BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

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| In re: Petition for Increase in Rates by Florida Power & Light Company. | DOCKET NO. 080677-EI |
| In re: 2009 Depreciation and Dismantlement Study by Florida Power & Light Company. | DOCKET NO. 090130-EI<br>Filed: July 16, 2009 |

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# TESTIMONY AND EXHIBITS OF JEFFRY POLLOCK

## ON BEHALF OF THE FLORIDA INDUSTRIAL POWER USERS GROUP

J. POLLOCK
INCORPORATED

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CLK Ct. Rp.


Vicki Gordon Kaufman
Jon C. Moyle, Jr.
Keefe Anchors Gordon & Moyle, PA
118 North Gadsden Street
Tallahassee, Florida 32301
Telephone: 850-681-3828
Facsimile: 850-681-8788

John W. McWhirter, Jr.
McWhirter Law Firm
400 N. Tampa St., Ste. 2450
P.O. Box 3350
Tampa, FL 33601-3350
Telephone: 813-505-8055
Facsimile: 813-221-1854

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## List of Acronyms

| | |
|---|---|
| AMI | Automated Metering Infrastructure |
| AD | Average Demand |
| A&E | Average and Excess |
| CFR | Code of Federal Regulations |
| CC | Combined Cycle Unit |
| CDR | Commercial/Industrial Demand Reduction Rider |
| CILC | Commercial/Industrial Load Control Program |
| CT | Combustion Turbine |
| FERC | Federal Energy Regulatory Commission |
| FIPUG | Florida Industrial Power Users Group |
| FPL | Florida Power & Light Company |
| GBRA | Generation Base Rate Adjustment |
| HLFT | High Load Factor Time-of-Use Rate |
| kW | Kilowatts |
| kWh | Kilowatt-hours |
| MPSC | Michigan Public Service Commission |
| MW | Megawatt |
| NARUC | National Association of Regulatory Utility Commissioners |
| O&M | Operation & Maintenance Expense |
| PEF | Progress Energy Florida |
| PPA | Purchased Power Agreement |
| SDTR | Seasonal Demand Time-of-Use Rate |
| SEC | Securities and Exchange Commission |
| S&P | Standard & Poor |
| TECO | Tampa Electric Company |
| TOU | Time-of-Use |
| WCEC | West County Energy Center |

## 1. INTRODUCTION, QUALIFICATIONS, AND PURPOSE

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Jeffry Pollock; 12655 Olive Blvd., Suite 335, 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 Masters 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. I have participated in regulatory matters before this Commission since 1976. More details are provided in Appendix A 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). Participating FIPUG companies take power from Florida Power & Light Company (FPL). These customers require a reliable low-cost supply of electricity to power their operations. Therefore, participating FIPUG companies have a direct and significant interest in the outcome of this proceeding.

Q WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A I will address the following issues:

- Depreciation-related matters (*e.g.*, the estimated life spans of FPL's coal and combined cycle units and the ratemaking adjustments to recognize that FPL has accumulated a $1.2 billion surplus depreciation reserve);
- The appropriate common equity ratio for determining FPL's cost of capital;
- The reasons that FPL's request for a rate increase in 2011 (Subsequent Year) is inappropriate;
- FPL's class cost-of-service study;
- Class revenue allocation; and
- Rate design.

**Q ARE YOU FILING ANY EXHIBITS IN CONNECTION WITH YOUR TESTIMONY?**

A Yes. I am filing **Exhibits JP-1** through **JP-11**. These exhibits were prepared by me or under my direction and supervision.

**Q IN SOME OF THESE EXHIBITS, YOU HAVE USED FPL'S CLAIMED REVENUE REQUIREMENTS. DOES THIS CONSTITUTE AN ENDORSEMENT OF THE COMPANY'S PROPOSALS?**

A No. My use of FPL's claimed revenue requirements is strictly for illustrative purposes and should not be interpreted as an endorsement of the proposed base revenue increases.

**Summary**

**Q PLEASE SUMMARIZE YOUR RECOMMENDATIONS.**

A First, with respect to revenue requirements, I am recommending:

- Reductions in depreciation expense based on longer life spans for FPL's coal (at least 55 years) and combined cycle (at least 35 years) units and a continuation of the $125 million depreciation adjustment authorized in FPL's 2005 rate case. The latter recommendation recognizes the very large ($1.2 billion) surplus in the depreciation reserve and the need to restore generational equity; that is, current ratepayers should be charged only for the assets that are consumed to provide electric service.

- For the same reason, FPL should charge the remaining costs of the plants that are being retired early to the depreciation reserve, rather than amortizing them as an additional expense, and it should suspend contributions to the fossil plant dismantling fund until after the next depreciation study.
- FPL's capital structure should be adjusted to reduce the amount of common equity to 50.2% on an adjusted basis, which is comparable to the equity ratios of other comparably-rated electric utilities.
- The Commission should reject FPL's attempt to implement a subsequent year base rate increase in 2011 because it is speculative, inappropriate and unnecessary.

Second, with respect to FPL's class cost-of-service study, the methodology used to allocate production plant costs should reflect cost-causation. FPL is a strongly summer peaking utility and experiences its tightest margins during the summer months. This suggests that greater emphasis should be placed on summer month demands than is provided in the Twelve Coincident Peak and 1/13$^{th}$ Average Demand (12CP-1/13$^{th}$ AD) method used by FPL. However, 12CP-1/13$^{th}$ AD has been adopted by this Commission in past cases and it should not be replaced with another method that places greater emphasis on energy usage. Should the Commission decide to replace 12CP-1/13$^{th}$ AD, it should adopt the Average and Excess method rather than a peak and average method because the former recognizes the dual functionality of generating plants (*i.e.,* serving both base and cycling loads) without double-counting peak demand.

FPL's proposed class revenue allocation should be rejected because it would result in some classes receiving base rate increases over 150% of the system average increase. This violates the Commission's policy regarding the use of cost-of-service study to set rates, subject to appropriate gradualism constraints.

Finally, FPL's proposed rate design should be revised to:

- More closely align the demand and energy charges to reflect the corresponding demand and non-fuel energy-related costs;
- Set the HLFT rates to blend at a 70% load factor with the corresponding GSD and GSLD rates;
- Correct the CILC rate design by spreading the payments to all customer classes (rather than being partially absorbed by the CILC customers); and
- Increase the CDR Rider credit to reflect the higher equipment costs and greater value of providing non-firm service than when the credit was first initiated.

## 2. DEPRECIATION

**Background**

**Q WHAT IS DEPRECIATION?**

A Depreciation reflects the consumption or use of assets used to provide utility service. Thus, it provides for capital recovery of a utility's current or original investment. Generally, this capital recovery occurs over the average service life of the investment or assets. The most commonly used definition of depreciation is found in the Code of Federal Regulations (CFR):

> Depreciation, as applied to depreciable electric plant, means the loss in service value not restored by current maintenance, incurred in connection with the consumption or prospective retirement of plant in the course of service from causes which are known to be in current operation and against which the utility is not protected by insurance. Among the causes to be given consideration are wear and tear, decay, action of the elements, inadequacy, obsolescence, changes in the art, changes in demand and requirements of public authorities. (*18 CFR Part 101*)

**Q WHAT ARE THE KEY PARAMETERS THAT DETERMINE THE AMOUNT OF DEPRECIATION RECOGNIZED FOR RATE-MAKING PURPOSES?**

A Depreciation accounting provides for the recovery of the original cost of an asset over its life span adjusted for net salvage. As a result, it is critical that appropriate average life span be used to develop the depreciation rates so that present and future ratepayers are treated equitably. In addition to capital recovery, depreciation rates also contain a provision for net salvage. Net salvage is the value of the scrap or reused materials less the removal cost of the asset being depreciated. A utility will reflect in its rates the net salvage over the useful life of the asset.

**Q HOW ARE DEPRECIATION RATES CALCULATED?**

A Depreciation rates are essentially calculated using the following formula:

$$Remaining\ Life\ Rate = \frac{100\% - Reserve\% - Avg.Future\ Net\ Salvage\%}{Avg.Remaining\ Life\ in\ Years}$$

The above formula is prescribed in Rule 25-6.0436. Under this method of developing depreciation rates, the un-depreciated portion of the plant in service, adjusted for net salvage, is recovered over the average remaining life of the asset or group of assets. Therefore, at the end of the useful life, the asset is fully depreciated.

<u>FPL's Depreciation Study</u>

**Q HAVE YOU REVIEWED THE DEPRECIATION STUDY FILED BY FPL IN THIS PROCEEDING?**

A Yes.

**Q WHAT DOES THE DEPRECIATION STUDY SHOW?**

A The study recommends higher depreciation rates, which would generate an additional $22.6 million of depreciation expense. The increase is primarily due to shorter assumed life spans for production investments. FPL is also proposing to accelerate the recovery of certain capital investments, which would further increase depreciation expense by an additional $78.6 million (*Exhibit CRC-1* at 51).

**Q WHAT ELSE DOES FPL'S DEPRECIATION STUDY SHOW?**

A The study also shows that, based on the assumed remaining lives of its investments and the projected book value as of December 31, 2009, FPL's book depreciation reserve is $1.245 billion higher than the "theoretical reserve." (*Id.* at 53). The theoretical reserve is the amount necessary to allow recovery of the existing investments over their projected remaining life spans. In other words, FPL has accrued a $1.245 billion reserve surplus.

**Q IS THERE ANYTHING NOTEWORTHY ABOUT THE $1.245 BILLION DEPRECIATION RESERVE SURPLUS?**

A Yes. The $1.245 billion surplus reserve occurs after a $500 million depreciation expense adjustment. The adjustment was the result of the Stipulation in FPL's 2005 rate case (Docket No. 050045-EI) authorizing FPL to reduce depreciation reserve by $125 million per year. FPL recorded a $125 million credit in depreciation expense in 2006, 2007 and 2008 and will record another $125 million credit in 2009. Therefore, by the end of 2009, FPL will have recorded $500 million associated with these credits in the depreciation reserve (*Direct Testimony and Exhibits of C. Richard Clarke* at 23).

**Q WHAT IS THE SIGNIFICANCE OF THE SURPLUS?**

A The purpose of depreciation is to recover capital investment, including removal costs. Such recovery should, to the extent possible, come from the customers that use the utility service. With the large depreciation surplus, the current generation of ratepayers has paid a disproportionate share of the assets consumed to provide utility services. Thus, it is clear that FPL's depreciation rates are neither fair nor equitable.

**Q WHAT DEPRECIATION ISSUES WILL YOU ADDRESS?**

A I will address:

- The life spans of coal and combined cycle units. Life spans are integral in determining the appropriate depreciation rates;
- FPL's proposed accelerated capital recovery of $314 million of early plant retirements; and
- Other measures to reduce the large surplus.

<u>**Life Spans**</u>

**Q HAVE YOU REVIEWED THE LIFE SPANS THAT FPL USED TO DETERMINE ITS PROPOSED DEPRECIATION RATES?**

A Yes. FPL's proposed life spans for coal and combined cycle (CC) units are shown in Exhibit CRC-1 and summarized below.

| Plant Type | FPL's Proposed Average Life Spans |
|---|---|
| Coal | 41 |
| Combined Cycle | 27 |

**Q ARE FPL'S PROPOSED LIFE SPANS APPROPRIATE?**

A No. FPL has significantly understated the life spans for these plant types.

**Q ON WHAT DO YOU BASE YOUR OPINION THAT FPL'S PROPOSED LIFE SPANS ARE SIGNIFICANTLY UNDERSTATED?**

A My opinion is based on actual plant lives, life spans used by other utilities for similar assets, and decisions by other regulatory commissions.

**Q WHAT LIFE SPAN DOES FPL ASSUME FOR ITS COAL UNITS?**

A FPL jointly owns Plant Scherer Unit No. 4 and St. John's River Power Park (SJRPP) station. According to Exhibit CRC-1, FPL assumes these facilities will be retired in 2029 and 2028, respectively. This translates into life spans of 40 years and 41 years, respectively.

**Q HAS FPL PROVIDED ANY JUSTIFICATION FOR THE PROPOSED LIFE SPANS?**

A No. The Company has not indicated when it will retire these units (*FPL's 2009 Ten Year Site Plan*, Schedule 1).

**Q ARE 40-41 YEAR LIFE SPANS REASONABLE FOR COAL UNITS?**

A No. FPL's proposed life spans are considerably shorter than the average lives of coal-fired plants as determined in proceedings. For example:

- 60 years for Indiana-Michigan Power company's Tanner Creek Units 1 through 4 and for its Rockport Unit 1 (Indiana Utility Regulatory Commission, Cause No. 43231, *Interim Order,* 6/13/2007);
- 55 years for coal plants operated by Southwestern Public Service Company (New Mexico Public Regulatory Commission, Case No. 07-00319-UT, *Order*, August 27, 2008);
- 59 to 68 years for coal units owned by AmerenUE (Missouri Public Service Commission, Cause No. ER-2007-0002, *Order,* May 22, 2007);
- 61 years for coal units owned by Rocky Mountain Power (Wyoming Public Service Commission, Docket No. 20000-257-EA-6, *Record No. 10794*, June 12, 2008);
- 60 years for Public Service Company of Oklahoma (Oklahoma Corporation Commission, Cause No. PUD 200600285, *Order No. 545168*, October 9, 2007); and
- 55 years for Georgia Power Company's Plant Scherer Units 1-3 (Georgia Public Service Commission, Docket No. 25060-U).

Thus, FPL's proposed life spans are considerably shorter than the life spans of actual coal-fired plants. Further, the two biggest operators of coal units in the nation, American Electric Power Company and The Southern Company, have determined that life spans of 60 years or more are achievable (Indiana Utility Regulatory Commission, Cause No. 43231, *Interim Order,* 6/13/2007, Florida Public Service Commission, Docket No. 050381-EI, *Order No. PSC-07-0012-PAA-EI*, January 2, 2007).

Q **IS FPL'S PLANT SCHERER UNIT 4 LOCATED AT THE SAME SITE AS GEORGIA POWER'S PLANT SCHERER UNITS 1-3?**

A Yes. I would also note the 55-year life span referenced above includes the Plant Scherer 3-4 common facilities, which FPL partially owns.

Q **DO OTHER FLORIDA UTILITIES USE LONGER LIFE SPANS THAN FPL FOR THEIR COAL UNITS?**

A Yes. Progress Energy Florida (PEF) proposes a 52-year average life span for its Crystal River Coal units in its pending rate case (Docket No. 090079-EI). In addition, Gulf Power Company extended the lives of the Plant Crist and Plant Smith units to 65 years (Docket No. 050381-EI, *Order No. PSC-07-0012-PAA-EI*, January 2, 2007).

Q **WHAT CONCLUSIONS CAN BE DRAWN FROM INDUSTRY EXPERIENCE AND THE SPECIFIC EXAMPLES YOU'VE DESCRIBED?**

A It appears that FPL has significantly understated the life span of its coal units, which results in increased depreciation costs which FPL wants ratepayers to bear. FPL's coal units represent a nearly $1 billion investment. Given this significant investment, it stands to reason that these capital intensive investments should be operated as long as possible to obtain the greatest level of economic benefit. Thus, it should normally be cost effective to maintain such equipment in operating condition over the long term.

For all of the above reasons, the Commission should use a life span of *at least* 55 years for FPL's coal units.

**Q WHAT IS THE IMPACT OF INCREASING THE LIFE SPANS OF FPL'S COAL UNITS TO 55 YEARS?**

A The impact of increasing the life spans would be to decrease the depreciation accruals for the coal plants by approximately $10.5 million annually as shown in **Exhibit JP-1**.

**Q HOW DID YOU CALCULATE THE CHANGE IN ANNUAL ACCRUALS?**

A I recalculated the depreciation rate by first calculating the ratio of my recommended life spans to FPL's proposed life span by unit by FERC account. This ratio was then multiplied by the corresponding whole life (by unit by FERC account) to determine the adjusted whole life. The revised remaining life is the sum of (1) the difference between the adjusted whole life and FPL's proposed whole life and (2) FPL's proposed remaining life. The revised depreciation rate is the ratio of the remaining recoverable cost (including FPL's proposed net salvage rate) to the revised remaining life.

**Q WHAT LIFE SPANS DOES FPL PROPOSE FOR ITS COMBINED CYCLE UNITS?**

A The average life span for FPL's combined cycle (CC) units is 27 years. This ranges from 25 years for Turkey Point, Martin 8, and Manatee to 43 years for Putnam. The new West County Energy Center (WCEC) CC units are projected to have 25-year life spans (FPL's *2009 Ten-Year Site Plan* at p. 106).

**Q HAS FPL JUSTIFIED THE LIFE SPANS OF ITS COMBINED CYCLE UNITS?**

A No. There are no expected retirement dates for these units (FPL's *2009 Ten-Year Site Plan* at Schedule 1). FPL has not explained why it cannot operate these units for much longer than 27 years (25 years for its newest, most efficient WCEC units). The CC units represent a combined $6.2 billion investment. Since these are the most efficient units on FPL's system, it should be economic to maintain them in good operating condition for much longer than 27 years.

**Q WHAT IS THE BASIS FOR YOUR OPINION THAT COMBINED CYCLE UNITS ARE CAPABLE OF OPERATING MUCH LONGER THAN 27 YEARS?**

A My opinion is based on industry projections and practices, including the following:

- 40 years for Rocky Mountain Power's CC units (Utah Public Service Commission, Docket No. 07-035-13 and Public Utility Commission of Oregon UM 1329, *Order No. 08-327*, June 17, 2008);
- Over 60 years for Public Service Company of Oklahoma (Oklahoma Corporation Commission Cause No. 200600285, *Order No. 545168*, October 9, 2007);
- 35 years for Nevada Power Company Silverhawk and Lenzie CC units (Nevada Public Utilities Commission, Docket No. 06-11023, May 24, 2007);
- 35 years for Georgia Power Company McIntosh CC units (Georgia Public Service Commission, Docket No. 25060-U).

Further, FPL's Putnam CC units have been in service for over 30 years (FPL's *2009 Ten-Year Site Plan* at Schedule 1). In addition, in a study of capacity needs, the Michigan Public Service Commission (MPSC) used a 40-year life span for new CC units (MPSC Docket No. U-14231).

**Q DO ANY OTHER FLORIDA UTILITIES USE LONGER LIFESPANS FOR THEIR COMBINED CYCLE UNITS?**

A Yes. Progress Energy Florida (PEF) proposes a 30-year life span for its Hines Units in its pending rate case (Docket No. 090079-EI). Further, Gulf Power recently extended the life of Plant Smith Unit 3 to 34 years (Docket No. 050381-EI, *Order No. PSC-07-0012-PAA-EI*, January 2, 2007). While conservative in light of the non-Florida examples cited above, these Florida examples further demonstrate the unreasonableness of FPL's proposed life spans.

**Q WHAT LIFE SPANS DO YOU RECOMMEND FOR COMBINED CYCLE UNITS?**

A Based on industry practices and recognizing FPL's over $6 billion investment, the Commission should increase the life span to *at least* 35 years.

**Q WHAT IS THE IMPACT OF INCREASING THE LIFE SPANS OF FPL'S COMBINED CYCLE UNITS TO 35 YEARS?**

A The increase of the life spans would decrease the depreciation accruals for the combined cycle plants by approximately $84.5 million annually as shown on **Exhibit (JP-1)**. In addition, the increased life span would also decrease annual accruals of WCEC-3 by about $12.8 million. These adjustments were quantified using the same methodology as described previously.

**Accelerated Capital Recovery**

**Q IS FPL PROPOSING TO ACCELERATE RECOVERY OF CERTAIN CAPITAL INVESTMENTS?**

A Yes. FPL proposes the early retirement of several steam plants and meters that will become obsolete because of the deployment of its Automated Metering Infrastructure (AMI). Because of the early retirement, FPL asserts that it has not recovered $44.9 million of steam production plant and $101 million of meter investment (including estimated removal costs). It proposes to recover these costs over four years. FPL is also proposing a four-year recovery of $168 million of investment resulting from various nuclear plant uprates, including estimated removal costs (*Exhibit CRC-1* at 57).

**Q WHAT IS THE MAGNITUDE OF THE PROPOSED ACCELERATED CAPITAL RECOVERY?**

A The total investment subject to accelerated recovery is $314.2 million. Assuming a four-year amortization period, FPL is proposing to increase depreciation expense by $78.6 million.

**Q IS FPL'S PROPOSED ACCELERATED CAPTIAL RECOVERY NECESSARY OR APPROPRIATE?**

A No. As previously stated, FPL has a $1.2 billion surplus in its depreciation reserve. Given this very large surplus, it is unnecessary to charge ratepayers for capital costs (including the costs of removal) for investments that FPL has chosen to retire early.

**Q SHOULD FPL'S DEPRECIATION PROPOSAL BE ADOPTED?**

A No. As previously stated, the purpose of depreciation is to recover capital investment, including removal costs. Equity and fairness demand that such recovery should, to the extent possible, come from the customers that use the utility service. With the large depreciation surplus, the current generation of ratepayers has paid a disproportionate share of the assets consumed to provide utility services. Thus, it is clear that FPL's depreciation rates are neither fair nor equitable. An additional payment, in the form of accelerated capital recovery, would only worsen the situation.

**Q HOW SHOULD THE CAPITAL COSTS OF INVESTMENTS FPL RETIRES EARLY BE TREATED FOR RATEMAKING PURPOSES?**

A The depreciation reserve is more than sufficient to allow recovery of the entire $314.2 million. Therefore, I recommend that the entire $314.2 million be used to offset the huge surplus in FPL's book depreciation reserve. Offsetting the entire $314.2 million would be a step toward moving the actual book reserve closer to the theoretical reserve. This would help restore generational equity.

**Q SHOULD THE COMMISSION TAKE ANY FURTHER STEPS TO RESTORE GENERATIONAL EQUITY?**

A Yes. The Commission should order FPL:

- To continue booking the $125 million depreciation expense adjustment; and
- To cease contributions to the fossil dismantlement fund.

This treatment should continue until FPL files its next depreciation study. Coupled with my recommendation to offset the $314.2 million of capital retirements and assuming FPL's next depreciation study is filed in 2012 (three years from the filing date of this case), the book reserve would be reduced by an additional $749 million. This would still leave nearly $0.5 billion in excess book depreciation reserve.

**Q IS THERE ANY PRECEDENT FOR REQUIRING FPL TO TAKE MEASURES NECESSARY TO ELIMINATE THE HUGE (OVER $1.2 BILLION) SURPLUS IN ITS DEPRECIATION RESERVE?**

A Yes. My recommendations to correct a reserve surplus are the same in concept as prior Commission actions allowing FPL to correct reserve deficiencies. For example:

- FPL was to book $126 million (in accord with preliminary implementation approved in Order PSC-95-0672-FOF-EI), an additional $30 million commencing in 1996, and additional expense in 1996 and 1997 equal to 100% of base rate revenues produced by retail sales between its "low band" and "most likely sales forecast" for 1996, and at least 50% of the base rate revenues produced by retail sales above FPL's most likely sales forecast for 1996 to correct a $175.3 million deficiency in the nuclear depreciation reserve and to correct the reserve deficiency existing in FPL's other production facilities, which was calculated to be $60.3 million as of January 1, 1994 (Docket No. 950359-EI, *Order No. PSC-96-0307-PHO-EI*); and
- FPL was ordered to amortize the gain realized from the sale of a combustion turbine from Port St. Joe to be used to offset the reserve deficiency at the Suwanee Peaking Plant. (Docket No. 971570-EI, *Order No. PSC-98-1723-FOF-EI*).

Since FPL now has a huge reserve surplus, similar adjustments are appropriate and necessary to restore generational equity and to help mitigate the impact of the proposed base rate increases.

**Q PLEASE SUMMARIZE YOUR RECOMMENDATIONS ON DEPRECIATION EXPENSE.**

A My recommendations are as follows:

| Adjustments | Amount ($Millions) |
|---|---|
| **Increase Coal Plant Life Spans to at Least 55 Years** | $ 10.5 |
| **Increase Combined Cycle Plant Life Spans to at Least 35 Years:** | |
| Existing Plants | $ 84.5 |
| West County Unit No. 3 | $ 12.8 |
| **Charge Early Retirements to the Depreciation Reserve** | $314.2 |
| **Continue the Depreciation Expense Adjustment** | $125.0 |
| **Cease Contributions to the Dismantlement Fund** | $ 15.3 |

## 3. CAPITAL STRUCTURE

Q **WHAT CAPITAL STRUCTURE IS FPL PROPOSING IN THIS PROCEEDING?**

A FPL's proposed regulatory capital structure is shown in the first column of the chart below:

| Component | MFR Schedule D-4 | FPL Adjusted (AP-7) | Excluding Imputed PPAS |
|---|---|---|---|
| **Long-Term Debt** | 31.52% | 43.1% | 39.20% |
| **Short-Term Debt** | 0.95% | 1.1% | 1.18% |
| **Common Equity** | 47.93% | 55.8% | 59.62% |
| **Customer Deposits** | 3.31% | | |
| **Deferred Taxes** | 15.96% | | |
| **Investment Tax Credits** | 0.33% | | |

The second column is the adjusted capital structure that FPL claims to be achieving, according to FPL witness Mr. Pimental. The adjusted capital structure excludes customer deposits, deferred income taxes, investment tax credits and imputes to debt the obligations under various firm Purchased Power Agreements (PPAs). The third column shows FPL's adjusted capital structure excluding the imputed PPAs.

Q **WHAT IS THE PROPOSED ADJUSTMENT FOR PURCHASED POWER OBLIGATIONS?**

A FPL's adjusted capital structure includes $949,260,000 of imputed debt for purchased power obligations. As can be seen in the third column of the above chart, without this imputed debt, FPL's equity ratio would approach 60%. This would make FPL among the least leveraged regulated electric utilities in the nation. For the reasons explained below, the Commission should set rates based on an adjusted capital structure (1) excluding imputed debt and (2) consisting of not more than 50% common equity.

**<u>Imputed Debt for Purchased Power Obligations</u>**

**Q WHY DOES FPL IMPUTE $949.3 MILLION OF DEBT RELATED TO PPAS?**

A FPL asserts that the financial community commonly takes into account obligations associated with PPAs. Since FPL has certain long-term PPAs, it is obligated to make certain fixed payments, which, it asserts, the rating agencies regard as equivalent to long-term debt (*Direct Testimony and Exhibits of Armando Pimental* at 34). According to FPL, long-term PPAs are those agreements that have a term of at least one year (*FPL's Response to SFHHA's Interrogatory No. 281*).

**Q DO YOU AGREE WITH THIS ADJUSTMENT?**

A No. It is unnecessary to impute debt for PPA obligations. The Commission's approval of PPAs is governed by Rule 25-17.0832 Florida Administrative Code (for standard offer and negotiated contracts). Once approved, FPL is allowed full and direct recovery of firm energy and purchased power capacity costs under the Fuel and Capacity Cost Recovery (CCR) clauses. Though such contracts are reviewed in the annual fuel adjustment proceeding, there is minimal recovery risk associated with PPAs.

Second, Moody's does not treat PPAs in the same way as Standard & Poor's (S&P).

Finally, the Commission has very recently addressed precisely this issue. In Tampa Electric's (TECO's) most recent rate case, TECO made the same argument that FPL puts forth here and it was rejected by the Commission.

Q **DO ALL RATING AGENCIES IMPUTE THE FIXED OBLIGATIONS UNDER PPAS IN EVALUATING A UTILITY'S FINANCIAL STRENGTH?**

A No. FPL's imputed debt adjustment reflects the methodology outlined by S&P. It is noteworthy that another ratings agency, Moody's, does not make a similar adjustment.

Q **HOW DOES S&P RECOGNIZE THE DEBT EQUIVALENT OF PPAS?**

A S&P quantifies the debt equivalent as the product of (1) a risk factor and (2) the net present value of the remaining capacity payments under each PPA. The risk factor is based primarily on the method of recovery of capacity payments.

Q **WHAT RISK FACTOR HAS FPL USED IN ITS IMPUTED DEBT ADJUSTMENT?**

A FPL has used a 25% risk factor (*Testimony and Exhibits of Armando Pimental* at 35-36). This choice is based on general criteria explained by S&P:

> If a regulator has established a power cost adjustment mechanism that recovers all prudent PPA costs, a risk factor of 25% is employed, because the recovery hurdle is lower than it is for a utility that must litigate time and again its right to recovery costs. (Standard & Poor's, *Corporate Credit Ratings 2008* at 75).

**Q DOES THIS ACCURATELY REFLECT THE RISKS ASSOCIATED WITH THE RECOVERY OF PURCHASED POWER CAPACITY COSTS IN FLORIDA?**

A No. Purchased power capacity costs are subject to dollar-for-dollar recovery through the CCR. This includes a true-up procedure that establishes a forward-looking charge, which is then reconciled based on actually incurred costs, with interest. The recovery mechanism is nearly identical to FPL's Fuel Charge.

**Q DOES S&P RECOGNIZE THE RELATIONSHIP BETWEEN RISK AND THE TYPE OF COST RECOVERY MECHANISM?**

A Yes. S&P states that:

> The calculated PV [present value] is adjusted to reflect the benefits of regulatory or legislative cost recovery mechanisms. The adjustment reduces the debt-equivalent amount by multiplying the PV by a specific risk factor that pertains to each contract. The stronger the recovery mechanisms, the smaller the risk factor. These risk factors typically range between 0% and 50%, but can be as high as 100%. (*Id.*)

Thus, S&P does not provide an objective standard for determining the appropriate risk factor. Dollar-for-dollar recovery of purchased power capacity costs is a very strong mechanism with no practical risk. The PPAs in question have been previously approved for recovery. In fact, the above discussion from S&P in conjunction with the policies and previous findings in Florida strongly suggest that the obligations under Commission-approved PPAs are risk free, so long as the utility properly manages the contracts.

**Q DOES MOODY'S CONSIDER PPAS AS INHERENTLY MORE RISKY FOR ELECTRIC UTILITIES?**

A No. Moody's specifically recognizes that the risk of PPAs is specifically related to the applicable cost recovery mechanism as well as market dynamics:

> Pass-through capability: Some utilities have the ability to pass through the cost of purchasing power under PPAs to their customers. As a result, the utility takes no risk that the cost of power is greater than the retail price it will receive. Accordingly Moody's regards these PPA obligations as operating costs with no long-term debt-like attributes. PPAs with no pass-through ability have a greater risk profile for utilities. In some markets, the ability to pass through costs of a PPA is enshrined in the regulatory framework, and in others can be dictated by market dynamics. As a market becomes more competitive, the ability to pass through costs may decrease and, as circumstances change, Moody's treatment of PPA obligations will alter accordingly. (Moody's, *Rating Methodology: Global Regulated Electric Utilities*, March 2005 at 9.)

Thus, it is clear that Moody's does not regard PPAs as inherently risky and thus it imputes no debt for these contracts where recovery is guaranteed.

**Q DOES FPL HAVE THE ABILITY TO PASS THROUGH THE COSTS OF ITS PPAS?**

A Yes. As explained earlier, FPL has the ability to directly pass through purchased power capacity costs. In the case of certain purchases mandated by state statute, such as those from renewable energy sources, up-front approval is required for non-standard offer contracts, while standard offer contracts are considered reasonable.

**Q DO FPL PPAS CONTAIN ANY CLAUSES FURTHER MITIGATING RISK?**

A Yes. FPL recently included a clause in a PPA stating that if the Commission does not allow recovery of contract costs from ratepayers, FPL does not have an obligation to pay under the agreement.

> Notwithstanding anything to the contrary in this Amended Agreement, if FPL, at any time during the Term of this Amended

> Agreement, fails to obtain or is denied the authorization of the FPSC, or the authorization of any other legislative, administrative, judicial or regulatory body which now has, or in the future may have, jurisdiction over FPL's rates and charges, to recover from its customers all of the payments required to be made to the Authority under the terms of this Amended Agreement or any subsequent amendment hereto, FPL may, at its sole option, adjust the payments made under this Amended Agreement to the amount(s) which FPL is authorized to recover from its customers. (<u>Negotiated Contract with The Solid Waste Authority of Palm Beach County</u>, paragraph 16.4, which was submitted for approval on March 25, 2009 in Docket No. 090150-EQ)

This makes FPL's "risk" virtually non-existent.

**Q DOES MOODY'S CONSIDER PPAS AS BEING LESS RISKY IN CERTAIN CIRCUMSTANCES?**

A Yes. Unlike S&P, Moody's recognizes that PPAs can be less risky for a utility:

> <u>Risk management</u>: An overarching principle is that PPAs have been used by utilities as a risk management tool and Moody's recognizes that this is the fundamental reason for their existence. Thus, Moody's will not automatically penalize utilities for entering into contracts for the purpose of reducing risk associated with power price and availability. Rather, we will look at the aggregate commercial position, evaluating the risk to a utility's purchase and supply obligations. In addition, PPAs are similar to other long-term supply contracts used by other industries and their treatment should not therefore be fundamentally different from that of other contracts of a similar nature. (*Id.*)

**Q ARE YOU SAYING THAT MOODY'S WILL NOT IMPUTE DEBT ASSOCIATED WITH PPAS?**

A No. Moody's states:

> *Methods of accounting for PPAs in our analysis*
>
> According to the weighting and importance of the PPA to each utility and the level of disclosure, Moody's may analytically assess the total obligations for the utility using one of the methods discussed below.

> Operating Cost: If a utility enters into a PPA for the purpose of providing an assured supply and there is reasonable assurance that regulators will allow the costs to be recovered in regulated rates, Moody's may view the PPA as being most akin to an operating cost. In this circumstance, there most likely will be no imputed adjustment to the obligations of the utility.

Based on the above statements by Moody's, it seems unlikely that debt will be imputed to FPL based on the cost recovery mechanisms applicable to purchased power capacity costs.

**Q IS THE DEBT THAT FPL PROPOSES TO IMPUTE FOR PPA OBLIGATIONS ACTUAL DEBT ON THE COMPANY'S BOOKS AND RECORDS?**

A No. FPL does not reflect its PPA obligations as debt in the normal course of accounting.

**Q HAS THE COMMISSION PREVIOUSLY RULED ON THIS ISSUE IN A RECENT CASE?**

A Yes. The Commission rejected TECO's proposal to impute additional equity in determining its capital structure to recognize the so-called risks associated with PPAs. The Commission stated that:

> The pro forma adjustment to equity proposed by TECO is not an actual equity investment in the utility. If this adjustment is approved for purposes of setting rates in this proceeding, the Company would essentially be allowed to earn a risk-adjusted equity return without having actually made the equity investment. The revenue requirement impact of recognizing this pro forma adjustment to equity in the capital structure is approximately $5 million per year. (*Order No. PSC-09-0283-FOF-EI* at 35)

The Commission went on to find:

> Companies with PPAs are not required by the rating agencies to make the pro forma adjustment in question. As the following passage explains, the Standard & Poors' (S&P) practice with

respect to PPAs described in witness Gillette's testimony is strictly for the rating agency's own analytical purposes:

> We adjust utilities' financial metrics, incorporating PPA fixed obligations, so that we can compare companies that finance and build generation capacity and those that purchase capacity to satisfy customer needs. The analytical goal of our financial adjustments for PPAs is to reflect fixed obligations in a way that depicts the credit exposure that is added by PPAs. That said, PPAs also benefit utilities that enter into contracts with suppliers because PPAs will typically shift various risks to the suppliers, such as construction risk and most of the operating risk. PPAs can also provide utilities with asset diversity that might not have been achievable through self-build. The principal risk borne by a utility that relies on PPAs is the recovery of the financial obligation in rates. (*Id.* at 35)

Further, in rejecting TECO's adjustment, the Commission held:

> With this proposed adjustment, we find that the Company is attempting to take a portion of S&P's consolidated credit assessment methodology and use it for a purpose it was never intended. (*Id.* at 36).

**Q SHOULD DEBT ASSOCIATED WITH PPAS BE IMPUTED IN ASSESSING THE PROPER CAPITAL STRUCTURE FOR FPL?**

A No. For all of the reasons stated above, imputed debt should not be included in assessing the reasonableness of FPL's capital structure.

## <u>Common Equity Ratio</u>

**Q DOES FPL PROPOSE TO ADJUST ITS EQUITY RATIO TO RECOGNIZE IMPUTED DEBT?**

A No. Unlike TECO, FPL does not propose a specific adjustment. Instead, FPL seeks to use the imputation argument to support its excessively high common equity ratio. As discussed below, without this adjustment, FPL is one of the least leveraged regulated electric utilities in the nation. Thus, the Commission should reduce the amount of common equity in determining FPL's cost of capital.

**Q HOW DOES FPL'S COMMON EQUITY RATIO COMPARE WITH OTHER ELECTRIC UTILITIES?**

A **Exhibit JP-2** is a comparison of common equity ratios for the 2006 to 2009 (1st Quarter) time frame published by SNL Financial. For this period, average common equity ratios for all electric utilities range from 46.1% to 47.6% (line 85). On a comparable basis, FPL's proposed 2010 common equity ratio is 59.6%, far above the average. Thus, FPL proposes a common equity ratio that is over 1,200 basis points higher than the electric utility average.

**Q WHAT IS THE CONSEQUENCE OF USING MORE EQUITY AND LESS DEBT TO FINANCE THE UTILITY'S RATE BASE?**

A Common equity is more expensive than debt. In this instance, FPL is asking for a common equity return that is nearly 700 basis points higher than its embedded cost of long-term debt. A utility having 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 higher the rates all FPL ratepayers will bear.

**Q IS A NEARLY 60% COMMON EQUITY RATIO NECESSARY TO MAINTAIN FPL'S CURRENT BOND RATING?**

A No. FPL is currently rated "A1" by Moody's and "A" by both Fitches and S&P. The chart below provides a comparison of the common equity ratios for other A-rated electric utilities. I included all electric utilities that had "A" or equivalent bond ratings from at least two of the three bond rating agencies.

| Year | All Electric Utilities | A-Rated Electric Utilities |
|---|---|---|
| 2006 | 47.6% | 50.9% |
| 2007 | 47.3% | 51.0% |
| 2008 | 46.4% | 49.5% |
| 2009 (Q1) | 46.1% | 49.5% |
| Average | 46.9% | 50.2% |

Thus, FPL's 59.6% proposed (unadjusted) common equity would be 940 basis points higher than comparably rated electric utilities.

**Q WHAT IS YOUR RECOMMENDATION FOR A COMMON EQUITY RATIO FOR FPL?**

A FPL's common equity ratio should be reduced to 50.2% on an adjusted basis for setting its cost of capital in this proceeding. This translates into a 40.36% regulatory common equity ratio. Reducing the regulatory common equity ratio to 40.36% lowers FPL's requested 2010 base revenue increase by about $192.9 million, as shown in **Exhibit JP-3**.

### 4. 2011 TEST YEAR- SUBSEQUENT YEAR ADJUSTMENT

**Q IS FPL SEEKING A "SECOND" SEPARATE RATE INCREASE AS PART OF ITS FILING?**

A Yes. Specifically, FPL is seeking what it has characterized as a "subsequent year adjustment." If approved, this adjustment would increase rates above the level proposed in the primary increase by an additional $247.4 million effective January 2011. This additional increase would also be above and beyond the increase that would occur if the Commission continues the Generation Base Rate Adjustment (GBRA) clause upon the in-service of the WCEC-3 facility in June of 2011.

**Q SHOULD THE COMMISSION GRANT A SUBSEQUENT YEAR RATE INCREASE?**

A No. As a preliminary matter, please note that I do not address the Commission's authority to grant a subsequent year rate increase. This is a legal question, which will be briefed.

From a factual perspective, the request for an additional increase in 2011 is an objectionable pancaking of two separate rate cases in a single proceeding.

More importantly, the second rate request is objectionable because the 2011 revenue requirements FPL attempts to rely upon are based on projections that were made in mid to late 2008. As such, they do not reflect FPLs actual budget for 2011.

Finally, considering the various cost recovery clauses, the ability to implement a limited proceeding, and my recommended adjustments to FPL's revenue requirements, a subsequent year increase is simply unnecessary.

**Q HOW WOULD YOU CHARACTERIZE THE "SUBSEQUENT YEAR ADJUSTMENT" PROPOSAL AND THE REQUESTED ADJUSTMENT?**

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 2011 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.

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

A The "subsequent year adjustment" is a filing that looks, feels and smells like a full rate case. First, the "subsequent year" adjustment is not a proposal to adjust rates based on a specific occurrence or event, such as what might be addressed in a limited 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 8% to 8.18% (2010 MFR Schedule A-1 and 2011 MFR Schedule A-1), increases in operation and maintenance (O&M), depreciation, and tax expenses, adjustments to billing determinants, capital additions and even inflation-related adjustments, all based on speculative costs projected for 2011. These are not specific subsequent year adjustments, but rather the full panoply of adjustments that are seen as part of a full rate increase filing.

**Q DOES FPL ACKNOWLEDGE THAT THE "SUBSEQUENT YEAR" ADJUSTMENT IS SIMPLY A SECOND RATE CASE?**

A Yes. FPL witness Ousdahl states that if the "subsequent year" adjustment is not approved "FPL will have to consider initiating another proceeding to seek further rate relief in 2011. Subsequent year adjustments are used for precisely this reason, to avoid the cost and distraction for all parties of back-to-back rate proceedings." (*Direct Testimony of Kim Ousdahl* at 12). Similarly, FPL witness Olivera points out that "[t]he Subsequent Year Adjustment allows the Company, the Commission and all parties to address in a single proceeding both the 2010 and 2011 needs, avoiding the time and expense of a separate rate proceeding for 2011." (*Direct Testimony of Armando J. Olivera* at 34.) The testimony of FPL makes it clear that the subsequent year adjustment is nothing more than a second rate case filed at same time as the first case.

**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 2011 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 an *opportunity* to earn the authorized return.

Further, as discussed later, the 2011 test year is based on a mid-year 2008 budget, prior to the current economic upheaval. FPL will not formally approve its 2011 budget until 2010, which is after this rate case will be decided. Thus, setting rates for 2011 is highly speculative. Rates should not be set based on speculation about the future.

And finally, the proposed 2011 increase may be unnecessary depending on the Commission's findings on FPL's 2010 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 2010 test year.

**Q IS IT A COMMON PRACTICE TO ALLOW UTILITIES TO FILE PANCAKED RATE CASES?**

A No. This practice is not widely used at the present time. In the past, this Commission allowed two-step increases to recognize major asset additions. However, this was prior to the advent of a large number of separate rate adjustment clauses, such as fuel, purchased power capacity, environmental, energy efficiency and even base rate adjustment clauses.

**Q WHAT IS YOUR UNDERSTANDING OF THE PROCESS FPL USED IN DEVELOPING THE 2011 TEST YEAR?**

A FPL witness Barrett describes the process in his direct testimony. As he explains, the underlying budget assumptions used for 2011 were all prepared prior to May 21, 2008. That is because the assumptions that FPL used were included in the Planning Process Guidelines FPL issued on May 21, 2008 (*Direct Testimony of Robert E. Barrett Jr.,* at 7). The planning process resulted in an O&M budget for 2009 as well as budgets for 2010 and 2011, a capital budget for 2009, and forecasted capital expenditures for 2010 through 2013 (*Id.* at 8). The results were reviewed in June 2008 and finally approved in late 2008 (*Id.* at 9.). The O&M budget is prepared annually for the next year and two additional years, with the next year done at a monthly level while the two "out" years are done on an annual basis. (*Id.* at 13.)

**Q WHAT IS SIGNIFICANT ABOUT THE USE OF NUMBERS CALCULATED IN MID-2008 TO SET RATES FOR 2011?**

A The use of projections calculated some two and half years prior to the date rates are to take effect by necessity will result in rates that are based on highly speculative information. 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 have often elapsed between rate cases. If the Commission were to base 2011 rates on speculative data from 2008 – which will change as 2011 gets closer – these inaccurate rates may be in effect for a long time and ratepayers may be paying more than necessary.

If FPL can support a case for rate relief in 2011, it can file a rate case or limited proceeding in 2010 when projections and budgets will be more accurate.

Q **DOES THE FORECASTED TEST YEAR FOR 2011 REPRESENT FPL'S APPROVED BUDGET FOR THAT YEAR?**

A No. It represents a forecast of sales, revenues and expenses (both O&M and capital) in 2011 based on information available in 2008. This forecast changes annually. Mr. Barrett acknowledges that FPL annually prepares, reviews and approves a formal budget (*Id.*). Thus, the 2011 budget will not be approved until 2010. Whether this formal 2011 budget will be even remotely similar to the 2011 forecast prepared in 2008 is yet to be seen. The scope and extent of changes will not be known until sometime in 2010. What this suggests is that FPL is asking the Commission and its ratepayers to accept FPL's prediction of the revenues it will generate and costs it will incur in 2011, based upon a mid to late 2008 forecast. This is a risk to which ratepayers should not be exposed.

Q **IS THERE A BASIS TO ASSUME THAT THE 2011 O&M AND CAPITAL FORECAST PREPARED IN MID TO LATE 2008 WILL CHANGE BETWEEN NOW AND 2011?**

A Yes. In fact, there have already been some changes that have occurred in terms of the timing of estimated capital expenditures. For example, in Response to SFHHA's Interrogatory No. 254, FPL acknowledges that the number of new distribution substations originally planned for the period 2009-2011 has declined from 16 (as identified in the *Direct Testimony of FPL witness Keener*) to 12. Further, the answer states that "final plans for each budget year and forecasts for subsequent years are reviewed and approved as part of FPL's annual normal planning and budget process, which takes place during the latter part of each year. As such, the final 2010 budget and forecasts for 2011/2012 will be approved in late 2009."

The above response clearly indicates that both the 2010 and the 2011 capital forecasts are far from final and are subject to change. In each instance, 2010 and 2011, the final capital budget for each year will not be approved until in the case of the 2010 capital budget, this year, and in the case of 2011 until 2010.

**Q IS THERE ANY OTHER INFORMATION THAT SUGGESTS THAT THE CAPITAL BUDGET IS SUBJECT TO REVISION?**

A Yes. A review of the capital budget numbers provided in a series of FPL 10Q filings with the Securities and Exchange Commission (SEC) for the quarters ending June 30, 2008, September 30, 2008 and March 31, 2009 indicate that the capital expenditures have changed over the nine month period. **Exhibit JP-4** provides a summary of the projected expenditures taken from the three 10Q filings. In those filings, by way of example, both the 2010 and the 2011 total capital expenditures have increased by over $300 and $200 million, respectively from September 2008 to March 2009. During the same period (September 2008 to March 2009), the 2009 capital expenditures have decreased by over $300 million. From the quarter ending June 2008 to the quarter ending March 2009, the 2009 expenditures have decreased by over $1 billion. These changes highlight the extent to which expenditures may change over a relatively short period of time.

**Q WHAT DO THESE CHANGES SUGGEST WITH REGARD TO THE 2011 TEST YEAR?**

A The revenues and expenses used to establish rates should be known and measurable. The substantial changes highlighted above raise serious questions as to whether the 2011 test year costs, revenues and other material information are sufficiently known and measurable so as to form an appropriate and sufficient basis for a "subsequent year adjustment" or full base rate increase. In effect, FPL is asking the Commission to accept that its 2011 forecast produced in mid- to late 2008 produces revenues and expenses that are known and measurable and sufficient upon which to increase base rates for the year 2011. The 2011 revenues, expenses, and plant balances represent a forecast prepared in 2008 before the full effect of the economic upheavals that occurred in late 2008 were known. This is simply the second year forecast and not a formal budget. At best, the 2011 costs are a preliminary estimate. Further, FPL has already acknowledged that there very well may be some reductions in the need for capital expenditures (FPL's *Response to SFHHA's Interrogatory No. 254*) as well as potential changes in the economic environment.

**Q WILL CHANGES MADE TO FPL'S 2010 REVENUE REQUIREMENTS OBVIATE THE NEED FOR A SECOND RATE CASE?**

A Yes. FPL's proposed second rate increase is $247 million. It is based on the same assumptions (*e.g.,* cost of capital, depreciation rates) as the first rate increase to take effect in 2010. To the extent that the Commission reduces

FPL's 2010 revenue requirement, it will also affect the 2011 revenue requirement obviating the need for another increase.

**Q DOES THE RECENT TECO RATE CASE OFFER FPL ANY SUPPORT FOR THE SUBSEQUENT YEAR INCREASE?**

A No. While I understand that TECO's second increase is still disputed and such dispute is not the subject of this testimony, TECO's circumstances are different from FPL's. TECO used a 2009 test year in measuring its base revenue requirements. The test year assumed that five new CTs would be placed into commercial operation in 2009. However, during the hearing, TECO indicated that it was not sure when this capacity would be placed in service or if all units would come on line. The Commission excluded the revenue requirements associated with the new generating plants from the rate increase, but granted TECO a limited second step rate increase, contingent on the commercial operation of the new capacity.

**Q DO THIS COMMISSION'S RULES PROVIDE FPL WITH THE OPPORTUNITY TO SEEK AN INCREASE IN BASE RATES WITHOUT FILING A FULL RATE CASE?**

A Yes. Florida utilities may file for a "limited proceeding" under Section 366.076 Florida Statutes. This statute allows base rates to be adjusted in the context of a limited proceeding upon appropriate proof. The ability to request a limited adjustment is also available to FPL.

**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 67% 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 IF THE COMMISSION PERMITS THE GBRA TO APPLY TO WCEC-3 WOULD THIS MAKE THE REQUESTED 2011 INCREASE EVEN MORE UNNECSSARY?**

A Yes. However, if the Commission does approve such an approach, it should make it clear that it applies only to WCEC-3 and the GBRA should then be terminated.

**Q WHAT IS YOUR RECOMMENDATION FOR THE 2011 TEST YEAR?**

A The Commission should reject FPL's attempt to implement a subsequent year base rate increase in 2011 because it is speculative, inappropriate and unnecessary.

## 5. CLASS COST-OF-SERVICE STUDY

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

A A cost-of-service study 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' cost-of-service. A class cost-of-service study 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.

**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 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. 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.

These three factors explain why some customers pay higher 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 factor customer are spread over more kWh usage than for a low load factor customer.

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. FPL's class cost-of-service study recognizes the different types of costs as well as the different ways electricity is used by various customers.

Q **WHAT METHODOLOGY DOES FPL USE TO ALLOCATE PRODUCTION AND TRANSMISSION PLANT-RELATED COSTS?**

A FPL uses the 12CP-1/13$^{th}$ AD method. The 12CP-1/13th AD method allocates costs partially on a coincident demand basis and partially on an average demand, or energy, basis. Further, the coincident demand portion is based on customer demands in all twelve months of the calendar year. Thus, 12CP-1/13th AD assumes that production and transmission plant-related costs are caused by year-round coincident peaks and average demand.

Q **ARE FPL'S PRODUCTION AND TRANSMISSION PLANT COSTS CAUSED BY YEAR-ROUND COINCIDENT PEAK AND AVERAGE DEMANDS?**

A No. FPL experiences its maximum annual demand for electricity in either the summer or winter months. This is shown in **Exhibit JP-5**, **page 1**, which is an analysis of FPL's monthly firm peak demands as a percent of the annual system analysis of FPL's monthly firm peak demands as a percent of the annual system peak for the years 2004 through 2008 and the 2010 Test Year. The peak demands in the other months are typically well below the summer and winter peak demands. These characteristics are further summarized in **Exhibit JP-5, page 2:**

- FPL's minimum month peak is 69% of the annual system peak.
- Monthly peak demands are only 86% of the annual system peak.
- Summer peak demands are 23% (or higher) of the non-summer peak demands.
- FPL's annual load factor is only 61%.

These ratios confirm that FPL has seasonal load characteristics. Thus, electricity demands in the spring and fall months are not relevant in determining the amount of capacity needed for FPL to provide reliable service.

Q **ARE THE MONTHLY PEAKS IN THE SPRING/FALL MONTHS IMPORTANT BECAUSE FPL HAS TO REMOVE GENERATION FOR SCHEDULED MAINTENANCE?**

A No. Although FPL does schedule most planned outages during the spring and fall months, this does not make these months important from a cost-causation perspective. Specifically, despite planned outages, FPL generally has higher reserve margins during the non-summer months than during the summer months. This is shown in **Exhibit JP-6**. The reserve margins were calculated as the margin (available capacity less scheduled outages less firm peak demand) divided by firm peak demand. FPL's summer month reserve margins, adjusted for scheduled outages, range from 27% to 47% of the corresponding non-summer month reserve margins.

Q WHAT DO THE PEAK DEMAND AND RESERVE MARGIN ANALYSES DEMONSTRATE?

A The analyses demonstrate that the summer peak demands determine FPL's capacity requirements. The other months are irrelevant. Thus, the 12CP method does not reflect cost-causation when measured by FPL's load and supply characteristics.

Q HAS THE COMMISSION PREVIOUSLY APPROVED THE 12CP-1/13TH AD METHOD?

A Yes.

Q WHY HAS THE COMMISSION APPROVED THIS METHOD IN THE PAST?

A It is my understanding that the Commission originally adopted the 12CP-1/13th AD method to recognize that both peak demand and load duration are the drivers that determine utility investment decisions. While I do not agree that 12CP-1/13th AD accurately reflects these two cost drivers, it is certainly more appropriate than methodologies that allocate a substantial portion of production and transmission plant costs on an average demand basis.

Q WHY IS IT INAPPROPRIATE TO ALLOCATE PRODUCTION PLANT COSTS ON AN AVERAGE DEMAND BASIS?

A Average demand is not a factor that causes a utility to incur production plant costs. Cost causation means allocating costs to classes that cause the utility to incur them. Production and transmission plant are built to provide reliable service, especially during critical demand and supply periods. For FPL, these periods occur primarily in the summer months. If FPL were to provide only the amount of capacity needed to meet average demand, it could not do so reliably. To ensure reliability, facilities must be sized to meet the projected maximum demand imposed on them.

This point is illustrated in **Exhibit JP-7**. A utility serves two customer classes (A and B) that each use 2,400 kWh of energy over a 24-hour period. Thus, both classes have an average demand of 100 kWh (2,400 kWh ÷ 24 hours). However, Class A has a cyclical load shape while Class B has a flat load shape. Because of its cyclical load shape, Class A's maximum demand is 200 kW. Class B's maximum demand is 100 kW. In order to serve both classes, the utility would require 300 kW (ignoring reserves). Had the utility provided only 200 kW (which is the combined average load of the two classes), it could not have provided reliable service.

In summary, cost-causation is primarily a function of peak demand. Thus, a proper cost allocation method should emphasize peak demand.

**Q IF THE COMMISSION SHOULD DECIDE TO PLACE MORE WEIGHT ON AVERAGE DEMAND, IS THERE A REASONABLE METHODOLOGY FOR DOING SO?**

A Although I disagree with the premise, if more emphasis is to be placed on average demand, my recommendation would be to adopt the Average and Excess (A&E) method. Under A&E, a portion of production/transmission plant costs equal to the utility's annual system load factor (or 59% as projected by FPL during the 2010 test year) would be allocated on average demand. The remaining costs would be allocated on the difference between a class' maximum demand and its average demand, which is the "Excess Demand" (ED) component of the A&E formula.

**Q HAVE YOU DEVELOPED ALLOCATION FACTORS USING THE A&E METHOD?**

A Yes. The derivation of the A&E allocation factors is presented in **Exhibit JP-8**. The primary inputs are the group coincident peak (GCP) and the AD, which are shown in columns 1 and 2, respectively. The A&E allocation factors are derived as follows:

$$A\&E = AD\,x\,LF + ED\,x\,(1 - \mathrm{LF})$$

**Where:** AD=Average Demand
LF=Annual System Load Factor
ED=Excess Demand

A&E recognizes dual cost-causers. First, some plant is required for year-round operation (*i.e.,* Average Demand). High load factor customers that use electricity throughout the year would receive a larger share of the Average Demand. Second, the remaining plant is required for cycling (*i.e.,* Excess Demand). Low load factor customers require more cycling capacity than do high load factor customers. This is reflected in apportioning more Excess Demand to the lower load factor classes.

**Q IS AVERAGE AND EXCESS A RECOGNIZED METHOD?**

A Yes. A&E is recognized in the NARUC *Electric Utility Cost Allocation Manual*. Specifically, A&E is listed under the category of "Energy-Weighting" methods.

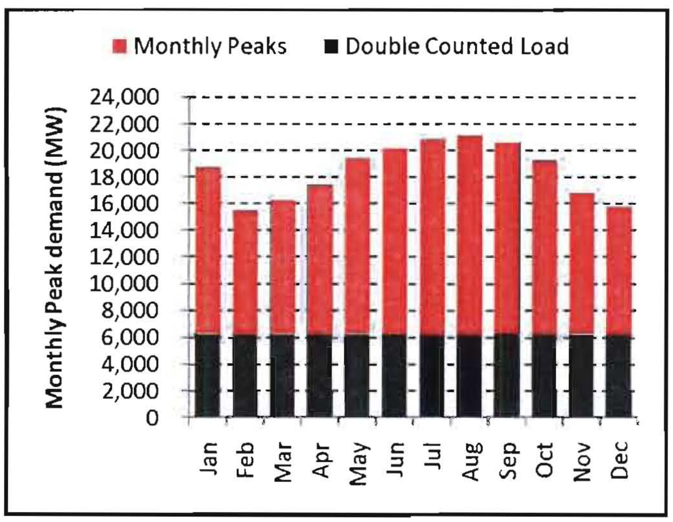
That is, it gives substantial weight to average demand or energy in determining cost causation.

**Q IS A&E SUPERIOR TO OTHER ENERGY WEIGHTING METHODS?**

A Yes. Unlike other energy weighting methods, such as peak and average, A&E does not double-count peak demand.

**Q WHAT DO YOU MEAN BY DOUBLE-COUNTING?**

A The peak and average method allocates production/transmission plant costs partially on average demand and partially on coincident peak demand. Double-counting occurs because average demand (which is the equivalent of year-round energy consumption divided by 8,760 hours) is also a component of the coincident peak demand.




The double-counting problem is illustrated above using the 12CP-50% AD method.

The portion of plant allocated on average demand is the black shaded area of the chart. Coincident demand is represented by the red shaded area. As can be seen, double-counting occurs because the portion of plant allocated on average demand overlaps the coincident peak demands.

By allocating some plant costs relative to average demand and some relative to coincident peak demand, energy is counted twice: once by itself and a second time as a subset of the coincident peak demand. If year-round energy is analogous to base load units which supply capacity on a continuing basis throughout the year, then it follows that the only time intermediate and peaking units would be needed is to meet system demands when they are in excess of the average year-round demand. Energy allocation advocates improperly allocate the cost of this additional capacity relative to the total coincident demand, rather than the excess demand.

**Q HAS THE DOUBLE-COUNTING PROBLEM BEEN CITED AS A CRITICAL FLAW IN ENERGY-BASED ALLOCATION METHODOLOGIES?**

A Yes. The Public Utility Commission of Texas (PUCT) has recognized the double-counting problem in numerous cases. For example:

> As to double-counting energy, the flaw in Dr. Johnson's proposal is the fact that the allocator being used to allocate peak demand, and 50% of the intermediate demand, includes with it an energy component. Dr. Johnson has elected to use a 4CP demand allocator, but such an allocator, because it looks at peak usage, necessarily includes within that peak usage average usage, or energy.
>
> * * *
>
> A substantial portion of average demand is being utilized in two different allocators, and this "double-dipping" is taking place. (El

Paso Electric Company, *Examiner's Report*, Docket No. 7460, at 193)

**Q SHOULD THE COMMISSION RETAIN THE 12CP-1/13TH AD METHOD?**

A Yes. While the 12CP-1/13th AD method does not reflect cost-causation because of FPL's seasonal load characteristics and the fact that reserve margins are much tighter during the summer months, the Commission has traditionally used this method as a reasonable basis to allocate costs to rate classes. Despite its flaws, this method does recognize the role that load duration plays in determining production plant costs. Thus, it is more compatible with system planning principles than peak and average methods, which not only place greater emphasis on average demand, but are flawed because peak demand is double-counted.

If faced with a choice between retaining 12CP-1/13$^{th}$ AD or using a method that gives more weight to AD, the Commission should adopt the A&E method. A&E accomplishes the first objective (*i.e.,* placing greater emphasis on average demand) while avoiding the fatal double-counting problem associated with flawed peak and average methods.

## 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 PLEASE EXPLAIN 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-of-service should be made gradually rather than all at once because it would result in rate shock to the affected customers.

Q PLEASE EXPLAIN HOW RATE ADMINISTRATION IS RELATED TO RATE CHANGE.

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 its General Service Demand rates.

**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 a 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 recent TECO 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. (Docket No. 080317–EI, *Order No. PSC-09-0283-FOF-EI,* Issued: April 30, 2009 at 86-87, footnote omitted).

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

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

A FPL's proposed base revenue increase is shown in **Exhibit JP-9**. The General Service Demand rates are shown in groups based on applicability. The groups are:

| Group | Rate Schedules |
|---|---|
| General Service Demand | GSD, GSDT, HLFT-1, SDTR-1; |
| General Service Large Demand-1 | GSLD-1, GSLDT-1, CS-1, CST-1, HLFT-2, SDTR-2; |
| General Service Large Demand-2 | GSLD-2, GSLDT-2, CS-2, CST-2, HLFT-3, SDTR-3; |
| General Service Large Demand-3 | GSLD-3, GSLDT-3. |

As can be seen in **Exhibit JP-9**, FPL is proposing a 25.0% base rate increase. The increases by class would range from 2.0% for standby service to a 57.6% increase for the CILC rate class.

**Q IS FPL'S PROPOSED CLASS REVENUE ALLOCATION CONSISTENT WITH THIS COMMISSION'S PRACTICES?**

A No. The proposed increases for the CILC, General Service Large Demand-1, and General Service Large Demand-2 groups exceed 150% of the system average increase. This is clearly contrary to this Commission's practice and precedents and should be rejected.

Q **DID THE COMMISSION RECENTLY ADDRESS CLASS REVENUE ALLOCATION?**

A Yes. The Commission recently addressed class revenue allocation in the TECO rate case. As previously cited, the Commission followed its past practices by limiting the lighting class increase to 150% of the system average retail base rate increase, excluding cost recovery clauses.

Q **SHOULD THE COMMISSION IGNORE GRADUALISM BECAUSE FPL PROJECTS A REDUCTION IN FUEL COSTS?**

A No. FPL has calculated bill impacts in MFR Schedule A-1 based on an assumed reduction in fuel charges. While a reduction is possible given the continued decline in natural gas prices since last summer and because FPL is installing more efficient generation, fuel costs are a function of commodity (e.g., coal, natural gas, and oil) prices, market energy prices, and FPL's generation mix, all of which are subject to (sometimes volatile) changes from time-to-time. These changes have nothing to do whatsoever with setting base rates as they are recovered annually outside of any rate case proceeding. Further, gradualism is not a consideration in setting the cost recovery clauses. Thus, a sudden increase in natural gas prices will not affect how base rates are determined in this case.

The Commission should continue to 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 changes should not be considered in setting base rates.

Q **HOW SHOULD ANY RATE INCREASE OR DECREASE RESULTING FROM THIS CASE BE ALLOCATED AMONG CUSTOMER CLASSES?**

A Consistent with Commission policy and precedent, rates for each class should be set at a level that will recover the cost of serving that class, subject to the policy that no class should receive an increase greater than 150% of the retail average base rate increase. This is reflected in **Exhibit JP-10** using FPL's proposed 2010 revenue requirement. However, as I noted earlier, this illustration is not an endorsement of the revenue requirement requested.

Specifically, the increases to the CILC, General Service Large Demand-1, and General Service Large Demand-2 rate groups were limited to 150% of the system average, while no class received a decrease. The remaining revenue shortfall was spread to those classes that would receive below-average base rate increases to move them equally toward cost.

Q **WOULD YOUR RECOMMENDED REVENUE ALLOCATION MOVE ALL CLASSES CLOSER TO COST?**

A Yes. This is shown in **Exhibit JP-11**, which shows the cost-of-service study results under my recommended class revenue allocation. All but one class (due to the 150% constraint) would be moved closer to cost. For the remaining classes, the movement toward cost would range from 9% to 33%.

## 7. RATE DESIGN

**Q WHAT RATE DESIGN ISSUES WILL YOU ADDRESS?**

A In this section, I will discuss the appropriate design of the firm and non-firm rates. Specifically, I will discuss:

- Demand and Non-Fuel Energy charges;
- The design of Rate CILC (Commercial/Industrial Load Control Program); and
- The credits paid under the Commercial/Industrial Demand Reduction Rider (CDR).

<u>Demand and Non-Fuel Energy Charges</u>

**Q DESCRIBE THE DEMAND AND NON-FUEL 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 non-fuel energy charges are billed on the kWh purchased.

**Q DO YOU AGREE WITH HOW FPL HAS PROPOSED TO DEVELOP THE DEMAND AND NON-FUEL ENERGY CHARGES?**

A No. Consistent with cost-causation, FPL's demand-related costs should be recovered through the demand charge and energy-related base rate costs should be collected through the energy charge. However, FPL's proposed General Service Demand rate designs do not follow this practice. Specifically, FPL has underpriced the demand charge and overpriced the energy charge (based on FPL's proposed revenue levels, which I do not endorse but have used for illustrative purposes). The demand and non-fuel energy charges should closely reflect the corresponding demand and non-fuel energy related costs as derived in the class cost-of-service study.

**Q WHAT ARE THE UNIT DEMAND AND ENERGY COSTS DERIVED FROM FPL'S CLASS COST-OF-SERVICE STUDY?**

A The 2010 unit costs for the General Service Demand class are as follows:

| | |
|---|---|
| **Demand Unit Cost** | $11.95 per kW-Month |
| **Non-Fuel Energy Unit Cost** | 0.715¢ per kWh |

The proposed standard rates are as follows:

| Rate | Demand Charge | Non-Fuel Energy Charge |
|---|---|---|
| **GSLD-1** | $10.45 | 1.506¢ |
| **GSLD-2** | $10.45 | 1.337¢ |

As can be seen, the proposed non-fuel energy charges are 87% and 111% higher than the corresponding non-fuel energy costs. The proposed time-of-use (TOU), High Load Factor (HLFT), and Seasonal (SDTR) rates, which are derived from the standard rates, exhibit similar tendencies:

| Rate | Equivalent Demand Charge | Non-Fuel Energy Charge | |
|---|---|---|---|
| | | On-Peak | Off-Peak |
| **GSLDT-1** | $10.45 | 2.488¢ | 1.072¢ |
| **HLFT-2** | $12.03 | 2.300¢ | 0.794¢ |
| **SDTR-2** | $10.44 | 6.028¢ | 1.037¢ |
| **GSLDT-2** | $10.45 | 2.371¢ | 0.954¢ |
| **HLFT-3** | $12.05 | 2.080¢ | 0.743¢ |
| **SDTR-3** | $10.35 | 4.665¢ | 0.921¢ |

And finally, the proposed Rate CILC energy charges are also above cost, as shown below. However, as explained later, this is the result of a different rate design issue.

| Rate | Non-Fuel Energy Costs | Non-Fuel Energy Charge |
|---|---|---|
| CILC-D | 0.710¢ | 1.506¢ |
| CILC-T | 0.688¢ | 1.267¢ |

**Q HAS FPL EXPLAINED WHY THE NON-FUEL ENERGY CHARGES ARE MUCH HIGHER THAN ACTUAL ENERGY COSTS?**

A No.

**Q HOW SHOULD THE GENERAL SERVICE DEMAND RATES BE DESIGNED?**

A The proposed CILC non-fuel energy charges would exceed unit costs. Accordingly, they should be scaled back to reflect cost, while the Demand charges should be correspondingly increased to recover the target revenues assigned to the CILC class.

**Q DO YOU HAVE ANY OTHER CONCERNS WITH THE PROPOSED GENERAL SERVICE RATE DESIGN?**

A Yes. The HLFT rates were designed for higher load factor customers. The average load factors for HLFT customers are about 80% as compared to only 64% for GSLDT customers. However, the proposed rates would make HLFT more expensive than GSLDT unless the customer can achieve load factors above 84% for HLFT-2 and over 100% for HLFT-3. The latter requirement is impractical, and it would result in customers migrating back to Rate GSLDT-2.

**Q HOW SHOULD THIS CONCERN BE RESOLVED?**

A The HLFT rates are a derivative of the GSLDT rates. Thus, it is essential to maintain a consistent relationship between GSLDT and HLFT to prevent customer migration. Therefore, I recommend that the HLFT rates be designed for customers with load factors above 70%. Blending the rates at a 70% load factor reflects the HLFT class' characteristics, and further, I believe it would be consistent with encouraging customers to improve load factor.

<u>CILC Rate Design</u>

**Q WHAT CONCERNS DO YOU HAVE WITH THE DESIGN OF THE CILC RATES?**

A The CILC rates have been designed to recover this class' cost of service. As explained above, the CILC non-fuel energy charges are significantly above the corresponding non-fuel energy costs. Yet, the demand charges are set to reflect unit demand costs. Thus, there is a rate design problem. If the rate is designed to recover actual cost, then both the demand and energy charges should reflect the corresponding per unit demand and energy costs.

**Q WHAT IS CAUSING THIS RATE DESIGN PROBLEM?**

A The problem is with the level of CILC payments included in the rate design for this class. Specifically, while FPL calculated the CILC base revenue requirements as the difference between the allocated firm cost of service (which assumed CILC customers receive firm service) and the following assumed level of incentive payments shown in the chart below (approximately $30.6 million), it did not use the same assumptions in its rate design. Rather, for rate design purposes, FPL used approximately $53 million as the amount of incentive payments and allocated the $22 million difference directly to CILC.

As the chart shows, the payments used in the rate design are much higher than those used to calculate the class' base revenue requirements:

| Rate | CILC Payments Embedded in the Proposed Rate Design | | | CILC Payments Assumed in Determining Class Revenue Requirements ($ Millions) |
|---|---|---|---|---|
| | Firm On-Peak - Load Control Charge ($/kW) | Load Control Billing Demand (MW) | Embedded CILC Payments ($ Millions) | |
| CILC-D | $7.26 | 4,942.9 | $35.9 | $19.7 |
| CILC-G | $6.99 | 395.6 | $2.8 | $1.4 |
| CILC-T | $6.92 | 2,104.7 | $14.5 | $9.5 |
| TOTAL | $21.17 | 7,443.2 | $53.2 | $30.6 |
| Source: Schedule E-14. | | | | |

Because the incentives reflected in the CILC rate design are higher than the incentives FPL used in deriving the CILC revenue requirement, there was a revenue shortfall. FPL seeks to recover this "shortfall" from within the CILC classes by increasing the non-fuel energy charges. This explains why the CILC non-fuel energy charges are higher than the CILC non-fuel energy unit costs.

Q **IS THIS RATE DESIGN APPROPRIATE?**

A No. The CILC payments should be restated to reflect the amounts in FPL's rate design. The $53 million should then be allocated to all customer classes (in the same manner as FPL allocated the estimated payments) in determining class revenue requirements.

## CDR Rider

**Q WHAT IS THE COMMERCIAL/INDUSTRIAL DEMAND REDUCTION RIDER?**

A The CDR Rider is an optional service under which a customer can elect to have its electricity curtailed under a variety of circumstances. The customer is required to have load control equipment installed to provide FPL direct control over the customer's electrical load. Thus, curtailments are made by FPL and not by the customer. This equipment is paid for by the customer through an additional Customer Charge. In return for agreeing to curtail load, the participating customers receive a credit. The current and proposed CDR Rider credit is $4.68 per kW of the Customer's Utility Controlled Demand.

**Q UNDER WHAT CIRCUMSTANCES CAN FPL CURTAIL LOAD UNDER THE CDR RIDER?**

A Load may be curtailed under any of the following circumstances:

> Control Condition:
> 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.

Thus, curtailments may occur during shortages of either generation or transmission capacity.

Q **HOW MUCH NOTICE IS REQUIRED BEFORE FPL CAN CURTAIL A CUSTOMER'S LOAD?**

A The tariff states that FPL will typically provide four hours advance notice. In emergencies, the required notice is 15 minutes. However, FPL reserves the right to interrupt in "less than 15 minutes' notice...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."

Q **HAS FPL MADE SHORT NOTICE CURTAILMENTS?**

A Yes. Since 2005, several curtailments have occurred with only five minutes' notice (*FPL's Response to FIPUG Interrogatory No.10*).

Q **IS THE SERVICE PROVIDED TO CDR RIDER CUSTOMERS THE SAME AS THE SERVICE PROVIDED UNDER FPL'S FIRM TARIFFS?**

A No. CDR Rider customers can be curtailed (on very short notice) to allow FPL to continue serving its firm customers. This includes instances when FPL is short of operating reserves. Further, FPL does not include load management programs in determining its future capacity needs (FPL, *Ten Year Site Plan* at 51 and Schedules 7.1 and 7.2). Thus, CDR Rider customers receive a lower quality of service than firm service customers.

Q **SHOULD THE CDR RIDER CREDIT REMAIN AT $4.68 PER KW?**

A No. The CDR Rider credit has not changed since 2004. However, costs for new generation and transmission capacity, upon which the CDR Rider is based, have increased since 2004. These higher costs are reflected in FPL's most recent *Ten Year Site Plan*. For example, WCEC Units 1 and 2 are projected to cost

\$512/kW based on 2009 in-service dates. However, WCEC-3 (2011 in-service date) is projected to cost over \$780/kW, while subsequent CC capacity additions are projected to cost over \$1,000/kW.

Further, load management is an important resource for the state of Florida. Interruptible tariffs have been in place for decades. In fact, FPL is projecting significant growth in non-firm load. Thus, this load has been and is projected to be a valuable resource to FPL and to the state as a whole. When capacity is needed to serve firm load customers, interruptible customers, statewide, may be called upon (with or without notice and without limitation as to the frequency and duration of curtailments) to discontinue service so that the lights will stay on for the firm customer base. Such interruptions often cause production to be shut down resulting in losses for the interruptible customer.

**Q HOW CAN THE COMMISSION NURTURE THIS VALUABLE RESOURCE?**

A The Commission should increase the CDR Rider credit to at least \$5.50/kW. This modest increase would allow the Rider to remain a viable non-firm rate option and encourage greater participation.

**Q HOW DID YOU DETERMINE THAT THE CDR RIDER CREDIT SHOULD BE INCREASED TO AT LEAST \$5.50/KW?**

A My recommendation is based on FPL's most recent Standard Offer filing (Docket No. 090166, filed April 1, 2009). FPL has conservatively assumed that its next avoided unit will not come on line until 2021. Thus, I discounted the 2021 avoided capacity cost to the period 2010 through 2012. This is the period in which the rates approved in this proceeding will be in effect.

**Q WHY DO YOU CHARACTERIZE THE $5.50 AS CONSERVATIVE?**

A FPL's avoided unit assumptions are based on projected lower load growth and the timely completion of its Turkey Point Units 6 and 7 in 2018 and 2020, respectively. These units will be among the first advanced design nuclear plants to be commissioned in the United States. No advanced design nuclear plants have been built and placed in operation in the U.S. Thus, there is considerable risk of delay. In fact, PEF recently announced a two-year delay of its planned advanced design nuclear units. These units are of the same design and manufacture as the Turkey Point additions. Any delay in completing these units may require FPL to add capacity sooner than 2021.

**Q DOES THIS CONCLUDE YOUR TESTIMONY?**

A Yes, it does.

# APPENDIX A

## Qualifications of Jeffry Pollock

**Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

A Jeffry Pollock. My business mailing address is 12655 Olive Blvd., Suite 335, 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 in Business Administration from Washington University. At various times prior to graduation, I worked for the McDonnell Douglas Corporation in the Corporate Planning Department; Sachs Electric Company; and L.K. Comstock & Company. While at McDonnell Douglas, I analyzed the direct operating cost of commercial aircraft.

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, Colorado, Delaware, Florida, Georgia, Ilinois, Indiana, Iowa, Louisiana, Minnesota, Mississippi, Missouri, Montana, New Jersey, New Mexico, 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 Bonneville Power Administration, Travis County (Texas) District Court, and the U.S. Federal District Court. A partial list of my appearances is attached hereto.

**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. Currently, J.Pollock has offices in St. Louis, Missouri and Austin and Houston, Texas.

# Appendix A
## Testimony Filed in Regulatory Proceedings
## <u>by Jeffry Pollock</u>

| PROJECT | UTILITY | ON BEHALF OF | Docket | TYPE | Regulatory Jurisdiction | Subject | DATE |
|---|---|---|---|---|---|---|---|
| 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 |
| 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 | Cross Rebuttal | GA | Cost allocation, Demand Ratchet Waivers | 12/22/2008 |
| 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 |

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| PROJECT | UTILITY | ON BEHALF OF | Docket | TYPE | Regulatory Jurisdiction | Subject | DATE |
|---|---|---|---|---|---|---|---|
| 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 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 |
| 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 |
| 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 | 3/20/2008 |
| 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 |

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|---|---|---|---|---|---|---|---|
| 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 |
| 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, | 12/17/2006 |
| 60503 | SOUTHWESTERN PUBLIC SERVICE COMPANY | Texas Industrial Energy Consumers | 32766 | Direct | TX | Fuel Reconcilation | 12/17/2006 |
| 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 | 09/07/06 |
| 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 |

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| PROJECT | UTILITY | ON BEHALF OF | Docket | TYPE | Regulatory Jurisdiction | Subject | DATE |
|---|---|---|---|---|---|---|---|
| 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.<br>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<br>Retail Energy Supply Association | BPU EM05020106<br>OAL PUC-1874-05 | Surrebuttal | NJ | Merger | 12/22/2005 |
| 50705 | SOUTHWESTERN PUBLIC SERVICE COMPANY | Occidental Periman Ltd.<br>Occidental Power Marketing | EL05-19-002;<br>ER05-168-001 | Responsive | FERC | Fuel Cost adjustment clause (FCAC) | 11/18/2005 |
| 50601 | PUBLIC SERVICE ELECTRIC AND GAS COMPANY AND EXELON CORPORATION | New Jersey Large Energy Consumers<br>Retail Energy Supply Association | BPU EM05020106<br>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.<br>Occidental Power Marketing | EL05-19-002;<br>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.<br>Occidental Power Marketing | EL05-19-00;<br>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 |

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|---|---|---|---|---|---|---|---|
| 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 |
| 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 |

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|---|---|---|---|---|---|---|---|
| 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 |
| 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 |

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|---|---|---|---|---|---|---|---|
| 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 |

# Appendix A
# Testimony Filed in Regulatory Proceedings
# by Jeffry Pollock

| PROJECT | UTILITY | ON BEHALF OF | Docket | TYPE | Regulatory Jurisdiction | Subject | DATE |
|---|---|---|---|---|---|---|---|
| 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 | 1/1/1994 |

## Appendix A
## Testimony Filed in Regulatory Proceedings
## by Jeffry Pollock

| PROJECT | UTILITY | ON BEHALF OF | Docket | TYPE | Regulatory Jurisdiction | Subject | DATE |
|---|---|---|---|---|---|---|---|
| 5971 | FLORIDA POWER & LIGHT COMPANY | Florida Industrial Power Users Group | 940042-EI | Direct | FL | Section 712 Standards of 1992 EPACT | 1/1/1994 |

Docket No. 080677-EI
Life Spans
Exhibit JP-1

# FLORIDA POWER & LIGHT COMPANY
## Estimated Impact of Revised Life Spans on Depreciation Expense
## Based on Original Cost of Electric Plant at December 31, 2009

| | | Year | FPL Proposed | | | Recommended | | | |
|---|---|---|---|---|---|---|---|---|---|
| Line | Plant Name | In-Service | Retirement | Life Span | Accrual | Retirement | Life Span | Accrual | Reduction |
| | | (1) | (2) | (3) | (4) | (5) | (6) | (7) | (8) |
| | **Steam - Coal Plants** | | | | | | | | |
| 1 | SJRPP | 1987 | 2028 | 41 | $12,157,102 | 2042 | 55 | $7,638,406 | $4,518,696 |
| 2 | Scherer | 1989 | 2029 | 40 | 15,126,450 | 2044 | 55 | 9,162,053 | 5,964,397 |
| 3 | **Total Steam - Coal Plant** | | | | $27,283,552 | | | $16,800,459 | $10,483,093 |
| | **Combined Cycle Plants** | | | | | | | | |
| 4 | Lauderdale | 1993 | 2020 | 27 | 25,656,797 | 2028 | 35 | 16,440,754 | 9,216,043 |
| 5 | Martin 8 | 2005 | 2030 | 25 | 21,027,815 | 2041 | 36 | 13,951,712 | 7,076,103 |
| 6 | Martin | 1994 | 2020 | 26 | 25,650,493 | 2029 | 35 | 15,603,918 | 10,046,575 |
| 7 | Sanford 4 | 2002 | 2028 | 26 | 39,428,523 | 2037 | 35 | 26,291,768 | 13,136,755 |
| 8 | Putnam | 1977 | 2020 | 43 | 9,544,913 | 2020 | 43 | 9,544,913 | 0 |
| 9 | Fort Myers | 2002 | 2028 | 26 | 35,039,946 | 2037 | 35 | 24,020,992 | 11,018,954 |
| 10 | Manatee | 2005 | 2030 | 25 | 22,550,959 | 2040 | 35 | 15,485,344 | 7,065,615 |
| 11 | Turkey Point | 2007 | 2032 | 25 | 25,179,803 | 2042 | 35 | 18,167,920 | 7,011,883 |
| 12 | West County Unit 1 and 2 | 2009 | 2034 | 25 | 66,656,862 | 2044 | 35 | 46,770,311 | 19,886,551 |
| 13 | **Total Combined Cycle** | | | | $270,736,111 | | | $186,277,632 | $84,458,479 |
| 14 | **Total Existing Plants** | | | | $298,019,663 | | | $203,078,091 | $94,941,572 |
| | **Future Combined Cycle Plants** | | | | | | | | |
| 15 | West County Unit 3 | 2011 | 2036 | 25 | $42,896,499 | 2046 | 35 | $30,098,666 | $12,797,833 |

**Table XIII**

## QUALITY MEASURES-UTILITY OPERATING COMPANIES

| | | CAPITAL STRUCTURE RATIOS* | | | | | | | | | | | | | | | | Credit Ratings | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | As of: 3/31/2009 | | | | As of: 12/31/2008 | | | | As of: 12/31/2007 | | | | As of: 12/31/2006 | | | | | | |
| Line | Company | LTD (%) | STD (%) | Prfd (%) | Com Equity (%) | LTD (%) | STD (%) | Prfd (%) | Com Equity (%) | LTD (%) | STD (%) | Prfd (%) | Com Equity (%) | LTD (%) | STD (%) | Prfd (%) | Com Equity (%) | Moody's | Fitch Ratings | S&P |
| 1 | AEP Texas Central Company | 78.6 | 5.3 | 0.2 | 15.9 | 77.6 | 7.2 | 0.2 | 15.0 | 82.1 | 4.3 | 0.2 | 13.5 | 85.7 | 2.3 | 0.2 | 11.8 | Baa2 | BBB | BBB |
| 2 | AEP Texas North Company | 50.7 | 4.5 | 0.3 | 44.4 | 51.0 | 4.0 | 0.3 | 44.6 | 42.3 | 5.3 | 0.4 | 52.0 | 46.0 | 1.5 | 0.4 | 52.2 | Baa2 | BBB+ | BBB |
| 3 | Alabama Power Company | 51.2 | 2.1 | 5.7 | 40.9 | 49.1 | 2.4 | 6.0 | 42.5 | na | na | na | na | 43.3 | 8.2 | 6.4 | 42.1 | A2 | A | A |
| 4 | Appalachian Power Company | 55.3 | 4.4 | 0.3 | 39.9 | 52.5 | 6.0 | 0.3 | 41.2 | 49.9 | 9.9 | 0.3 | 39.8 | 48.6 | 7.7 | 0.4 | 43.3 | Baa2 | BBB | BBB |
| 5 | Arizona Public Service Company | 49.2 | 3.5 | 0.0 | 47.3 | 42.5 | 7.8 | 0.0 | 49.7 | 44.6 | 3.4 | 0.0 | 52.0 | 47.3 | 0.0 | 0.0 | 52.7 | Baa2 | BBB- | BBB- |
| 6 | Atlantic City Electric Company | 63.5 | 3.5 | 0.4 | 32.6 | 62.9 | 3.4 | 0.4 | 33.3 | 58.0 | 9.1 | 0.4 | 32.6 | 63.3 | 4.7 | 0.4 | 31.6 | Baa1 | BBB | BBB |
| 7 | Baltimore Gas and Electric Company | 49.0 | 10.3 | 4.2 | 36.1 | 49.9 | 10.4 | 4.7 | 34.9 | 45.3 | 9.1 | 4.6 | 40.6 | 41.2 | 7.2 | 5.7 | 45.9 | Baa2 | | |
| 8 | Carolina Power & Light Company | 46.3 | 0.0 | 0.0 | 53.0 | 44.1 | 1.4 | 0.7 | 53.8 | 42.8 | 6.1 | 0.8 | 50.3 | 48.8 | 2.8 | 0.8 | 47.5 | A3 | A- | BBB+ |
| 9 | CenterPoint Energy Houston Electric, LLC | 70.9 | 3.3 | 0.0 | 25.8 | 70.3 | 3.3 | 0.0 | 26.4 | 63.7 | 2.6 | 0.0 | 33.7 | 66.4 | 2.4 | 0.0 | 31.2 | Baa3 | BBB | BBB |
| 10 | Central Hudson Gas & Electric Corp | 48.1 | 4.6 | 2.4 | 44.8 | 48.5 | 5.3 | 2.5 | 43.7 | 49.6 | 5.2 | 2.6 | 42.6 | 46.4 | 6.3 | 2.9 | 44.4 | A2 | A- | A |
| 11 | Central Illinois Light Company | 26.2 | 5.2 | 1.8 | 66.8 | 23.3 | 19.7 | 1.6 | 55.5 | 14.5 | 30.5 | 1.7 | 53.3 | 18.0 | 23.5 | 2.1 | 56.4 | Ba1 | BBB | BBB- |
| 12 | Central Illinois Public Service Company | 44.0 | 0.0 | 5.2 | 50.7 | 41.6 | 6.1 | 4.9 | 47.3 | 41.0 | 12.6 | 4.5 | 42.0 | 44.9 | 3.3 | 4.8 | 47.0 | Ba1 | BBB- | BBB- |
| 13 | Cilcorp Inc | 48.0 | 20.7 | 0.0 | 29.5 | 31.2 | 24.0 | 1.1 | 43.7 | 30.6 | 28.8 | 1.1 | 39.6 | 36.9 | 17.5 | 1.3 | 44.3 | | BBB- | BBB- |
| 14 | Cleco Power LLC | 52.1 | 2.9 | 0.0 | 45.0 | 52.0 | 3.1 | 0.0 | 44.9 | 48.5 | 0.0 | 0.0 | 51.5 | 42.7 | 4.1 | 0.0 | 53.2 | | | BBB |
| 15 | Cleveland Electric Illuminating Company | 45.1 | 11.3 | 0.0 | 43.0 | 44.5 | 10.6 | 0.0 | 44.9 | 39.6 | 20.0 | 0.0 | 40.4 | 50.0 | 9.4 | 0.0 | 40.7 | Baa3 | BB+ | BBB |
| 16 | Columbus Southern Power Company | 46.9 | 9.7 | 0.0 | 43.4 | 52.3 | 2.8 | 0.0 | 44.9 | 46.4 | 8.2 | 0.0 | 45.4 | 53.2 | 0.2 | 0.0 | 46.7 | A3 | BBB+ | BBB |
| 17 | Commonwealth Edison Company | 41.4 | 1.5 | 0.0 | 57.1 | 41.9 | 0.7 | 0.0 | 57.4 | 37.5 | 6.6 | 0.0 | 55.9 | 37.8 | 4.7 | 0.0 | 57.5 | Baa3 | BB+ | |
| 18 | Connecticut Light and Power Company | 54.1 | 2.2 | 2.2 | 41.6 | 51.2 | 5.6 | 2.2 | 41.0 | 56.4 | 0.9 | 2.5 | 40.2 | 58.3 | 6.7 | 3.0 | 32.0 | Baa1 | BBB | BBB |
| 19 | Consolidated Edison Company of New York | 48.8 | 2.5 | 1.1 | 47.6 | 46.1 | 4.0 | 1.2 | 48.7 | 44.0 | 5.1 | 1.3 | 49.5 | 47.5 | 2.3 | 1.5 | 48.7 | A3 | BBB+ | A- |
| 20 | Consumers Energy Company | 53.6 | 2.4 | 0.5 | 43.5 | 49.7 | 4.9 | 0.5 | 44.8 | 48.5 | 5.8 | 0.5 | 45.1 | 57.4 | 1.2 | 0.6 | 40.8 | | BBB- | BBB- |
| 21 | Dayton Power and Light Company | 36.7 | 6.3 | 1.0 | 56.1 | 37.4 | 0.0 | 1.0 | 61.6 | 38.2 | 0.9 | 1.0 | 59.8 | 38.5 | 0.0 | 1.1 | 60.3 | A2 | A- | A- |
| 22 | Delmarva Power & Light Company | 40.9 | 14.7 | 0.0 | 44.4 | 40.7 | 14.6 | 0.0 | 44.7 | 35.0 | 20.4 | 0.0 | 44.5 | 36.8 | 17.4 | 1.2 | 44.6 | Baa2 | BBB+ | BBB |
| 23 | Detroit Edison Company | 53.5 | 4.3 | 0.0 | 42.3 | 57.2 | 2.6 | 0.0 | 40.2 | 52.4 | 9.8 | 0.0 | 37.8 | 57.3 | 5.1 | 0.0 | 37.6 | Baa1 | BBB | BBB |
| 24 | Duke Energy Carolinas, LLC | 46.5 | 2.1 | 0.0 | 51.4 | 48.4 | 1.4 | 0.0 | 50.1 | 37.6 | 7.9 | 0.0 | 54.5 | 44.8 | 2.0 | 0.0 | 53.2 | A3 | | A- |
| 25 | Duke Energy Indiana, Inc. | 52.7 | 2.2 | 0.0 | 45.1 | 48.4 | 4.2 | 0.0 | 47.5 | 45.7 | 3.2 | 0.0 | 51.0 | 47.6 | 6.0 | 0.0 | 46.5 | Baa1 | | A- |
| 26 | Duke Energy Kentucky, Inc. | 42.4 | 0.0 | na | na | 43.0 | 3.5 | 0.0 | 53.5 | 37.9 | 7.0 | 0.0 | 55.1 | 41.9 | 6.5 | 0.0 | 51.6 | | | A- |
| 27 | Duke Energy Ohio, Inc. | 24.6 | 3.3 | 0.0 | 72.2 | 20.9 | 4.2 | 0.0 | 75.0 | 20.9 | 3.6 | 0.0 | 75.5 | 20.8 | 4.4 | 0.0 | 74.8 | Baa1 | | A- |
| 28 | Entergy Arkansas, Inc. | 51.3 | 1.9 | 0.0 | 43.3 | 51.7 | 1.8 | 3.6 | 42.9 | 47.3 | 1.7 | 4.0 | 47.1 | 46.2 | 1.9 | 3.9 | 48.0 | Baa2 | BBB- | BBB |
| 29 | Entergy Gulf States, Inc. | 53.8 | 7.0 | 0.3 | 38.9 | 55.2 | 6.9 | 0.3 | 37.6 | 46.7 | 18.7 | 0.3 | 34.3 | 51.5 | 0.5 | 1.0 | 47.0 | Baa3 | BB+ | BBB |
| 30 | Entergy Louisiana, LLC | 43.6 | 1.8 | 3.1 | 51.5 | 44.9 | 1.2 | 3.2 | 50.7 | 41.9 | 1.6 | 3.6 | 52.9 | 45.0 | 1.5 | 3.8 | 49.8 | Baa2 | BBB- | BBB |
| 31 | Entergy Mississippi, Inc. | 48.6 | 1.7 | 0.0 | 46.2 | 49.5 | 0.1 | 3.6 | 46.9 | 49.8 | 0.1 | 3.6 | 46.5 | 54.3 | 0.0 | 3.4 | 42.2 | Baa3 | BBB- | BBB |

Source: SNL Financial

Table XIII

## QUALITY MEASURES-UTILITY OPERATING COMPANIES

| | | CAPITAL STRUCTURE RATIOS* | | | | | | | | | | | | | | | | Credit Ratings | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | As of: 3/31/2009 | | | | As of: 12/31/2008 | | | | As of: 12/31/2007 | | | | As of: 12/31/2006 | | | | | | |
| Line | Company | LTD | STD | Prfd | Com Equity | LTD | STD | Prfd | Com Equity | LTD | STD | Prfd | Com Equity | LTD | STD | Prfd | Com Equity | Moody's | Fitch Ratings | S&P |
| | | (%) | (%) | (%) | (%) | (%) | (%) | (%) | (%) | (%) | (%) | (%) | (%) | (%) | (%) | (%) | (%) | | | |
| 32 | Entergy New Orleans, Inc. | 54.0 | 0.0 | 0.0 | 42.1 | 54.1 | 0.0 | 3.9 | 41.9 | 54.7 | 6.0 | 3.9 | 35.4 | 50.5 | 11.4 | 4.3 | 33.8 | Ba2 | BB+ | BBB- |
| 33 | Entergy Texas, Inc. | 58.3 | 4.2 | 0.0 | 37.5 | 52.0 | 4.8 | 0.0 | 43.2 | 45.7 | 12.8 | 0.0 | 41.5 | 52.4 | 0.0 | 0.0 | 47.6 | Ba1 | BB+ | BBB |
| 34 | Florida Power & Light Company | 39.8 | 5.0 | 0.0 | 55.2 | 36.8 | 7.2 | 0.0 | 56.0 | 37.3 | 8.1 | 0.0 | 54.6 | 34.0 | 5.1 | 0.0 | 60.9 | A1 | A | A |
| 35 | Florida Power Corporation | 50.4 | 7.4 | 0.4 | 41.8 | 53.1 | 5.4 | 0.4 | 41.0 | 44.9 | 8.3 | 0.5 | 46.3 | 47.3 | 1.7 | 0.6 | 50.4 | A3 | A- | BBB+ |
| 36 | Georgia Power Company | 47.5 | 4.3 | 1.7 | 46.5 | 47.4 | 4.3 | 1.8 | 46.5 | 43.8 | 6.7 | 2.0 | 47.5 | 42.5 | 8.5 | 0.4 | 48.6 | A2 | A | A |
| 37 | Gulf Power Company | 46.4 | 3.3 | 4.7 | 45.6 | 44.3 | 7.7 | 5.1 | 42.9 | 45.9 | 2.8 | 6.1 | 45.3 | 46.3 | 8.0 | 3.6 | 42.1 | A2 | A- | A |
| 38 | Hawaiian Electric Company, Inc. | 41.9 | 1.4 | 1.0 | 55.1 | 41.7 | 1.9 | 1.6 | 54.8 | 43.0 | 1.4 | 1.7 | 53.9 | 40.9 | 6.0 | 1.8 | 51.2 | Baa1 | | BBB |
| 39 | Idaho Power Co. | 48.2 | 6.9 | 0.0 | 44.9 | 46.1 | 7.6 | 0.0 | 46.4 | 47.7 | 5.8 | 0.0 | 46.5 | 43.8 | 6.5 | 0.0 | 49.7 | Baa1 | BBB | BBB |
| 40 | Illinois Power Company | 42.2 | 9.2 | 1.7 | 46.9 | 43.4 | 9.4 | 1.7 | 45.5 | 39.7 | 9.0 | 1.8 | 49.4 | 37.0 | 5.4 | 2.0 | 55.7 | Ba1 | BBB- | BBB- |
| 41 | Indiana Michigan Power Company | 55.4 | 1.9 | 0.2 | 42.4 | 41.9 | 15.4 | 0.2 | 42.5 | 48.0 | 7.5 | 0.3 | 44.3 | 51.3 | 5.3 | 0.3 | 43.2 | Baa2 | BBB- | BBB |
| 42 | Interstate Power & Light Company | 36.0 | 7.7 | 7.7 | 48.6 | 36.3 | 7.5 | 7.8 | 48.5 | 40.0 | 1.7 | 9.7 | 48.7 | 35.6 | 5.4 | 8.0 | 50.9 | A3 | | BBB+ |
| 43 | Jersey Central Power & Light Co. | 41.5 | 0.7 | 0.0 | 57.9 | 34.7 | 3.4 | 0.0 | 61.9 | 32.9 | 3.3 | 0.0 | 63.7 | 28.1 | 4.7 | 0.0 | 67.2 | Baa2 | BBB | BBB |
| 44 | Kansas City Power & Light | 48.8 | 5.7 | 0.0 | 45.4 | 40.8 | 11.2 | 0.0 | 47.9 | 35.2 | 12.9 | 0.0 | 51.9 | 24.1 | 20.9 | 0.0 | 54.9 | Baa1 | | BBB |
| 45 | Kentucky Power Company | 42.9 | na | na | 41.0 | 44.2 | 13.9 | 0.0 | 41.9 | 49.0 | 5.9 | 0.0 | 45.2 | 14.9 | 41.6 | 0.0 | 43.5 | Baa2 | BBB- | BBB |
| 46 | Metropolitan Edison Company | 33.7 | 17.9 | 0.0 | 48.4 | 28.4 | 16.2 | 0.0 | 55.4 | 28.9 | 15.2 | 0.0 | 55.9 | 31.0 | 11.0 | 0.0 | 58.0 | Baa2 | BBB- | BBB |
| 47 | Mississippi Power Company | 42.3 | 0.1 | 2.8 | 54.8 | 33.5 | 6.1 | 3.0 | 57.5 | 30.0 | 1.2 | 3.5 | 65.3 | 29.2 | 5.4 | 3.4 | 61.9 | A1 | A+ | A |
| 48 | Nevada Power Company | 58.2 | 0.1 | 0.0 | 41.6 | 56.2 | 0.1 | 0.0 | 43.6 | 51.5 | 0.2 | 0.0 | 48.4 | 52.2 | 0.1 | 0.0 | 47.7 | Ba3 | BB | BB |
| 49 | Northern States Power Company - MN | 44.0 | 4.1 | 0.0 | 52.0 | 44.5 | 5.2 | 0.0 | 50.3 | 43.8 | 6.1 | 0.0 | 50.1 | 45.9 | 1.8 | 0.0 | 52.3 | A3 | A- | BBB+ |
| 50 | Northern States Power Company - WI | 43.9 | 0.1 | 0.0 | 56.0 | 48.6 | 0.1 | 0.0 | 51.3 | 28.0 | 16.6 | 0.0 | 55.4 | 39.0 | 3.8 | 0.0 | 57.1 | | A- | A- |
| 51 | NSTAR Electric Company | 41.4 | 8.9 | 1.0 | 48.6 | 40.3 | 10.8 | 1.0 | 47.9 | 45.1 | 8.7 | 1.1 | 45.1 | 42.8 | 10.2 | 1.1 | 45.9 | A1 | A+ | A+ |
| 52 | Ohio Edison Company | 44.5 | 3.3 | 0.0 | 51.8 | 44.5 | 4.1 | 0.0 | 51.4 | 30.0 | 13.8 | 0.0 | 56.2 | 33.2 | 8.2 | 0.0 | 58.6 | Baa2 | BBB- | BBB |
| 53 | Ohio Power Company | 50.3 | 6.7 | 0.3 | 42.4 | 52.7 | 3.9 | 0.3 | 42.8 | 53.1 | 3.1 | 0.3 | 43.2 | 51.7 | 4.5 | 0.7 | 43.1 | | BBB | BBB |
| 54 | Oklahoma Gas and Electric Company | 44.6 | 2.6 | 0.0 | 52.8 | 45.6 | 0.5 | 0.0 | 53.9 | 32.2 | 13.3 | 0.0 | 54.4 | 37.2 | 4.5 | 0.0 | 58.3 | A2 | A+ | BBB+ |
| 55 | Orange and Rockland Utilities, Inc. | 41.9 | 9.7 | 0.0 | 48.4 | 47.6 | 0.3 | 0.0 | 52.1 | 48.3 | 5.4 | 0.0 | 46.4 | 51.2 | 6.6 | 0.0 | 42.3 | Baa1 | A- | A- |
| 56 | Pacific Gas and Electric Company | 49.0 | 3.5 | 1.2 | 46.4 | 48.7 | 6.0 | 1.2 | 44.0 | 49.4 | 4.7 | 1.3 | 44.7 | 48.2 | 7.7 | 1.4 | 42.6 | A3 | A- | BBB+ |
| 57 | PECO Energy Company | 49.0 | 9.6 | 1.5 | 39.9 | 52.5 | 7.3 | 1.5 | 38.7 | 48.6 | 15.6 | 1.5 | 34.3 | 63.5 | 6.2 | 1.5 | 28.9 | | BBB+ | |
| 58 | Pennsylvania Electric Company | 30.0 | 24.0 | 0.0 | 46.0 | 31.5 | 21.2 | 0.0 | 47.3 | 37.7 | 10.4 | 0.0 | 51.9 | 23.2 | 9.7 | 0.0 | 67.1 | Baa2 | BBB- | BBB |
| 59 | Portland General Electric Company | 43.3 | 5.0 | 0.0 | 51.7 | 40.7 | 12.1 | 0.0 | 47.3 | 49.9 | 0.0 | 0.0 | 50.1 | 40.6 | 6.4 | 0.0 | 53.0 | Baa2 | | BBB+ |
| 60 | Potomac Electric Power Company | 53.9 | 4.8 | 0.0 | 41.3 | 52.2 | 6.1 | 0.0 | 41.7 | 45.7 | 11.8 | 0.0 | 42.5 | 44.5 | 11.4 | 0.0 | 44.1 | Baa2 | BBB+ | BBB |
| 61 | PPL Electric Utilities Corporation | 37.0 | 14.4 | 8.8 | 39.8 | 36.3 | 16.8 | 8.6 | 38.3 | 38.7 | 13.2 | 9.1 | 38.9 | 39.8 | 16.7 | 8.4 | 35.1 | Baa1 | BBB | A- |
| 62 | Public Service Company of Colorado | 37.5 | 3.3 | 0.0 | 59.2 | 37.5 | 4.0 | 0.0 | 58.6 | 32.3 | 9.8 | 0.0 | 57.9 | 34.6 | 8.9 | 0.0 | 56.5 | Baa1 | BBB+ | BBB+ |
| 63 | Public Service Company of New Hampshire | 56.5 | 2.8 | 0.0 | 40.7 | 57.6 | 2.9 | 0.0 | 39.5 | 60.6 | 1.5 | 0.0 | 37.9 | 62.5 | 2.7 | 0.0 | 34.7 | Baa2 | BBB | BBB |

Source: SNL Financial

**Table XIII**

## QUALITY MEASURES-UTILITY OPERATING COMPANIES

| | | CAPITAL STRUCTURE RATIOS* | | | | | | | | | | | | | | | | Credit Ratings | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | As of: 3/31/2009 | | | | As of: 12/31/2008 | | | | As of: 12/31/2007 | | | | As of: 12/31/2006 | | | | | | |
| Line | Company | LTD | STD | Prfd | Com Equity | LTD | STD | Prfd | Com Equity | LTD | STD | Prfd | Com Equity | LTD | STD | Prfd | Com Equity | Moody's | Fitch Ratings | S&P |
| | | (%) | (%) | (%) | (%) | (%) | (%) | (%) | (%) | (%) | (%) | (%) | (%) | (%) | (%) | (%) | (%) | | | |
| 64 | Public Service Company of New Mexico | 44.3 | 1.6 | 0.0 | 49.5 | na | na | na | na | 25.8 | 22.7 | 0.0 | 51.0 | 40.4 | 10.3 | 0.5 | 48.8 | Baa3 | BB | BB- |
| 65 | Public Service Company of Oklahoma | 52.0 | 3.0 | 0.3 | 44.7 | 48.9 | 7.1 | 0.3 | 43.7 | 58.7 | 0.1 | 0.3 | 40.9 | 50.2 | 5.8 | 0.4 | 43.6 | Baa1 | BBB | BBB |
| 66 | Public Service Electric and Gas Company | 50.3 | 6.2 | 0.9 | 42.5 | 54.6 | 3.0 | 0.9 | 41.4 | 54.5 | 5.8 | 0.9 | 38.7 | 57.3 | 3.8 | 1.0 | 37.9 | Baa1 | BBB+ | BBB |
| 67 | San Diego Gas & Electric Co. | 43.5 | 2.1 | 0.0 | 50.1 | na | na | na | na | na | na | na | na | 43.6 | 3.7 | 2.1 | 50.6 | A2 | A+ | A |
| 68 | Sierra Pacific Power Company | 59.0 | 0.0 | 0.0 | 41.0 | 61.4 | 0.0 | 0.0 | 38.6 | 49.6 | 4.6 | 0.0 | 45.8 | 54.7 | 0.1 | 0.0 | 45.2 | Ba3 | BB | BB |
| 69 | South Carolina Electric & Gas Co. | 51.2 | 2.2 | 1.7 | 43.4 | na | na | na | na | na | na | na | na | na | na | na | na | A3 | BBB+ | BBB+ |
| 70 | Southern California Edison Co. | 39.8 | 11.1 | 5.6 | 41.2 | 43.0 | 11.8 | 7.5 | 37.7 | 38.6 | 3.8 | 10.4 | 47.2 | 42.1 | 3.2 | 10.4 | 44.3 | A3 | A- | BBB+ |
| 71 | Southern Indiana Gas and Electric Company | na | na | na | na | 34.3 | 18.2 | 0.0 | 47.5 | 39.8 | 10.1 | 0.0 | 50.2 | 41.8 | 4.8 | 0.0 | 53.4 | Baa1 | | A- |
| 72 | Southwestern Electric Power Company | 51.4 | 2.2 | 0.2 | 46.2 | 55.1 | 1.0 | 0.2 | 43.7 | 56.2 | 0.8 | 0.2 | 42.7 | 37.8 | 17.4 | 0.4 | 44.4 | | BBB | BBB |
| 73 | Southwestern Public Service Company | 50.0 | 0.0 | 0.0 | 50.0 | 47.2 | 5.1 | 0.0 | 47.6 | 46.0 | 7.3 | 0.0 | 46.7 | 47.8 | 3.1 | 0.0 | 49.1 | Baa1 | BBB | |
| 74 | Tampa Electric Company | 46.6 | 2.5 | 0.0 | 51.0 | 47.1 | 0.9 | 0.0 | 52.0 | 50.2 | 0.8 | 0.0 | 49.0 | 45.5 | 5.8 | 0.0 | 48.7 | BBB | BBB | BBB |
| 75 | Texas-New Mexico Power Company | 40.0 | 5.0 | 0.0 | 55.0 | 0.0 | 43.9 | 0.0 | 56.1 | 22.2 | 20.2 | 0.0 | 57.5 | 44.8 | 0.3 | 0.0 | 54.9 | Baa3 | BB+ | BB- |
| 76 | Toledo Edison Company | 33.9 | 12.0 | 0.0 | 53.8 | 33.6 | 12.5 | 0.0 | 53.9 | 37.8 | 1.7 | 0.0 | 60.5 | 35.0 | 17.9 | 0.0 | 47.0 | Baa3 | BB+ | BBB |
| 77 | Tucson Electric Power Company | 68.4 | 1.6 | 0.0 | 30.0 | 69.8 | 1.4 | 0.0 | 28.8 | 60.7 | 10.4 | 0.0 | 28.9 | 68.6 | 4.3 | 0.0 | 27.0 | Baa3 | BB | BB+ |
| 78 | Union Electric Company | 51.4 | 3.8 | 1.4 | 43.3 | 49.0 | 3.4 | 1.5 | 46.0 | 45.5 | 3.3 | 1.6 | 49.5 | 46.4 | 3.8 | 1.8 | 48.1 | Baa2 | BBB+ | BBB- |
| 79 | Vectren Utility Holdings, Inc. | 44.3 | 4.5 | 0.0 | 51.2 | 41.3 | 10.5 | 0.0 | 48.2 | 41.9 | 15.2 | 0.0 | 42.9 | 43.1 | 12.5 | 0.0 | 44.4 | | | A- |
| 80 | Virginia Electric and Power Company | 45.1 | 5.0 | 1.9 | 48.0 | 46.3 | 3.3 | 2.0 | 48.4 | 45.6 | 4.7 | 2.2 | 47.5 | 32.4 | 16.9 | 2.3 | 48.3 | Baa1 | BBB+ | A- |
| 81 | Western Massachusetts Electric Company | 52.5 | 14.3 | 0.0 | 33.2 | 55.7 | 9.1 | 0.0 | 35.2 | 60.2 | 2.3 | 0.0 | 37.5 | 59.1 | 5.0 | 0.0 | 35.8 | Baa2 | BBB | BBB |
| 82 | Wisconsin Electric Power Company | 50.8 | 3.9 | 0.5 | 44.8 | 52.0 | 0.7 | 0.5 | 46.7 | 39.4 | 7.2 | 0.6 | 52.8 | 37.3 | 11.7 | 0.6 | 50.4 | A1 | A | A- |
| 83 | Wisconsin Power and Light Company | 36.6 | 7.0 | 0.0 | 53.7 | 41.5 | 2.0 | 2.8 | 53.7 | 34.5 | 7.5 | 3.2 | 54.8 | 22.8 | 13.1 | 3.3 | 60.8 | A2 | | A- |
| 84 | Wisconsin Public Service Corp | 41.1 | 0.5 | 2.4 | 56.1 | 40.6 | 2.8 | 2.4 | 54.2 | 37.5 | 3.0 | 2.5 | 56.9 | 34.1 | 3.8 | 2.8 | 59.4 | A2 | | A- |
| 85 | **84 Co. Average** | 47.3 | 5.0 | 0.9 | 46.1 | 45.9 | 6.6 | 1.2 | 46.4 | 43.8 | 7.7 | 1.2 | 47.3 | 44.2 | 6.8 | 1.3 | 47.6 | | | |

Source: SNL Financial

Docket No. 080677-EI
Adjustment
Exhibit JP-3

# FLORIDA POWER & LIGHT COMPANY

## Impact of Capital Structure Adjustment

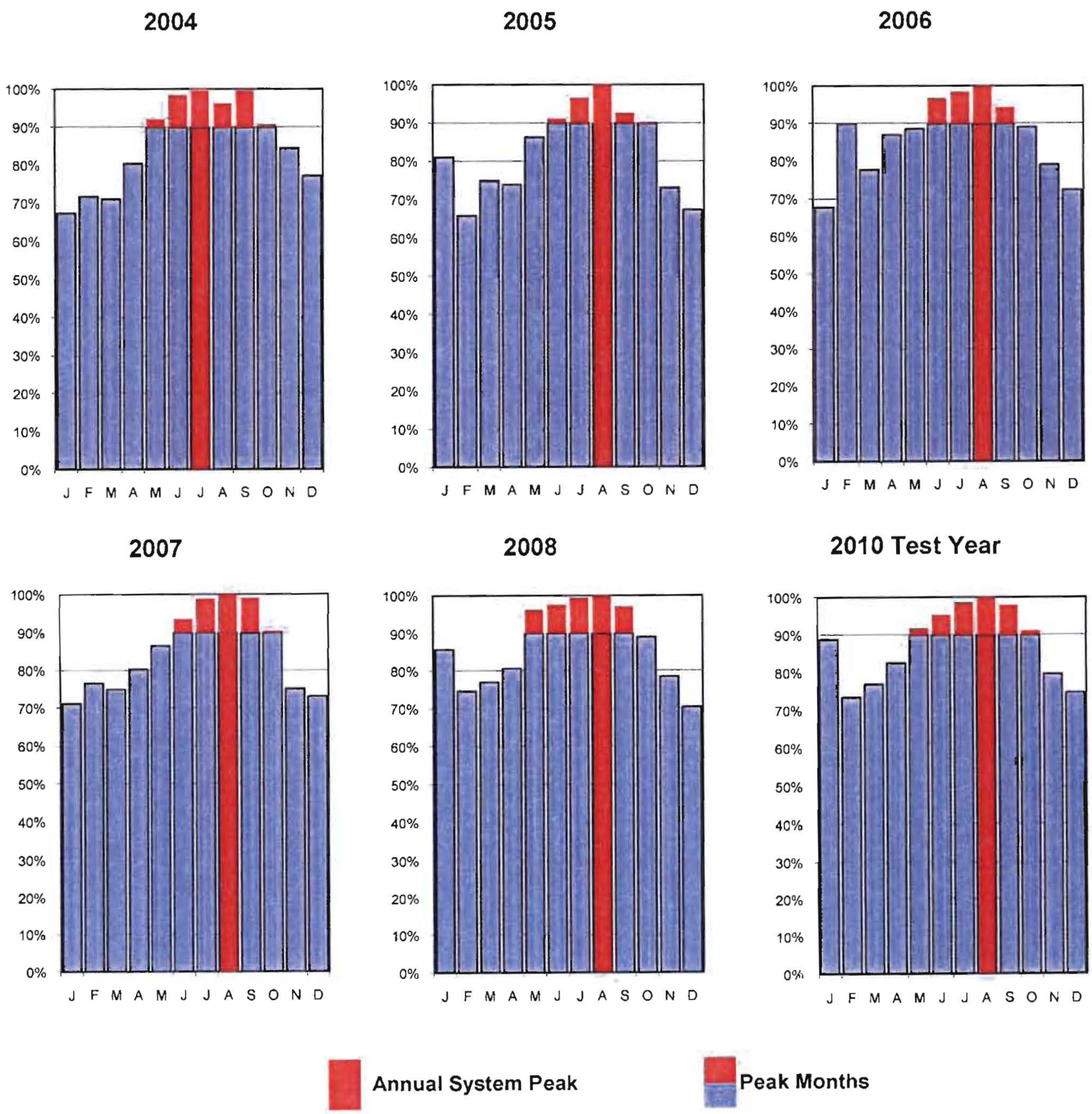
| Line | Class of Capital | Ratio | Cost Rate | Weighted Cost | Pre-Tax Weighted Cost |
|---|---|---|---|---|---|
| | | (1) | (2) | (3) | (4) |
| 1 | Long Term Debt | 39.09% | 5.55% | 2.17% | 2.17% |
| 2 | Preferred Stock | 0.00% | 0.00% | 0.00% | 0.00% |
| 3 | Customer Deposits | 3.31% | 5.98% | 0.20% | 0.20% |
| 4 | Common Equity | 40.36% | 12.50% | 5.04% | 8.24% |
| 5 | Short Term Debt | 0.95% | 2.96% | 0.03% | 0.03% |
| 6 | Deferred Income Tax | 15.96% | 0.00% | 0.00% | 0.00% |
| 7 | Investment Tax Credits | 0.33% | 8.97% | 0.03% | 0.04% |
| 8 | Total | 100.00% | | 7.47% | 10.68% |
| 9 | FPL Proposed | | | | 11.81% |
| 10 | Rate Base (000) | | | | $ 17,063,585 |
| 11 | Impact on Revenue Deficiency (000) | | | | $ 192,924 |

# FLORIDA POWER & LIGHT COMPANY
## Comparison of Capital Expenditures from Form 10Q Reports
## $ in Millions

| Line | Capital Type | Form 10Q Version 6/30/2008 | 9/30/2008 | 3/31/2009 |
|---|---|---|---|---|
| | | (1) | (2) | (3) |
| | **2009 Capital Expenditures** | | | |
| | Generation | | | |
| 1 | New | $1,190 | $1,075 | $1,110 |
| 2 | Existing | $790 | $655 | $545 |
| 3 | Generation Total | $1,980 | $1,730 | $1,655 |
| 4 | Transmission and Distribution | $1,090 | $595 | $445 |
| 5 | Nuclear Fuel | $165 | $165 | $65 |
| 6 | General and Other | $145 | $190 | $150 |
| 7 | Total | $3,380 | $2,680 | $2,315 |
| | **2010 Capital Expenditures** | | | |
| | Generation | | | |
| 8 | New | $910 | $915 | $1,190 |
| 9 | Existing | $675 | $665 | $680 |
| 10 | Generation Total | $1,585 | $1,580 | $1,870 |
| 11 | Transmission and Distribution | $1,130 | $845 | $865 |
| 12 | Nuclear Fuel | $200 | $200 | $205 |
| 13 | General and Other | $230 | $290 | $290 |
| 14 | Total | $3,145 | $2,915 | $3,230 |
| | **2011 Capital Expenditures** | | | |
| | Generation | | | |
| 15 | New | $490 | $510 | $755 |
| 16 | Existing | $575 | $645 | $455 |
| 17 | Generation Total | $1,065 | $1,155 | $1,210 |
| 18 | Transmission and Distribution | $1,180 | $925 | $1,165 |
| 19 | Nuclear Fuel | $175 | $175 | $195 |
| 20 | General and Other | $225 | $315 | $225 |
| 21 | Total | $2,645 | $2,570 | $2,795 |
| | **2012 Capital Expenditures** | | | |
| 22 | Generation | | | |
| 23 | New | $760 | $830 | $340 |
| 24 | Existing | $455 | $610 | $515 |
| 25 | Generation Total | $1,215 | $1,440 | $855 |
| 26 | Transmission and Distribution | $1,150 | $925 | $930 |
| 27 | Nuclear Fuel | $195 | $215 | $220 |
| 28 | General and Other | $215 | $315 | $300 |
| 29 | Total | $2,775 | $2,895 | $2,305 |

Docket No. 080677-EI
Monthly Peak
Demand
Exhibit JP-5


## FLORIDA POWER & LIGHT COMPANY
Analysis of Monthly Peak Demands
As a Percentage of the Annual System Peak
for the Years 2004-2008 and 2010 Test Year



# FLORIDA POWER & LIGHT COMPANY
## Analysis of System Peak Load Characteristics
## 2004-2008 (Actual) and Test Year

| Line | Year | Peak Demand | Minimum Demand | Average Demand | Average Summer Demand | Average Non-Summer Demand | Winter Peak Demand |
|---|---|---|---|---|---|---|---|
| | | (1) | (2) | (3) | (4) | (5) | (6) |
| | | Peak Demand (MW) | | | | | |
| 1 | 2004 | 20,545 | 13,857 | 17,643 | 20,291 | 16,320 | 15,871 |
| 2 | 2005 | 22,361 | 14,738 | 18,509 | 21,273 | 17,128 | 18,108 |
| 3 | 2006 | 21,819 | 14,800 | 18,937 | 21,254 | 17,778 | 19,683 |
| 4 | 2007 | 21,962 | 15,619 | 18,665 | 21,516 | 17,239 | 16,815 |
| 5 | 2008 | 21,060 | 14,849 | 18,373 | 20,758 | 17,180 | 18,055 |
| 6 | 2010 Test Year | 21,147 | 15,533 | 18,525 | 20,727 | 17,424 | 18,790 |

| | | Ratio Analysis | | | | | |
|---|---|---|---|---|---|---|---|
| | | Minimum to Annual Peak | Average to Annual Peak | Avg Summer % More Than Avg Non-Sum | Avg Summer Peak to Peak Demand | Avg Non-Sum Peak to Peak Demand | Annual Load Factor |
| 6 | 2004 | 67% | 86% | 24% | 99% | 79% | 63% |
| 7 | 2005 | 66% | 83% | 24% | 95% | 77% | 62% |
| 8 | 2006 | 68% | 87% | 20% | 97% | 81% | 58% |
| 9 | 2007 | 71% | 85% | 25% | 98% | 78% | 61% |
| 10 | 2008 | 71% | 87% | 21% | 99% | 82% | 61% |
| 11 | Average (Actual) | 69% | 86% | 23% | 98% | 80% | 61% |
| 12 | 2010 Test Year | 73% | 88% | 19% | 98% | 82% | 59% |

*Source: Schedule E-18*

# FLORIDA POWER & LIGHT COMPANY

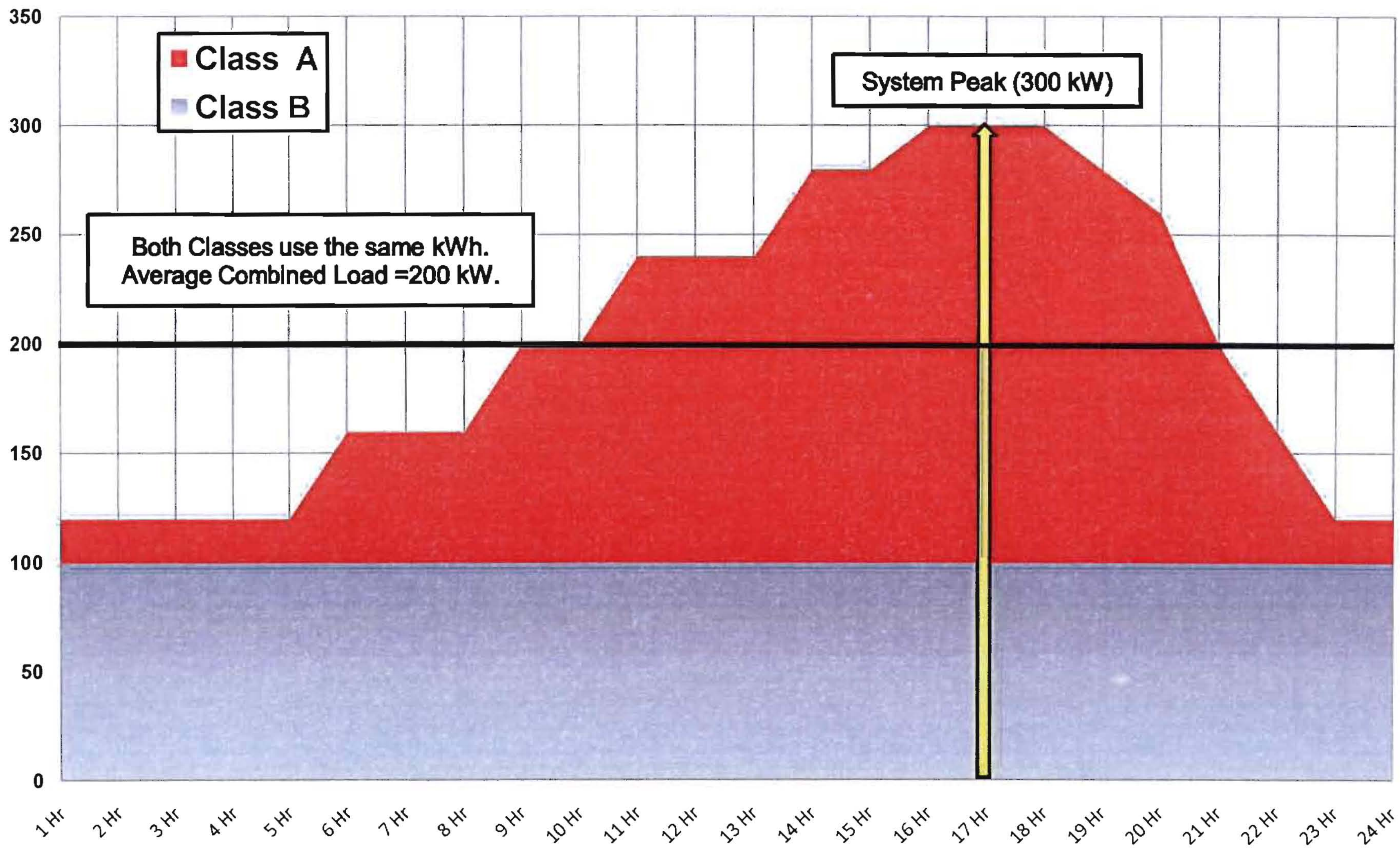
## Reserve Margins as a Percent of Firm Peak Demand

| Line | Year | Data | Average Summer Months | Average Non-Summer Months | Ratio of Summer to Non-Summer Margins |
|---|---|---|---|---|---|
| | | | (1) | (2) | (3) |
| 1 | 2004 | Actual | 10% | 26% | 37% |
| 2 | 2005 | Actual | 8% | 17% | 47% |
| 3 | 2006 | Actual | 11% | 25% | 44% |
| 4 | 2007 | Actual | 7% | 27% | 27% |
| 5 | 2008 | Actual | 13% | 32% | 41% |

Docket No. 080677-EI
Peak Demand
Illustration
Exhibit JP-7

# FLORIDA POWER & LIGHT COMPANY

## Why Electric Facilities are Sized to Meet Peak Demand



Docket No. 080677-EI
Derivation of AED
Allocation Factor
Exhibit JP-8

# FLORIDA POWER & LIGHT COMPANY
## Derivation of Production Plant Allocation Factors
## Average and Excess Demand Allocation Method
## Test Year Ending December 31, 2010

| Line | Rate Class | Group Coincident Peak | Average Demand Amount | Average Demand Percent | Excess Demand Amount | Excess Demand Percent | AED Allocation |
|---|---|---|---|---|---|---|---|
| | | (1) | (2) | (3) | (4) | (5) | (6) |
| 1 | Residential | 12,240 | 6,256 | 50.93% | 5,984 | 60.42% | 54.82% |
| 2 | General Service | 1,438 | 716 | 5.83% | 721 | 7.28% | 6.43% |
| 3 | General Service Demand | 4,912 | 3,008 | 24.49% | 1,904 | 19.22% | 22.33% |
| 4 | General Service Large Demand-1 | 2,109 | 1,347 | 10.96% | 762 | 7.70% | 9.62% |
| 5 | General Service Large Demand-2 | 373 | 252 | 2.05% | 121 | 1.22% | 1.71% |
| 6 | General Service Large Demand-3 | 49 | 28 | 0.23% | 21 | 0.21% | 0.22% |
| 7 | CILC | 763 | 568 | 4.62% | 195 | 1.97% | 3.54% |
| 8 | MET | 20 | 11 | 0.09% | 9 | 0.09% | 0.09% |
| 9 | Lighting | 196 | 81 | 0.66% | 115 | 1.16% | 0.87% |
| 10 | Standby Service | 87 | 16 | 0.13% | 71 | 0.72% | 0.37% |
| 11 | Total Retail | 22,187 | 12,283 | 100.00% | 9,903 | 100.00% | 100.00% |

(4) Column (1) - Column (2)

(6) Column (3) x 59% + Column (5) x 41%

Docket No. 080677-EI
Revenue Allocation
Exhibit JP-9

# FLORIDA POWER & LIGHT COMPANY
## Proposed Class Revenue Allocation
## (Dollar Amounts in $000)
## Test Year Ending December 31, 2010

| | | Base Revenues at: | | | | |
|---|---|---|---|---|---|---|
| | | Present | Proposed | Proposed Increase | | Relative |
| Line | Rate Class | Rates | Rates | Amount | Percent | Increase |
| | | (1) | (2) | (3) | (4) | (5) |
| 1 | **Residential** | $2,316,398 | $2,798,422 | $482,024 | 20.8% | 83% |
| 2 | **General Service** | 291,367 | 309,854 | 18,487 | 6.3% | 25% |
| | **General Service Demand:** | | | | | |
| 3 | GSD, HLFT-1, SDTR-1 | 789,424 | 1,031,195 | 241,771 | 30.6% | 123% |
| 4 | GSLD-1, CS-1, HLFT-2, SDTR-2 | 271,233 | 417,195 | 145,962 | 53.8% | 216% |
| 5 | GSLD-2, CS-2, HLFT-3, SDTR-3 | 46,458 | 69,347 | 22,890 | 49.3% | 197% |
| 6 | GSLD-3, CS-3 | 4,445 | 5,911 | 1,466 | 33.0% | 132% |
| 7 | **Lighting** | 82,632 | 96,637 | 14,004 | 16.9% | 68% |
| 8 | **CILC-1** | 71,922 | 113,350 | 41,429 | 57.6% | 231% |
| 9 | **Standby Service** | 4,039 | 4,119 | 80 | 2.0% | 8% |
| 10 | **MET** | 2,808 | 3,743 | 935 | 33.3% | 133% |
| 11 | Total Retail | $3,880,727 | $4,849,773 | $969,047 | 25.0% | 100% |

Docket No. 080677-EI
Revenue Allocation
Exhibit JP-10

# FLORIDA POWER & LIGHT COMPANY
## Recommended Class Revenue Allocation
## (Dollar Amounts in $000)
## Test Year Ending December 31, 2010

| Line | Rate Class | Base Revenues at Present Rates | Recommended Allocation | | Relative Increase |
|---|---|---|---|---|---|
| | | | Amount | Percent | |
| | | (1) | (2) | (3) | (4) |
| 1 | **Residential** | $2,316,398 | $529,736 | 22.9% | 92% |
| 2 | **General Service** | 291,367 | 55,802 | 19.2% | 77% |
| | **General Service Demand:** | | | | |
| 3 | GSD, HLFT-1, SDTR-1 | 789,424 | 220,405 | 27.9% | 112% |
| 4 | GSLD-1, CS-1, HLFT-2, SDTR-2 | 271,233 | 101,594 | 37.5% | 150% |
| 5 | GSLD-2, CS-2, HLFT-3, SDTR-3 | 46,458 | 17,401 | 37.5% | 150% |
| 6 | GSLD-3, CS-3 | 4,445 | 1,173 | 26.4% | 106% |
| 7 | **Lighting** | 82,632 | 15,091 | 18.3% | 73% |
| 8 | **CILC-1** | 71,922 | 26,939 | 37.5% | 150% |
| 9 | **Standby Service** | 4,039 | 80 | 2.0% | 8% |
| 10 | **MET** | 2,808 | 825 | 29.4% | 118% |
| 11 | Total Retail | $3,880,727 | $969,047 | 25.0% | 100% |

Docket No. 080677-EI
Cost Study Results
Exhibit JP-11

# FLORIDA POWER & LIGHT COMPANY
## Summary of Class Cost-of-Service Study Results
## At the Recommended Class Revenue Allocation
## (Dollar Amounts in $000)
## Test Year Ending December 31, 2010

| | | Present Rates | | | Recommended Allocation | | | Movement Toward Cost |
|---|---|---|---|---|---|---|---|---|
| Line | Rate Class | Rate of Return | Relative ROR | Subsidy | Rate of Return | Relative ROR | Subsidy | |
| | | (1) | (2) | (3) | (4) | (5) | (6) | (7) |
| 1 | **Residential** | 4.55% | 107 | $46,873 | 8.27% | 103 | $42,777 | 9% |
| 2 | **General Service** | 6.37% | 150 | 37,214 | 9.93% | 124 | 33,962 | 9% |
| | **General Service Demand:** | | | | | | | |
| 3 | GSD, HLFT-1, SDTR-1 | 4.05% | 95 | (12,169) | 7.81% | 98 | (11,105) | 9% |
| 4 | GSLD-1, CS-1, HLFT-2, SDTR-2 | 2.05% | 48 | (54,860) | 6.13% | 77 | (46,403) | 15% |
| 5 | GSLD-2, CS-2, HLFT-3, SDTR-3 | 2.13% | 50 | (9,014) | 6.23% | 78 | (7,499) | 17% |
| 6 | GSLD-3, CS-3 | 3.60% | 85 | (200) | 7.41% | 93 | (183) | 9% |
| 7 | **Lighting** | 4.55% | 107 | 1,213 | 8.27% | 103 | 1,107 | 9% |
| 8 | **CILC-1** | 2.95% | 69 | (10,486) | 6.30% | 79 | (13,580) | -30% |
| 9 | **Standby Service** | 14.01% | 329 | 1,541 | 14.50% | 181 | 1,027 | 33% |
| 10 | **MET** | 3.73% | 88 | (113) | 7.52% | 94 | (103) | 9% |
| 11 | Total Retail | 4.25% | 100 | ($0) | 8.00% | 100 | $0 | 10% |

## CERTIFICATE OF SERVICE

**I HEREBY CERTIFY** that a true and correct copy of the foregoing Florida Industrial Power Users Group's Testimony and Exhibit of Jeffry Pollock has been served by First Class United States Mail this 16th day of July, 2009, to the following:

Lisa Bennett, Theresa Farley Walsh
Anna Williams, Jean Hartman, Martha Brown
Florida Public Service Commission
Division of Legal Services
2540 Shumard Oak Boulevard
Tallahassee, Florida 32399-0850
lbennett@psc.state.fl.us
tfwalsh@psc.state.fl.us
anwillia@psc.state.fl.us
jhartman@psc.state.fl.us
mbrown@psc.state.fl.us

J.R Kelly/Charles Rehwinkel
Office of Public Counsel
111 West Madison Street
Room 812
Tallahassee, Florida 32399
Rehwinkel.Charles@leg.state.fl.us

Robert Scheffel Wright
John T. LaVia, III
Young van Assenderp, P.A.
225 South Adams Street, Suite 200
Tallahassee, Florida 32301
swright@yvlaw.net

Thomas Saporito
Saporito Energy Consultants
Post Office Box 8413
Jupiter, FL 33468-8413
support@saporitoenergyconsultants.com

Jack Leon
Senior Attorney
Florida Power & Light Company
8250 W. Flagler Street
Suite 6514
Miami, FL 33174
Jack.Leon@fpl.com

J. Wiseman
Andrews Kurth LLP
13501 I Street NW
Suite 1100
Washington, DC 20005
kwiseman@andrewskurth.com

Wade Litchfield
Florida Power & Light Company
215 South Monroe Street
Suite 810
Tallahassee, FL 32301-1859
Wade_litchfield@fpl.com

John T. Butler
Florida Power & Light Company
700 Universe Blvd.
Juno Beach, FL 33408-0420
John.Butler@fpl.com

Robert A. Sugarman
I.B.E.W. System Council U-4
c/o Sugarman Law Firm
100 Miracle Mile
Suite 300
Coral Gables, FL 33134
sugarman@sugarmansusskind.com

s/Vicki Gordon Kaufman
Vicki Gordon Kaufman