1. Transmission (page 1)
2. Distribution Primary (page 2)

A transmission-level customer takes service directly from the transmission system. This means that the customer owns all of the transformation equipment, as well as the lower voltage distribution facilities used to deliver electricity throughout the customer's grid.

In contrast to Transmission service, Distribution Primary service requires that the utility own not only the transformation equipment to step power down from transmission to distribution level, but also the wires to deliver electricity to the customer. Thus, Distribution Primary service requires the utility to invest in hundreds, or even thousands, of miles of distribution wires and related facilities. It also incurs more electrical losses as power and energy are delivered through the distribution system. Because of the necessity of providing additional wires, related facilities, and the incurrence of greater losses, Distribution Primary service is more costly to provide than either Transmission or Distribution Substation services.

Q. IS DISTRIBUTION SUBSTATION SERVICE DIFFERENT FROM TRANSMISSION AND OTHER TYPES OF DISTRIBUTION DELIVERY SERVICES?

A. Yes. Distribution Substation service is shown in **Exhibit ___ (JP-12)**, page 3. It is clearly distinguishable. Unlike transmission service, a Distribution Substation customer does not own the initial transformation equipment located at the substation where electricity is stepped down from transmission voltage to a distribution voltage. However, a Distribution Substation customer owns its own distribution facilities. The ownership of private distribution lines distinguishes a Distribution Substation customer from a Distribution Primary customer. The difference is that the former provides its own distribution wires service, not the utility. Thus, Distribution Substation service is distinct from both Transmission and Distribution Primary services.

Q. DOES FPL'S COST-OF-SERVICE STUDY RECOGNIZE DISTRIBUTION SUBSTATION SERVICE?

A. No. FPL's CCOSS treats the customers receiving Distribution Substation service the same as all other Primary Distribution customers. This is despite the fact that no primary distribution investment is required by FPL to service a Distribution Substation customer.

Q. WHAT IS THE CONSEQUENCE OF THE FAILURE TO SEPARATELY RECOGNIZE DISTRIBUTION SUBSTATION SERVICE?

A. FPL includes the loads of customers that take Distribution Substation service in allocating primary distribution costs.[41] Thus, in addition to allocating distribution substation costs, Distribution Substation customers were allocated costs associated with FERC Account Nos. 364, 365, 366, 367, and 368.

Thus, Distribution Substation customers are paying distribution costs that they do not impose on the system because they hook up to the distribution system at the substation. It also means that FPL has over-stated the allocation of distribution primary costs to those distribution level non-residential customer classes that have customers taking Distribution Substation service. Accordingly, the rates of return calculated for these classes in FPL's CCOSS are understated.

Q. WHAT CUSTOMER CLASSES HAVE LOADS TAKING DISTRIBUTION SUBSTATION SERVICE?

A. This is unknown because FPL does not track statistics on the customers that take Distribution Substation service.[42]

Q. WHAT DO YOU RECOMMEND?

A. FPL should be ordered to develop the information necessary to identify the customers that take Distribution Substation service. This includes the loads and number of accounts of these customers.

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[41] FPL's Response to FIPUG's Interrogatory No. 85.

[42] *Id.*

FPL should also be ordered to file a new Distribution Substation tariff that reflects the lower costs of providing this type of distribution service. The new tariff should be filed within 90 days after a final order is issued in this proceeding.

Revised Class Cost-of-Service Study

Q. HAVE YOU CONDUCTED A CLASS COST-OF-SERVICE STUDY THAT INCORPORATES YOUR RECOMMENDED CHANGES TO FPL'S STUDY?

A. Yes. The revised CCOSS at present rates is provided in **Exhibit ___ (JP-13)**. The revised CCOSS incorporates the following changes:

- Production plant and related costs were allocated to customers classes using the 12CP+1/13th AD method.
- Distribution network costs (*i.e.,* FERC Account Nos. 364-368) were partially classified as customer-related using the same percentages developed by Gulf and TECO in their most recent rate cases.

However, the revised CCOSS does not recognize Distribution Substation service because FPL could not provide the necessary information. Thus, the rates of return from the classes that most likely serve Distribution Substation customers (*i.e.,* GSLD, CILC-1-D) are understated.

Q. HAVE YOU DEVELOPED A CLASS REVENUE ALLOCATION BASED ON THE REVISED CLASS COST-OF-SERVICE STUDY?

A. Yes. **Exhibit ___ (JP-14)** is my recommended base revenue allocation using the CCOSS presented in **Exhibit ___ (JP-13)**. It is designed to move all rates approximately the same distance closer to cost except in limited circumstances when gradualism was applied. To give appropriate recognition to gradualism, I limited the base revenue increase to 150% of FPL's proposed 15.4% system average base rate increase, which is 23.1%, excluding the clauses. This proposal does not change the current CILC/CDR credits.

Q. WOULD ALL RATES MOVE CLOSER TO COST UNDER YOUR PROPOSED CLASS REVENUE ALLOCATION?

A. Yes. **Exhibit ___ (JP-15)** summarizes the revised CCOSS results at present and recommended rates. As can be seen, the major customer classes (and rates overall) would move approximately 23% closer to cost.

8. GSLD/CILC RATE DESIGN

Q. WHAT RATE DESIGN ISSUES WILL YOU ADDRESS?

A. Rate design is the continuation of the cost allocation process. Many of the same principles that drive the CCOSS and class revenue allocation also affect rate design. In this section, I will discuss:

- The Demand and Energy charges in the GSLD and CILC rates.
- Why the CILC/CDR credits cannot and should not be "reset" as FPL is proposing in this proceeding.

<u>Demand and Energy Charges</u>

Q. DESCRIBE THE DEMAND AND ENERGY CHARGES.

A. These charges are designed to recover base rate (non-fuel) costs. Demand charges are billed relative to a customer's maximum metered (kW) demand in the billing month, while the Energy charges are billed on the amount of kWh purchased.

Q. HOW IS FPL PROPOSING TO CHANGE THE DEMAND AND ENERGY CHARGES?

A. FPL states that it increased the current Demand and Energy charges by the same rate class percentage maintaining demand and energy rate relationships established in previous rate proceedings. Further, the Energy charges were adjusted to achieve revenue neutrality.[43]

FPL's proposed GSLD and CILC rate designs are shown in **Exhibit ___ (JP-16)**. As can be seen, FPL's proposed rate design would essentially increase the Demand and Energy charges by approximately the same percentage.

[43] Direct Testimony of Tiffany C. Cohen, Exhibit TCC-6 at 7-8 and 16-17.

Q. HOW SHOULD THE GSLD/CILC RATES BE DESIGNED?

A. Consistent with cost causation, the Customer, Demand and Energy charges should closely reflect the customer-related, demand-related, and energy-related unit costs as derived in the CCOSS. Ironically, FPL followed this practice in designing the proposed Customer charges, but it ignored this practice in designing the proposed Demand and Energy charges.

Q. WHAT ARE THE UNIT ENERGY COSTS DERIVED FROM THE CLASS COST-OF-SERVICE STUDY?

A. The 2017 unit energy costs and the corresponding proposed charges for the GSLD and CILC classes are as follows:

GSLD/CILC Energy Charges (¢/kWh)

Class	Unit Cost[44]	Present Charge	Proposed Charge
GSLD-1	0.7788	1.035	1.314
GSLD-2	0.7739	1.003	1.291
GSLD-3	0.7556	0.892	1.127
CILC-1D	0.7734	0.822	1.272
CILC-1T	0.7562	0.731	1.307

The unit costs are based on the 12CP+1/13th AD CCOSS at equalized rates of return. As can be seen, FPL's proposed Energy charges would be significantly (between 49% and 73%) higher than the corresponding energy costs. All of the current Energy charges (except CILC-1T) already exceed unit cost. The fact that the proposed standard Energy charges would exceed unit cost means that the

[44] MFR No. E-6b, Attachment No. 2 of 2 at 2 and 6.

corresponding Demand charges are understated, and a significant amount of demand-related costs would be collected in the Energy charge. The proposed time-of-use (TOU) rates, which are derived from the standard rates, were also designed to collect a significant amount of demand-related costs in the proposed On-Peak Energy charges.

Q. HAS FPL ADEQUATELY EXPLAINED WHY THE ENERGY CHARGES ARE MUCH HIGHER THAN ACTUAL ENERGY COSTS?

A. No. As previously stated, FPL proposed maintaining the existing relationships while adjusting the Energy charges to achieve the desired class revenue targets.

Q. WHAT DO YOU RECOMMEND?

A. The GSLD and CILC Energy charges should move closer to unit cost. However, my analysis reveals that the GSLD and CILC Energy charges are, for the most part, already above cost. Based on this fact, coupled with recognizing gradualism, I recommend that the increase in the current GSLD and CILC standard Energy charges should not exceed 50% of the increase in the corresponding Demand charges. Any revenue shortfall resulting from this change should be recovered in the corresponding GSLD and CILC Demand Charges.

CILC/CDR Credits

Q. IS FPL PROPOSING ANY CHANGE IN THE DESIGN OF ITS NON-FIRM RATES?

A. Yes. FPL is proposing to "reset" the payments to customers taking non-firm service under Rate CILC and Rider CDR. The proposal would reduce the payments by about 37% as shown in the table below.

FPL's Proposed Reset of the CILC/CDR Credits ($000)				
Customer Class	Present Rates[45]	Proposed Rates	Reduction[46]	Percent Reduction
	(1)	(2) = (1) – (3)	(3)	(4)
CILC-1D	$27,076	$17,132	$9,943	37%
CILC-1G	945	575	370	39%
CILC-1T	13,667	8,433	5,234	38%
GSD	6,139	3,938	2,201	36%
GSLD-1	11,579	7,428	4,152	36%
GSLD-2	2,982	1,913	1,069	36%
Total	$62,387	$39,418	$22,969	37%

The impact of FPL's proposal would reduce the credits by $23 million or 37%. The reductions in the CDR and CILC credits would be 36% and 38% respectively.

Q. HOW ARE THE CREDITS PAID TO THE CILC AND CDR CUSTOMERS RECOVERED?

A. These payments are recovered in the Conservation clause, and they are paid by all customers, including the CILC and CDR customers.

Q. PLEASE DESCRIBE THE CILC RATE.

A. The CILC (Commercial and Industrial Load Control) rate is a tariff that allows FPL to control customer-established loads of 200 kW or greater during system emergencies. Load control equipment is installed at the customer's facility to allow FPL to control

[45] FPL's Response to OPC Production of Documents Request No. 2, Deaton Workpaper Sheet E-5 Test.

[46] MFR No. E-14 Attachment 2 of 6 at 30.

customer loads. In return for agreeing to allow FPL to control a portion or all of a customer's load, the customer receives a lower rate. The terms under which FPL can control a customer's load are as follows:

> The Customer's controllable load served under this Rate Schedule is subject to control when such control alleviates any emergency conditions or capacity shortages, either power supply or transmission, or whenever system load, actual or projected, would otherwise require the peaking operation of the Company's generators. Peaking operation entails taking base loaded units, cycling units or combustion turbines above the continuous rated output, which may overstress the generators.
>
> <u>Frequency</u>: The Control Conditions will typically result in less than fifteen (15) Load Control Periods per year and will not exceed twenty-five (25) Load Control Periods per year. Typically, the Company will not initiate a Load Control Period within six (6) hours of a previous Load Control Period.
>
> <u>Notice</u>: The Company will provide one (1) hour's advance notice or more to a Customer prior to controlling the Customer's controllable load. Typically, the Company will provide advance notice of four (4) hours or more prior to a Load Control Period.
>
> <u>Duration</u>: The duration of a single Load Control Period will typically be four (4) hours and will not exceed six (6) hours.
>
> In the event of an emergency, such as a Generating Capacity Emergency (see Definitions) or a major disturbance, greater frequency, less notice, or longer duration than listed above may occur. If such an emergency develops, the Customer will be given 15 minutes' notice. Less than 15 minutes' notice may only be given in the event that failure to do so would result in loss of power to firm service customers or the purchase of emergency power to serve firm service customers. The Customer agrees that the Company will not be liable for any damages or injuries that may occur as a result of providing no notice or less than one (1) hour's notice.[47]

[47] FPL Tariff, Fourth Revised Sheet No. 8.652.

Q. PLEASE DESCRIBE RIDER CDR.

A. Rider CDR (Commercial/Industrial Demand Reduction) is similar to CILC. This program allows FPL to control customer-established loads of 200 kW or greater during system emergencies. Load control equipment is installed at the customer's facility to allow FPL to control customer loads. The terms under which FPL can control a CDR customer's load are similar to CILC as follows:

> The Customer's controllable load served under this Rider is subject to control when such control alleviates any emergency conditions or capacity shortages, either power supply or transmission, or whenever system load, actual or projected, would otherwise require the peaking operation of the Company's generators. Peaking operation entails taking base loaded units, cycling units or combustion turbines above the continuous rated output, which may overstress the generators.
>
> <u>Frequency</u>: The Control Conditions will typically result in less than fifteen (15) Load Control Periods per year and will not exceed twenty-five (25) Load Control Periods per year. Typically, the Company will not initiate a Load Control Period within six (6) hours of a previous Load Control Period.
>
> <u>Notice</u>: The Company will provide one (1) hour's advance notice or more to a Customer prior to controlling the Customer's controllable load. Typically, the Company will provide advance notice of four (4) hours or more prior to a Load Control Period.
>
> <u>Duration</u>: The duration of a single Load Control Period will typically be three (3) hours and will not exceed six (6) hours.
>
> In the event of an emergency, such as a Generating Capacity Emergency (see Definitions) or a major disturbance, greater frequency, less notice, or longer duration than listed above may occur. If such an emergency develops, the Customer will be given 15 minutes' notice. Less than 15 minutes' notice may only be given in the event that failure to do so would result in loss of power to firm service customers or the purchase of emergency power to serve firm service customers. The Customer agrees that the Company will not be liable

> for any damages or injuries that may occur as a result of providing no notice or less than one (1) hour's notice.[48]

Q. DO THE CILC AND CDR TARIFFS PROVIDE BENEFITS TO FPL AND ITS FIRM CUSTOMERS?

A. Yes. By agreeing to curtail load during system emergencies and other capacity-related events, FPL is able to maintain reliable service to its firm customers with less installed capacity, and thus, less costs. This is because under the Commission-approved statewide reserve margin requirement, non-firm load is not included in FPL's peak demand projections that are used to assess resource adequacy when planning to meet its firm load.

Q. WHY IS FPL PROPOSING TO "RESET" THE CILC/CDR CREDITS?

A. FPL has provided no real explanation other than a desire to maintain them at the levels that existed prior to the 2012 Settlement adjusted only for the commensurate base rate increases for the Canaveral, Riviera and Port Everglades modernizations.[49] Further, the proposed reset is not based on any updated cost-effectiveness studies.[50]

Q. DOES THIS EXPLANATION JUSTIFY REDUCING THE CILC/CDR CREDITS BY OVER 30%, AS FPL IS PROPOSING IN THIS CASE?

A. No. First, FPL believes that because the CILC/CDR credits are set in the Demand

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[48] FPL Tariff, Second Revised Sheet No. 8.681.

[49] FPL's Response to FIPUG's Interrogatory No. 31.

[50] FPL's Response to FIPUG's Interrogatory No. 24.

Side Management Docket, they cannot be changed in a base rate case.[51] FPL's explanation assumes that the credits established in the last Demand Side Management Docket were based on the levels authorized prior to the settlement of its last rate case.

Q. WHEN WERE THE CURRENT CILC/CDR CREDITS ESTABLISHED?

A. They were established in FPL's last rate case, Docket No. 120015-EI. The rates approved in the last rate case became effective on January 2, 2013.

Q. WHY WERE THE CREDITS INCREASED IN THE LAST RATE CASE?

A. Prior to the last rate case, the CDR credits had not been increased since 2004, and I am unaware of any changes in the CILC incentive payments since prior to FPL's 2008 rate case. The increase in the credits in the 2012 rate case, thus, reflects inflationary factors, coupled with strong load growth that has prompted FPL to add new capacity to maintain reliability. FPL can use interruptible load to defer new generation capacity, such as peaking units. Hence, the higher CILC/CDR credits recognized the greater value of interruptible service in allowing FPL to maintain reliable service to its firm customers at a lower cost than building new capacity.

Q. WHEN DID FPL'S MOST RECENT DEMAND SIDE MANAGEMENT DOCKET OCCUR?

A. FPL's most recent Demand Side Management case was Docket No. 150085-EG. A final order in this case was issued on August 19, 2015. Thus, the evaluation of the

[51] Direct Testimony of Tiffany C. Cohen, Exhibit TCC-6 at 17.

CILC/CDR programs was based on the credits approved in the settlement of the last rate case, which the Commission accepted.[52]

Q. DID THE FINAL ORDER IN THE DEMAND SIDE MANAGEMENT DOCKET APPROVE THE CONTINUATION OF THE CILC/CDR PROGRAMS?

A. Yes. In approving the continuation of the CILC/CDR programs, the Order states:

> All of FPL's proposed programs with allocated demand and energy savings pass both the RIM and Participants tests, with the exception of one residential program. These tests consist of the benefits divided by the costs, as defined by Rule 25-17.008, F.A.C., so that programs are determined to be cost-effective if the result of the test is a ratio greater than 1.00.[53]

Further, the then effective Rider CDR was found to have a benefit-cost ratio of 1.6 times, meaning that it is still cost-effective.

Q. SHOULD THE COMMISSION APPROVE FPL'S PROPOSED 37% REDUCTION IN THE CILC/CDR CREDITS?

A. No. The Commission's Order in FPL's most recent Demand Side Management Docket approved the continuation of the CILC/CDR programs then in effect, which are the same credits that were implemented following the settlement of FPL's last rate case. Thus, FPL's point that the credits cannot be changed in this case is correct, which means that the credits cannot now be reset as FPL is proposing. Further, the credits should not be reset as they help FPL avoid or defer new

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[52] FPL's Response to FIPUG's Interrogatory No. 31.

[53] *In Re: Petition for Approval of Florida Power & Light Company's Demand-Side Management Plan and Request to Cancel Closed on Call Tariff Sheets*, Docket No. 150085-EG, Order No. PSC-15-0331-PAA-EG at 6 (Aug. 19, 2015).

generation capacity and the corresponding associated capital expenditures and other fixed costs.

Q, WHAT DO YOU RECOMMEND?

A. The Commission should reject FPL's proposal to reset the CILC/CDR credits.

9. CONCLUSION

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS.

A. The Commission should accept the following recommendations:

- FPL's proposed SYA should be rejected because it is speculative, inappropriate and unnecessary.
- The proposed 50 basis point performance incentive should be rejected because it is unnecessary to reward FPL for providing the quality service that is expected and because it would force customers to pay twice (in the form of higher rates) for the many cost-reduction measures that have been implemented.
- CWIP should be removed from rate base because it is not needed to preserve FPL's financial integrity and because its four-year rate plan would result in rate shock.
- The 2017 cost of long-term debt should be reduced to 4.5489% to recognize the more recent lower interest rate projections and global and other economic events.
- FPL's proposed 11% ROE (excluding the performance incentive) is clearly excessive given that it would be coupled with a 60% financial equity ratio and because it would be significantly higher than has been previously authorized both by this Commission and state regulatory commissions in rate case decision since 2012. Assuming no change in the equity ratio, FPL's ROE should be set below the average of the ROEs authorized by state regulatory commissions.
- FPL's equity ratio is 890 basis points higher than other vertically integrated investor-owned electric utilities, which have average financial equity ratios of 51.1%. Accordingly, FPL's financial equity ratio should not exceed 51.1%.
- Base rates should move closer to cost using an appropriate CCOSS and properly recognizing gradualism.
- FPL's proposed application of gradualism is flawed and would not prevent the CILC/CDR customers from experiencing substantial rate shock. Further, gradualism should apply to changes in base rates because the clauses are not subject to change in this proceeding.
- FPL's CCOSS should be rejected because it does not reflect cost causation.
- There is no valid justification to change the production plant allocation method that is currently being used not only by FPL, but also by Duke, Gulf, and TECO. Similarly, approximately 26% of FPL's distribution

network costs should be classified as customer-related costs, which is also consistent with Gulf, TECO and many other electric utilities

- FPL should file a tariff to recognize the lower cost of serving customers directly at (or within two spans of) a distribution substation within 90 days after a final order is issued in this proceeding.
- The GSLD and CILC Energy charges are already above cost and should not be increased by more than 50% of the increase in the corresponding Demand charges.
- The CILC/CDR credits cannot and should not be reset in this proceeding because doing so would violate past practice and unnecessarily diminish the value of a system resource that helps FPL provide reliable service at the lowest reasonable cost.

Q. DOES THAT CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

APPENDIX A

Qualifications of Jeffry Pollock

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. Jeffry Pollock. My business mailing address is 12647 Olive Blvd., Suite 585, St. Louis, Missouri 63141.

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

A. I am an energy advisor and President of J. Pollock, Incorporated.

Q. PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A. I have a Bachelor of Science Degree in Electrical Engineering and a Masters Degree in Business Administration from Washington University. I have also completed a Utility Finance and Accounting course.

Upon graduation in June 1975, I joined Drazen-Brubaker & Associates, Inc. (DBA). DBA was incorporated in 1972 assuming the utility rate and economic consulting activities of Drazen Associates, Inc., active since 1937. From April 1995 to November 2004, I was a managing principal at Brubaker & Associates (BAI).

During my tenure at both DBA and BAI, I have been engaged in a wide range of consulting assignments including energy and regulatory matters in both the United States and several Canadian provinces. This includes preparing financial and economic studies of investor-owned, cooperative and municipal utilities on revenue requirements, cost of service and rate design, and conducting site evaluation. Recent engagements have included advising clients on electric restructuring issues, assisting clients to procure and manage electricity in both competitive and regulated markets, developing and issuing requests for proposals (RFPs), evaluating RFP responses and contract negotiation. I was also responsible for developing and presenting seminars on electricity issues.

I have worked on various projects in over 20 states and several Canadian provinces, and have testified before the Federal Energy Regulatory Commission and the state regulatory commissions of Alabama, Arizona, Arkansas, Colorado, Delaware, Florida, Georgia, Illinois, Indiana, Iowa, Kansas, Louisiana, Minnesota, Mississippi, Missouri, Montana, New Jersey, New Mexico, New York, Ohio, Pennsylvania, Texas, Virginia, Washington, and Wyoming. I have also appeared before the City of Austin Electric Utility Commission, the Board of Public Utilities of Kansas City, Kansas, the Board of Directors of the South Carolina Public Service Authority (a.k.a. Santee Cooper), the Bonneville Power Administration, Travis County (Texas) District Court, and the U.S. Federal District Court.

Q. PLEASE DESCRIBE J. POLLOCK, INCORPORATED.

A. J.Pollock assists clients to procure and manage energy in both regulated and competitive markets. The J.Pollock team also advises clients on energy and regulatory issues. Our clients include commercial, industrial and institutional energy consumers. J.Pollock is a registered Class I aggregator in the State of Texas.

Appendix B
Testimony Filed in Regulatory Proceedings
by Jeffry Pollock

PROJECT	UTILITY	ON BEHALF OF	DOCKET	TYPE	REGULATORY JURISDICTION	SUBJECT	DATE
160103	CENTERPOINT ENERGY ARKANSAS GAS	Arkansas Gas Consumers, Inc.	15-098-U	Supplemental	AR	Support for Settlement Stipulation	7/1/2016
160503	MIDAMERICAN ENERGY COMPANY	Tech Customers	RPU-2016-0001	Direct	IA	Application of Advanced Ratemaking Principles to Wind XI	6/21/2016
151101	NORTHERN STATES POWER COMPANY	Xcel Large Industrials	15-826	Direct	MN	Class Cost-of-Service Study, Class Revenue Allocation, Multi-Year Rate Plan, Rate Design	6/14/2016
160103	CENTERPOINT ENERGY ARKANSAS GAS	Arkansas Gas Consumers, Inc.	15-098-U	Surrebuttal	AR	Incentive Compensation, Class Cost-of-Service Study, Class Revenue Allocation, LCS-1 Rate Design	6/7/2016
150504	SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd.	15-00296-UT	Direct	NM	Support of Stipulation	5/13/2016
160102	CHEYENNE LIGHT, FUEL AND POWER COMPANY	Dyno Nobel, Inc. and HollyFrontier Cheyenne Refining LLC	20003-146-ET-15	Cross	WY	Large Power Contract Service Tariff	4/15/2016
160103	CENTERPOINT ENERGY ARKANSAS GAS	Arkansas Gas Consumers, Inc.	15-098-U	Direct	AR	Incentive Compensation, Class Cost-of-Service Study, Class Revenue Allocation, Act 725, Formula Rate Plan	4/14/2016
160102	CHEYENNE LIGHT, FUEL AND POWER COMPANY	Dyno Nobel, Inc. and HollyFrontier Cheyenne Refining LLC	20003-146-ET-15	Direct	WY	Large Power Contract Service Tariff	3/18/2016
150803	ENTERGY LOUISIANA, LLC, ENTERGY GULF STATES LOUISIANA, L.L.C., AND ENTERGY LOUISIANA POWER, LLC	Occidental Chemical Corporation	U-33770	Cross-Answering	LA	Approval to Construct St. Charles Power Station	2/26/2016
151102	NORTHERN INDIANA PUBLIC SERVICE COMPANY	NLMK-Indiana	44688	Cross-Answering	IN	Cost-of-Service Study, Rider 775	2/16/2016
150803	ENTERGY LOUISIANA, LLC, ENTERGY GULF STATES LOUISIANA, L.L.C., AND ENTERGY LOUISIANA POWER, LLC	Occidental Chemical Corporation	U-33770	Direct	LA	Approval to Construct St. Charles Power Station	1/21/2016
150701	ELECTRIC TRANSMISSION TEXAS LLC	Freeport-McMoRan Copper & Gold, Inc.	44941	Cross-Rebuttal	TX	Class Cost-of-Service Study, Class Revenue Allocation; Rate Design	1/15/2016
150503	ENTERGY ARKANSAS, INC.	Arkansas Electric Energy Consumers, Inc.	15-015	Supplemental	AR	Support for Settlement Stipulation	12/31/2015
150701	ELECTRIC TRANSMISSION TEXAS LLC	Freeport-McMoRan Copper & Gold, Inc.	44941	Direct	TX	Class Cost-of-Service Study, Class Revenue Allocation; Rate Design	12/11/2015

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150503	ENTERGY ARKANSAS, INC.	Arkansas Electric Energy Consumers, Inc.	15-015	Surrebuttal	AR	Post-Test-Year Additions; Class Cost-of-Service Study; Class Revenue Allocation; Rate Design; Riders; Formula Rate Plan	11/24/2015
131001	MID-KANSAS ELECTRIC COMPANY, LLC, PRAIRIE LAND ELECTRIC COOPERATIVE, INC., SOUTHERN PIONEER ELECTRIC COMPANY, THE VICTORY ELECTRIC COOPERATIVE ASSOCIATION, INC., AND WESTERN COOPERATIVE ELECTRIC ASSOCIATION, INC.	Western Kansas Industrial Electric Consumers	16-MKEE-023	Direct	KS	Formula Rate Plan for Distribution Utility	11/17/2015
130901	ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	45084	Direct	TX	Transmission Cost Recovery Factor Revenue Increase.	11/17/2015
140103	GEORGIA POWER COMPANY	Georgia Industrial Group and Georgia Assocation of Manufacturers	39638	Direct	GA	Natural Gas Price Assumptions, IFR Mechanism, Seasonal FCR-24 Rates, Imputed Capacity	11/4/2015
150801	NEW YORK STATE ELECTRIC & GAS CORPORATION and ROCHESTER GAS AND ELECTRIC CORPORATION	Multiple Intervenors	15-E-0283 15-G-0284 15-E-0285 15-G-0286	Rebuttal	NY	Electric and Gas Embedded Class Cost-of-Service Studies, Class Revenue Allocation	10/13/2015
150503	ENTERGY ARKANSAS, INC.	Arkansas Electric Energy Consumers, Inc.	15-015	Direct	AR	Post-Test-Year Additions; Class Cost-of-Service Study; Class Revenue Allocation; Rate Design; Riders; Formula Rate Plan	9/29/2015
150801	NEW YORK STATE ELECTRIC & GAS CORPORATION and ROCHESTER GAS AND ELECTRIC CORPORATION	Multiple Intervenors	15-E-0283 15-G-0284 15-E-0285 15-G-0286	Direct	NY	Electric and Gas Embedded Class Cost-of-Service Studies, Class Revenue Allocation, Electric Rate Design	9/15/2015
130602	SHARYLAND UTILITIES	Texas Industrial Energy Consumers	44620	Cross-Rebuttal	TX	Transmission Cost Recovery Factor Class Allocation Factors.	9/8/2015
150503	ENTERGY ARKANSAS, INC.	Arkansas Electric Energy Consumers, Inc.	14-118	Surrebuttal	AR	Proposed Acquisition of Union Power Station Power Block 2 and Cost Recovery	8/21/2015
130602	SHARYLAND UTILITIES	Texas Industrial Energy Consumers	44620	Direct	TX	Transmission Cost Recovery Factor Class Allocation Factors	8/7/2015
150303	PECO ENERGY COMPANY	Philadelphia Area Industrial Energy Users Group	2015-2468981	Surrebuttal	PA	Class Cost-of-Service, Capacity Reservation Rider	8/4/2015
130701	WESTAR ENERGY INC. and KANSAS GAS & ELECTRIC CO.	Occidental Chemical Corporation	15-WSEE-115-RTS	Cross-Answering	KS	Class Cost-of-Service Study, Revenue Allocation	7/22/2015
150303	PECO ENERGY COMPANY	Philadelphia Area Industrial Energy Users Group	2015-2468981	Rebuttal	PA	Class Cost-of-Service, Class Revenue Allocation, Rate Design, Capacity Reservation Rider, Revenue Deoupling	7/21/2015
150504	SOUTHWEST ERN PUBLIC SERVICE COMPANY	Occidental Periman Ltd.	15-00083	Direct	NM	Long-Term Purchased Power Agreements	7/10/2015

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150503	ENTERGY ARKANSAS, INC.	Arkansas Electric Energy Consumers, Inc.	15-014	Surrebuttal	AR	Solar Power Purchase Agreement	7/10/2015
130701	WESTAR ENERGY INC. and KANSAS GAS & ELECTRIC CO.	Occidental Chemical Corporation	15-WSEE-115-RTS	Direct	KS	Class Cost-of-Service and Electric Distrbution Grid Resiliency Program	7/9/2015
130901	ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	43958	Supplemental DIrect	TX	Certificiate of Need for Union Power Station Power Block 1	7/7/2015
150503	ENTERGY ARKANSAS, INC.	Arkansas Electric Energy Consumers, Inc.	14-118	Direct	AR	Proposed Acquisition of Union Power Station Power Block 2 and Cost Recovery	7/2/2015
150303	PECO ENERGY COMPANY	Philadelphia Area Industrial Energy Users Group	2015-2468981	Direct	PA	Class Cost-of-Service, Class Revenue Allocation, Rate Design, Capacity Reservation Rider	6/23/2015
150503	ENTERGY ARKANSAS, INC.	Arkansas Electric Energy Consumers, Inc.	15-014-U	Direct	AR	Solar Power Purchase Agreement	6/19/2015
140201	FLORIDA POWER & LIGHT COMPANY	Florida Industrial Power Users Group	150075	Direct	FL	Cedar Bay Power Purchase Agreement	6/8/2015
140105	SOUTHWEST ERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	43695	Cross-Rebuttal	TX	Class Cost of Service Study; Class Revenue Allocation	6/8/2015
140201	FLORIDA POWER AND LIGHT COMPANY, DUKE ENERGY FLORIDA, GULF POWER COMPANY, TAMPA ELECTRIC COMPANY	Florida Industrial Power Users Group	140226	Surrebuttal	FL	Opt-Out Provision	5/20/2015
140105	SOUTHWEST ERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	43695	Direct	TX	Post-Test Year Adjustments; Weather Normalization	5/15/2015
140105	SOUTHWEST ERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	43695	Direct	TX	Class Cost of Service Study; Class Revenue Allocation	5/15/2015
130901	ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	43958	Direct	TX	Certificiate of Need for Union Power Station Power Block 1	4/29/2015
140404	SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Industrial Energy Consumers	42370	Cross-Rebuttal	TX	Allocation and recovery of Municipal Rate Case Expenses and the proposed Rate-Case-Expense Surcharge Tariff.	1/27/2015
140904	WEST PENN POWER COMPANY	West Penn Power Industrial Intervenors	2014-2428742	Surrebuttal	PA	Class Cost-of-Service Study; Class Revenue Allocation; Large Commercial and Industrial Rate Design; Storm Damage Charge Rider	1/6/2015
140903	PENNSYLVANIA ELECTRIC COMPANY	Penelec Industrial Customer Alliance	2014-2428743	Surrebuttal	PA	Class Cost-of-Service Study; Class Revenue Allocation; Large Commercial and Industrial Rate Design; Storm Damage Charge Rider	1/6/2015

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140902	METROPOLITAN EDISON COMPANY	Med-Ed Industrial Users Group	2014-2428745	Surrebuttal	PA	Class Cost-of-Service Study; Class Revenue Allocation; Large Commercial and Industrial Rate Design; Storm Damage Charge Rider	1/6/2015
140904	WEST PENN POWER COMPANY	West Penn Power Industrial Intervenors	2014-2428742	Rebuttal	PA	Class Cost-of-Service Study; Class Revenue Allocation; Large Commercial and Industrial Rate Design; Storm Damage Charge Rider	12/18/2014
140903	PENNSYLVANIA ELECTRIC COMPANY	Penelec Industrial Customer Alliance	2014-2428743	Rebuttal	PA	Class Cost-of-Service Study; Class Revenue Allocation; Large Commercial and Industrial Rate Design; Storm Damage Charge Rider	12/18/2014
140902	METROPOLITAN EDISON COMPANY	Med-Ed Industrial Users Group	2014-2428745	Rebuttal	PA	Class Cost-of-Service Study; Class Revenue Allocation; Large Commercial and Industrial Rate Design; Storm Damage Charge Rider	12/18/2014
140804	PUBLIC SERVICE COMPANY OF COLORADO	Colorado Healthcare Electric Coordinating Council	14AL-0660E	Cross	CO	Clean Air Clean Jobs Act Rider; Transmission Cost Adjustment	12/17/2014
140904	WEST PENN POWER COMPANY	West Penn Power Industrial Intervenors	2014-2428742	Direct	PA	Class Cost-of-Service Study; Class Revenue Allocation, Rate Design, Partial Services Rider; Storm Damage Rider	11/24/2014
140903	PENNSYLVANIA ELECTRIC COMPANY	Penelec Industrial Customer Alliance	2014-2428743	Direct	PA	Class Cost-of-Service Study; Class Revenue Allocation, Rate Design, Partial Services Rider; Storm Damage Rider	11/24/2014
140902	METROPOLITAN EDISON COMPANY	Med-Ed Industrial Users Group	2014-2428745	Direct	PA	Class Cost-of-Service Study; Class Revenue Allocation, Rate Design, Partial Services Rider; Storm Damage Rider	11/24/2014
140905	CENTRAL HUDSON GAS & ELECTRIC	Multiple Intervenors	14-E-0318 / 14-G-0319	Direct	NY	Class Cost-of-Service Study; Class Revenue Allocation (Electric)	11/21/2014
140804	PUBLIC SERVICE COMPANY OF COLORADO	Colorado Healthcare Electric Coordinating Council	14AL-0660E	Direct	CO	Clean Air Clean Jobs Act Rider; Electric Commodity Adjustment Incentive Mechanism	11/7/2014
140201	FLORIDA POWER AND LIGHT COMPANY	Florida Industrial Power Users Group	140001-E	Direct	FL	Cost-Effectiveness and Policy Issues Surrounding the Investment in Working Gas Production Facilities	9/22/2014
140401	ROCKY MOUNTAIN POWER	Wyoming Industrial Energy Consumers	20000-446-ER14	Surrebuttal	WY	Class Cost-of-Service, Rule 12 (Line Extension Policy)	9/19/2014

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140805	INDIANA MICHIGAN POWER COMPANY	I&M Industrial Group	44511	Direct	IN	Clean Energy Solar Pilot Project, Solar Power Rider and Green Power Rider	9/17/2014
140201	VARIOUS UTILITIES	Florida Industrial Power Users Group	140002-EI	Direct	FL	Energy Efficiency Cost Recovery Opt-Out Provision	9/5/2014
140401	ROCKY MOUNTAIN POWER	Wyoming Industrial Energy Consumers	20000-446-ER14	Cross	WY	Class Cost-of-Service Study; Rule 12 Line Extension	9/5/2014
131002	NORTHERN STATES POWER COMPANY	Xcel Large Industrials	E-002/GR-13-868	Surrebuttal	MN	Nuclear Depreciation Expense, Monticello EPU/LCM Project, Class Cost-of-Service Study, Class Revenue Allocation, Fuel Clause Rider Reform, Rate Design	8/4/2014
140401	ROCKY MOUNTAIN POWER	Wyoming Industrial Energy Consumers	20000-446-ER14	Direct	WY	Class Cost-of-Service Study, Rule 12 Line Extension	7/25/2014
140601	DUKE ENERGY FLORIDA	NRG Florida, LP	140111 and 140110	Direct	FL	Cost-Effectiveness of Proposed Self Build Generating Projects	7/14/2014
131002	NORTHERN STATES POWER COMPANY	Xcel Large Industrials	E-002/GR-13-868	Rebuttal	MN	Class Cost-of-Service Study, Class Revenue Allocation	7/7/2014
140303	PPL ELECTRIC UTILITIES CORPORATION	PP&L Industrial Customer Alliance	2013-2398440	Rebuttal	PA	Energy Efficiency Cost Recovery	7/1/2014
131002	NORTHERN STATES POWER COMPANY	Xcel Large Industrials	E-002/GR-13-868	Direct	MN	Revenue Requirements, Fuel Clause Rider, Class Cost-of-Service Study, Rate Design and Revenue Allocation	6/5/2014
140303	PPL ELECTRIC UTILITIES CORPORATION	PP&L Industrial Customer Alliance	2013-2398440	Direct	PA	Energy Efficiency Cost Recovery	5/23/2014
140105	SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	42042	Direct	TX	Transmission Cost Recovery Factor	4/24/2014
130901	ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	41791	Cross	TX	Class Cost-of-Service Study and Rate Design	1/31/2014
130901	ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	41791	Direct	TX	Revenue Requirements, Fuel Reconciliation; Cost Allocation Issues; Rate Design Issues	1/10/2014
131005	DUQUESNE LIGHT COMPANY	Duquesne Industrial Intervenors	R-2013-2372129	Supplemental Surrebuttal	PA	Class Cost-of-Sevice Study	12/13/2013
131005	DUQUESNE LIGHT COMPANY	Duquesne Industrial Intervenors	R-2013-2372129	Surrebuttal	PA	Class Cost-of-Service Study; Cash Working Capital; Miscellaneous General Expense; Uncollectable Expense; Class Revenue Allocation	12/9/2013
131005	DUQUESNE LIGHT COMPANY	Duquesne Industrial Intervenors	R-2013-2372129	Rebuttal	PA	Rate L Transmission Service; Class Revenue Allocation	11/26/2013
130905	ENTERGY TEXAS, INC. ITC HOLDINGS CORP.	Texas Industrial Energy Consumers	41850	Direct	TX	Rate Mitigation Plan; Conditions re Transfer of Control of Ownership	11/6/2013

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130501	MIDAMERICAN ENERGY COMPANY	Deere & Company	RPU-2013-0004	Surrebuttal	IA	Class Cost-of-Service Study; Class Revenue Allocation; Depreciation Surplus	11/4/2013
130602	SHARYLAND UTILITIES	Texas Inustrial Energy Consumers and Atlas Pipeline Mid-Continent WestTex, LLC	41474	Cross-Rebuttal	TX	Customer Class Definitions; Class Revenue Allocation; Allocation of TTC costs	11/4/2013
131005	DUQUESNE LIGHT COMPANY	Duquesne Industrial Intervenors	R-2013-2372129	Direct	PA	Class Cost-of-Service, Class Revenue Allocations	11/1/2013
130906	PUBLIC SERVICE ENERGY AND GAS	New Jersey Large Energy Users Coalition	EO13020155 and GO13020156	Direct	NJ	Energy Strong	10/28/2013
130602	SHARYLAND UTILITIES	Texas Inustrial Energy Consumers and Atlas Pipeline Mid-Continent WestTex, LLC	41474	Direct	TX	Regulatory Asset Cost Recovery; Class Cost-of-Service Study, Class Revenue Allocation, Rate Design	10/18/2013
130903	GEORGIA POWER COMPANY	Georgia Industrial Group and Georgia Association of Manufacturers	36989	Direct	GA	Depreciation Expense, Alternate Rate Plan, Return on Equity, Class Cost-of-Service Study, Class Revenue Allocation, Rate Design	10/18/2013
130501	MIDAMERICAN ENERGY COMPANY	Deere & Company	RPU-2013-0004	Rebutal	IA	Class Cost-of-Service Study	10/1/2013
130902	FLORIDA POWER AND LIGHT COMPANY	Florida Industrial Power Users Group	130007	Direct	FL	Environmental Cost Recovery Clause	9/13/2013
130501	MIDAMERICAN ENERGY COMPANY	Deere & Company	RPU-2013-0004	Direct	IA	Class Cost-of-Service Study, Class Revenue Allocation, Depreciation, Cost Recovery Clauses, Revenue Sharing, Revenue True-up	9/10/2013
130202	SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd.	12-00350-UT	Rebuttal	NM	RPS Cost Rider	9/9/2013
130701	WESTAR ENERGY INC. and KANSAS GAS & ELECTRIC CO.	Occidental Chemical Corporation	13-WSEE-629-RTS	Cross-Answering	KS	Cost Allocation Methodology	9/5/2013
130202	SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd.	12-00350-UT	Direct	NM	Class Cost-of-Service Study	8/22/2013
130701	WESTAR ENERGY INC. and KANSAS GAS & ELECTRIC CO.	Occidental Chemical Corporation	13-WSEE-629-RTS	Direct	KS	Class Revenue Allocation.	8/21/2013
130203	ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	41437	Direct	TX	Avoided Cost; Standby Rate Design	8/14/2013
100902	MID-KANSAS ELECTRIC COMPANY, LLC	Western Kansas Industrial Electric Consumers	13-MKEE-699	Direct	KS	Class Revenue Allocation	8/12/2013
100902	MID-KANSAS ELECTRIC COMPANY, LLC	Western Kansas Industrial Electric Consumers	13-MKEE-447	Supplemental	KS	Testimony in Support of Settlement	8/9/2013
100902	MID-KANSAS ELECTRIC COMPANY, LLC	Western Kansas Industrial Electric Consumers	13-MKEE-447	Supplemental	KS	Modification Agreement	7/24/2013

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130201	TAMPA ELECTRIC COMPANY	Florida Industrial Power Users Group	130040	Direct	FL	GSD-IS Consolidation, GSD and IS Rate Design, Class Cost-of-Service Study, Planned Outage Expense, Storm Damage Expense	7/15/2013
100902	MID-KANSAS ELECTRIC COMPANY, LLC	Western Kansas Industrial Electric Consumers	13-MKEE-452	Supplemental	KS	Testimony in Support of Nonunanimous Settlement	6/28/2013
121203	JERSEY CENTRAL POWER & LIGHT COMPANY	Gerdau Ameristeel Sayreville, Inc.	ER12111052	Direct	NJ	Cost of Service Study for GT-230 KV Customers; AREP Rider	6/14/2013
100902	MID-KANSAS ELECTRIC COMPANY, LLC	Western Kansas Industrial Electric Consumers	13-MKEE-447	Direct	KS	Wholesale Requirements Agreement; Process for Excemption From Regulation; Conditions Required for Public Interest Finding on CCN spin-down	5/14/2013
100902	MID-KANSAS ELECTRIC COMPANY, LLC	Western Kansas Industrial Electric Consumers	13-MKEE-452	Cross	KS	Formula Rate Plan for Distribution Utility	5/10/2013
100902	MID-KANSAS ELECTRIC COMPANY, LLC	Western Kansas Industrial Electric Consumers	13-MKEE-452	Direct	KS	Formula Rate Plan for Distribution Utility	5/3/2013
121001	ENTERGY TEXAS, INC. ITC HOLDINGS CORP.	Texas Industrial Energy Consumers	41223	Direct	TX	Public Interest of Proposed Divestiture of ETI's Transmission Business to an ITC Holdings Subsidiary	4/30/2013
121101	NORTHERN STATES POWER COMPANY	Xcel Large Industrials	12-961	Surrebuttal	MN	Depreciation; Used and Useful; Cost Allocation; Revenue Allocation	4/12/2013
121101	NORTHERN STATES POWER COMPANY	Xcel Large Industrials	12-961	Rebuttal	MN	Class Revenue Allocation.	3/25/2013
121101	NORTHERN STATES POWER COMPANY	Xcel Large Industrials	12-961	Direct	MN	Depreciation; Used and Useful; Property Tax; Cost Allocation; Revenue Allocation; Competitive Rate & Property Tax Riders	2/28/2013
91203	ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	38951	Second Supplemental Rebuttal	TX	Competitive Generation Service Tariff	2/1/2013
91203	ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	38951	Second Supplemental Direct	TX	Competitive Generation Service Tariff	1/11/2013
110202	SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Industrial Energy Consumers	40443	Cross Rebuttal	TX	Cost Allocation and Rate Design	1/10/2013
110202	SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Industrial Energy Consumers	40443	Direct	TX	Application of the Turk Plant Cost-Cap; Revenue Requirements; Class Cost-of-Service Study; Class Revenue Allocation; Industrial Rate Design	12/10/2012
120301	FLORIDA POWER AND LIGHT COMPANY	Florida Industrial Power Users Group	120015	Corrected Supplemental Rebuttal	FL	Support for Non-Unanimous Settlement	11/13/2012
120301	FLORIDA POWER AND LIGHT COMPANY	Florida Industrial Power Users Group	120015	Corrected Supplemental Direct	FL	Support for Non-Unanimous Settlement	11/13/2012

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120602	NIAGARA MOHAWK POWER CORP.	Multiple Intervenors	12-E-0201/12-G-0202	Rebuttal	NY	Electric and Gas Class Cost-of-Service Studies.	9/25/2012
120602	NIAGARA MOHAWK POWER CORP.	Multiple Intervenors	12-E-0201/12-G-0202	Direct	NY	Electric and Gas Class Cost-of-Service Study; Revenue Allocation; Rate Design; Historic Demand	8/31/2012
100902	MID-KANSAS ELECTRIC COMPANY, LLC	Western Kansas Industrial Electric Consumers	12-MKEE-650-TAR	Direct	KS	Transmission Formula Rate Plan	7/31/2012
120502	WESTAR ENERGY INC. and KANSAS GAS & ELECTRIC CO.	Occidental Chemical Corporation	12-WSEE-651-TAR	Direct	KS	TDC Tariff	7/30/2012
120301	FLORIDA POWER AND LIGHT COMPANY	Florida Industrial Power Users Group	120015	Direct	FL	Class Cost-of-Service Study, Revenue Allocation, and Rate Design	7/2/2012
120101	LONE STAR TRANSMISSION, LLC	Texas Industrial Energy Consumers	40020	Direct	TX	Revenue Requirement, Rider AVT	6/21/2012
111102	ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	39896	Cross	TX	Class Cost-of-Service Study, Revenue Allocation, and Rate Design	4/13/2012
111102	ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	39896	Direct	TX	Revenue Requirements, Class Cost-of-Service Study, Revenue Allocation, and Rate Design	3/27/2012
91023	ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	38951	Supplemental Rebuttal	TX	Competitive Generation Service Issues	2/24/2012
91203	ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	38951	Supplemental Direct	TX	Competitive Generation Service Issues	2/10/2012
101101	AEP TEXAS CENTRAL COMPANY	Texas Industrial Energy Consumers	39722	Direct	TX	Carrying Charge Rate Applicable to the Additional True-Up Balance and Tax Balances	11/4/2011
110703	GULF POWER COMPANY	Florida Industrial Power Users Group	110138-EI	Direct	FL	Cost Allocation and Storm Reserve	10/14/2011
90404	CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC	Texas Industrial Energy Consumers	39504	Direct	TX	Carrying Charge Rate Applicable to the Additional True-Up Balance and Taxes	9/12/2011
101101	AEP TEXAS NORTH COMPANY	Texas Industrial Energy Consumers	39361	Cross-Rebuttal	TX	Energy Efficiency Cost Recovery Factor	8/10/2011
101101	AEP TEXAS CENTRAL COMPANY	Texas Industrial Energy Consumers	39360	Cross-Rebuttal	TX	Energy Efficiency Cost Recovery Factor	8/10/2011
100503	ONCOR ELECTRIC DELIVERY COMPANY, LLC	Texas Industrial Energy Consumers	39375	Direct	TX	Energy Efficiency Cost Recovery Factor	8/2/2011
90103	ALABAMA POWER COMPANY	Alabama Industrial Energy Consumers	31653	Direct	AL	Renewable Purchased Power Agreement	7/28/2011
101101	AEP TEXAS NORTH COMPANY	Texas Industrial Energy Consumers	39361	Direct	TX	Energy Efficiency Cost Recovery Factor	7/26/2011
101101	AEP TEXAS CENTRAL COMPANY	Texas Industrial Energy Consumers	36360	Direct	TX	Energy Efficiency Cost Recovery Factor	7/20/2011
90201	ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	39366	Direct	TX	Energy Efficiency Cost Recovery Factor	7/19/2011
90404	CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC	Texas Industrial Energy Consumers	39363	Direct	TX	Energy Efficiency Cost Recovery Factor	7/15/2011

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101201	NORTHERN STATES POWER COMPANY	Xcel Large Industrials	E002/GR-10-971	Surrebuttal	MN	Depreciation; Non-Asset Margin Sharing; Step-In Increase; Class Cost-of-Service Study; Class Revenue Allocation; Rate Design	5/26/2011
101201	NORTHERN STATES POWER COMPANY	Xcel Large Industrials	E002/GR-10-971	Rebuttal	MN	Classification of Wind Investment	5/4/2011
101201	NORTHERN STATES POWER COMPANY	Xcel Large Industrials	E002/GR-10-971	Direct	MN	Surplus Depreciation Reserve, Incentive Compensation, Non-Asset Trading Margin Sharing, Cost Allocation, Class Revenue Allocation, Rate Design	4/5/2011
101202	ROCKY MOUNTAIN POWER	Wyoming Industrial Energy Consumers	20000-381-EA-10	Direct	WY	2010 Protocols	2/11/2011
100802	TEXAS-NEW MEXICO POWER COMPANY	Texas Industrial Energy Consumers	38480	Direct	TX	Cost Allocation, TCRF	11/8/2010
90402	GEORGIA POWER COMPANY	Georgia Industrial Group/Georgia Traditional Manufacturers Group	31958	Direct	GA	Alternate Rate Plan, Return on Equity, Riders, Cost-of-Service Study, Revenue Allocation, Economic Development	10/22/2010
90404	CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC	Texas Industrial Energy Consumers	38339	Cross-Rebuttal	TX	Cost Allocation, Class Revenue Allocation	9/24/2010
90404	CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC	Texas Industrial Energy Consumers	38339	Direct	TX	Pension Expense, Surplus Depreciation Reserve, Cost Allocation, Rate Design, Riders	9/10/2010
100303	NIAGARA MOHAWK POWER CORP.	Multiple Intervenors	10-E-0050	Rebuttal	NY	Multi-Year Rate Plan, Cost Allocation, Revenue Allocation, Reconciliation Mechanisms, Rate Design	8/6/2010
100303	NIAGARA MOHAWK POWER CORP.	Multiple Intervenors	10-E-0050	Direct	NY	Multi-Year Rate Plan, Cost Allocation, Revenue Allocation, Reconciliation Mechanisms, Rate Design	0714/2010
91203	ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	37744	Cross Rebuttal	TX	Cost Allocation, Revenue Allocation, CGS Rate Design, Interruptible Service	6/30/2010
91203	ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	37744	Direct	TX	Class Cost of Service Study, Revenue Allocation, Rate Design, Competitive Generation Services, Line Extension Policy	6/9/2010
90201	ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	37482	Cross Rebuttal	TX	Allocation of Purchased Power Capacity Costs	2/3/2010
90402	GEORGIA POWER COMPANY	Georgia Industrial Group/Georgia Traditional Manufacturers Group	28945	Direct	GA	Fuel Cost Recovery	1/29/2010
90201	ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	37482	Direct	TX	Purchased Power Capacity Cost Factor	1/22/2010
90403	VIRGINIA ELECTRIC AND POWER COMPANY	MeadWestvaco Corporation	PUE-2009-00081	Direct	VA	Allocation of DSM Costs	1/13/2010
90201	ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	37580	Direct	TX	Fuel refund	12/4/2009

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90403	VIRGINIA ELECTRIC AND POWER COMPANY	MeadWestvaco Corporation	PUE-2009-00019	Direct	VA	Standby rate design; dynamic pricing	11/9/2009
80601	SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	37135	Direct	TX	Transmission cost recovery factor	10/22/2009
80703	MID-KANSAS ELECTRIC COMPANY, LLC	Western Kansas Industrial Electric Consumers	09-MKEE-969-RTS	Direct	KS	Revenue requirements, TIER, rate design	10/19/2009
90601	VARIOUS UTILITIES	Florida Industrial Power Users Group	090002-EG	Direct	FL	Interruptible Credits	10/2/2009
80505	ONCOR ELECTRIC DELIVERY COMPANY	Texas Industrial Energy Consumers	36958	Cross Rebuttal	TX	2010 Energy efficiency cost recovery factor	8/18/2009
81001	PROGRESS ENERGY FLORIDA	Florida Industrial Power Users Group	90079	Direct	FL	Cost-of-service study, revenue allocation, rate design, depreciation expense, capital structure	8/10/2009
90404	CENTERPOINT	Texas Industrial Energy Consumers	36918	Cross Rebuttal	TX	Allocation of System Restoration Costs	7/17/2009
90301	FLORIDA POWER AND LIGHT COMPANY	Florida Industrial Power Users Group	080677	Direct	FL	Depreciation; class revenue allocation; rate design; cost allocation; and capital structure	7/16/2009
90201	ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	36956	Direct	TX	Approval to revise energy efficiency cost recovery factor	7/16/2009
90601	VARIOUS UTILITIES	Florida Industrial Power Users Group	VARIOUS DOCKETS	Direct	FL	Conservation goals	7/6/2009
90201	ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	36931	Direct	TX	System restoration costs under Senate Bill 769	6/30/2009
90502	SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Industrial Energy Consumers	36966	Direct	TX	Authority to revise fixed fuel factors	6/18/2009
80805	TEXAS-NEW MEXICO POWER COMPANY	Texas Industrial Energy Consumers	36025	Cross-Rebuttal	TX	Cost allocatiion, revenue allocation and rate design	6/10/2009
80805	TEXAS-NEW MEXICO POWER COMPANY	Texas Industrial Energy Consumers	36025	Direct	TX	Cost allocation, revenue allocation, rate design	5/27/2009
81201	NORTHERN STATES POWER COMPANY	Xcel Large Industrials	08-1065	Surrebuttal	MN	Cost allocation, revenue allocation, rate design	5/27/2009
90403	VIRGINIA ELECTRIC AND POWER COMPANY	MeadWestvaco Corporation	PUE-2009-00018	Direct	VA	Transmission cost allocation and rate design	5/20/2009
90101	NORTHERN INDIANA PUBLIC SERVICE COMPANY	Beta Steel Corporation	43526	Direct	IN	Cost allocation and rate design	5/8/2009
81203	ENTERGY SERVICES, INC	Texas Industrial Energy Consumers	ER008-1056	Rebuttal	FERC	Rough Production Cost Equalization payments	5/7/2009
81201	NORTHERN STATES POWER COMPANY	Xcel Large Industrials	08-1065	Rebuttal	MN	Class revenue allocation and the classification of renewable energy costs	5/5/2009
81201	NORTHERN STATES POWER COMPANY	Xcel Large Industrials	08-1065	Direct	MN	Cost-of-service study, class revenue allocation, and rate design	4/7/2009
81203	ENTERGY SERVICES, INC	Texas Industrial Energy Consumers	ER08-1056	Answer	FERC	Rough Production Cost Equalization payments	3/6/2009
80901	ROCKY MOUNTAIN POWER	Wyoming Industrial Energy Consumers	20000-333-ER-08	Direct	WY	Cost of service study; revenue allocation; inverted rates; revenue requirements	1/30/2009

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81203	ENTERGY SERVICES	Texas Industrial Energy Consumers	ER08-1056	Direct	FERC	Entergy's proposal seeking Commission approval to allocate Rough Production Cost Equalization payments	1/9/2009
80505	ONCOR ELECTRIC DELIVERY COMPANY & TEXAS ENERGY FUTURE HOLDINGS LTD	Texas Industrial Energy Consumers	35717	Cross Rebuttal	TX	Retail transformation; cost allocation, demand ratchet waivers, transmission cost allocation factor	12/24/2008
70101	GEORGIA POWER COMPANY	Georgia Industrial Group and Georgia Traditional Manufacturers Association	27800	Direct	GA	Cash Return on CWIP associated with the Plant Vogtle Expansion	12/19/2008
80505	ONCOR ELECTRIC DELIVERY COMPANY & TEXAS ENERGY FUTURE HOLDINGS LTD	Texas Industrial Energy Consumers	35717	Direct	TX	Revenue Requirement, class cost of service study, class revenue allocation and rate design	11/26/2008
80802	TAMPA ELECTRIC COMPANY	The Florida Industrial Power Users Group and Mosaic Company	080317-EI	Direct	FL	Revenue Requirements, retail class cost of service study, class revenue allocation, firm and non firm rate design and the Transmission Base Rate Adjustment	11/26/2008
80601	SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	35763	Supplemental Direct	TX	Recovery of Energy Efficiency Costs	11/6/2008
80601	SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	35763	Cross-Rebuttal	TX	Cost Allocation, Demand Ratchet, Renewable Energy Certificates (REC)	10/28/2008
80601	SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	35763	Direct	TX	Revenue Requirements, Fuel Reconciliation Revenue Allocation, Cost-of-Service and Rate Design Issues	10/13/2008
50106	ALABAMA POWER COMPANY	Alabama Industrial Energy Consumers	18148	Direct	AL	Energy Cost Recovery Rate (WITHDRAWN)	9/16/2008
50701	ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	35269	Direct	TX	Allocation of rough production costs equalization payments	7/9/2008
70703	ENTERGY GULF STATES UTILITIES, TEXAS	Texas Industrial Energy Consumers	34800	Direct	TX	Non-Unanimous Stipulation	6/11/2008
50103	TEXAS PUC STAFF	Texas Industrial Energy Consumers	33672	Supplemental Rebuttal	TX	Transmission Optimization and Ancillary Services Studies	6/3/2008
50103	TEXAS PUC STAFF	Texas Industrial Energy Consumers	33672	Supplemental Direct	TX	Transmission Optimization and Ancillary Services Studies	5/23/2008
60104	SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Industrial Energy Consumers	33891	Supplemental Cross Rebuttal	TX	Certificate of Convenience and Necessity	5/21/2008
60104	SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Industrial Energy Consumers	33891	Supplemental Direct	TX	Certificate of Convenience and Necessity	5/8/2008
70703	ENTERGY GULF STATES UTILITES, TEXAS	Texas Industrial Energy Consumers	34800	Cross-Rebuttal	TX	Cost Allocation and Rate Design and Competitive Generation Service	4/18/2008
70703	ENTERGY GULF STATES UTILITES, TEXAS	Texas Industrial Energy Consumers	34800	Direct	TX	Eligible Fuel Expense	4/11/2008
70703	ENTERGY GULF STATES UTILITES, TEXAS	Texas Industrial Energy Consumers	34800	Direct	TX	Competitive Generation Service Tariff	4/11/2008

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70703	ENTERGY GULF STATES UTILITES, TEXAS	Texas Industrial Energy Consumers	34800	Direct	TX	Revenue Requirements	4/11/2008
70703	ENTERGY GULF STATES UTILITES, TEXAS	Texas Industrial Energy Consumers	34800	Direct	TX	Cost of Service study, revenue allocation, design of firm, interruptible and standby service tariffs; interconnection costs	4/11/2008
41229	TEXAS-NEW MEXICO POWER COMPANY	Texas Industrial Energy Consumers	35038	Rebuttal	TX	Over $5 Billion Compliance Filing	4/14/2008
60303	GEORGIA POWER COMPANY	Georgia Industrial Group/Georgia Traditional Manufacturers Group	26794	Direct	GA	Fuel Cost Recovery	4/15/2008
71202	SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Periman Ltd.	07-00319-UT	Rebuttal	NM	Revenue requirements, cost of service study, rate design	3/28/2008
61101	AEP TEXAS CENTRAL COMPANY	Texas Industrial Energy Consumers	35105	Direct	TX	Over $5 Billion Compliance Filing	3/24/2008
51101	CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC	Texas Industrial Energy Consumers	32902	Direct	TX	Over $5 Billion Compliance Filing	3/20/2008
71202	SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Periman Ltd.	07-00319-UT	Direct	NM	Revenue requirements, cost of service study (COS); rate design	3/7/2008
50701	ENTERGY GULF STATES UTILITIES TEXAS	Texas Industrial Energy Consumers	34724	Direct	TX	IPCR Rider increase and interim surcharge	11/28/2007
70601	GEORGIA POWER COMPANY	Georgia Industrial Group/Georgia Traditional Manufacturers Group	25060-U	Direct	GA	Return on equity; cost of service study; revenue allocation; ILR Rider; spinning reserve tariff; RTP	10/24/2007
70303	ONCOR ELECTRIC DELIVERY COMPANY & TEXAS ENERGY FUTURE HOLDINGS LTD	Texas Industrial Energy Consumers	34077	Direct	TX	Acquisition; public interest	9/14/2007
60104	SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Industrial Energy Consumers	33891	Direct	TX	Certificate of Convenience and Necessity	8/30/2007
61201	ALTAMAHA ELECTRIC MEMBERSHIP CORPORATION	SP Newsprint Company	25226-U	Rebuttal	GA	Discriminatory Pricing; Service Territorial Transfer	7/17/2007
61201	ALTAMAHA ELECTRIC MEMBERSHIP CORPORATION	SP Newsprint Company	25226-U	Direct	GA	Discriminatory Pricing; Service Territorial Transfer	7/6/2007
70502	PROGRESS ENERGY FLORIDA	Florida Industrial Power Users Group	070052-EI	Direct	FL	Nuclear uprate cost recovery	6/19/2007
70603	ELECTRIC TRANSMISSION TEXAS LLC	Texas Industrial Energy Consumers	33734	Direct	TX	Certificate of Convenience and Necessity	6/8/2007
60601	TEXAS PUC STAFF	Texas Industrial Energy Consumers	32795	Rebuttal Remand	TX	Interest rate on stranded cost reconciliation	6/15/2007
60601	TEXAS PUC STAFF	Texas Industrial Energy Consumers	32795	Remand	TX	Interest rate on stranded cost reconciliation	6/8/2007
50103	TEXAS PUC STAFF	Texas Industrial Energy Consumers	33672	Rebuttal	TX	CREZ Nominations	5/21/2007
50701	ENTERGY GULF STATES UTILITES, TEXAS	Texas Industrial Energy Consumers	33687	Direct	TX	Transition to Competition	4/27/2007
50103	TEXAS PUC STAFF	Texas Industrial Energy Consumers	33672	Direct	TX	CREZ Nominations	4/24/2007
61101	AEP TEXAS CENTRAL COMPANY	Texas Industrial Energy Consumers	33309	Cross-Rebuttal	TX	Cost Allocation,Rate Design, Riders	4/3/2007
50701	ENTERGY GULF STATES UTILITIES TEXAS	Texas Industrial Energy Consumers	32710	Cross-Rebuttal	TX	Fuel and Rider IPCR Reconcilation	3/16/2007
61101	AEP TEXAS NORTH COMPANY	Texas Industrial Energy Consumers	33310	Direct	TX	Cost Allocation,Rate Design, Riders	3/13/2007
61101	AEP TEXAS CENTRAL COMPANY	Texas Industrial Energy Consumers	33309	Direct	TX	Cost Allocation,Rate Design, Riders	3/13/2007
50701	ENTERGY GULF STATES UTILITIES TEXAS	Texas Industrial Energy Consumers	32710	Direct	TX	Fuel and Rider IPCR Reconcilation	2/28/2007

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41219	AEP TEXAS NORTH COMPANY	Texas Industrial Energy Consumers	31461	Direct	TX	Rider CTC design	2/15/2007
50701	ENTERGY GULF STATES UTILITIES TEXAS	Texas Industrial Energy Consumers	33586	Cross-Rebuttal	TX	Hurricane Rita reconstruction costs	1/30/2007
60104	SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Industrial Energy Consumers	32898	Direct	TX	Fuel Reconciliation	1/29/2007
50701	ENTERGY GULF STATES UTILITIES TEXAS	Texas Industrial Energy Consumers	33586	Direct	TX	Hurricane Rita reconstruction costs	1/18/2007
60303	GEORGIA POWER COMPANY	Georgia Industrial Group/Georgia Textile Manufacturers Group	23540-U	Direct	GA	Fuel Cost Recovery	1/11/2007
60503	SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	32766	Cross Rebuttal	TX	Cost allocation, Cost of service, Rate design	1/8/2007
60503	SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	32766	Direct	TX	Cost allocation, Cost of service, Rate design	12/22/2006
60503	SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	32766	Direct	TX	Revenue Requirements,	12/15/2006
60503	SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	32766	Direct	TX	Fuel Reconcilation	12/15/2006
50701	ENTERGY GULF STATES UTILITIES TEXAS	Texas Industrial Energy Consumers	32907	Cross Rebuttal	TX	Hurricane Rita reconstruction costs	10/12/06
50701	ENTERGY GULF STATES UTILITIES TEXAS	Texas Industrial Energy Consumers	32907	Direct	TX	Hurricane Rita reconstruction costs	10/09/06
60601	TEXAS PUC STAFF	Texas Industrial Energy Consumers	32795	Cross Rebuttal	TX	Stranded Cost Reallocation	09/07/06
60101	COLQUITT EMC	ERCO Worldwide	23549-U	Direct	GA	Service Territory Transfer	08/10/06
60601	TEXAS PUC STAFF	Texas Industrial Energy Consumers	32795	Direct	TX	Stranded Cost Reallocation	08/23/06
60104	SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Industrial Energy Consumers	32672	Direct	TX	ME-SPP Transfer of Certificate to SWEPCO	8/23/2006
50503	AEP TEXAS CENTRAL COMPANY	Texas Industrial Energy Consumers	32758	Direct	TX	Rider CTC design and cost recovery	08/24/06
60503	SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	32685	Direct	TX	Fuel Surcharge	07/26/06
60301	PUBLIC SERVICE ELECTRIC AND GAS COMPANY	New Jersey Large Energy Consumers	171406	Direct	NJ	Gas Delivery Cost allocation and Rate design	06/21/06
60303	GEORGIA POWER COMPANY	Georgia Industrial Group/Georgia Textile Manufacturers Group	22403-U	Direct	GA	Fuel Cost Recovery Allowance	05/05/06
50503	AEP TEXAS CENTRAL COMPANY	Texas Industrial Energy Consumers	32475	Cross-Rebuttal	TX	ADFIT Benefit	04/27/06
50503	AEP TEXAS CENTRAL COMPANY	Texas Industrial Energy Consumers	32475	Direct	TX	ADFIT Benefit	04/17/06
41229	TEXAS-NEW MEXICO POWER COMPANY	Texas Industrial Energy Consumers	31994	Cross-Rebuttal	TX	Stranded Costs and Other True-Up Balances	3/16/2006
41229	TEXAS-NEW MEXICO POWER COMPANY	Texas Industrial Energy Consumers	31994	Direct	TX	Stranded Costs and Other True-Up Balances	3/10/2006
50303	SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Periman Ltd. Occidental Power Marketing	ER05-168-001	Direct	NM	Fuel Reconciliation	3/6/2006
50701	ENTERGY GULF STATES UTILITIES TEXAS	Texas Industrial Energy Consumers	31544	Cross-Rebuttal	TX	Transition to Competition Costs	01/13/06
50701	ENTERGY GULF STATES UTILITIES TEXAS	Texas Industrial Energy Consumers	31544	Direct	TX	Transition to Competition Costs	01/13/06
50601	PUBLIC SERVICE ELECTRIC AND GAS COMPANY AND EXELON CORPORATION	New Jersey Large Energy Consumers Retail Energy Supply Association	BPU EM05020106 OAL PUC-1874-05	Surrebuttal	NJ	Merger	12/22/2005
50705	SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Periman Ltd. Occidental Power Marketing	EL05-19-002; ER05-168-001	Responsive	FERC	Fuel Cost adjustment clause (FCAC)	11/18/2005

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50601	PUBLIC SERVICE ELECTRIC AND GAS COMPANY AND EXELON CORPORATION	New Jersey Large Energy Consumers Retail Energy Supply Association	BPU EM05020106 OAL PUC-1874-05	Direct	NJ	Merger	11/14/2005
50102	PUBLIC UTILITY COMMISSION OF TEXAS	Texas Industrial Energy Consumers	31540	Direct	TX	Nodal Market Protocols	11/10/2005
50701	ENTERGY GULF STATES UTILITIES TEXAS	Texas Industrial Energy Consumers	31315	Cross-Rebuttal	TX	Recovery of Purchased Power Capacity Costs	10/4/2005
50701	ENTERGY GULF STATES UTILITIES TEXAS	Texas Industrial Energy Consumers	31315	Direct	TX	Recovery of Purchased Power Capacity Costs	9/22/2005
50705	SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Periman Ltd. Occidental Power Marketing	EL05-19-002; ER05-168-001	Responsive	FERC	Fuel Cost Adjustment Clause (FCAC)	9/19/2005
50503	AEP TEXAS CENTRAL COMPANY	Texas Industrial Energy Consumers	31056	Direct	TX	Stranded Costs and Other True-Up Balances	9/2/2005
50705	SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Periman Ltd. Occidental Power Marketing	EL05-19-00; ER05-168-00	Direct	FERC	Fuel Cost adjustment clause (FCAC)	8/19/2006
50203	GEORGIA POWER COMPANY	Georgia Industrial Group/Georgia Textile Manufacturers Group	19142-U	Direct	GA	Fuel Cost Recovery	4/8/2005
41230	CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC	Texas Industrial Energy Consumers	30706	Direct	TX	Competition Transition Charge	3/16/2005
41230	CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC	Texas Industrial Energy Consumers	30485	Supplemental Direct	TX	Financing Order	1/14/2005
41230	CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC	Texas Industrial Energy Consumers	30485	Direct	TX	Financing Order	1/7/2005
8201	PUBLIC SERVICE COMPANY OF COLORADO	Colorado Energy Consumers	04S-164E	Cross Answer	CO	Cost of Service Study, Interruptible Rate Design	12/13/2004
8201	PUBLIC SERVICE COMPANY OF COLORADO	Colorado Energy Consumers	04S-164E	Answer	CO	Cost of Service Study, Interruptible Rate Design	10/12/2004
8244	GEORGIA POWER COMPANY	Georgia Industrial Group/Georgia Textile Manufacturers Group	18300-U	Direct	GA	Revenue Requirements, Revenue Allocation, Cost of Service, Rate Design, Economic Development	10/8/2004
8195	CENTERPOINT, RELIANT AND TEXAS GENCO	Texas Industrial Energy Consumers	29526	Direct	TX	True-Up	6/1/2004
8156	GEORGIA POWER COMPANY/SAVANNAH ELECTRIC AND POWER COMPANY	Georgia Industrial Group	17687-U/17688-U	Direct	GA	Demand Side Management	5/14/2004
8148	TEXAS-NEW MEXICO POWER COMPANY	Texas Industrial Energy Consumers	29206	Direct	TX	True-Up	3/29/2004
8095	CONECTIV POWER DELIVERY	New Jersey Large Energy Consumers	ER03020110	Surrebuttal	NJ	Cost of Service	3/18/2004
8111	AEP TEXAS CENTRAL COMPANY	Texas Industrial Energy Consumers	28840	Rebuttal	TX	Cost Allocation and Rate Design	2/4/2004
8095	CONECTIV POWER DELIVERY	New Jersey Large Energy Consumers	ER03020110	Direct	NJ	Cost Allocation and Rate Design	1/4/2004
7850	RELIANT ENERGY HL&P	Texas Industrial Energy Consumers	26195	Supplemental Direct	TX	Fuel Reconciliation	9/23/2003
8045	VIRGINIA ELECTRIC AND POWER COMPANY	Virginia Committee for Fair Utility Rates	PUE-2003-00285	Direct	VA	Stranded Cost	9/5/2003
8022	GEORGIA POWER COMPANY	Georgia Industrial Group/Georgia Textile Manufacturers Group	17066-U	Direct	GA	Fuel Cost Recovery	7/22/2003
8002	AEP TEXAS CENTRAL COMPANY	Flint Hills Resources, LP	25395	Direct	TX	Delivery Service Tariff Issues	5/9/2003
7857	PUBLIC SERVICE ELECTRIC AND GAS COMPANY	New Jersey Large Energy Consumers	ER02050303	Supplemental	NJ	Cost of Service	3/14/2003
7850	RELIANT ENERGY HL&P	Texas Industrial Energy Consumers	26195	Direct	TX	Fuel Reconciliation	12/31/2002
7857	PUBLIC SERVICE ELECTRIC AND GAS COMPANY	New Jersey Large Energy Consumers	ER02050303	Surrebuttal	NJ	Revenue Allocation	12/16/2002
7836	PUBLIC SERVICE COMPANY OF COLORADO	Colorado Energy Consumers	02S-315EG	Answer	CO	Incentive Cost Adjustment	11/22/2002
7857	PUBLIC SERVICE ELECTRIC AND GAS COMPANY	New Jersey Large Energy Consumers	ER02050303	Direct	NJ	Revenue Allocation	10/22/2002
7863	DOMINION VIRGINIA POWER	Virginia Committee for Fair Utility Rates	PUE-2001-00306	Direct	VA	Generation Market Prices	8/12/2002

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7718	FLORIDA POWER CORPORATION	Florida Industrial Power Users Group	000824-EI	Direct	FL	Rate Design	1/18/2002
7633	GEORGIA POWER COMPANY	Georgia Industrial Group/Georgia Textile Manufacturers Group	14000-U	Direct	GA	Cost of Service Study, Revenue Allocation, Rate Design	10/12/2001
7555	TAMPA ELECTRIC COMPANY	Florida Industrial Power Users Group	010001-EI	Direct	FL	Rate Design	10/12/2001
7658	SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Industrial Energy Consumers	24468	Direct	TX	Delay of Retail Competition	9/24/2001
7647	ENTERGY GULF STATES, INC.	Texas Industrial Energy Consumers	24469	Direct	TX	Delay of Retail Competition	9/22/2001
7608	RELIANT ENERGY HL&P	Texas Industrial Energy Consumers	23950	Direct	TX	Price to Beat	7/3/2001
7593	GEORGIA POWER COMPANY	Georgia Industrial Group/Georgia Textile Manufacturers Group	13711-U	Direct	GA	Fuel Cost Recovery	5/11/2001
7520	GEORGIA POWER COMPANY SAVANNAH ELECTRIC & POWER COMPANY	Georgia Industrial Group/Georgia Textile Manufacturers Group	12499-U,13305-U, 13306-U	Direct	GA	Integrated Resource Planning	5/11/2001
7303	ENTERGY GULF STATES, INC.	Texas Industrial Energy Consumers	22356	Rebuttal	TX	Allocation/Collection of Municipal Franchise Fees	3/31/2001
7309	SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	22351	Cross-Rebuttal	TX	Energy Efficiency Costs	2/22/2001
7305	CPL, SWEPCO, and WTU	Texas Industrial Energy Consumers	22352, 22353, 22354	Cross-Rebuttal	TX	Allocation/Collection of Municipal Franchise Fees	2/20/2001
7423	GEORGIA POWER COMPANY	Georgia Industrial Group/Georgia Textile Manufacturers Group	13140-U	Direct	GA	Interruptible Rate Design	2/16/2001
7305	CPL, SWEPCO, and WTU	Texas Industrial Energy Consumers	22352, 22353, 22354	Supplemental Direct	TX	Transmission Cost Recovery Factor	2/13/2001
7310	TEXAS-NEW MEXICO POWER COMPANY	Texas Industrial Energy Consumers	22349	Cross-Rebuttal	TX	Rate Design	2/12/2001
7308	TXU ELECTRIC COMPANY	Texas Industrial Energy Consumers	22350	Cross-Rebuttal	TX	Unbundled Cost of Service	2/12/2001
7303	ENTERGY GULF STATES, INC.	Texas Industrial Energy Consumers	22356	Cross-Rebuttal	TX	Stranded Cost Allocation	2/6/2001
7308	TXU ELECTRIC COMPANY	Texas Industrial Energy Consumers	22350	Direct	TX	Rate Design	2/5/2001
7303	ENTERGY GULF STATES, INC.	Texas Industrial Energy Consumers	22356	Supplemental Direct	TX	Rate Design	1/25/2001
7307	RELIANT ENERGY HL&P	Texas Industrial Energy Consumers	22355	Cross-Rebuttal	TX	Stranded Cost Allocation	1/12/2001
7303	ENTERGY GULF STATES, INC.	Texas Industrial Energy Consumers	22356	Direct	TX	Stranded Cost Allocation	1/9/2001
7307	RELIANT ENERGY HL&P	Texas Industrial Energy Consumers	22355	Direct	TX	Cost Allocation	12/13/2000
7375	CENTRAL POWER AND LIGHT COMPANY	Texas Industrial Energy Consumers	22352	Cross-Rebuttal	TX	CTC Rate Design	12/1/2000
7375	CENTRAL POWER AND LIGHT COMPANY	Texas Industrial Energy Consumers	22352	Direct	TX	Cost Allocation	11/1/2000
7308	TXU ELECTRIC COMPANY	Texas Industrial Energy Consumers	22350	Direct	TX	Cost Allocation	11/1/2000
7308	TXU ELECTRIC COMPANY	Texas Industrial Energy Consumers	22350	Cross-Rebuttal	TX	Cost Allocation	11/1/2000
7305	CPL, SWEPCO, and WTU	Texas Industrial Energy Consumers	22352, 22353, 22354	Direct	TX	Excess Cost Over Market	11/1/2000
7315	VARIOUS UTILITIES	Texas Industrial Energy Consumers	22344	Direct	TX	Generic Customer Classes	10/14/2000
7308	TXU ELECTRIC COMPANY	Texas Industrial Energy Consumers	22350	Direct	TX	Excess Cost Over Market	10/10/2000
7315	VARIOUS UTILITIES	Texas Industrial Energy Consumers	22344	Rebuttal	TX	Excess Cost Over Market	10/1/2000
7310	TEXAS-NEW MEXICO POWER COMPANY	Texas Industrial Energy Consumers	22349	Cross-Rebuttal	TX	Generic Customer Classes	10/1/2000
7310	TEXAS-NEW MEXICO POWER COMPANY	Texas Industrial Energy Consumers	22349	Direct	TX	Excess Cost Over Market	9/27/2000
7307	RELIANT ENERGY HL&P	Texas Industrial Energy Consumers	22355	Cross-Rebuttal	TX	Excess Cost Over Market	9/26/2000
7307	RELIANT ENERGY HL&P	Texas Industrial Energy Consumers	22355	Direct	TX	Excess Cost Over Market	9/19/2000

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7334	GEORGIA POWER COMPANY	Georgia Industrial Group/Georgia Textile Manufacturers Group	11708-U	Rebuttal	GA	RTP Petition	3/24/2000
7334	GEORGIA POWER COMPANY	Georgia Industrial Group/Georgia Textile Manufacturers Group	11708-U	Direct	GA	RTP Petition	3/1/2000
7232	PUBLIC SERVICE COMPANY OF COLORADO	Colorado Industrial Energy Consumers	99A-377EG	Answer	CO	Merger	12/1/1999
7258	TXU ELECTRIC COMPANY	Texas Industrial Energy Consumers	21527	Direct	TX	Securitization	11/24/1999
7246	CENTRAL POWER AND LIGHT COMPANY	Texas Industrial Energy Consumers	21528	Direct	TX	Securitization	11/24/1999
7089	VIRGINIA ELECTRIC AND POWER COMPANY	Virginia Committee for Fair Utility Rates	PUE980813	Direct	VA	Unbundled Rates	7/1/1999
7090	AMERICAN ELECTRIC POWER SERVICE CORPORATION	Old Dominion Committee for Fair Utility Rates	PUE980814	Direct	VA	Unbundled Rates	5/21/1999
7142	SHARYLAND UTILITIES, L.P.	Sharyland Utilities	20292	Rebuttal	TX	Certificate of Convenience and Necessity	4/30/1999
7060	PUBLIC SERVICE COMPANY OF COLORADO	Colorado Industrial Energy Consumers Group	98A-511E	Direct	CO	Allocation of Pollution Control Costs	3/1/1999
7039	SAVANNAH ELECTRIC AND POWER COMPANY	Various Industrial Customers	10205-U	Direct	GA	Fuel Costs	1/1/1999
6945	TAMPA ELECTRIC COMPANY	Florida Industrial Power Users Group	950379-EI	Direct	FL	Revenue Requirement	10/1/1998
6873	GEORGIA POWER COMPANY	Georgia Industrial Group	9355-U	Direct	GA	Revenue Requirement	10/1/1998
6729	VIRGINIA ELECTRIC AND POWER COMPANY	Virginia Committee for Fair Utility Rates	PUE960036,PUE960296	Direct	VA	Alternative Regulatory Plan	8/1/1998
6713	CENTRAL POWER AND LIGHT COMPANY	Texas Industrial Energy Consumers	16995	Cross-Rebuttal	TX	IRR	1/1/1998
6582	HOUSTON LIGHTING & POWER COMPANY	Lyondell Petrochemical Company	96-02867	Direct	COURT	Interruptible Power	1997
6758	SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Industrial Energy Consumers	17460	Direct	TX	Fuel Reconciliation	12/1/1997
6729	VIRGINIA ELECTRIC AND POWER COMPANY	Virginia Committee for Fair Utility Rates	PUE960036,PUE960296	Direct	VA	Alternative Regulatory Plan	12/1/1997
6713	CENTRAL POWER AND LIGHT COMPANY	Texas Industrial Energy Consumers	16995	Direct	TX	Rate Design	12/1/1997
6646	ENTERGY TEXAS	Texas Industrial Energy Consumers	16705	Rebuttal	TX	Competitive Issues	10/1/1997
6646	ENTERGY TEXAS	Texas Industrial Energy Consumers	16705	Rebuttal	TX	Competition	10/1/1997
6646	ENTERGY TEXAS	Texas Industrial Energy Consumers	473-96-2285/16705	Direct	TX	Rate Design	9/1/1997
6646	ENTERGY TEXAS	Texas Industrial Energy Consumers	16705	Direct	TX	Wholesale Sales	8/1/1997
6744	TAMPA ELECTRIC COMPANY	Florida Industrial Power Users Group	970171-EU	Direct	FL	Interruptible Rate Design	5/1/1997
6632	MISSISSIPPI POWER COMPANY	Colonial Pipeline Company	96-UN-390	Direct	MS	Interruptible Rates	2/1/1997
6558	TEXAS-NEW MEXICO POWER COMPANY	Texas Industrial Energy Consumers	15560	Direct	TX	Competition	11/11/1996
6508	TEXAS UTILITIES ELECTRIC COMPANY	Texas Industrial Energy Consumers	15195	Direct	TX	Treatment of margins	9/1/1996
6475	TEXAS UTILITIES ELECTRIC COMPANY	Texas Industrial Energy Consumers	15015	DIRECT	TX	Real Time Pricing Rates	8/8/1996
6449	CENTRAL POWER AND LIGHT COMPANY	Texas Industrial Energy Consumers	14965	Direct	TX	Quantification	7/1/1996
6449	CENTRAL POWER AND LIGHT COMPANY	Texas Industrial Energy Consumers	14965	Direct	TX	Interruptible Rates	5/1/1996
6449	CENTRAL POWER AND LIGHT COMPANY	Texas Industrial Energy Consumers	14965	Rebuttal	TX	Interruptible Rates	5/1/1996
6523	PUBLIC SERVICE COMPANY OF COLORADO	Multiple Intervenors	95A-531EG	Answer	CO	Merger	4/1/1996
6235	TEXAS UTILITIES ELECTRIC COMPANY	Texas Industrial Energy Consumers	13575	Direct	TX	Competitive Issues	4/1/1996
6435	SOUTHWESTERN PUBLIC SERVICE COMMISSION	Texas Industrial Energy Consumers	14499	Direct	TX	Acquisition	11/1/1995

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6391	HOUSTON LIGHTING & POWER COMPANY	Grace, W.R. & Company	13988	Rebuttal	TX	Rate Design	8/1/1995
6353	SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	14174	Direct	TX	Costing of Off-System Sales	8/1/1995
6157	WEST TEXAS UTILITIES COMPANY	Texas Industrial Energy Consumers	13369	Rebuttal	TX	Cancellation Term	8/1/1995
6391	HOUSTON LIGHTING & POWER COMPANY	Grace, W.R. & Company	13988	Direct	TX	Rate Design	7/1/1995
6157	WEST TEXAS UTILITIES COMPANY	Texas Industrial Energy Consumers	13369	Direct	TX	Cancellation Term	7/1/1995
6296	GEORGIA POWER COMPANY	Georgia Industrial Group	5601-U	Rebuttal	GA	EPACT Rate-Making Standards	5/1/1995
6296	GEORGIA POWER COMPANY	Georgia Industrial Group	5601-U	Direct	GA	EPACT Rate-Making Standards	5/1/1995
6278	COMMONWEALTH OF VIRGINIA	VCFUR/ODCFUR	PUE940067	Rebuttal	VA	Integrated Resource Planning	5/1/1995
6295	GEORGIA POWER COMPANY	Georgia Industrial Group	5600-U	Supplemental	GA	Cost of Service	4/1/1995
6063	PUBLIC SERVICE COMPANY OF COLORADO	Multiple Intervenors	94I-430EG	Rebuttal	CO	Cost of Service	4/1/1995
6063	PUBLIC SERVICE COMPANY OF COLORADO	Multiple Intervenors	94I-430EG	Reply	CO	DSM Rider	4/1/1995
6295	GEORGIA POWER COMPANY	Georgia Industrial Group	5600-U	Direct	GA	Interruptible Rate Design	3/1/1995
6278	COMMONWEALTH OF VIRGINIA	VCFUR/ODCFUR	PUE940067	Direct	VA	EPACT Rate-Making Standards	3/1/1995
6125	SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	13456	Direct	TX	DSM Rider	3/1/1995
6235	TEXAS UTILITIES ELECTRIC COMPANY	Texas Industrial Energy Consumers	13575|13749	Direct	TX	Cost of Service	2/1/1995
6063	PUBLIC SERVICE COMPANY OF COLORADO	Multiple Intervenors	94I-430EG	Answering	CO	Competition	2/1/1995
6061	HOUSTON LIGHTING & POWER COMPANY	Texas Industrial Energy Consumers	12065	Direct	TX	Rate Design	1/1/1995
6181	GULF STATES UTILITIES COMPANY	Texas Industrial Energy Consumers	12852	Direct	TX	Competitive Alignment Proposal	11/1/1994
6061	HOUSTON LIGHTING & POWER COMPANY	Texas Industrial Energy Consumers	12065	Direct	TX	Rate Design	11/1/1994
5929	CENTRAL POWER AND LIGHT COMPANY	Texas Industrial Energy Consumers	12820	Direct	TX	Rate Design	10/1/1994
6107	SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Industrial Energy Consumers	12855	Direct	TX	Fuel Reconciliation	8/1/1994
6112	HOUSTON LIGHTING & POWER COMPANY	Texas Industrial Energy Consumers	12957	Direct	TX	Standby Rates	7/1/1994
5698	GULF POWER COMPANY	Misc. Group	931044-EI	Direct	FL	Standby Rates	7/1/1994
5698	GULF POWER COMPANY	Misc. Group	931044-EI	Rebuttal	FL	Competition	7/1/1994
6043	EL PASO ELECTRIC COMPANY	Phelps Dodge Corporation	12700	Direct	TX	Revenue Requirement	6/1/1994
6082	GEORGIA PUBLIC SERVICE COMMISSION	Georgia Industrial Group	4822-U	Direct	GA	Avoided Costs	5/1/1994
6075	GEORGIA POWER COMPANY	Georgia Industrial Group	4895-U	Direct	GA	FPC Certification Filing	4/1/1994
6025	MISSISSIPPI POWER & LIGHT COMPANY	MIEG	93-UA-0301	Comments	MS	Environmental Cost Recovery Clause	1/21/1994
5971	FLORIDA POWER & LIGHT COMPANY	Florida Industrial Power Users Group	940042-EI	Direct	FL	Section 712 Standards of 1992 EPACT	1/1/1994

APPENDIX C

Procedures for Conducting a Class Cost-of-Service Study

Q. WHAT PROCEDURES ARE USED IN A COST-OF-SERVICE STUDY?

A. The basic procedure for conducting a class cost-of-service study is fairly simple. First, we identify the different types of costs (functionalization), determine their primary causative factors (classification), and then apportion each item of cost among the various rate classes (allocation). Adding up the individual pieces gives the total cost for each class.

Identifying the utility's different levels of operation is a process referred to as functionalization. The utility's investments and expenses are separated into production, transmission, distribution, and other functions. To a large extent, this is done in accordance with the Uniform System of Accounts developed by the Federal Energy Regulatory Commission (FERC).

Once costs have been functionalized, the next step is to identify the primary causative factor (or factors). This step is referred to as classification. Costs are classified as demand-related, energy-related or customer-related. Demand (or capacity) related costs vary with peak demand, which is measured in kilowatts (or kW). This includes production, transmission, and some distribution investment and related fixed operation and maintenance (O&M) expenses. As explained later, peak demand determines the amount of capacity needed for reliable service. Energy-related costs vary with the production of energy, which is measured in kilowatt-hours (or kWh). Energy-related costs include fuel and variable O&M expense. Customer-related costs vary directly with the number of customers and include expenses such as meters, service drops, billing, and customer service.

Each functionalized and classified cost must then be allocated to the various customer classes. This is accomplished by developing allocation factors that reflect the percentage of the total cost that should be paid by each class. The allocation factors should reflect cost causation; that is, the degree to which each class caused the utility to incur the cost.

Q. WHAT KEY PRINCIPLES ARE RECOGNIZED IN A CLASS COST-OF-SERVICE STUDY?

A. A properly conducted class cost-of-service study recognizes two key cost causation principles. First, customers are served at different delivery voltages. This affects the amount of investment the utility must make to deliver electricity to the meter. Second, since cost causation is also related to how electricity is used, both the timing and rate of energy consumption (*i.e.*, demand) are critical. Because electricity cannot be stored for any significant time period, a utility must acquire sufficient generation resources and construct the required transmission facilities to meet the maximum projected demand, including a reserve margin as a contingency against forced and unforced outages, severe weather, and load forecast error. Customers that use electricity during the critical peak hours cause the utility to invest in generation and transmission facilities.

Q. WHAT FACTORS CAUSE THE PER-UNIT COSTS TO DIFFER AMONG CUSTOMER CLASSES?

A. Factors that affect the per-unit cost include whether a customer's usage is constant or fluctuating (load factor), whether the utility must invest in transformers and distribution systems to provide the electricity at lower voltage levels, the amount of electricity that a customer uses, and the quality of service (*e.g.,* firm or non-firm). In general, industrial consumers are less costly to serve on a per unit basis because they:

1. Operate at higher load factors;
2. Take service at higher delivery voltages; and
3. Use more electricity per customer.

A customer that purchases non-firm or interruptible service is receiving a lower quality of service than firm service. Thus, non-firm service is less costly per unit than firm service for customers that otherwise have the same characteristics.

All of these factors explain why some customers pay lower average rates than others.

For example, the difference in the losses incurred to deliver electricity at the various delivery voltages is a reason why the per-unit energy cost to serve is not the same for all customers. More losses occur to deliver electricity at distribution voltage (either primary or secondary) than at transmission voltage, which is generally the level at which industrial customers take service. This means that the cost per kWh is lower for a transmission customer than a distribution customer. The cost to deliver a kWh at primary distribution, though higher than the per-unit cost at transmission, is lower than the delivered cost at secondary distribution.

In addition to lower losses, transmission customers do not use the distribution system. Instead, transmission customers construct and own their own distribution systems. Thus, distribution system costs are not allocated to transmission level customers who do not use that system. Distribution customers, by contrast, require substantial investments in these lower voltage facilities to provide service. Secondary distribution customers require more investment than do primary distribution customers. This results in a different cost to serve each type of customer.

Two other cost drivers are efficiency and size. These drivers are important because most fixed costs are allocated on either a demand or customer basis.

Efficiency can be measured in terms of load factor. Load factor is the ratio of average demand (*i.e.*, energy usage divided by the number of hours in the period) to peak demand. A customer that operates at a high load factor is more efficient than a lower load factor customer because it requires less capacity for the same amount of energy. For example, assume that two customers purchase the same amount of energy, but one customer has an 80% load factor and the other has a 40% load factor. The 40% load factor customers would have twice the peak demand of the 80% load factor customers, and the utility would therefore require twice as much capacity to serve the 40% load factor customer as the 80% load factor. Stated differently, the fixed costs to serve a high load factor customer are spread over more kWh usage than for a low load factor customer.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for rate increase by Florida Power & Light Company	**DOCKET NO. 160021-EI** **Filed: July 7, 2016**

AFFIDAVIT OF JEFFRY POLLOCK

State of Missouri)
) SS
County of St. Louis)

Jeffry Pollock, being first duly sworn, on his oath states:

1. My name is Jeffry Pollock. I am President of J. Pollock, Incorporated, 12647 Olive Blvd., Suite 585, St. Louis, Missouri 63141. We have been retained by Florida Industrial Power Users Group to testify in this proceeding on its behalf;

2. Attached hereto and made a part hereof for all purposes is my Direct Testimony and Exhibits, which have been prepared in written form for introduction into evidence in Florida Public Service Commission Docket No. 160021-EI; and,

3. I hereby swear and affirm that the answers contained in my testimony and the information in my exhibits are true and correct.

Jeffry Pollock

Subscribed and sworn to before me this 7th day of July, 2016.

KITTY TURNER
Notary Public - Notary Seal
State of Missouri
Commissioned for Lincoln County
My Commission Expires: April 25, 2019
Commission Number: 15390610

Kitty Turner, Notary Public
Commission #: 15390610

My Commission expires on April 25, 2019.

FLORIDA POWER & LIGHT COMPANY
Analysis of Historical and Projected Weather Normalized Retail Sales and Number of Customers

Line	Year	Forecast or Actual	Sales to Ultimate Consumers (GWh)	Growth Rate	Total Average Number of Customers	Growth Rate
		(1)	(2)	(3)	(4)	(5)
1	2011	Actual	101,569		4,547,051	
2	2012	Actual	102,853	1.3%	4,576,449	0.6%
3	2013	Actual	103,198	0.3%	4,626,934	1.1%
4	2014	Actual	104,849	1.6%	4,708,829	1.8%
5	2015	Actual	105,704	0.8%	4,775,382	1.4%
6	**2011-2015**			1.0%		1.2%
7	2016	Forecast	107,467	1.7%	4,845,390	1.5%
8	**2017**	**Forecast**	**107,382**	**-0.1%**	**4,917,036**	**1.5%**
9	**2018**	**Forecast**	**108,041**	**0.6%**	**4,989,889**	**1.5%**
10	2016-2018			0.3%		1.5%

Source: FPL's Response to Staff's Interrogatory No. 158 and 2016 Ten Year Site Plan.

Docket No. 160021-EI
2017 Debt Cost 10 Basis Points Lower
Exhibit___(JP-2)

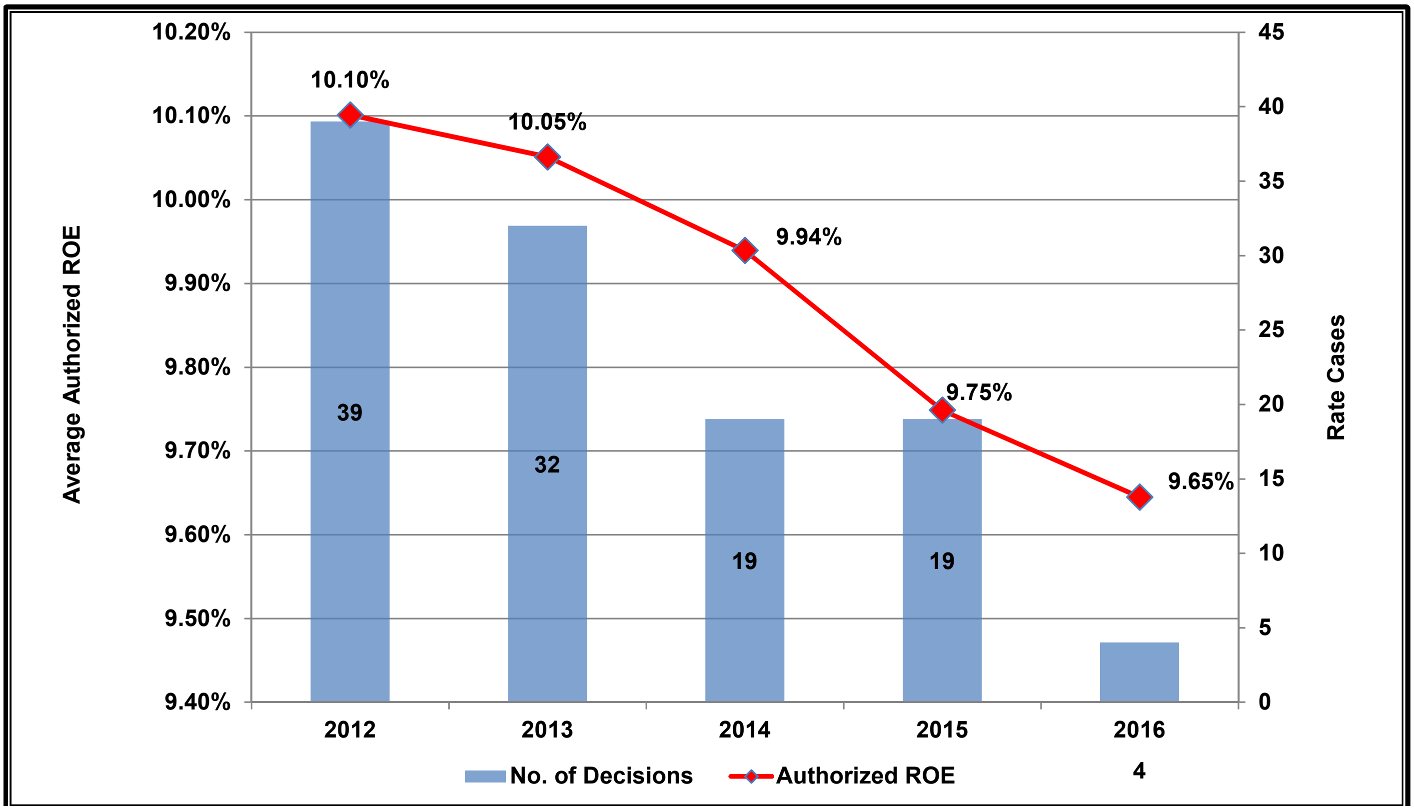
FLORIDA POWER & LIGHT COMPANY
2017 Cost of Long-Term Debt Adjusted For Lower Interest Rates

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
Line No.	Description/Coupon Rate	Issue Date	Maturity Date	Principal Amount Sold (Face Value)	13-Month Average Principal Amt. Outstanding	Discount (Premium) on Principal Amount Sold	Issuing Expense on Principal Amount Sold	Life (Years)	Annual Amortization (6+7)/(8)	Interest Expense (Coupon Rate) (1) x (5)	Total Annual Cost (9)+(10)	Unamortized Discount (Premium) Associated with (6)	Unamort. Issuing Expense & Loss on Reacquired Debt Associated with (7)
1	First Mortgage Bonds:												
2	5.56%	Nov 2017	Nov 2047	$800,000	$123,077		$7,000	30.00	$30	$6,843	$6,873		$1,074
3	5.56%	Mar 2017	Mar 2047	$500,000	$384,615		$4,375	30.00	$112	$21,385	$21,497		$3,318
4	2.75%	Jun 2013	Jun 2023	$500,000	$500,000	$1,905	$5,650	10.00	$751	$13,750	$14,501	$1,127	$3,314
5	5.625%	Apr 2003	Apr 2034	$500,000	$418,172	$6,480	$2,199	31.00	$280	$23,522	$23,802	$3,500	$1,190
6	5.4%	Sep 2005	Oct 2035	$300,000	$229,586	$4,030	$1,594	30.08	$187	$12,398	$12,584	$2,439	$969
7	5.65%	Jan 2006	Feb 2037	$400,000	$394,991	$6,364	$1,996	31.08	$269	$22,317	$22,586	$4,010	$1,257
8	6.2%	Apr 2006	Apr 2036	$300,000	$219,161	$2,693	$1,738	30.00	$148	$13,588	$13,736	$1,692	$1,092
9	4.95%	Jun 2005	Jun 2035	$300,000	$300,000	$4,893	$1,635	30.00	$218	$14,850	$15,068	$2,922	$976
10	5.85%	Dec 2002	Feb 2033	$200,000	$170,695	$2,212	$911	30.17	$104	$9,986	$10,089	$1,143	$471
11	5.85%	Apr 2007	May 2037	$300,000	$230,521	$600	$4,097	30.08	$156	$13,485	$13,642	$396	$2,706
12	5.55%	Oct 2007	Nov 2017	$300,000	$253,846	$84	$3,524	10.08	$299	$13,875	$14,174	$3	$123
13	5.95%	Jan 2008	Feb 2038	$600,000	$600,000	$3,260	$7,839	30.08	$369	$35,700	$36,069	$2,233	$5,369
14	5.96%	Mar 2009	Apr 2039	$500,000	$500,000	$500	$6,256	30.08	$233	$29,800	$30,033	$264	$4,796
15	5.25%	Dec 2010	Feb 2041	$400,000	$400,000	$989	$5,408	30.17	$206	$21,000	$21,206	$776	$4,081
16	5.69%	Feb 2010	Feb 2040	$500,000	$500,000	$670	$6,890	30.00	$252	$28,450	$28,702	$505	$5,205
17	5.125%	Jun 2011	Jun 2041	$250,000	$250,000	$225	$3,488	30.00	$118	$12,813	$12,930	$179	$2,642
18	5.65%	Jan 2004	Feb 2035	$240,000	$204,431	$2,775	$1,260	31.08	$130	$11,550	$11,680	$1,567	$716
19	5.95%	Oct 2003	Oct 2033	$300,000	$272,444	$5,802	$1,527	30.00	$244	$16,210	$16,455	$3,143	$827
20	4.125%	Dec 2011	Feb 2042	$600,000	$600,000	$1,482	$8,250	30.17	$319	$24,750	$25,069	$1,208	$6,623
21	3.8%	Dec 2012	Dec 2042	$400,000	$400,000	$1,984	$5,700	30.00	$241	$15,200	$15,441	$1,684	$4,451
22	4.05%	May 2012	Jun 2042	$600,000	$600,000	$840	$8,150	30.08	$290	$24,300	$24,590	$696	$6,537
23	4.05%	Sep 2014	Oct 2044	$500,000	$500,000	$1,650	$6,775	30.08	$278	$20,250	$20,528	$1,495	$6,081
24	3.25%	May 2014	Jun 2024	$500,000	$500,000	$645	$5,650	10.08	$643	$16,250	$16,893	$442	$4,008
25	3.85%	Nov 2015	Nov 2025	$600,000	$600,000		$6,600	10.00	$525	$18,000	$18,525		$4,396
26	4.75%	Mar 2016	Mar 2046	$300,000	$300,000		$2,625	30.00	$87	$15,690	$15,777		$2,512
27	Storm Securitization Bonds:												
29	5.256%	May 2007	Aug 2019	$288,000	$168,957	$96	$3,334	12.25	$280	$8,901	$9,181	$8	$575

FLORIDA POWER & LIGHT COMPANY
2017 Cost of Long-Term Debt Adjusted For Lower Interest Rates

Line No.	(1) Description/Coupon Rate	(2) Issue Date	(3) Maturity Date	(4) Principal Amount Sold (Face Value)	(5) 13-Month Average Principal Amt. Outstanding	(6) Discount (Premium) on Principal Amount Sold	(7) Issuing Expense on Principal Amount Sold	(8) Life (Years)	(9) Annual Amortization (6+7)/(8)	(10) Interest Expense (Coupon Rate) (1) x (5)	(11) Total Annual Cost (9)+(10)	(12) Unamortized Discount (Premium) Associated with (6)	(13) Unamort. Issuing Expense & Loss on Reacquired Debt Associated with (7)
30	Term Loans:												
31	Var Term Loan	Nov 2015	Nov 2018	$600,000	$600,000		$32	3.00	$999	$6,882	$7,881		$14
32	Unsecured Pollution Control and Industrial Development Bonds:												
33	Var Broward County	Jun 2015	Jun 2045	$85,000	$85,000		$720	30.00	$16	$975	$991		$596
34	Var Dade County	Aug 1991	Feb 2023	$15,000	$15,000		$520	31.50	$17	$183	$200		$92
35	Var Dade County	Dec 1993	Jun 2021	$45,750	$45,750		$711	27.50	$26	$570	$596		$101
36	Var Jacksonville	Mar 1994	Sep 2024	$45,960	$45,960		$397	30.50	$13	$573	$586		$93
37	Var Manatee	Mar 1994	Sep 2024	$16,510	$16,510		$132	30.50	$4	$206	$210		$31
38	Var Putnam	Mar 1994	Sep 2024	$4,480	$4,480		$83	30.50	$3	$56	$59		$19
39	Var Jacksonville	May 1992	May 2027	$28,300	$28,300		$371	35.00	$11	$353	$363		$104
40	Var Dade County	Mar 1995	Apr 2020	$8,635	$8,635		$182	25.08	$7	$106	$113		$20
41	Var Jacksonville	Jun 1995	May 2029	$51,940	$51,940		$345	33.92	$10	$635	$645		$120
42	Var Martin	Apr 2000	Jul 2022	$95,700	$95,700		$499	22.25	$22	$1,193	$1,216		$112
43	Var St. Lucie	Sep 2000	Sep 2028	$242,210	$242,210		$570	28.00	$20	$2,960	$2,981		$227
44	Var St. Lucie		May 2024	$78,785	$78,785		$442	21.00	$21	$963	$984		$144
45	Gain/Loss on Reacquired Debt				-								$92,402
46	Total			$12,296,270	$10,938,767	$50,179	$119,476		$7,942	$480,518	$488,456	$31,431	$169,386
47	Less Unamortized Premium, Discount, Issue												
48	and Loss Col (12) + (13)				($200,817)								
49	Net				$10,737,950								
50	Embedded Cost of Long-Term Debt Col (11)/Net				4.5489%								

Average Authorized Return on Equity for Vertically Integrated Electric IOU's In Rate Cases Decided in 2012-March 2016



Source: SNL, a Subsidiary of S&P Global Credit Research

Summary of Authorized Returns on Equity In Rate Cases Decided in 2012-March 2016 for Vertically Integrated Electric Utilities

Line	State	Company	Case Identification	Date	Order Year	Return on Equity (%)	Test Year	Lag (months)
		(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	Alabama	Alabama Power Company	18117, 18416	2013	2013	13.29	N/A	N/A
2	Arizona	Arizona Public Service Co.	D-E-01345A-11-0224	5/15/2012	2012	10.00	12/2010	11
3	Arizona	UNS Electric Inc.	D-E-04204A-12-0504	12/17/2013	2013	9.50	06/2012	11
4	Arizona	Tucson Electric Power Co.	D-E-01933A-12-0291	6/11/2013	2013	10.00	12/2011	11
5	Arkansas	Entergy Arkansas Inc.	D-13-028-U	12/30/2013	2013	9.50	12/2012	10
6	Arkansas	Entergy Arkansas Inc.	D-15-015-U	2/23/2016	2016	9.75	03/2015	10
7	California	Liberty Utilities LLC	A-12-02-014	11/29/2012	2012	9.88	12/2013	9
8	California	San Diego Gas & Electric Co.	Ap-12-04-016 (Elec)	12/20/2012	2012	10.30	12/2013	8
9	California	Pacific Gas and Electric Co.	Ap-12-04-018 (Elec)	12/20/2012	2012	10.40	12/2013	8
10	California	Southern California Edison Co.	Ap-12-04-015	12/20/2012	2012	10.45	12/2013	8
11	Colorado	Public Service Co. of CO	D-11AL-947E	4/26/2012	2012	10.00	NA	5
12	Colorado	Black Hills Colorado Electric	D-14AL-0393E	12/18/2014	2014	9.83	12/2013	7
13	Colorado	Public Service Co. of CO	D-14AL-0660E	2/24/2015	2015	9.83	12/2013	8
14	Florida	Gulf Power Co.	D-110138-EI	2/27/2012	2012	10.25	12/2012	7
15	Florida	Florida Power & Light Co.	D-120015-EI	12/13/2012	2012	10.50	12/2013	8
16	Florida	Gulf Power Co.	D-130140-EI	12/3/2013	2013	10.25	12/2014	4
17	Florida	Tampa Electric Co.	D-130040-EI	9/11/2013	2013	10.25	12/2014	5
18	Florida	Florida Public Utilities Co.	D-140025-EI	9/15/2014	2014	10.25	09/2015	4
19	Georgia	Georgia Power Co.	D-36989	12/17/2013	2013	10.95	12/2016	5
20	Hawaii	Hawaii Electric Light Co	D-2009-0164	4/4/2012	2012	10.00	12/2010	28
21	Hawaii	Hawaiian Electric Co.	D-2010-0080	6/29/2012	2012	10.00	12/2011	23
22	Hawaii	Maui Electric Company Ltd	D-2009-0163	5/2/2012	2012	10.00	12/2010	31
23	Hawaii	Maui Electric Company Ltd	D-2011-0092	5/31/2013	2013	9.00	12/2012	22
24	Idaho	Avista Corp.	C-AVU-E-12-08	3/27/2013	2013	9.80	06/2012	5
25	Idaho	Avista Corp.	C-AVU-E-15-05	12/18/2015	2015	9.50	12/2014	6
26	Illinois	MidAmerican Energy Co.	D-14-0066	11/6/2014	2014	9.56	12/2012	10
27	Indiana	Indiana Michigan Power Co.	Ca-44075	2/13/2013	2013	10.20	03/2011	16
28	Indiana	Indianapolis Power & Light Co.	Ca-44576	3/16/2016	2016	9.85	06/2014	14
29	Kansas	Kansas City Power & Light	D-12-KCPE-764-RTS	12/13/2012	2012	9.50	12/2011	7
30	Kansas	Westar Energy Inc.	D-13-WSEE-629-RTS	11/21/2013	2013	10.00	03/2011	7
31	Kansas	Kansas City Power & Light	D-15-KCPE-116-RTS	9/10/2015	2015	9.30	06/2014	8
32	Kentucky	Kentucky Utilities Co.	C-2012-00221	12/20/2012	2012	10.25	03/2012	5
33	Kentucky	Louisville Gas & Electric Co.	C-2012-00222 (elec.)	12/20/2012	2012	10.25	03/2012	5
34	Louisiana	Entergy Gulf States LA LLC	D-U-32707	12/16/2013	2013	9.95	NA	10
35	Louisiana	Entergy Louisiana LLC	D-U-32708	12/16/2013	2013	9.95	NA	10
36	Louisiana	Southwestern Electric Power Co	D-U-32220	2/27/2013	2013	10.00	12/2011	7
37	Louisiana	Entergy Louisiana LLC	D-UD-13-01	7/10/2014	2014	9.95	NA	15
38	Michigan	Wisconsin Electric Power Co.	C-U-16830	6/26/2012	2012	10.10	12/2012	11
39	Michigan	Indiana Michigan Power Co.	C-U-16801	2/15/2012	2012	10.20	12/2012	7
40	Michigan	Consumers Energy Co.	C-U-16794	6/7/2012	2012	10.30	09/2012	12

Source: SNL, a Subsidiary of S&P Global Credit Research

Summary of Authorized Returns on Equity
In Rate Cases Decided in 2012-March 2016
for Vertically Integrated Electric Utilities

Line	State	Company	Case Identification	Date	Order Year	Return on Equity (%)	Test Year	Lag (months)
		(1)	(2)	(3)	(4)	(5)	(6)	(7)
41	Michigan	Upper Peninsula Power Co.	C-U-17274	12/19/2013	2013	10.15	12/2014	5
42	Michigan	Consumers Energy Co.	C-U-17087	5/15/2013	2013	10.30	12/2013	7
43	Michigan	Wisconsin Public Service Corp.	C-U-17669	4/23/2015	2015	10.20	12/2015	6
44	Michigan	Consumers Energy Co.	C-U-17735	11/19/2015	2015	10.30	05/2016	11
45	Michigan	DTE Electric Co.	C-U-17767	12/11/2015	2015	10.30	06/2016	11
46	Minnesota	Northern States Power Co. - MN	D-E-002/GR-10-971	3/29/2012	2012	10.37	12/2011	17
47	Minnesota	Northern States Power Co. - MN	D-E-002/GR-12-961	8/8/2013	2013	9.83	12/2013	9
48	Minnesota	Northern States Power Co. - MN	D-E-002/GR-13-868	3/26/2015	2015	9.72	12/2014	16
49	Mississippi	Entergy Mississippi Inc.	D-2014-UN-0132	12/11/2014	2014	10.07	12/2015	6
50	Missouri	Union Electric Co.	C-ER-2012-0166	12/12/2012	2012	9.80	09/2011	10
51	Missouri	Kansas City Power & Light	C-ER-2012-0174	1/9/2013	2013	9.70	09/2011	10
52	Missouri	KCP&L Greater Missouri Op Co	C-ER-2012-0175 (MPS)	1/9/2013	2013	9.70	09/2011	10
53	Missouri	KCP&L Greater Missouri Op Co	C-ER-2012-0175 (L&P)	1/9/2013	2013	9.70	09/2011	10
54	Missouri	Kansas City Power & Light	C-ER-2014-0370	9/2/2015	2015	9.50	03/2014	10
55	Missouri	Union Electric Co.	C-ER-2014-0258	4/29/2015	2015	9.53	03/2014	10
56	Nevada	Sierra Pacific Power Co.	D-13-06002	12/16/2013	2013	10.12	12/2012	6
57	Nevada	Nevada Power Co.	D-14-05004	10/9/2014	2014	9.80	12/2013	5
58	New Mexico	Southwestern Public Service Co	C-12-00350-UT	3/26/2014	2014	9.96	12/2014	15
59	New Mexico	El Paso Electric Co.	C-15-00127-UT	6/8/2016	2016	9.48	12/2014	13
60	North Carolina	Virginia Electric & Power Co.	D-E-22, Sub 479	12/21/2012	2012	10.20	12/2011	8
61	North Carolina	Duke Energy Carolinas LLC	D-E-7, Sub 989	1/27/2012	2012	10.50	12/2010	7
62	North Carolina	Duke Energy Carolinas LLC	D-E-7, Sub 1026	9/24/2013	2013	10.20	06/2012	7
63	North Carolina	Duke Energy Progress LLC	D-E-2, Sub 1023	5/30/2013	2013	10.20	03/2012	7
64	North Dakota	Northern States Power Co. - MN	C-PU-10-657	2/29/2012	2012	10.40	12/2011	14
65	North Dakota	Northern States Power Co. - MN	C-PU-12-813	2/26/2014	2014	9.75	NA	14
66	Oklahoma	Oklahoma Gas and Electric Co.	Ca-PUD201100087	7/9/2012	2012	10.20	12/2010	11
67	Oregon	PacifiCorp	D-UE-246	12/20/2012	2012	9.80	12/2013	9
68	Oregon	Idaho Power Co.	D-UE-233	2/23/2012	2012	9.90	12/2011	6
69	Oregon	Portland General Electric Co.	D-UE-262	12/9/2013	2013	9.75	12/2014	9
70	Oregon	PacifiCorp	D-UE-263	12/18/2013	2013	9.80	12/2014	9
71	Oregon	Portland General Electric Co.	D-UE-283	12/4/2014	2014	9.68	12/2015	9
72	Oregon	Portland General Electric Co.	D-UE-294	12/15/2015	2015	9.60	12/2016	10
73	South Carolina	South Carolina Electric & Gas	D-2012-218-E	12/19/2012	2012	10.25	12/2011	5
74	South Carolina	Duke Energy Carolinas LLC	D-2011-271-E	1/25/2012	2012	10.50	12/2010	5
75	South Carolina	Duke Energy Carolinas LLC	D-2013-59-E	9/11/2013	2013	10.20	06/2012	5
76	South Dakota	Northern States Power Co. - MN	D-EL11-019	6/19/2012	2012	9.25	12/2010	11
77	Texas	Entergy Texas Inc.	D-39896	9/13/2012	2012	9.80	06/2011	9
78	Texas	Southwestern Electric Power Co	D-40443	10/3/2013	2013	9.65	12/2011	14
79	Texas	Entergy Texas Inc.	D-41791	5/16/2014	2014	9.80	03/2013	7
80	Texas	Southwestern Public Service Co	D-43695	12/17/2015	2015	9.70	06/2014	12

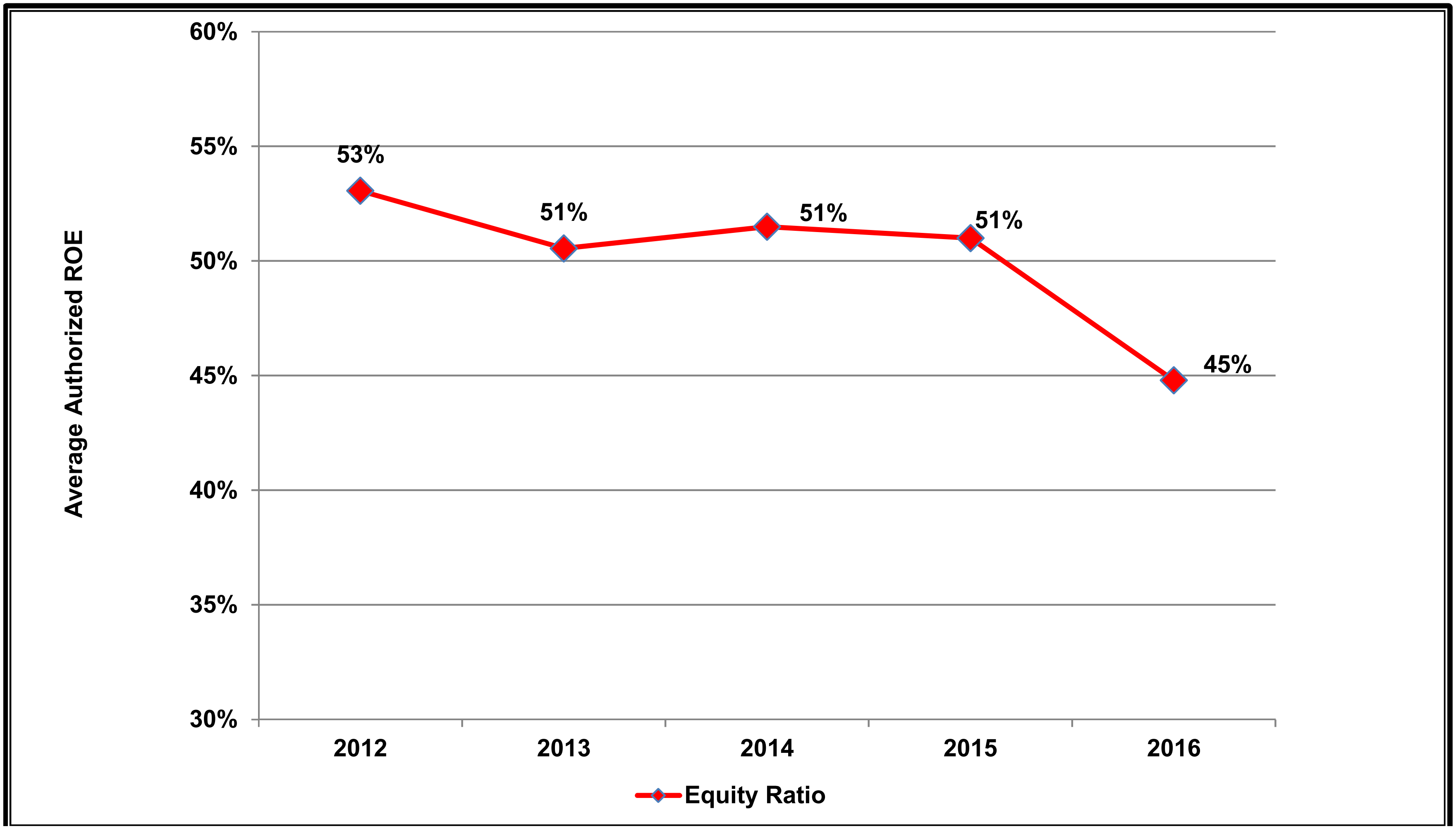
Source: SNL, a Subsidiary of S&P Global Credit Research

Summary of Authorized Returns on Equity In Rate Cases Decided in 2012-March 2016 for Vertically Integrated Electric Utilities

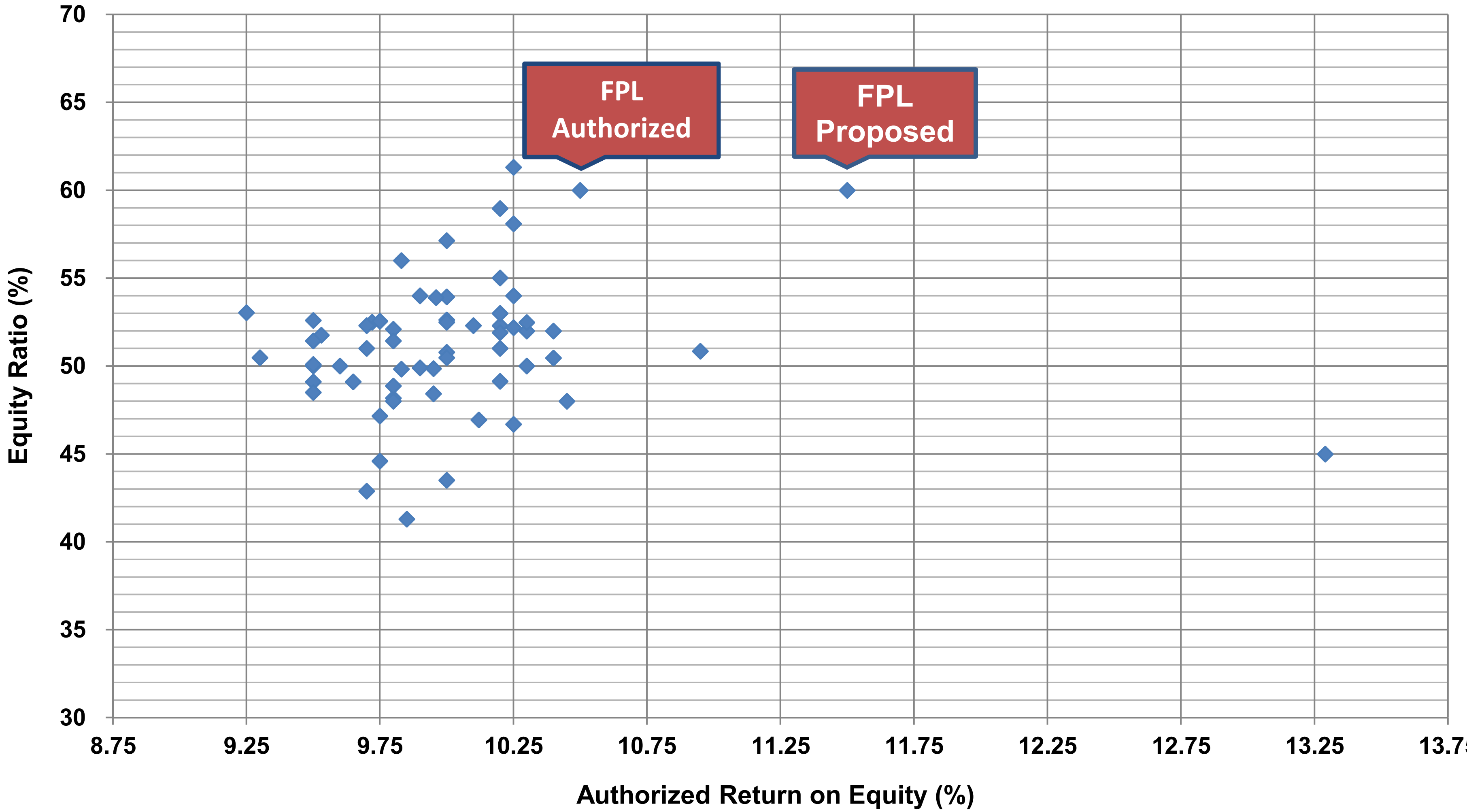
Line	State	Company	Case Identification	Date	Order Year	Return on Equity (%)	Test Year	Lag (months)
		(1)	(2)	(3)	(4)	(5)	(6)	(7)
81	Utah	PacifiCorp	D-11-035-200	9/19/2012	2012	9.80	05/2013	7
82	Utah	PacifiCorp	D-13-035-184	8/29/2014	2014	9.80	06/2015	7
83	Vermont	Green Mountain Power Corp	D-8190, 8191	8/25/2014	2014	9.60	09/2013	8
84	Virginia	Virginia Electric & Power Co.	C-PUE-2013-00020	11/26/2013	2013	10.00	12/2012	8
85	Virginia	Appalachian Power Co.	C-PUE-2014-00026	11/26/2014	2014	9.70	12/2013	8
86	Washington	Avista Corp.	D-UE-120436	12/26/2012	2012	9.80	12/2011	8
87	Washington	Puget Sound Energy Inc.	D-UE-111048	5/7/2012	2012	9.80	12/2010	10
88	Washington	PacifiCorp	D-UE-130043	12/4/2013	2013	9.50	06/2012	10
89	Washington	Puget Sound Energy Inc.	D-UE-130137	6/25/2013	2013	9.80	06/2012	4
90	Washington	PacifiCorp	D-UE-140762	3/25/2015	2015	9.50	12/2013	10
91	Washington	Avista Corp.	D-UE-150204	1/6/2016	2016	9.50	09/2014	11
92	West Virginia	Appalachian Power Co.	C-14-1152-E-42T	5/26/2015	2015	9.75	12/2013	11
93	Wisconsin	Madison Gas and Electric Co.	D-3270-UR-118 (elec)	11/9/2012	2012	10.30	12/2013	7
94	Wisconsin	Wisconsin Public Service Corp.	D-6690-UR-121 (Elec)	10/24/2012	2012	10.30	12/2013	6
95	Wisconsin	Northern States Power Co - WI	D-4220-UR-118 (elec)	12/14/2012	2012	10.40	12/2013	6
96	Wisconsin	Wisconsin Electric Power Co.	D-05-UR-106 (WEP-Elec)	11/28/2012	2012	10.40	12/2013	8
97	Wisconsin	Wisconsin Power and Light Co	D-6680-UR-118 (elec)	6/15/2012	2012	10.40	12/2013	1
98	Wisconsin	Northern States Power Co - WI	D-4220-UR-119 (Elec)	12/5/2013	2013	10.20	12/2014	6
99	Wisconsin	Wisconsin Public Service Corp.	D-6690-UR-122 (Elec)	11/6/2013	2013	10.20	12/2014	7
100	Wisconsin	Madison Gas and Electric Co.	D-3270-UR-120 (Elec)	11/26/2014	2014	10.20	12/2015	7
101	Wisconsin	Northern States Power Co - WI	D-4220-UR-120 (Elec)	12/12/2014	2014	10.20	12/2015	6
102	Wisconsin	Wisconsin Electric Power Co.	D-05-UR-107 (WEP-Elec)	11/14/2014	2014	10.20	12/2015	5
103	Wisconsin	Wisconsin Public Service Corp.	D-6690-UR-123 (Elec)	11/6/2014	2014	10.20	12/2015	7
104	Wisconsin	Wisconsin Power and Light Co	D-6680-UR-119 (Elec)	6/6/2014	2014	10.40	12/2015	1
105	Wisconsin	Northern States Power Co - WI	D-4220-UR-121 (Elec)	12/3/2015	2015	10.00	12/2016	6
106	Wisconsin	Wisconsin Public Service Corp.	D-6690-UR-124 (Elec)	11/19/2015	2015	10.00	12/2016	7
107	Wyoming	Cheyenne Light Fuel Power Co.	D-20003-114-ER-11 (elec)	6/18/2012	2012	9.60	08/2011	6
108	Wyoming	PacifiCorp	D-20000-405-ER-11	7/16/2012	2012	9.80	03/2013	7
109	Wyoming	Cheyenne Light Fuel Power Co.	D-20003-132-ER-13	7/31/2014	2014	9.90	06/2013	8
110	Wyoming	PacifiCorp	D-20000-469-ER-15	12/30/2015	2015	9.50	12/2015	10
111	Wyoming	PacifiCorp	D-20000-446-ER-14	1/23/2015	2015	9.50	06/2015	10

Source: SNL, a Subsidiary of S&P Global Credit Research

Average of the Last Authorized Financial Equity Ratio For Each Vertically Integrated Electric IOU In Rate Cases Decided in 2012-March 2016



Last Authorized Return on Equity and Financial Equity Ratio for Each Vertically Integrated Electric IOU In Rate Cases Decided in 2012-March 2016



Last Authorized Return on Equity and Financial Equity Ratio for Each Vertically Integrated Electric IOU In Rate Cases Decided in 2012-March 2016

Line	Company	State	Order Year	Authorized ROE	Equity Ratio
		(1)	(2)	(3)	(4)
1	Alabama Power Co.	Alabama	2013	13.29	45.00
2	Arizona Public Service Co.	Arizona	2012	10.00	53.94
3	Tucson Electric Power Co.	Arizona	2013	10.00	43.50
4	UNS Electric Inc.	Arizona	2013	9.50	52.60
5	Entergy Arkansas Inc.	Arkansas	2016	9.75	44.60
6	Pacific Gas and Electric Co.	California	2012	10.40	52.00
7	San Diego Gas & Electric Co.	California	2012	10.30	52.00
8	Southern California Edison Co.	California	2012	10.45	48.00
9	Black Hills Colorado Electric	Colorado	2014	9.83	49.83
10	Public Service Co. of CO	Colorado	2015	9.83	56.00
11	**Florida Power & Light Co.**	**Florida**	**2012**	**10.50**	**60.00**
12	**Florida Power & Light Co.**	**Florida**	**2017**	**11.50**	**60.00**
13	**Gulf Power Co.**	**Florida**	**2013**	**10.25**	**46.69**
14	**Tampa Electric Co.**	**Florida**	**2013**	**10.25**	**54.00**
15	**Florida Public Utilities Co.**	**Florida**	**2014**	**10.25**	**58.09**
16	Georgia Power Co.	Georgia	2013	10.95	50.84
17	Avista Corp.	Idaho	2015	9.50	50.00
18	Indiana Michigan Power Co.	Indiana	2013	10.20	52.30
19	Indianapolis Power & Light Co.	Indiana	2016	9.85	41.30
20	Westar Energy Inc.	Kansas	2013	10.00	52.63
21	Kansas City Power & Light	Kansas	2015	9.30	50.48
22	Louisville Gas & Electric Co.	Kentucky	2012	10.25	61.31
23	Entergy Gulf States LA LLC	Louisiana	2013	9.95	49.86
24	Southwestern Electric Power Co	Louisiana	2013	10.00	50.79
25	Entergy Louisiana LLC	Louisiana	2014	9.95	48.43
26	Indiana Michigan Power Co.	Michigan	2012	10.20	49.13
27	Wisconsin Electric Power Co.	Michigan	2012	10.10	52.30
28	Consumers Energy Co.	Michigan	2015	10.30	52.48
29	DTE Electric Co.	Michigan	2015	10.30	50.00
30	Northern States Power Co. - MN	Minnesota	2015	9.72	52.50
31	KCP&L Greater Missouri Op Co	Missouri	2013	9.70	52.30
32	Kansas City Power & Light	Missouri	2015	9.50	50.09
33	Union Electric Co.	Missouri	2015	9.53	51.76
34	Sierra Pacific Power Co.	Nevada	2013	10.12	46.94
35	Nevada Power Co.	Nevada	2014	9.80	48.17
36	Southwestern Public Service Co	New Mexico	2014	9.96	53.89
37	Virginia Electric & Power Co.	North Carolina	2012	10.20	51.00
38	Duke Energy Carolinas LLC	North Carolina	2013	10.20	53.00
39	Northern States Power Co. - MN	North Dakota	2014	9.75	52.56
40	Oklahoma Gas and Electric Co.	Oklahoma	2012	10.20	55.01
41	Idaho Power Co.	Oregon	2012	9.90	49.90
42	PacifiCorp	Oregon	2013	9.80	52.10

Source: SNL, a Subsidiary of S&P Global Credit Research

Last Authorized Return on Equity and Financial Equity Ratio for Each Vertically Integrated Electric IOU In Rate Cases Decided in 2012-March 2016

Line	Company	State	Order Year	Authorized ROE	Equity Ratio
		(1)	(2)	(3)	(4)
43	Portland General Electric Co.	Oregon	2015	9.60	50.00
44	South Carolina Electric & Gas	South Carolina	2012	10.25	52.18
45	Duke Energy Carolinas LLC	South Carolina	2013	10.20	53.00
46	Northern States Power Co. - MN	South Dakota	2012	9.25	53.04
47	Southwestern Electric Power Co	Texas	2013	9.65	49.10
48	Entergy Texas Inc.	Texas	2014	9.80	48.87
49	Southwestern Public Service Co	Texas	2015	9.70	51.00
50	PacifiCorp	Utah	2014	9.80	51.43
51	Virginia Electric & Power Co.	Virginia	2013	10.00	57.13
52	Appalachian Power Co.	Virginia	2014	9.70	42.89
53	Puget Sound Energy Inc.	Washington	2013	9.80	48.00
54	PacifiCorp	Washington	2015	9.50	49.10
55	Avista Corp.	Washington	2016	9.50	48.50
56	Appalachian Power Co.	West Virginia	2015	9.75	47.16
57	Madison Gas and Electric Co.	Wisconsin	2014	10.20	58.96
58	Wisconsin Electric Power Co.	Wisconsin	2014	10.20	51.90
59	Wisconsin Power and Light Co	Wisconsin	2014	10.40	50.46
60	Northern States Power Co - WI	Wisconsin	2015	10.00	52.49
61	Wisconsin Public Service Corp.	Wisconsin	2015	10.00	50.47
62	Cheyenne Light Fuel Power Co.	Wyoming	2014	9.90	54.00
63	PacifiCorp	Wyoming	2015	9.50	51.44
64	**Average**			10.01	51.10

Source: SNL, a Subsidiary of S&P Global Credit Research

FLORIDA POWER & LIGHT COMPANY
Proposed Base Revenue Increase By Rate Class
Test Year Ending December 31, 2017
(Dollar Amounts in Thousands)

Line	Rate Class	Base Revenue at Present Rates	Base Revenue Increase Amount	Base Revenue Increase Percent
		(1)	(2)	(3)
1	**Residential**	$3,504,590	$454,224	13.0%
2	**General Service Non-Demand**	373,326	22,470	6.0%
3	**General Service Demand**	1,131,513	223,476	19.8%
	General Service Large Demand			
4	GSLD-1	369,413	106,706	28.9%
5	GSLD-2	75,325	23,663	31.4%
6	GSLD-3	4,562	1,306	28.6%
7	Total GSLD	449,300	131,674	29.3%
	C&I Load Control			
8	CILC-1D	60,642	34,572	57.0%
9	CILC-1G	3,162	890	28.1%
10	CILC-1T	22,161	17,195	77.6%
11	Total C&I Load Control	85,965	52,657	61.3%
12	**MET**	4,092	578	14.1%
	Lighting			
13	SL-1	91,266	7,535	8.3%
14	SL-2	1,507	14	0.9%
15	OL-1	14,050	96	0.7%
16	OS-2	992	188	18.9%
17	Total Lighting	107,815	7,833	7.3%
	Standby Service			
18	SST-DST	4,399	45	1.0%
19	SST-TST	801	130	16.2%
20	Total Standby Service	5,200	175	3.4%
21	**Total Electricity Sales**	$5,661,800	$893,088	15.8%
22	**Other Revenues**	260,405	(3,885)	-1.5%
23	**Total Retail**	$5,922,205	$889,204	15.0%

Source: MFR E-13a Test Year.

FLORIDA POWER & LIGHT COMPANY

Proposed Cumulative 2017 & 2018
Base Revenue Increases By Rate Class
Test Year Ending December 31, 2018
(Dollar Amounts in Thousands)

Line	Rate Class	Base Revenue at Present Rates	Base Revenue Increase Amount	Base Revenue Increase Percent
		(1)	(2)	(3)
1	**Residential**	$3,527,881	$609,545	17.3%
2	**General Service Non-Demand**	371,184	39,078	10.5%
3	**General Service Demand**	1,139,819	266,933	23.4%
	General Service Large Demand			
4	GSLD-1	370,560	138,872	37.5%
5	GSLD-2	75,021	30,623	40.8%
6	GSLD-3	4,626	1,382	29.9%
7	Total GSLD	450,207	170,877	38.0%
	C&I Load Control			
8	CILC-1D	60,518	42,137	69.6%
9	CILC-1G	3,154	1,061	33.7%
10	CILC-1T	22,461	18,733	83.4%
11	Total C&I Load Control	86,132	61,931	71.9%
12	**MET**	4,089	729	17.8%
	Lighting			
13	SL-1	93,803	10,669	11.4%
14	SL-2	1,538	15	1.0%
15	OL-1	17,807	116	0.7%
16	OS-2	992	243	24.5%
17	Total Lighting	114,141	11,044	9.7%
	Standby Service			
18	SST-DST	4,399	48	1.1%
19	SST-TST	801	177	22.1%
20	Total Standby Service	5,200	225	4.3%
21	**Total Electricity Sales**	$5,698,652	$1,160,361	20.4%
22	**Other Revenues**	268,876	(3,885)	-1.4%
23	**Total Retail**	$5,967,529	$1,156,477	19.4%

Source: MFR E-13a Subsequent Year Adjustment.

FLORIDA POWER & LIGHT COMPANY
FPL's Application of Gradualism
Test Year Ending December 31, 2017
(Dollar Amounts in Thousands)

Line	Customer Class	Operating Revenues at Present Rates Including Clauses	Base Revenue Increase		Reset CILC/CDR Credits	Net Revenue Increase	
			Amount	Percent		Amount	Percent
		(1)	(2)	(3)	(4)	(5)	(6)
1	**Residential**	$6,143,554	$454,224	7.4%	$0	$454,224	7.4%
2	**General Service**	645,785	22,470	3.5%	0	22,470	3.5%
3	**General Service Demand**	2,250,043	223,476	9.9%	2,201	221,275	9.8%
	General Service Large Demand						
4	GSLD-1	831,541	106,706	12.8%	4,152	102,554	12.3%
5	GSLD-2	183,114	23,663	12.9%	1,069	22,594	12.3%
6	GSLD-3	11,615	1,306	11.2%	0	1,306	11.2%
7	Total GSLD	1,026,270	131,674	12.8%	5,221	126,454	12.3%
	C&I Load Control						
8	CILC-1D	199,642	34,572	17.3%	9,943	24,629	12.3%
9	CILC-1G	8,344	890	10.7%	370	520	6.2%
10	CILC-1T	96,985	17,195	17.7%	5,234	11,961	12.3%
11	Total C&I Load Control	304,971	52,657	17.3%	15,547	37,110	12.2%
12	**MET**	8,003	578	7.2%	0	578	7.2%
	Lighting						
13	SL-1	118,835	7,535	6.3%	0	7,535	6.3%
14	SL-2	2,864	14	0.5%	0	14	0.5%
15	OL-1	19,323	96	0.5%	0	96	0.5%
16	OS-2	1,522	188	12.3%	0	188	12.3%
17	Total Lighting	142,544	7,833	5.5%	0	7,833	5.5%
	Standby Service						
18	SST-DST	1,692	45	2.7%	0	45	2.7%
19	SST-TST	7,638	130	1.7%	0	130	1.7%
20	Total Standby Service	9,330	175	1.9%	0	175	1.9%
21	**Total Electricity Sales**	$10,530,500	$893,088	8.5%	$22,969	$870,119	8.3%
22	**Gradualism Cap at 150%**			12.7%			12.4%
	Source: MFR Schedule E-14,Attachment 2	Cols 2 + 23	Col 21	(3) ÷ (1)	Col 14	(2) - (4)	

Docket No. 160021-EI
Gradualism
Exhibit___(JP-7)

FLORIDA POWER & LIGHT COMPANY
FPL's Proposed Class Revenue Allocation
Measured as a Percent of Sales Revenues Including Clauses
Test Year Ending December 31, 2017
(Dollar Amounts in Thousands)

Line	Customer Class	Sales Revenues at Present Rates Including Clauses	Base Revenue Increase	
			Amount	Percent
		(1)	(2)	(3)
1	**Residential**	$5,995,904	$454,224	7.6%
2	**General Service**	633,296	22,470	3.5%
3	**General Service Demand**	2,220,474	223,476	10.1%
	General Service Large Demand			
4	GSLD-1	811,644	106,706	13.1%
5	GSLD-2	178,440	23,663	13.3%
6	GSLD-3	11,556	1,306	11.3%
7	Total GSLD	1,001,640	131,674	13.1%
	C&I Load Control			
8	CILC-1D	170,858	34,572	20.2%
9	CILC-1G	7,330	890	12.1%
10	CILC-1T	82,839	17,195	20.8%
11	Total C&I Load Control	261,027	52,657	20.2%
12	**MET**	7,934	578	7.3%
	Lighting			
13	SL-1	117,575	7,535	6.4%
14	SL-2	2,843	14	0.5%
15	OL-1	18,642	96	0.5%
16	OS-2	1,486	188	12.6%
17	Total Lighting	140,547	7,833	5.6%
	Standby Service			
18	SST-DST	5,268	45	0.9%
19	SST-TST	4,006	130	3.2%
20	Total Standby Service	9,274	175	1.9%
21	**Total Electricity Sales**	$10,270,095	$893,088	8.7%
22	**Gradualism Cap at 150%**			13.0%
Source: MFR Schedule E-14,Attachment 2		Cols 19 + 23	Col 21	(3) ÷ (1)

Docket No. 160021-EI
Allocation Reflecting
Gradualism
Exhibit___(JP-8)

FLORIDA POWER & LIGHT COMPANY
Class Revenue Allocation
Gradualism Applied on Sales Revenues Including Clauses
CILC/CDR Credits Retained
Test Year Ending December 31, 2017
(Dollar Amounts in Thousands)

Line	Customer Class	Sales Revenues at Present Rates Including Clauses	Base Revenue Increase Amount	Base Revenue Increase Percent
		(1)	(2)	(3)
1	**Residential**	$5,995,904	$474,116	7.9%
2	**General Service**	633,296	36,867	5.8%
3	**General Service Demand**	2,220,474	188,931	8.5%
	General Service Large Demand			
4	GSLD-1	811,644	103,162	12.7%
5	GSLD-2	178,440	22,680	12.7%
6	GSLD-3	11,556	1,221	10.6%
7	Total GSLD	1,001,640	127,064	12.7%
	C&I Load Control			
8	CILC-1D	170,858	21,717	12.7%
9	CILC-1G	7,330	551	7.5%
10	CILC-1T	82,839	10,529	12.7%
11	Total C&I Load Control	261,027	32,797	12.6%
12	**MET**	7,934	575	7.3%
	Lighting			
13	SL-1	117,575	9,451	8.0%
14	SL-2	2,843	0	0.0%
15	OL-1	18,642	0	0.0%
16	OS-2	1,486	189	12.7%
17	Total Lighting	140,547	9,640	6.9%
	Standby Service	0		
18	SST-DST	5,268	127	2.4%
19	SST-TST	4,006	0	0.0%
20	Total Standby Service	9,274	127	1.4%
21	**Total Electricity Sales**	$10,270,095	$870,117	8.5%
22	**Gradualism Cap at 150%**			12.7%

Docket No. 160021-EI
COSS Results No Reset
With Gradualism
Exhibit___(JP-9)

FLORIDA POWER & LIGHT COMPANY
Summary of FPL's Class Cost-of-Service Study Results
At Present and Proposed Rates Applying Gradualism
To Total Revenues Including Clauses
CILC/CDR Credits Retained
Test Year Ending December 31, 2017
(Dollar Amounts in Thousands)

		Present Rates			Proposed Rates			Movement
Line	Customer Class	Rate of Return	Parity Index	Subsidy	Rate of Return	Parity Index	Subsidy	Toward Cost
		(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	Residential	5.30%	106	$101,905	6.79%	103	$56,998	44%
2	General Service	5.98%	120	31,180	7.16%	108	17,313	44%
3	General Service Demand	4.74%	95	(25,804)	6.47%	98	(14,392)	44%
4	GS Large Demand	3.10%	62	(98,977)	5.51%	83	(58,151)	41%
5	C&I Load Control	3.66%	74	(17,574)	6.11%	92	(6,662)	62%
6	MET	5.18%	104	78	6.72%	102	44	44%
7	Lighting	5.87%	118	7,429	7.03%	106	3,490	53%
8	Standby Service	10.40%	209	1,763	10.79%	163	1,360	23%
9	Total Retail	4.97%	100	$0	6.61%	100	($0)	44%

CHAPTER 6

CLASSIFICATION AND ALLOCATION OF DISTRIBUTION PLANT

Distribution plant equipment reduces high-voltage energy from the transmission system to lower voltages, delivers it to the customer and monitors the amounts of energy used by the customer.

Distribution facilities provide service at two voltage levels: primary and secondary. Primary voltages exist between the substation power transformer and smaller line transformers at the customer's points of service. These voltages vary from system to system and usually range between 480 volts to 35 KV. In the last few years, advances in equipment and cable technology have permitted the use of higher primary distribution voltages. Primary voltages are reduced to more usable secondary voltages by smaller line transformers installed at customer locations along the primary distribution circuit. However, some large industrial customers may choose to install their own line transformers and take service at primary voltages because of their large electrical requirements.

In some cases, the utility may choose to install a transformer for the exclusive use of a single commercial or industrial customer. On the other hand, in service areas with high customer density, such as housing tracts, a line transformer will be installed to serve many customers. In this case, secondary voltage lines run from pole-to-pole or from handhole-to-handhole, and each customer is served by a drop tapped off the secondary line leading directly to the customer's premise.

I. COST ACCOUNTING FOR DISTRIBUTION PLANT AND EXPENSES

The Federal Energy Regulatory Commission (FERC) Uniform System of Accounts requires separate accounts for distribution investment and expenses. Distribution plant accounts are summarized and classified in Table 6-1. Distribution expense accounts are summarized and classified in Table 6-2. Some utilities may choose to establish subaccounts for more detailed cost reporting.

TABLE 6-1

CLASSIFICATION OF DISTRIBUTION PLANT[1]

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

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

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

TABLE 6-2

CLASSIFICATION OF DISTRIBUTION EXPENSES[1]

FERC Uniform System of Accounts No.	Description	Demand Related	Customer Related
	Operation [2]		
580	Operation Supervision & Engineering	X	X
581	Load Dispatching	X	-
582	Station Expenses	X	-
583	Overhead Line Expenses	X	X
584	Underground Line Expenses	X	X
585	Street Lighting & Signal System Expenses [1]	-	-
586	Meter Expenses	-	X
587	Customer Installation Expenses	-	X
588	Miscellaneous Distribution Expenses	X	X
589	Rents	X	X
	Maintenance [2]		
590	Maintenance Supervision & Engineering	X	X
591	Maintenance of Structures	X	X
592	Maintenance of Station Equipment	X	-
593	Maintenance of Overhead Lines	X	X
594	Maintenance of Underground Lines	X	X
595	Maintenance of Line Transformers	X	X
596	Maint. of Street Lighting & Signal Systems [1]	-	-
597	Maintenance of Meters	-	X
598	Maint. of Miscellaneous Distribution Plants	X	X

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

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

To ensure that costs are properly allocated, the analyst must first classify each account as demand-related, customer-related, or a combination of both. The classification depends upon the analyst's evaluation of how the costs in these accounts were incurred. In making this determination, supporting data may be more important than theoretical considerations.

Allocating costs to the appropriate groups in a cost study requires a special analysis of the nature of distribution plant and expenses. This will ensure that costs are assigned to the correct functional groups for classification and allocation. As indicated in Chapter 4, all costs of service can be identified as energy-related, demand-related, or customer-related. Because there is no energy component of distribution-related costs, we need consider only the demand and customer components.

To recognize voltage level and use of facilities in the functionalization of distribution costs, distribution line costs must be separated into overhead and underground, and primary and secondary voltage classifications. A typical functionalization and classification of distribution plant would appear as follows:

Substations:		Demand
Distribution:	Overhead Primary	
		Demand
		Customer
	Overhead Secondary	
		Demand
		Customer
	Underground Primary	
		Demand
		Customer
	Underground Secondary	
		Demand
		Customer
	Line Transformers	
		Demand
		Customer
Services:	Overhead	
		Demand
		Customer
	Underground	
		Demand
		Customer
Meters:		Customer
Street Lighting:		Customer
Customer Accounting:		Customer
Sales:		Customer

From this breakdown it can be seen that each distribution account must be analyzed before it can be assigned to the appropriate functional category. Also, these accounts must be classified as demand-related, customer-related, or both. Some utilities assign distribution to customer-related expenses. Variations in the demands of various customer groups are used to develop the weighting factors for allocating costs to the appropriate group.

II. DEMAND AND CUSTOMER CLASSIFICATIONS 0F DISTRIBUTION PLANT ACCOUNTS

When the utility installs distribution plant to provide service to a customer and to meet the individual customer's peak demand requirements, the utility must classify distribution plant data separately into demand- and customer-related costs.

Classifying distribution plant as a demand cost assigns investment of that plant to a customer or group of customers based upon its contribution to some total peak load. The reason is that costs are incurred to serve area load, rather than a specific number of customers.

Distribution substations costs (which include Accounts 360 -Land and Land Rights, 361 - Structures and Improvements, and 362 -Station Equipment), are normally classified as demand-related. This classification is adopted because substations are normally built to serve a particular load and their size is not affected by the number of customers to be served.

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

A. The Minimum-Size Method

Classifying distribution plant with the minimum-size method assumes that a minimum size distribution system can be built to serve the minimum loading requirements of the customer. The minimum-size method involves determining the minimum size pole, conductor, cable, transformer, and service that is currently installed by the utility. Normally, the average book cost for each piece of equipment determines the price of all installed units. Once determined for each primary plant account, the minimum size distribution system is classified as customer-related costs. The demand-related costs for each account are the difference between the total investment in the account and customer-related costs. Comparative studies between the minimum-size and other methods show that it generally produces a larger customer component than the zero-intercept method (to be discussed). The following describes the methodologies for determining the minimum size for distribution plant Accounts 364, 365, 366, 367, 368, and 369.

1. Account 364 - Poles, Towers, and Fixtures

- Determine the average installed book cost of the minimum height pole currently being installed.
- Multiply the average book cost by the number of poles to find the customer component. Balance of plant account is the demand component.

2. Account 365 - Overhead Conductors and Devices

- Determine minimum size conductor currently being installed.
- Multiply average installed book cost per mile of minimum size conductor by the number of circuit miles to determine the customer component. Balance of plant account is demand component. (Note: two conductors in minimum system.)

3. Accounts 366 and 367 - Underground Conduits, Conductors, and Devices

- Determine minimum size cable currently being installed.
- Multiply average installed book cost per mile of minimum size cable by the circuit miles to determine the customer component. Balance of plant Account 367 is demand component. (Note: one cable with ground sheath is minimum system.) Account 366 conduit is assigned, basedon ratio of cable account.
- Multiply average installed book cost of minimum size transformer by number of transformers in plant account to determine the customer component. Balance of plant account is demand component.

4. Account 368 - Line Transformers

- Determine minimum size transformer currently being installed.

- Multiply average installed book cost of minimum size transformer by number of transformers in plant account to determine the customer component.

5. **Account 369 - Services**

- Determine minimum size and average length of services currently being installed.

- Estimate cost of minimum size service and multiply by number of services to get customer component.

- If overhead and underground services are booked separately, they should be handled separately. Most companies do not book service by size. This requires an engineering estimate of the cost of the minimum size, average length service. The resultant estimate is usually higher than the average book cost. In addition, the estimate should be adjusted for the average age of service, using a trend factor.

B. The Minimum-Intercept Method

The minimum-intercept method seeks to identify that portion of plant related to a hypothetical no-load or zero-intercept situation. This requires considerably more data and calculation than the minimum-size method. In most instances, it is more accurate, although the differences may be relatively small. The technique is to relate installed cost to current carrying capacity or demand rating, create a curve for various sizes of the equipment involved, using regression techniques, and extend the curve to a no-load intercept. The cost related to the zero-intercept is the customer component. The following describes the methodologies for determining the minimum intercept for distribution-plant Accounts 364, 365, 366, 367, and 368.

1. **Account 364 - Poles, Towers, and Fixtures**

- Determine the number, investment, and average installed book cost of distribution poles by height and class of pole. (Exclude stubs for guying.)

- Determine minimum intercept of pole cost by creating a regression equation, relating classes and heights of poles, and using the Class 7 cost intercept for each pole of equal height weighted by the number of poles in each height category.

- Multiply minimum intercept cost by total number of distribution poles to get customer component.

- Balance of pole investment is assigned to demand component.

- Total account dollars are assigned based on ratio of pole investment. (Transformer platforms in Account 364 are all demand-related. They should be removed before determining the account ratio of customer- and demand-related costs, and then they should be added to the demand portion of Account 364.)

2. Account 365 - Overhead Conductors and Devices

- If accounts are divided between primary and secondary voltages, develop a customer component separately for each. The total investment is assigned to primary and secondary; then the customer component is developed for each. Since conductors generally are of many types and sizes, select those sizes and types which represent the bulk of the investment in this account, if appropriate.

- When developing the customer component, consider only the investment in conductors, and not such devices as circuit breakers, insulators, switches, etc. The investment in these devices will be assigned later between the customer and demand component, based on the conductor assignment.

  - Determine the feet, investment, and average installed book cost per foot for distribution conductors by size and type.

  - Determine minimum intercept of conductor cost per foot using cost per foot by size and type of conductor weighted by feet or investment in each category, and developing a cost for the utility's minimum size conductor.

  - Multiply minimum intercept cost by the total number of circuit feet times 2. (Note that circuit feet, not conductor feet, are used to get customer component.)

  - Balance of conductor investment is assigned to demand.

  - Total primary or secondary dollars in the account, including devices, are assigned to customer and demand components based on conductor investment ratio.

3. Accounts 366 and 367 - Underground Conduits, Conductors, and Devices

- The customer demand component ratio is developed for conductors and applied to conduits. Underground conductors are generally booked by type and size of conductor for both one-conductor (l/c) cable and three-conductor (3/c) cables. If conductors are booked by voltage, as between primary and secondary, a customer component is developed for each. If network and URD investments are segregated, a customer component must be developed for each.

- The conductor sizes and types for the customer component derivation are restricted to l/c cable. Since there are generally many types and sizes of l/c cable, select those sizes and types which represent the bulk of the investment, when appropriate.
  - Determine the feet, investment, and average installed book cost per foot for l/c cables by size and type of cable.
  - Determine minimum intercept of cable cost per foot using cost per foot by size and type of cable weighted by feet of investment in each category.
  - Multiply minimum intercept cost by the total number of circuit feet (l/c cable with sheath is considered a circuit) to get customer component.
  - Balance of cable investment is assigned to demand.
  - Total dollars in Accounts 366 and 367 are assigned to customer and demand components based on conductor investment ratio.

4. **Account 368 - Line Transformers**

- The line transformer account covers all sizes and voltages for single- and three-phase transformers. Only single-phase sizes up to and including 50 KVA should be used in developing the customer components. Where more than one primary distribution voltage is used, it may be appropriate to use the transformer price from one or two predominant, selected voltages.
  - Determine the number, investment, and average installed book cost per transformer by size and type (voltage).
  - Determine zero intercept of transformer cost using cost per transformer by type, weighted by number for each category.
  - Multiply zero intercept cost by total number of line transformers to get customer component.
  - Balance of transformer investment is assigned to demand component.
  - Total dollars in the account are assigned to customer and demand components based on transformer investment ratio from customer and demand components.

C. The Minimum-System vs. Minimum-Intercept Approach

When selecting a method to classify distribution costs into demand and customer costs, the analyst must consider several factors. The minimum-intercept method can sometimes produce statistically unreliable results. The extension of the regression equation beyond the boundaries of the data normally will intercept the Y axis at a positive value. In some cases, because of incorrect accounting data or some other abnormality in the data, the regression equation will intercept the Y axis at a negative value. When this happens, a review of the accounting data must be made, and suspect data deleted.

The results of the minimum-size method can be influenced by several factors. The analyst must determine the minimum size for each piece of equipment: "Should the minimum size be based upon the minimum size equipment currently installed, historically installed, or the minimum size necessary to meet safety requirements?" The manner in which the minimum size equipment is selected will directly affect the percentage of costs that are classified as demand and customer costs.

Cost analysts disagree on how much of the demand costs should be allocated to customers when the minimum-size distribution method is used to classify distribution plant. When using this distribution method, the analyst must be aware that the minimum-size distribution equipment has a certain load-carrying capability, which can be viewed as a demand-related cost.

When allocating distribution costs determined by the minimum-size method, some cost analysts will argue that some customer classes can receive a disproportionate share of demand costs. Their rationale is that customers are allocated a share of distribution costs classified as demand-related. Then those customers receive a second layer of demand costs that have been mislabeled customer costs because the minimum-size method was used to classify those costs.

Advocates of the minimum-intercept method contend that this problem does not exist when using their method. The reason is that the customer cost derived from the minimum-intercept method is based upon the zero-load intercept of the cost curve. Thus, the customer cost of a particular piece of equipment has no demand cost in it whatsoever.

D. Other Accounts

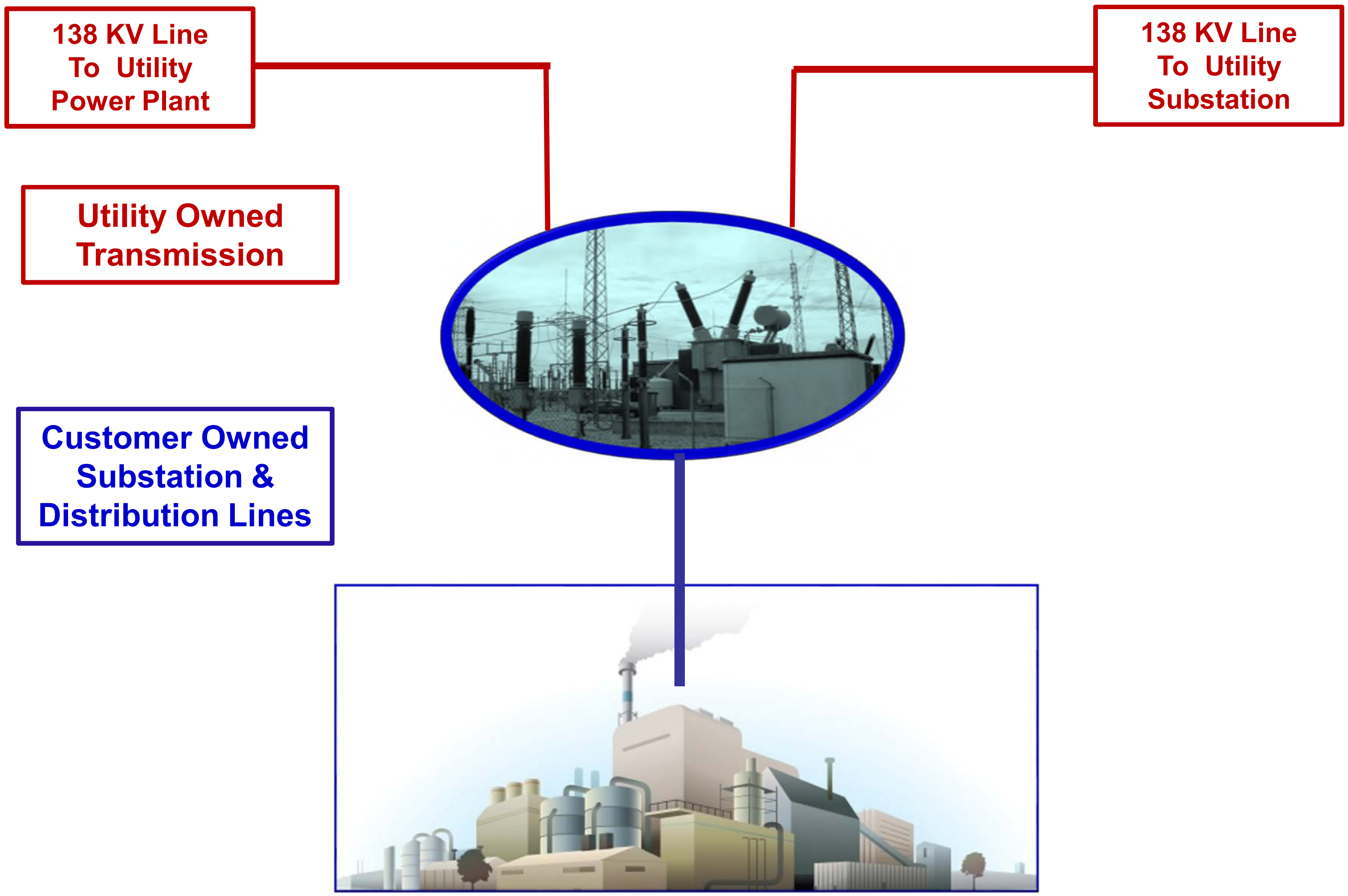
The preceding discussion of the merits of minimum-system versus the zero-intercept classification schemes will affect the major distribution-plant accounts for FERC Accounts 364 through 368. Several other plant accounts remain to be classified. While the classification of the following distribution-plant accounts is an important step,

FLORIDIA POWER & LIGHT COMPANY

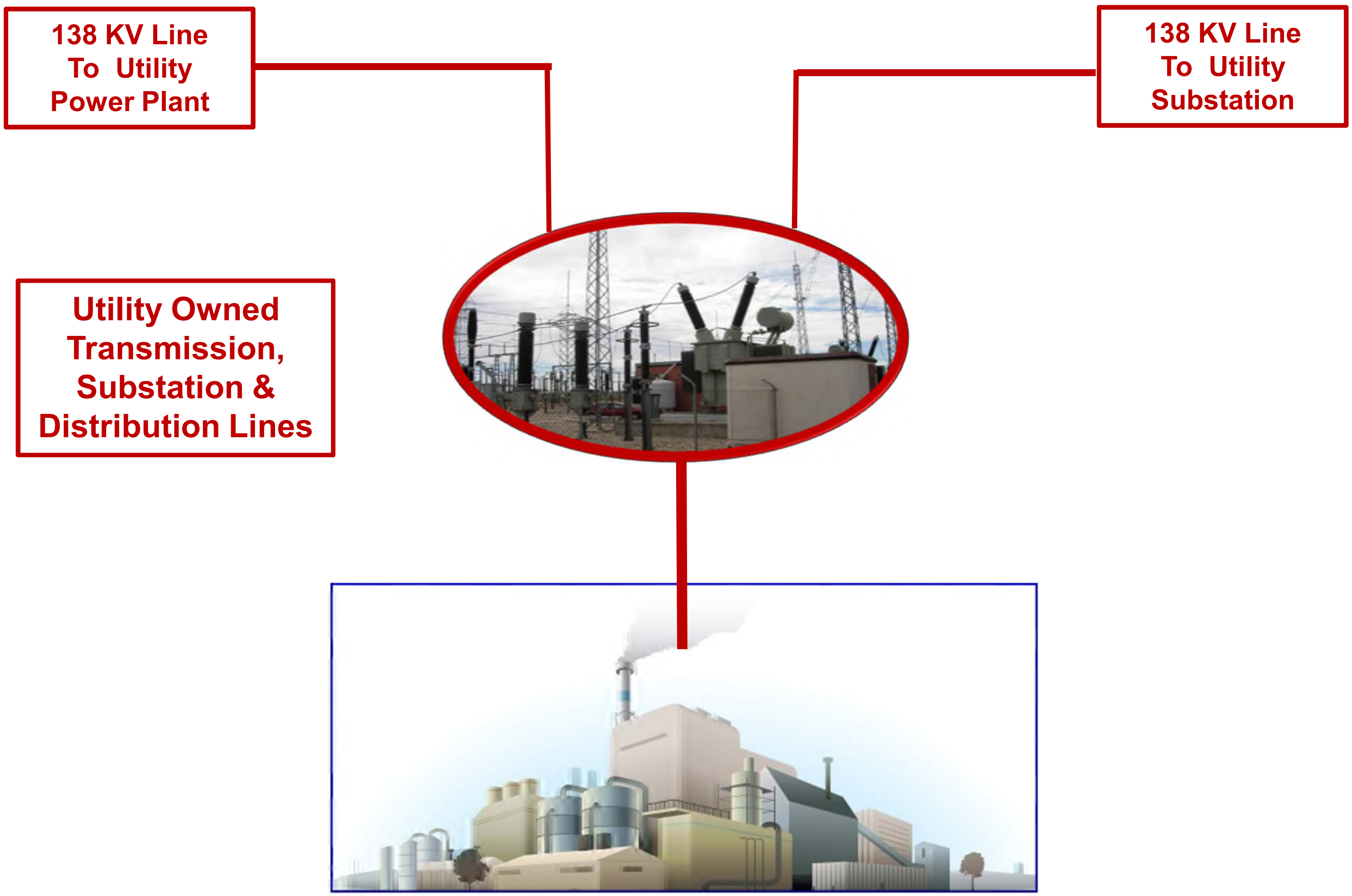
Utilities that Classify a Portion of their Distribution Network Investment as Customer-Related

			FERC Account No.					
Line	Utility	Docket/Case No.	364	365	366	367	368	Total
			(1)	(2)	(3)	(4)	(5)	(6)
1	Alabama Power Company	18117 & 18416	100%	50%	100%	50%	28%	57%
2	Ameren Missouri	ER-2011-0028	22%	41%	68%	68%	57%	50%
3	Central Hudson Gas & Electric Company	09-E-0588	70%	71%	77%	75%	53%	67%
4	Georgia Power Company	D-36989	63%	31%	7%	8%	25%	36%
5	Gulf Power Company	110138-EI	65%	13%	4%	5%	25%	27%
6	Kentucky Utilities	2014-00371	57%	57%	70%	70%	48%	56%
7	Louisville Gas and Electric Company	2008-00252	61%	61%	63%	63%	49%	59%
8	Metropolitan Edison	R-2016-2537349	73%	82%	0%	90%	52%	72%
9	Minnesota Power	D-E-015/GR-09-1151	35%	35%	26%	26%	22%	29%
10	Mississippi Power Company	N/A	50%	53%	46%	59%	51%	52%
11	New York State Electric & Gas Corporation	15-E-283	50%	50%	50%	50%	50%	50%
12	Niagara Mohawk	12-E-0201	54%	53%	52%	50%	0%	40%
13	Northern States Power Company	E002/GR-15-826	56%	56%	65%	65%	59%	61%
14	Pennsylvania Electric Company	R-2016-2537352	74%	84%	0%	82%	62%	76%
15	Progress Energy Carolina	E-2,Sub 537A	56%	56%	0%	0%	30%	32%
16	Rochester Gas and Electric Corporation	15-E-285	50%	50%	50%	50%	50%	50%
17	South Carolina Electric & Gas Company	2009-489-E	40%	40%	41%	41%	27%	37%
18	Tampa Electric Company	130040-EI	67%	11%	9%	N/A	24%	25%
19	Virginia Electric Power Company	07551-EL-AIR	45%	20%	17%	17%	10%	19%
20	West Pennsylvania Power Company	R-2016-2537359	82%	92%	0%	87%	71%	75%
21	Wisconsin Public Service Corporation	6690-UR-119	49%	71%	0%	72%	64%	59%

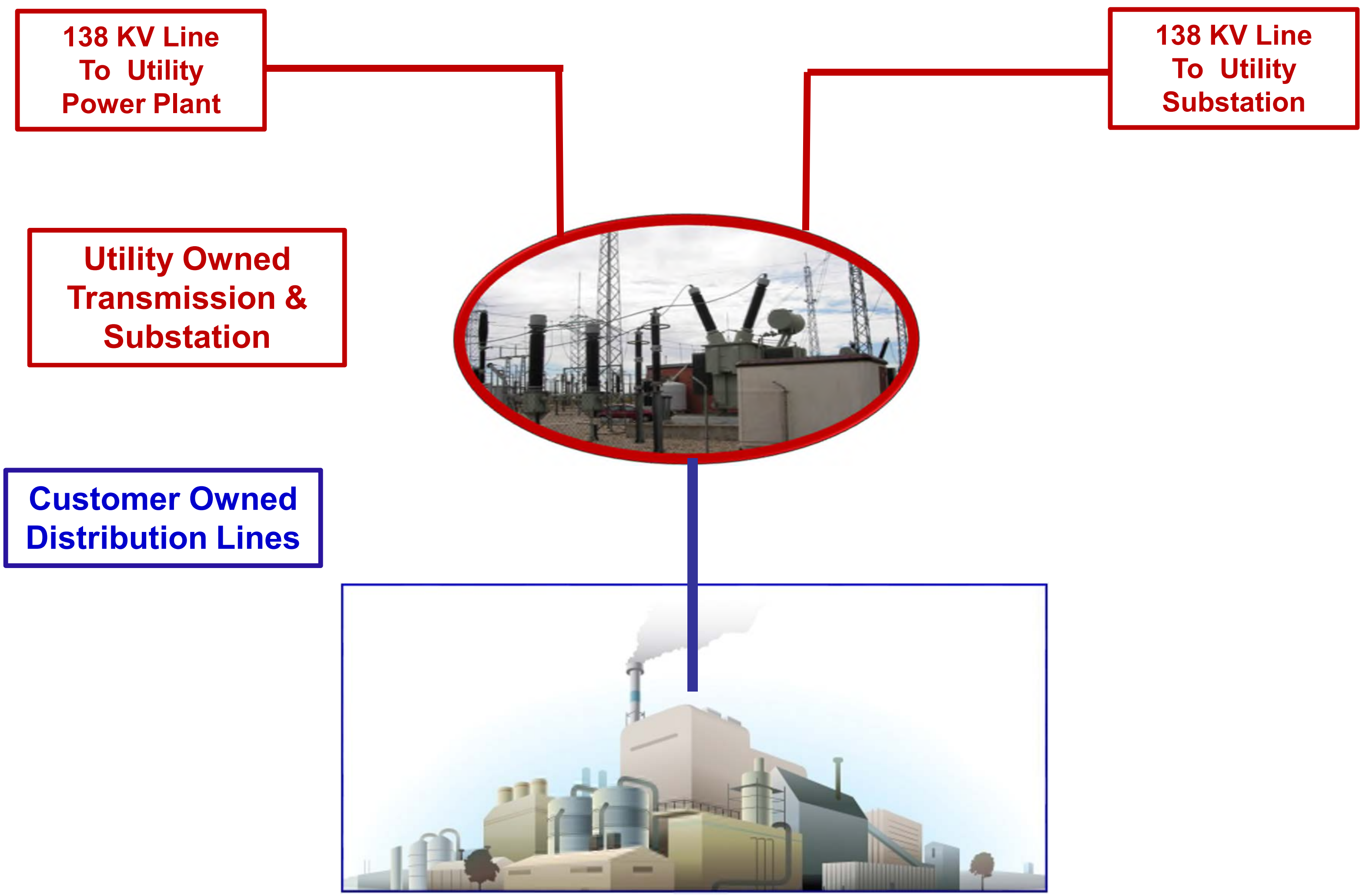
Transmission Service



Distribution Primary Service



Distribution Substation Service



FLORIDA POWER & LIGHT COMPANY
FIPUG's Class Cost-of-Service Study
Test Year Ending 12-31-17
(Dollar Amounts in 000)

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
Line No.	Methodology: 12CP and 1/13th With Minimum Distribution System	TOTAL RETAIL	CILC-1D	CILC-1G	CILC-1T	GS(T)-1	GSCU-1	GSD(T)-1	GSLD(T)-1	GSLD(T)-2	GSLD(T)-3
1	**RATE BASE -**										
2	Electric Plant In Service	43,122,297	678,826	27,598	274,724	2,591,459	26,900	8,335,573	3,316,110	644,621	34,707
3	Accum Depreciation & Amortization	(13,074,538)	(199,904)	(8,189)	(79,068)	(790,504)	(8,433)	(2,479,816)	(983,909)	(190,173)	(10,079)
4	Net Plant In Service	30,047,759	478,923	19,409	195,657	1,800,955	18,467	5,855,757	2,332,201	454,449	24,628
5	Plant Held For Future Use	233,315	4,219	165	1,840	13,459	116	49,480	19,980	3,986	243
6	Construction Work in Progress	747,987	12,463	497	5,694	44,420	458	148,449	59,341	11,785	744
7	Net Nuclear Fuel	630,075	15,678	597	8,603	35,101	413	151,865	61,743	14,687	987
8	Total Utility Plant	31,659,136	511,282	20,669	211,794	1,893,936	19,455	6,205,551	2,473,264	484,907	26,602
9	Working Capital - Assets	3,552,622	62,286	2,469	28,371	218,802	2,618	697,515	276,784	58,801	3,368
10	Working Capital - Liabilities	(2,675,642)	(45,579)	(1,808)	(20,152)	(165,885)	(1,971)	(517,611)	(204,986)	(43,089)	(2,397)
11	Working Capital - Net	876,981	16,707	661	8,218	52,917	646	179,904	71,799	15,712	971
12	**Total Rate Base**	32,536,116	527,989	21,330	220,012	1,946,853	20,101	6,385,455	2,545,063	500,619	27,573
13											
14	**REVENUES -**										
15	Sales of Electricity	5,728,329	87,803	4,110	35,874	369,374	4,185	1,138,580	381,368	78,386	4,567
16	Other Operating Revenues	193,876	1,250	52	435	12,757	149	18,307	6,034	1,247	54
17	**Total Operating Revenues**	5,922,205	89,053	4,162	36,308	382,131	4,334	1,156,887	387,402	79,634	4,621
18											
19	**EXPENSES -**										
20	Operating & Maintenance Expense	(1,354,606)	(21,948)	(876)	(9,340)	(85,590)	(1,046)	(253,169)	(99,688)	(20,778)	(1,112)
21	Depreciation Expense	(1,672,107)	(26,689)	(1,083)	(11,536)	(100,993)	(1,057)	(322,576)	(127,750)	(25,194)	(1,435)
22	Taxes Other Than Income Tax	(578,191)	(9,219)	(374)	(3,788)	(34,857)	(365)	(112,200)	(44,579)	(8,741)	(475)
23	Amortization of Property Losses	6,182	85	4	25	389	5	1,096	431	82	3
24	Gain or Loss on Sale of Plant	5,759	97	4	0	340	2	1,222	502	95	0
25	**Total Operating Expenses**	(3,592,963)	(57,675)	(2,325)	(24,639)	(220,711)	(2,461)	(685,626)	(271,084)	(54,536)	(3,019)
26											
27	**Net Operating Income Before Taxes**	2,329,242	31,378	1,837	11,669	161,420	1,873	471,260	116,319	25,098	1,603
28	Income Taxes	(711,051)	(9,083)	(585)	(3,247)	(50,980)	(605)	(144,959)	(30,419)	(6,832)	(461)
29	**NOI Before Curtailment Adjustment**	1,618,191	22,295	1,252	8,422	110,440	1,268	326,301	85,900	18,266	1,142
30											
31	Curtailment Credit Revenue	587	0	0	0	0	0	388	130	70	0
32	Reassign Curtailment Credit Revenue	(587)	(11)	(0)	(6)	(33)	(0)	(128)	(52)	(10)	(1)
33	Net Curtailment Credit Revenue	0	(11)	(0)	(6)	(33)	(0)	259	78	59	(1)
34	Net Curtailment NOI Adjustment	0	(7)	(0)	(4)	(20)	(0)	159	48	36	(0)
36	**Net Operating Income (NOI)**	1,618,778	22,284	1,252	8,416	110,407	1,267	326,560	85,978	18,325	1,141
37											
38	**Rate of Return (ROR)**	4.97%	4.22%	5.87%	3.83%	5.67%	6.30%	5.11%	3.38%	3.66%	4.14%
39	**Parity At Present Rates**	1.000	0.849	1.180	0.769	1.140	1.268	1.028	0.679	0.736	0.832

FLORIDA POWER & LIGHT COMPANY
FIPUG's Class Cost-of-Service Study
Test Year Ending 12-31-17
(Dollar Amounts in 000)

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Line No.	Methodology: 12CP and 1/13th With Minimum Distribution System	MET	OL-1	OS-2	RS(T)-1	SL-1	SL-2	SST-DST	SST-TST
1	**RATE BASE -**								
2	Electric Plant In Service	27,325	127,339	8,302	26,385,057	611,855	8,431	5,330	18,139
3	Accum Depreciation & Amortization	(8,010)	(49,627)	(2,610)	(8,029,924)	(224,712)	(2,524)	(1,595)	(5,461)
4	Net Plant In Service	19,314	77,712	5,692	18,355,133	387,144	5,907	3,735	12,678
5	Plant Held For Future Use	172	125	41	138,221	1,035	49	34	149
6	Construction Work in Progress	490	1,486	114	452,447	8,906	155	85	452
7	Net Nuclear Fuel	525	576	62	335,168	3,298	193	68	511
8	Total Utility Plant	20,502	79,898	5,908	19,280,969	400,383	6,303	3,922	13,791
9	Working Capital - Assets	2,348	5,421	609	2,137,272	53,032	817	422	1,687
10	Working Capital - Liabilities	(1,731)	(3,681)	(471)	(1,623,347)	(40,817)	(602)	(326)	(1,187)
11	Working Capital - Net	616	1,740	138	513,925	12,215	215	95	500
12	**Total Rate Base**	21,119	81,639	6,047	19,794,893	412,598	6,518	4,018	14,291
13									
14	**REVENUES -**								
15	Sales of Electricity	4,095	14,051	992	3,506,958	91,274	1,508	801	4,401
16	Other Operating Revenues	46	907	18	151,421	1,134	20	13	32
17	**Total Operating Revenues**	4,142	14,959	1,010	3,658,379	92,408	1,529	814	4,434
18									
19	**EXPENSES -**								
20	Operating & Maintenance Expense	(843)	(1,903)	(254)	(833,574)	(23,471)	(297)	(167)	(550)
21	Depreciation Expense	(1,101)	(5,060)	(302)	(1,021,244)	(24,855)	(331)	(193)	(708)
22	Taxes Other Than Income Tax	(371)	(1,446)	(109)	(353,515)	(7,721)	(115)	(72)	(245)
23	Amortization of Property Losses	3	26	2	3,894	134	1	1	2
24	Gain or Loss on Sale of Plant	4	7	3	3,440	40	1	2	0
25	**Total Operating Expenses**	(2,307)	(8,376)	(660)	(2,200,999)	(55,873)	(741)	(429)	(1,501)
26									
27	**Net Operating Income Before Taxes**	1,834	6,583	350	1,457,380	36,535	788	385	2,933
28	Income Taxes	(585)	(2,067)	(100)	(448,003)	(11,693)	(265)	(125)	(1,043)
29	**NOI Before Curtailment Adjustment**	1,249	4,516	249	1,009,377	24,842	522	260	1,890
30									
31	Curtailment Credit Revenue	0	0	0	0	0	0	0	0
32	Reassign Curtailment Credit Revenue	(0)	(0)	(0)	(343)	(1)	(0)	(0)	(0)
33	Net Curtailment Credit Revenue	(0)	(0)	(0)	(343)	(1)	(0)	(0)	(0)
34	Net Curtailment NOI Adjustment	(0)	(0)	(0)	(210)	(0)	(0)	(0)	(0)
36	**Net Operating Income (NOI)**	1,249	4,516	249	1,009,034	24,842	522	260	1,890
37									
38	**Rate of Return (ROR)**	5.91%	5.53%	4.12%	5.10%	6.02%	8.01%	6.47%	13.22%
39	**Parity At Present Rates**	1.189	1.112	0.829	1.025	1.211	1.611	1.301	2.659

FLORIDA POWER & LIGHT COMPANY
Recommended Class Revenue Allocation
Test Year Ending December 31, 2017
(Dollar Amounts in Thousands)

Line	Customer Class	Base Revenues At Present Rates	Base Revenue Increase	
			Amount	Percent
		(1)	(2)	(3)
1	**Residential**	$3,504,590	$521,530	14.9%
2	**General Service**	373,326	46,733	12.5%
3	**General Service Demand**	1,131,513	166,410	14.7%
	General Service Large Demand			
4	GSLD-1	369,413	85,197	23.1%
5	GSLD-2	75,325	17,372	23.1%
6	GSLD-3	4,562	1,052	23.1%
7	Total GSLD	449,300	103,621	23.1%
	C&I Load Control			
8	CILC-1D	60,642	13,986	23.1%
9	CILC-1G	3,162	494	15.6%
10	CILC-1T	22,161	5,111	23.1%
11	Total C&I Load Control	85,965	19,591	22.8%
12	**MET**	4,092	486	11.9%
	Lighting			
13	SL-1	91,266	9,319	10.2%
14	SL-2	1,507	127	8.4%
15	OL-1	14,050	1,983	14.1%
16	OS-2	992	229	23.1%
17	Total Lighting	107,815	11,658	10.8%
	Standby Service			
18	SST-DST	4,399	83	1.9%
19	SST-TST	801	0	0.0%
20	Total Standby Service	5,200	83	1.6%
21	**Total Electricity Sales**	$5,661,800	$870,113	15.4%

Docket No. 160021-EI
Recommended Allocation
Exhibit___(JP-15)

FLORIDA POWER & LIGHT COMPANY
Summary of FIPUG's Class Cost-of-Service Study Results
At Present and Recommended Rates
Test Year Ending December 31, 2017
(Dollar Amounts in Thousands)

		Present Rates			Recommended Rates			Movement
Line	Customer Class	Rate of Return	Parity Index	Subsidy	Rate of Return	Parity Index	Subsidy	Toward Cost
		(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	Residential	5.10%	102	$39,990	6.70%	101	$30,499	24%
2	General Service	5.68%	114	22,574	7.13%	108	16,918	25%
3	General Service Demand	5.11%	103	14,637	6.71%	102	11,148	24%
4	GS Large Demand	3.43%	69	(77,282)	5.50%	83	(55,460)	28%
5	C&I Load Control	4.15%	84	(10,289)	5.72%	87	(11,177)	-9%
6	MET	5.91%	119	324	7.33%	111	247	24%
7	Lighting	5.94%	120	8,026	7.36%	111	6,208	23%
8	Standby Service	11.74%	236	2,020	12.02%	182	1,616	20%
9	Total Retail	4.97%	100	($0)	6.61%	100	($0)	23%

FLORIDA POWER & LIGHT COMPANY

Comparison of Present and Proposed Tariff Charge

GSLD and CILC Rates

Line	Rate Schedule	Type of Charge	Current Rates	1/1/17 Rates	Percent Increase
			(1)	(2)	(3)
	GSLDT-1	**General Service Large Demand (2000 kW+)**			
1		Customer Charge	$61.83	$75.00	21.3%
2		Demand Charge	$9.96	$12.60	26.5%
3		On-Peak Energy Charge	2.380	3.025	27.1%
4		Off-Peak Energy Charge	1.035	1.314	27.0%
	GSLDT-2	**General Service Large Demand (2000 kW+)**			
5		Customer Charge	$219.22	$250.00	14.0%
6		Demand Charge	$10.28	$13.20	28.4%
7		On-Peak Energy Charge	2.041	2.615	28.1%
8		Off-Peak Energy Charge	1.003	1.291	28.7%
	GSLDT-3	**General Service Large Demand (2000 kW+)**			
9		Customer Charge	$1,620.94	$3,075.00	89.7%
10		Demand Charge	$8.20	$10.40	26.8%
11		On-Peak Energy Charge	1.043	1.286	23.3%
12		Off-Peak Energy Charge	0.892	1.127	26.3%
	CDR	**Commercial/Industrial Demand Response**			
13		Credit	($8.20)	($5.26)	-35.9%
14		Adder	$533.99	$125.00	-76.6%
	CILC-1	**Commercial/Industrial Load Control Program**			
		Customer Charge			
15		(G) 200-499kW	$112.42	$ 125.00	11.2%
16		(D) above 500kW	$168.63	$ 275.00	63.1%
17		(T) transmission	$2,220.26	$ 3,200.00	44.1%
		Base Demand Charge			
		per kW of Max Demand (All kW)			
18		(G) 200-499kW	$3.82	$ 4.90	28.3%
19		(D) above 500kW	$3.49	$ 5.50	57.6%
20		(T) transmission	None	None	N/A
		per kW of Load Control On-Peak			
21		(G) 200-499kW	$2.54	$ 3.30	29.9%
22		(D) above 500kW	$2.54	$ 4.00	57.5%
23		(T) transmission	$2.49	$ 4.40	76.7%
		per kW of Firm On-Peak Demand (All kW)			
24		(G) 200-499kW	$9.30	$ 12.00	29.0%
25		(D) above 500kW	$9.08	$ 14.20	56.4%
26		(T) transmission	$9.17	$ 16.40	78.8%
		Base Energy Charge			
		On-Peak			
27		(G) 200-499kW	1.425	1.828	28.3%
28		(D) above 500kW	0.822	1.272	54.7%
29		(T) transmission	0.731	1.307	78.8%
		Off-Peak			
30		(G) 200-499kW	1.425	1.828	28.3%
31		(D) above 500kW	0.822	1.272	54.7%
32		(T) transmission	0.731	1.307	78.8%

Source: MFR E-13c

CERTIFICATE OF SERVICE

I **HEREBY CERTIFY** that a true and correct copy of the foregoing has been furnished by electronic mail this 7th day of July, 2016, to the following:

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