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>ORDER NO. PSC-10-0153-FOF-EI<br>ISSUED: March 17, 2010 |

The following Commissioners participated in the disposition of this matter:

NANCY ARGENZIANO, Chairman
LISA POLAK EDGAR
NATHAN A. SKOP
DAVID E. KLEMENT
BEN A. "STEVE" STEVENS III

APPEARANCES:

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ORDER DENYING IN PART, AND GRANTING IN PART, FLORIDA POWER & LIGHT COMPANY'S REQUEST FOR A PERMANENT RATE INCREASE AND SETTING DEPRECIATION AND DISMANTLEMENT RATES AND SCHEDULES

BY THE COMMISSION:

## BACKGROUND

This proceeding commenced on March 18, 2009, with the filing of a petition for a permanent rate increase by Florida Power & Light Company (FPL or Company). The Company is engaged in business as a public utility providing electric service as defined in Section 366.02, Florida Statutes (F.S.), and is subject to our jurisdiction. FPL provides electric service to approximately 4.5 million retail customers in all or parts of 35 Florida counties.

FPL requested an increase in its retail rates and charges to generate $1.044 billion in additional gross annual revenues, effective January 4, 2010. If granted, this increase would have allowed the Company to earn an overall rate of return of 8.00 percent or a 12.50 percent return on equity, with a range of 11.50 percent to 13.50 percent. The Company based its request on a projected test year ending December 31, 2010. FPL also requested a $247.4 million subsequent year base rate increase effective January 2011. This additional increase would have allowed the Company to earn an overall rate of return of 8.18 percent or a 12.50 percent return on equity (range 11.50 percent to 13.50 percent). The Company based its subsequent year request on a projected test year ending December 31, 2011. In addition to its 2010 and 2011 rate increases, FPL requested approval of a Generation Base Rate Adjustment (GBRA) mechanism that would allow FPL to increase base rates for revenue requirements associated with new generating additions approved under the Power Plant Siting Act at the time the plants enter commercial service. FPL did not request any interim rate relief. Order No. PSC-09-0351-PCO-EI, issued May 22, 2009, in this docket, suspended the proposed final rates.

The Office of Public Counsel (OPC), the Office of the Attorney General (AG), the Florida Industrial Power Users Group (FIPUG), The Florida Retail Federation (FRF), the Florida Association for Fairness in Rate Making (AFFIRM), the Federal Executive Agencies (FEA), the South Florida Hospital and Healthcare Association (SFHHA), the Associated Industries of Florida (AIF), the City of South Daytona, Florida (South Daytona), the I.B.E.W. System Council U-4 (SCU-4), the FPL Employee Intervenors (Employee Intervenors), and Richard Unger (Unger) intervened in this proceeding. OPC, AG, FIPUG, FRF, AFFIRM, FEA, SFHHA, South Daytona and Mr. Unger objected to FPL's petition for rate increase. OPC, FIPUG, and SFHHA filed testimony supporting a rate decrease.

Pursuant to Florida Statutes, we conducted 9 customer service hearings at the following locations and dates: Sarasota and Ft. Myers, June 19, 2009; Daytona Beach, June 23, 2009; Melbourne and West Palm Beach, June 24, 2009; Ft. Lauderdale and Miami, June 25, 2009; and Miami Gardens and Plantation, June 26, 2009. The Technical Hearing was held in Tallahassee on August 24-28 and 31, 2009, September 2-5, 16 and 17, 2009, and October 21-23, 2009. During the hearing, we approved several stipulated issues, which are reflected in Appendix A to this Order.

On January 13, 2010, at a Special Agenda Conference, we considered the revenue requirements and rate design for FPL. At a January 29, 2010, Special Agenda Conference, we considered the rates to be charged to FPL's customers. This Order reflects our decisions in these dockets. We have jurisdiction over this matter pursuant to Chapter 366, F.S., including Sections 366.041, 366.06, 366.07, and 366.076, F.S.

## 2010 PROPOSED TEST PERIOD

### Legal authority to approve base rate increase

The parties requested that we rule on whether we had the legal authority to use a projected test year in setting rates. In 1983, the Florida Supreme Court, in a telecommunications case, settled that question:

> Section 364.035(1), Florida Statutes (1981) [telecommunications], provides that the Commission has the authority to fix "just, reasonable, and compensatory rates." Nothing in the decisions of this Court or any legislative act prohibits the use of a projected test year by the Commission in setting a utility's rates. We agree with the Commission that it may allow the use of a projected test year as an accounting mechanism to minimize regulatory lag. The projected test period established by the Commission is a ratemaking tool which allows the Commission to determine, as accurately as possible, rates which would be just and reasonable to the customer and properly compensatory to the utility.

Southern Bell Tel. & Tel. Co. v. Public Service Commission, 443 So. 2d 92, 97 (Fla. 1983) (Southern Bell). As we had the authority in telecommunications to use a projected test year, so also do we have the authority to fix "just, reasonable, and compensatory rates" for investor-owned electric utilities. See Section 366.041(1), F.S. A comparison of Section 364.035(1) to

366.041(1), F.S., reveals virtually identical language for the two different industries. In 1985, in an investor-owned electric utility case, the Florida Supreme Court acknowledged our inherent authority to combat regulatory lag by considering and recognizing factors which affect future rates and to grant rate increases based on those factors. Floridians United for Safe Energy, Inc. v. Public Service Commission, 475 So. 2d 241, 242 (Fla. 1985) (Floridians United).

By adopting Rule 25-6.140, Florida Administrative Code (F.A.C.), we codified the Supreme Court's decisions in Southern Bell and Floridians United by requiring an investor-owned electric utility to give an explanation for the test year if the utility chooses to select a projected test year. We have on numerous occasions over the past 20 years used the projected test year method of accounting to set rates for electric utilities. Accordingly, we determine that we have the legal authority to approve a base rate increase using a 2010 projected test year.

Projected Test Period

FPL proposed to utilize a fully projected 2010 test year as the basis for its overall jurisdictional revenue requirement calculation. Generally, the periods covered in FPL's Minimum Filing Requirements (MFRs) in support of its application were the 2008 historical year, 2009 Prior Year, and 2010 Test Year. FPL filed its MFRs based upon forecasts completed in late 2008. The accuracy of FPL's 2010 forecasts is discussed more extensively in our consideration of forecasts of customers, below.

As we have acknowledged in prior dockets, there are primarily two options we may use in evaluating a utility's rate case. The two options are the historic test year and the projected test year. Both options have strengths and weaknesses. In determining to use the projected test year for Gulf[1] in its 2001 rate request, we stated:

> The historical test year has the advantage of using actual data for much of rate base, NOI, and capital structure; however, the pro forma adjustments usually do not represent all the changes that occur from the end of the historical period to the time new rates are in effect. Therefore, this option generally does not present as complete an analysis of the expected financial operations as a projected test year.
>
> The main advantage of a projected test year is that it includes all information related to rate base, NOI, and capital structure for the time new rates will be in effect. However, the data is projected and its accuracy depends on the Company's ability to use the forecast for setting rates.

In granting Gulf's request for the use of the projected test year, we acknowledged that extensive discovery was conducted on the forecasts, and, with adjustments, was appropriate.

In this docket, we find that the projected test year of the twelve months ended December 31, 2010, provides the best opportunity for a proper matching of revenues, expenses, and rate

[1] Order No. PSC-02-0787-FOF-EI, issued June 10, 2002, in Docket No. 010949-EI, In re: Request for rate increase by Gulf Power Company.

base investment for 2010. Accordingly, we accept FPL's proposed 2010 year proposed, with the adjustments discussed below.

Forecasts of customers

FPL's 2010 forecast of customers, kilowatt hours (kWh), and kilowatts (kW) by rate class are consistent with the sales and customer forecast by revenue class and reflect the particular billing determinants specified in each rate schedule if certain adjustments are made to the forecast. Both FPL and OPC suggested changes to FPL's load forecast.

FPL's 2010 forecast of customers, kWh, and kW was sponsored by FPL witnesses Rosemary Morley and Philip Q. Hanser. The two primary elements of FPL's projections were its forecasts of the total number of customers and the Net Energy for Load (NEL). FPL forecasted the total number of customers with an econometric model using population and seasonal factors as explanatory variables. FPL forecasted NEL per customer with an econometric model based upon the level of economic activity, weather, and the price of electricity. NEL was then projected by multiplying the customer forecasts by the NEL per customer forecasts. FPL relied upon independent sources for its forecast assumptions such as the University of Florida's Bureau of Economic and Business Research (BEBR) for its population projections, and Global Insight, Moody's Economy.com, and the Florida Legislature for its economic projections.

These aggregate forecasts were then broken down into separate revenue class forecasts (e.g. Residential, Commercial, Industrial, etc.) for the number of customers and kWh sales by revenue class. These projections were ultimately used to determine the level of test year revenues FPL would earn in 2010 under its current rates and, together with the Company's revenue requirement for 2010, determine the amount of rate relief FPL was requesting in its petition.

FPL's forecast was prepared in late 2008 and used historical monthly data from 1990 through October 2008 for its customer forecast, and historical monthly data from 1998 through October 2008 for its NEL per customer forecast. FPL's customer forecast relied upon the University of Florida's October 2008 population projections. FPL's economic assumptions used in its NEL model were based upon economic forecasts formulated in the latter half of 2008 from Global Insight, Economy.com and other sources. In light of the current economic conditions, we have concern over the use of historic data to guide us in this current economy and believe adjustments are necessary.

In an attempt to reflect current economic conditions not captured in the historic data, FPL made several adjustments to the output of its NEL per customer econometric model. First, FPL adjusted for the impact of two wholesale contracts. Second, FPL reduced its NEL forecast to capture the influence of changes in the appliance stock and new energy efficiency standards. Third, after adjusting the NEL forecast for these two effects, FPL made a "re-anchoring" adjustment to the output of its NEL model so that the output of the model equaled the latest available actual 2008 level of sales. Fourth, FPL adjusted its NEL per customer forecast to capture the impact of the recent escalation in the number of homes left vacant due to the housing crisis. Many of these vacant homes were still active accounts although they consumed only a small amount of electricity. Because FPL believed that the impact of these vacant homes was not fully reflected in the historical data used to estimate the econometric models, FPL adjusted downwards its NEL per customer forecasts to reflect the presence of these "minimal use customers" during 2009, 2010, and 2011. As a result, FPL projected the number of customers to increase by 0.2 percent in 2009, and increase by 0.6 percent in 2010. FPL projects NEL per customer to decrease by 1.7 percent in 2009, and increase by 0.1 percent in 2010.

We agree with the first two adjustments made by FPL. However, as to the third and fourth adjustments suggested by FPL, we disagree. While FPL's third and fourth suggested adjustments were made to reflect the impact of changing economic times, we believe that OPC witness's Brown's methodology more appropriately incorporates this uncertainty into the load forecast.

With respect to FPL's third suggested adjustment, the "re-anchoring" adjustment, we agree that such an adjustment is appropriate. However, since the increase in the number of "minimal use customers" began prior to 2008, we agree with OPC witness Brown that it is appropriate to apply the "minimal use customer" adjustment to the 2008 output of FPL's NEL model prior to making the "re-anchoring" adjustment.

With respect to FPL's adjustment for "minimal use customers," we find that the measurement of the percentage of customers who normally use a minimal amount of electricity should be based upon data spanning a longer period, such as from September 2002 through December 2007, instead of the shorter time period of August 2003 through December 2004 used by FPL. The use of the longer time period results in increasing the percentage of normally occurring "minimal use customers" from FPL's suggested 7.0 percent to 7.42 percent.

Based on the foregoing, we adopt FPL's load forecast and its first and second adjustments made to account for the impact of two wholesale contracts and to capture the influence of changes in the appliance stock and new energy efficiency standards. We also adjust FPL's load forecast for minimal use customers to reflect a 7.42 percent historical average and find that it is appropriate to perform the "minimal use customer" adjustment to the 2008 output of FPL's NEL model before performing the "re-anchoring" adjustment. As a result of the forecasts and adjustments, in 2010, FPL's revised net energy for load is 111,299,656,865 kWh. This adjustment to FPL's load forecast increases test year revenues by $36,969,000.

## 2011 PROPOSED SUBSEQUENT YEAR TEST PERIOD

### Legal authority to approve base rate increase

FPL petitioned for a $247 million increase in revenue requirements beginning in 2011 in addition to its petitioned for 2010 revenue increase. The 2011 requested increase was based upon a 2011 subsequent test year. As a preliminary matter, the parties asked us to determine whether we have the legal authority to approve a 2011 subsequent year increase such as that asked for by FPL. The parties next asked us to address whether we should, from a policy perspective and from a factual perspective, approve a 2011 subsequent year adjustment.

Our legal ability to use a subsequent year adjustment has previously been confirmed by the Legislature, by the Florida Supreme Court, and by us. In 1983, the Legislature enacted the following amendment to Chapter 366, F.S.:

> The commission may adopt rules for the determination of rates in full revenue requirement proceedings which rules provide for adjustments of rates based on revenues and costs during the period new rates are to be in effect and for incremental adjustments in rates for subsequent periods.

Section 366.076(2), F.S. In 1987, we adopted Rule 25-6.0425, F.A.C., allowing us in a full revenue requirements proceeding to approve incremental adjustments for periods subsequent to the initial period in which new rates will be in effect.

The Florida Supreme Court, in the case of Floridians United, held that even without the authority of Section 366.076, F.S., we had the authority to approve subsequent year adjustments. The Floridians United case was an appeal from our prior order granting FPL a 1984 rate increase and a subsequent year adjustment for 1985. While the appellants challenged the constitutionality of the statute (Section 366.076, F.S.) that we relied upon as authority to grant the subsequent year adjustment, the Court never reached that issue. Rather, the Supreme Court agreed that we had authority to grant subsequent year adjustments even prior to the legislative enactment of Section 366.076(2), F.S:

> We agree that PSC's authority to grant subsequent year adjustments predated the enactment of chapter 83-222 and it is therefore unnecessary to address the constitutionality of the chapter. [citations omitted]

Id.

We have used subsequent year adjustments in prior proceedings. In addition to the 1985 subsequent year adjustment for FPL considered in Floridians United, we approved a request by Tampa Electric Company for a projected test year of 1993 and a subsequent test year of 1994. In that docket, we stated that we had authority to do so and that the facts supported our approval of the 1994 subsequent year adjustment for TECO. See Order No. PSC-93-0165-FOF-EI, issued February 2, 1993, in Docket No. 920324-EI, In re: Application for a rate increase by Tampa Electric Company.

Based on the foregoing, we determine that we have the legal authority to grant a subsequent year adjustment if the facts warrant such an adjustment. We next address whether FPL has supported its petition for a 2011 subsequent year adjustment.

Policy decision for subsequent year adjustment

OPC asserted that it did not object to the concept of a subsequent test year on legal grounds per se. Rather, OPC disputed the validity of the application of a subsequent test year to this particular docket. Although each of the intervenors objected to our ability to make a subsequent year adjustment, the basis of their objections appeared to be that from a policy and a factual standpoint, FPL did not prove that a 2011 subsequent year adjustment was appropriate. Having acknowledged that we have the legal authority to grant FPL's request for a 2011 subsequent year adjustment, we next examine whether granting FPL's request is appropriate from a policy perspective.

We believe that back-to-back rate increases should be allowed only in extraordinary circumstances. Historically, we have used the test year concept for setting rates. Under this concept, the test year is deemed to be representative of the future, and used to set rates that will allow the utility the opportunity to earn a rate of return within an allowed range. If the test year is truly representative of the future, then the utility should earn a return within the allowed range for at least the first 12 months of new rates.

FPL witness Olivera explained that the Company was requesting a subsequent year increase in base rates effective January 1, 2011, to address the deterioration in earnings that will take place during 2010. According to witness Olivera, the subsequent year adjustment allows us, as well as the Company, 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. FPL witness Barrett testified that:

> Given the significant time and financial resource commitments involved in fully litigated base rate proceedings, the Commission, the Company, and other stakeholders would benefit by minimizing the frequency of these costly proceedings. One mechanism by which the Commission can address this issue is through the use of a Subsequent Year Adjustment for 2011, the year following the Test Year.

According to SFHHA witness Kollen, there is no evidence that there will be actual savings to ratepayers resulting from the avoidance of a separate proceeding sometime in 2010 for rates that will be effective in 2011. If the Company's 2011 test year costs are reduced as the result of the Company's cost cutting efforts compared to its projections for 2011, then the cost of a separate proceeding in 2010 is likely to pale against the effect of such savings in a subsequent proceeding.

We agree with SFHHA that there is no evidence that ratepayers would receive any savings by avoiding a separate rate proceeding sometime in 2010 for rates that would be effective in 2011. FPL witness Barrett admitted that FPL did not perform a cost-benefit analysis to examine whether the costs of a rate case outweighed savings that could result from re-examining changing costs.

The subsequent increase requested in this case is based on a second projected test year of 2011 and is in fact a second full rate case filing. FPL claims that this second case is necessary "to address the deterioration in earnings that will take place during 2010." However, it is important to note here that filing two general rate cases with back-to-back projected test years deprives us and deprives the Company's ratepayers of the benefit of an additional twelve months of actual economic data and operating history of the Company. This additional data could be used to validate whether an additional increase is truly necessary and whether the second test year is really representative of the future.

The Company's ratepayers deserve a full investigation into the cause of FPL's claimed deterioration of its earnings. Two general rate increases that are barely twelve months apart justify the time and expense of a second separate proceeding. Two back-to-back general rate increases are especially of concern when one considers that the need for base rate increases has already been reduced for FPL due to the effect of the cost recovery clauses. Cost recovery clauses provide for approximately 61 percent of FPL's revenue and reduce the risk of under-recovery of a substantial portion of FPL's operating costs. The recovery of costs through the clauses should limit the need and frequency of full rate cases for FPL.

States that make use of a projected test year, like Florida, typically only attempt to look one year into the future. FPL is asking us to look far beyond the horizon, into 2011, and raise consumers' rates not only in 2010 based on a 2010 projected test year, but to raise consumers rates again in 2011 based on speculative and untested projections for a 2011 subsequent projected test year. These test years were developed in 2008. As one reaches farther into the future, predictions and projections of future economic conditions become less certain and more subject to the vagaries of changing variables. This is particularly true given that for 2010, FPL projected results based upon the assumption of a "down economy," and for 2011 projected results based upon a "down economy just beginning to recover."

Because of unpredictable changes in the economy, it is certainly possible that FPL's perceived need for a 2011 base rate increase could be offset by changes in sales growth, billing determinants, additional Stimulus Bill of the American Recovery and Reinvestment Act of 2009 (Stimulus Bill) benefits, and other cost-decreasing measures. At a time when Florida's ratepayers have been hit hard by the downturn in the economy, it makes sense to wait and see if a subsequent rate case is justified. FPL's claim that it will need a rate increase in 2011 simply is too speculative, and is hereby rejected.

Factual support for 2011 subsequent year adjustment

We realize that our decision on the policy of whether a subsequent year adjustment is appropriate incorporates many of the facts from the case. However, we think it important to address in more detail the appropriateness of the 2011 test year and whether the facts in this docket support the use of a 2011 subsequent year adjustment. FPL witness Barrett explained that the Company provided forecasted information for 2009, 2010, and 2011 for use in this proceeding. The Company included 2011 year data in support of its requested Subsequent Year Adjustment. According to witness Barrett, FPL applied the same rigor to its forecast of 2011 as it did for 2009 and 2010, to be confident that the costs proposed were appropriate for setting rates in this proceeding.

FPL witness Barrett stated that final approvals for these forecasts were made in late 2008 and reflected the Company's best assessment of the business environment. Discussing the prevailing business environment at the time the forecasts were being finalized, witness Barrett testified that "All of these factors have combined to plunge Florida into an economic deterioration not seen since the early 1970s. [. . . ] Every major assumption used in the forecast reflects the severe economic downturn."

We are concerned with the reliability of the forecasted data used to develop the 2011 test year and subsequent rate increase. FPL has stretched its forecasts far into the future during a period when "every major assumption used in the forecast reflects the effects of the most severe economic downturn since the early 1970's." OPC witness Brown testified that "[t]he farther into the future that a utility attempts to project data, there is a greater amount of uncertainty and the data becomes less reliable." Witness Brown further noted that "This is particularly of concern as our country and the customers in FPL's service territory are facing the current economic crisis. Projections of when and how economic recovery will occur are extremely speculative."

The forecasted 2011 test year was prepared in late 2008, when the economic environment was extremely volatile. The last month of the 2011 test year was at least 36 months away from the last actual historical data point when the forecast was prepared. Even in times of economic stability, projections this far in the future strain the reliability and accuracy of data that is needed to set rates.

SFHHA witness Kollen testifed that the record was insufficient for us to determine what the reasonable revenues and costs would be in 2011, given the present economic uncertainty:

> First, the Commission cannot determine at this time what the reasonable revenues and costs will be in 2011 given the present economic uncertainty. It will be difficult enough to determine the reasonable level of revenues and costs for the 2010 test year, which itself is two years removed from actual experience and is based on a budgeting process covering 2009 and 2010, but which began in mid-2008 prior to the meltdown in the financial markets and the recession. Since 2008, the Company has engaged in extensive cost reductions compared to its 2009 budget, thus rendering the 2009 budget unreliable as the basis for the 2010 test year forecast, and even more so for the 2011 subsequent test year forecast.

In the first four months of 2009, the Company experienced a $38 million budget variance in O&M expenses and a $169 million budget variance in capital projects. Both of these variances were favorable and were explained by FPL witness Barrett. However, variances of this magnitude, in the very beginning of a forecast, when projections should be the most accurate, show how unpredicted events and management's reactions to the actual business conditions can make projections inaccurate. The further those projections go into the future, the less predictable the underlying assumptions become.

<u>Forecast of customers</u>

Above, we addressed FPL's overall projections for 2011 and stated our concern for their accuracy. We now address the appropriateness of FPL's 2011 forecast of customers, kWh, and kW which were sponsored by FPL witnesses Rosemary Morley and Philip Q. Hanser.

FPL used the same methodology for its 2011 forecast by revenue and rate classes, as it did for its 2010 forecast. OPC witness Brown testified that, due to the uncertainty associated with the current economic downturn, economic projections of when an economic recovery will occur are extremely speculative. She also noted that if the economic recovery was either faster or greater than expected under FPL's assumptions, there would be a potential for excess earnings at ratepayers' expense. She concluded by saying that although OPC was willing to accept the uncertainty associated with a 2010 test year, the 2011 test year projections incorporate an unacceptable additional level of uncertainty and should be rejected.

We share OPC witness Brown's concern that economic projections formulated in late 2008 and extending through 2011 incorporate an unacceptable level of uncertainty for the purpose of setting rates. Hearing Exhibit 412 is illustrative of our concern. This exhibit showed the Low, Medium, and High Case scenarios for the University of Florida's population forecast used in FPL's customer growth model. As this exhibit showed, as the forecast horizon extended further into the future, the range between the Low and High Case scenarios became wider. We believe that this wider range is indicative of the University of Florida's acknowledgement that its forecast for population growth is subject to more variability as the forecast horizon extends further into the future. Furthermore, as acknowledged by FPL witness Morley under cross examination, the University of Florida revised its population forecast "with some frequency" during 2008. These revisions, which extended into 2009, added an additional degree of variability to the population projections as the forecast bands shifted either upward or downward. Because the population projection from the University of Florida was the primary driver in FPL's customer model, increased variability in the 2011 population projection led to increased variability in the number of customers in 2011. Because of the way FPL's models were structured, an increase in the variability of the number of customers in 2011 flowed through to total NEL, and ultimately to the number of customers and kWh sales by revenue class.

Because there was no empirical data (such as stabilized customer growth rates) in the record to indicate that the uncertainty associated with the current economic downturn was nearing an end, we are concerned that during the twelve months of 2010, additional economic volatility could cause the number of customers and kWh sales in 2011 to deviate significantly from FPL's projections.

In conclusion, while we recognize that we have the legal authority to grant a subsequent year adjustment when the facts so warrant, we decline to do so in the present case. FPL's 2011 subsequent test year and its forecasts of customers, kWh, and kW by revenue and rate classes for the 2011 projected test year are too speculative and are therefore not appropriate for rate setting purposes. The projection period is too far in the future and was developed in times of great economic instability to have confidence in the integrity of the data. Actual events in 2009 have already shown the potential for significant variance from the projections. In denying FPL's petition for a 2011 subsequent year adjustment, we recognize that if the Company is unable to earn within its allowed range of return, it has the option of filing for a base rate increase including a request for interim rate relief. Accordingly, we find that FPL's projected subsequent test year of 2011 is not appropriate and we deny FPL's request for a subsequent increase in January 2011 based on this record.

## GENERATION BASE RATE ADJUSTMENT

For the reasons explained in detail below, we do not approve FPL's request for a Generation Base Rate Adjustment (GBRA) mechanism that would authorize FPL to increase base rates for revenue requirements associated with new generating additions approved under the Power Plant Siting Act at the time they enter commercial service. The existing ratemaking procedure provided by Florida Statutes and our rules provides for a more rigorous and thorough review of the costs and earnings associated with new generating units. Section 366.06(2), F.S., provides that when approved rates charged by a utility do not provide reasonable compensation for electrical service, the utility may request that we hold a public hearing and determine reasonable rates to be charged by the utility. Section 366.071, F.S., provides expedited approval of interim rates until issuance of a final order for a rate change. Rule 25-0243, F.A.C., establishes the minimum filing requirements for utilities in a rate case. These procedures have been sufficient in the past for FPL and other regulated utilities wishing to recover capital expenditures when a new generating facility begins commercial service. We find that the GBRA shall expire as scheduled when new rates are established as delineated in this Order.

### GBRA Background

The GBRA was one of several elements of a negotiated settlement agreement between the parties that we approved in FPL's 2005 rate case, Order No. PSC-05-0902-S-EI, issued September 14, 2005, in Docket No. 050045-EI, In re: Petition for rate increase by Florida Power & Light Company (2005 Settlement Order). The GBRA permitted FPL to increase base rates to recover capital costs associated with new generation facilities as they entered commercial service. The stipulation specified the basis for the costs, as well as the return on equity and capital structure to be used in the calculation of the cost factor to be submitted for our approval using the Capacity Clause projection filing for any necessary true-up. Other elements of the settlement agreement prohibited FPL from petitioning for an increase in retail base rates during the term of the agreement, and established a revenue sharing arrangement between FPL's shareholders and customers. The conditions under which we approved the negotiated settlement agreement are far different from the proposal to establish the GBRA in this case.

### Differences From the 2005 Stipulation

FPL's current request to permanently establish the GBRA differs markedly from the 2005 negotiated settlement agreement that we approved.[2] Acceptance of the GBRA provision of the settlement agreement was contingent upon several provisions, a result of the "give-and-take" in negotiating the agreement. First, the stipulation specified the term of the agreement as effective for a minimum of four years – January 1, 2006, through December 31, 2009 – and to remain in effect until new base rates and charges become effective by order of the Commission.[3] FPL's current request to continue the GBRA specifies no end date. Second, FPL's base rates could not change during the term of the settlement agreement; FPL's current request to continue the GBRA specifies no restriction on changes to base rates. Third, the negotiated agreement provided a

[2] Id.
[3] Ibid., Attachment A, page 3.

revenue sharing plan between shareholders and customers. FPL's current request to continue the GBRA specifies no such revenue sharing arrangement. To date, FPL has flowed $386,928,000 through the GBRA mechanism for three generating units as a result of the stipulated settlement.[4] If the GBRA is made permanent, the amount that FPL proposes to add to rate base under the GBRA mechanism is $3.2 billion over the next five years.[5]

FPL witness Ousdahl acknowledged that the GBRA is materially different from a rate case, because it is an interim base rate measure. We agree that the GBRA specified in the settlement agreement is an interim measure because it has an ending date, and costs would be rolled into base rates at the next rate case. The GBRA mechanism that FPL has asked us to approve in this docket would have no such limit. It has no ending date, and it is intended to cover the costs of all future power plants that receive need determination approval. As FPL witness Barrett acknowledged, the GBRA mechanism would allow FPL to recover such costs without regard to whether earnings were sufficient to cover the addition of a new plant.

Existing Ratemaking Policy and the Proposed GBRA

Parties are in agreement that rate cases are often costly and administratively burdensome. For example, the expenses associated with FPL's rate case in this docket were estimated at $4 – 5 million during the hearing. Comparatively, the cumulative total rate increase that FPL requested is approximately $1.5 billion. FPL's requested rate increase included new power plants, transmission and distribution projects, administrative costs, operation and maintenance expenses, and other expenses.

The record indicates that FPL built several generating units since 1985 without seeking a rate increase. FPL witness Barrett also acknowledged that if economic conditions or other factors changed, it was possible that FPL's base rates could be sufficient to cover the cost of a new generating unit in whole or in part without the application of a GBRA. Other factors, such as the addition of new customers and increased electricity sales tend to offset the additional costs of new power plants. FPL witness Barrett testified that under certain hypothetical circumstances, with a GBRA mechanism in place, customers' bills could go up as a result of adding new generation, though FPL's earnings would remain unaffected.

According to FPL, we should approve continuation of the GBRA because it is "reasonable, cost-based and sends the appropriate price signals to customers." While the term "cost-based" may accurately describe the GBRA, a rate case proceeding provides more of an opportunity to rigorously review costs and earnings as a whole. Regarding the price signals, we agree that implementation of the GBRA may link reductions in fuel costs to increases in base rates that may occur as a new plant is put in service. However, a traditional base rate proceeding could also be timed (based on the Company's request) to coincide with the in-service date of a new plant, thus achieving the same result. FPL witness Barrett testified that it is possible for the Company to structure the timing of a rate request associated with a new plant so that both the

[4] The jurisdictional revenue requirements $121,310,000 for Turkey Point 5, $138,519,000 for West County 1, and $127,099,000 for West County 2.
[5] Representing costs of FPL's West County Unit 3, Cape Canaveral, and Riviera Beach projects.

plant's costs and its fuel savings benefits are received by the customer at the same time. FPL witness Pimentel stated that "the reason that we're requesting the GBRA, first and foremost, is as we build generation that's been approved by this Commission in need determinations, we're trying to match the customer savings and fuel efficiency with the actual capital that we are putting into the business." This goal could be achieved within the process of a traditional rate case.

Another of FPL's arguments for the GBRA mechanism was that it has the potential to avoid the need for a rate case. It is not possible for us or interested parties to examine projected costs at the same level of detail during a need determination proceeding as we would be able to do in a traditional rate case proceeding. A need determination examines costs only in comparison to alternative sources of generation. It does not allow for a review of the full scope of costs and earnings, as a rate case does. FPL witness Barrett acknowledged that the GBRA mechanism would be a limited-scope proceeding focused only on the GBRA, and intervenors would not be able to raise other cost issues in such a proceeding. SFHHA witness Kollen also argued against the GBRA because FPL would have the ability to impose a base rate increase for new generation and transmission projects without consideration of other revenues and costs. OPC witness Brown explained that if the GBRA is approved and the economy subsequently recovers, FPL's shareholders may earn greater returns that could be sufficient to cover the cost of new generating units without increasing base rates. According to OPC, having a GBRA mechanism in place would mean FPL would have less incentive to control overall costs. Witness Brown also pointed out that under the GBRA, FPL would essentially be "imposing a surcharge on customers' bills to cover the costs associated with a single component of its overall costs of providing service," and we would not have the ability to evaluate whether FPL's existing base rates were sufficient to cover some or all of the costs.

The time period required for a traditional rate case proceeding differs from that required for need determination proceedings that the GBRA mechanism would utilize. Rate cases generally take at least eight months to complete and include five months devoted to discovery prior to hearing, in accordance with Section 366.06, F.S. Need determination proceedings are required to be completed within 135 days from the date a petition is filed per Section 403.519 (4), F.S. Witness Barrett stated that the GBRA mechanism protects customers "in the event that we're able to bring in a unit less than the costs that were estimated for that unit and approved through the need process, so there would be an automatic true-up for customers." Witness Barrett also acknowledged, however, that a rate case serves as the ultimate true-up, and a rate case is generally beneficial for regulators and customers.

Witness Ousdahl agreed with the statement that "One of the benefits of a base rate proceeding from a consumer's perspective is that a base rate proceeding would examine a utility's entire cost of service to determine whether reductions in rate base may offset capital additions." Witness Ousdahl also agreed that as part of a base rate proceeding we have the opportunity to examine whether a utility's accumulated depreciation or increases in a utility's billing determinants would result in a decrease in its rate base. One criticism that SFHHA witness Kollen had of the GBRA mechanism is that "it provides the Company an almost unfettered ability to automatically impose base rate increases to recover selective increases in certain costs without consideration of increases in revenues and reductions in all other costs."

Witness Kollen was also concerned that the GBRA mechanism that FPL asked us to approve was not clearly defined. Witness Kollen pointed out that "the GBRA mechanism is not even a proposed tariff even though it is self-implementing. There is no proposed tariff to review. There is not even a detailed description of the mechanism and the revenue requirement computations in the testimony of any FPL witness." FPL is currently building several new power plants, West County 3, Riviera Beach, and Cape Canaveral. Witness Deaton acknowledged that between 2010 and 2015, FPL will be adding $3.255 billion in capital costs to rate base for these power plants if we approve the GBRA. This suggests that in the absence of the GBRA, FPL may file a rate case in 2013 for the next new plant.

The record shows that FPL already collects about 61 percent of its total revenues through various "pass-through" mechanisms and cost recovery clauses. We are not convinced that adding another such mechanism, by permanently implementing a GBRA for FPL, would provide advantages over traditional rate case procedures found in Section 366.06, F.S. We find no justification in the record for approving a cost-recovery mechanism for FPL's new generation that is different from what applies to all other investor-owned electric utilities. Approving a GBRA for FPL on a permanent basis would constitute a significant change in our general ratemaking policies. As we said in Order No. PSC-09-0283-FOF-EI: "[a]cceptance of a settlement among parties is not the same as establishing a generic policy." [6] FPL witness Ousdahl stated: "We are asking the Commission to formalize its policy with regard to GBRA." We are not inclined to formalize our policy with regard to GBRA in the manner FPL requested. There is no record evidence, beyond FPL's suggestion, supporting adoption of a GBRA-like procedure for other utilities. We do not want to set such a precedent here.

We deny FPL's request to continue the GBRA mechanism. It is not possible for us to exercise as adequate a level of economic oversight within the context of a GBRA mechanism as we can exercise within the context of a traditional rate case proceeding. Furthermore, a policy change of this magnitude, which would ultimately affect other utilities, deserves a more thorough review through a separate generic proceeding.

## JURISDICTIONAL SEPARATION

FPL's witness Ender testified that the Company's 2010 transmission service revenues were allocated as credits to offset retail jurisdictional revenues consistent with our order in FPL's last fully litigated rate case, but witness Ender did note that, historically, we have required utilities to separate, not credit back, any costs and revenues associated with firm wholesale transmission sales that last over one year in duration.

According to OPC's witness Brown, FPL created a revenue credit methodology that charged the retail jurisdiction with all costs of transmission, and provided an offsetting revenue

[6] Order No. PSC-09-0283-FOF-EI, issued April 30, 2009, in Docket No. 080317-EI, In re: Petition for rate increase by Tampa Electric Company, p. 126.

credit for transmission revenues received from non-retail jurisdictional customers. Witness Brown contended that while FPL's approach might be appropriate for non-firm or short-term transmission services, revenue crediting for long term contracts could create a subsidy for long-term firm transmission service customers. To remove the effect of this revenue credit method, witness Brown stated that FPL would need to reduce its requested jurisdictional revenue requirements by $18.5 million in 2010.

In his rebuttal testimony, witness Ender indicated that FPL did not oppose OPC's method of addressing transmission related costs and revenues for long-term firm non-jurisdictional transmission service contracts, but the actual revenue amount that should be separated was approximately $23.0 million. OPC agreed with the adjusted amount.

We agree with OPC's position on this matter. Separating all revenues and costs associated with forecasted long-term firm non-jurisdictional transmission service contracts ensures that jurisdictional customers will not subsidize non-jurisdictional transactions. We also agree that the information concerning the costs and revenues associated with these sales is more accurately presented, based on forecasted transactions for 2010, by FPL.

Based on the above, we find that all costs and revenues associated with long-term firm non-jurisdictional transmission service contracts shall be separated. We make the following jurisdictional adjustments to remove the effects of the revenue crediting method employed by FPL: reduce plant in service by $386,896,000; reduce accumulated depreciation by $144,299,000; reduce plant held for future use by $4,200,000; reduce construction work in progress by $18,623,000; increase working capital by $3,700,000; decrease operating revenues by $33,639,000; decrease O&M expenses by $10,462,000; decrease depreciation and amortization by $10,352,000; decrease taxes other than income by $4,918,000 and increase amortization of regulatory asset by $17,000. We also find that FPL appropriately separated all other costs and revenues between the wholesale and retail jurisdictions.

## QUALITY OF SERVICE

FPL provides electric service to about 4.4 million customers. FPL's service territory covers 28,000 square miles, uses 67,000 miles of electrical conductor consisting of 42,000 miles of overhead wires and about 25,000 miles of underground cable, 1.1 million poles, and approximately 800,000 transformers. The distribution business unit is divided into five regions (North, East, West, Broward, and Miami-Dade), which are further divided into seventeen management areas with 35 service centers.

The quality and reliability of the electric service provided by a utility is objectively measured through the use of electric industry reliability indices and the number and types of customer complaints. We have established specific reporting requirements and reliability indices in Rule 25-6.0455, F.A.C., which are used to analyze the quality and reliability of an electric utility's distribution system. The reliability indices track the duration and frequency of power interruptions and are typically examined at a system level. The System Average Interruption Duration Index (SAIDI), the System Average Interruption Frequency Index (SAIFI), and the Customer Average Interruption Duration Index (CAIDI) are the most common indices. In effect, they are measures of unreliability. As the indices increase, reliability becomes worse. All of the indices provide information about average system performance over a specific time period. Accordingly, it is best to examine the current results of a single utility and make a determination as to whether the trend of the current and past results are improving or worsening. However, using averages as the sole basis for decision making can mask the interruption for a specific customer. Therefore, it is important to recognize that an individual customer's outage experience will be averaged within the system indices and that customer complaints relating to the utility's service quality must also be analyzed.

Service Hearings and Complaints

The Commission conducted nine service hearings in FPL's service territory that began on June 19, 2009, and concluded on June 26, 2009. The service hearings took place in Sarasota, Fort Myers, Daytona Beach, Melbourne, West Palm Beach, Fort Lauderdale, Miami, Miami Gardens, and Plantation. A total of 418 customers testified at the service hearings, covering topics that ranged from billing issues, deposit requirements, support of FPL, lack of support for the rate base adjustment, and service quality issues. Service quality issues were reported by 55 customers or approximately 13 percent of the customers at the service hearings.

At the technical hearing, during cross examination on FPL's Service Hearing Report, FPL witness Santos explained that the complaints concerning outages and service reliability are handled by the distribution business unit and that the service reliability issues were addressed by that unit. Our review of the Service Hearing Report concerning service reliability indicates that the momentary power interruptions (MPIs) experienced by many of FPL's customers involved vegetation or lightning strikes. In order to resolve the MPIs that did not involve lightning strikes, FPL reported that the Vegetation Management Department was either scheduled to perform trimming or was in the process of correcting problems that were identified following vegetation surveys concerning the customer complaints. FPL witness Spoor testified that the outages caused by vegetation appeared to be trending upward for the years 2006 through 2008 and that the years 2004 and 2005 experienced natural pruning caused by the hurricanes. As the AG pointed out in its brief, MPIs and outages related to vegetation do appear to be increasing.

Regarding customer complaints, staff witness Hicks testified that 14,700 complaints were logged against FPL for a two year period between July 1, 2007, and June 30, 2009. Of the logged complaints, 12,236 were directly transferred to FPL through our Transfer-Connect program. The most common FPL complaints were billing issues, which accounted for 71 percent of the complaints during the two year period while 29 percent involved quality of service issues. In her rebuttal testimony, FPL witness Santos responded that the data shows on an annual basis only 0.16 percent of FPL customers contacted us with service complaints. According to witness Santos, that demonstrates that FPL has a very low rate of complaints, and compares favorably to the other Florida IOUs.

With respect to the J.D. Power 2009 residential customer satisfaction study for the South Region Large Segment, FPL witness Olivera agreed that the study shows FPL slightly below average. In explaining, witness Olivera stated that the J.D. Power study examines a ". . . whole bunch of dimensions," not just reliability. Witness Olivera also stated the average for the East Region Large Segment is 593, whereas FPL is 632, which is above the Southeast Region Large Segment. We agree with FPL, in principle, that an analysis of adequate electric reliability should not be based on a single dimension. In this case, however, the service reliability complaints plotted in the Review of Florida's Investor Owned Utilities' Service Reliability in 2007 indicated in Figure 4.9 that the reliability related complaints reported to us for FPL have been trending slightly upward since 1999. Service reliability complaints included service interruptions, quality of service, repair, safety, and trees. The observation that customer service reliability complaints reported to us are trending upward lends support to the AG's argument that the service hearings held within the FPL service territory indicated that FPL's service varies in different locations. Therefore, we can not agree that FPL is ". . . operating well beyond the level required to provide reliable electrical service." In our view, the electrical service reliability of FPL's system is more appropriately characterized as adequate.

Reliability Indices

FPL witness Sonnelitter testified that FPL's transmission reliability was in the top 10 percent of the utilities surveyed in a recent bench marking study. FPL's transmission SAIDI indicted that when an outage occurred on the transmission system it lasted for less than one minute or 0.5 minutes, whereas for the Southeast Region of the US, transmission SAIDI lasted for 5.8 minutes.

As mentioned above, Rule 25-6.0455, F.A.C., requires each electric investor owned utility to file an Annual Distribution Reliability Report with us. The report contains a number of mathematical calculations relating to the duration and frequency of outages that occur on a utility's distribution system on an actual and adjusted basis. FPL witnesses Spoor and Reed testified that FPL's three indices (SAIDI, SAIFI, and CAIDI) indicated that FPL was providing better than average numbers for the distribution system.

FPL's distribution system SAIDI is graphically represented in Figure 1 below and shows that for the years 2004 and 2005 an average interruption lasted for 70 minutes and in 2006 an interruption lasted an average of 74 minutes. SAIDI declined in 2007 and sharply declined in 2008 to 67 minutes.

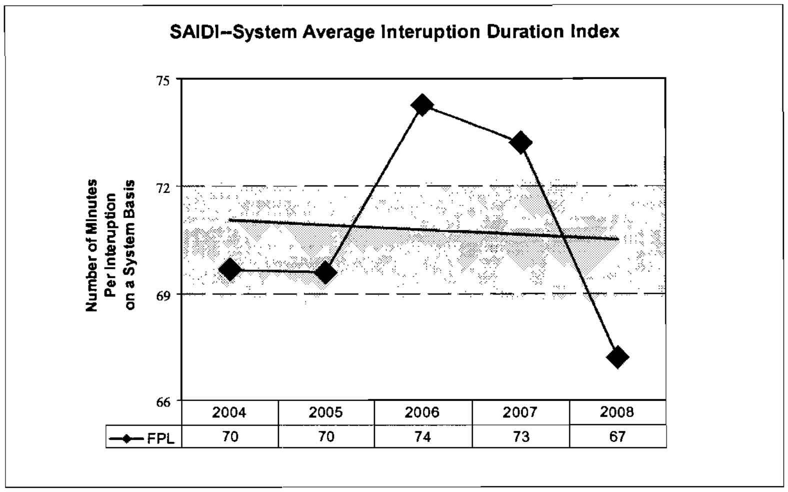


**Figure 1. SAIDI**

FPL's distribution system analysis also includes the frequency or number of times an interruption occurred on the distribution system. Figure 2 indicates that FPL customers experienced 1.2 outages in 2004, and in 2008 the number of outages declined to 1.07 outages. This metric is used in conjunction with SAIDI.

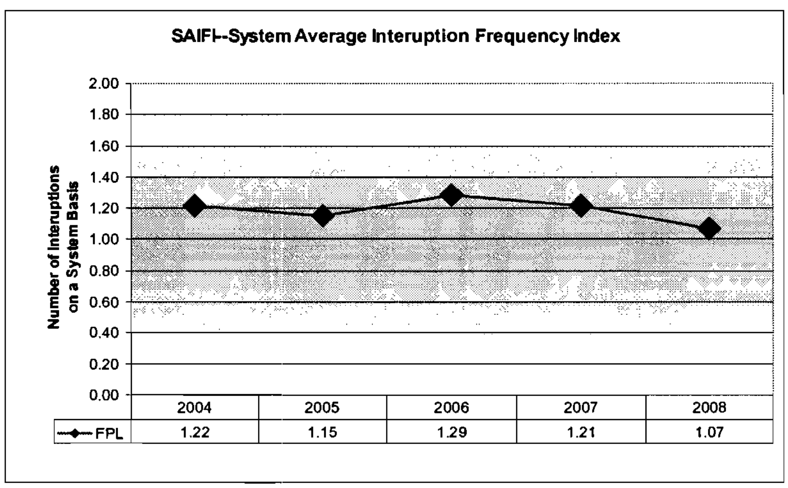


**Figure 2. SAIFI**

The remaining metric or index is CAIDI, and it represents the length of time, in minutes, that an FPL customer can expect a distribution system outage or interruption to last. Figure 3 indicates that CAIDI had a low of 57 minutes in 2004 and increased to 63 minutes in 2008.

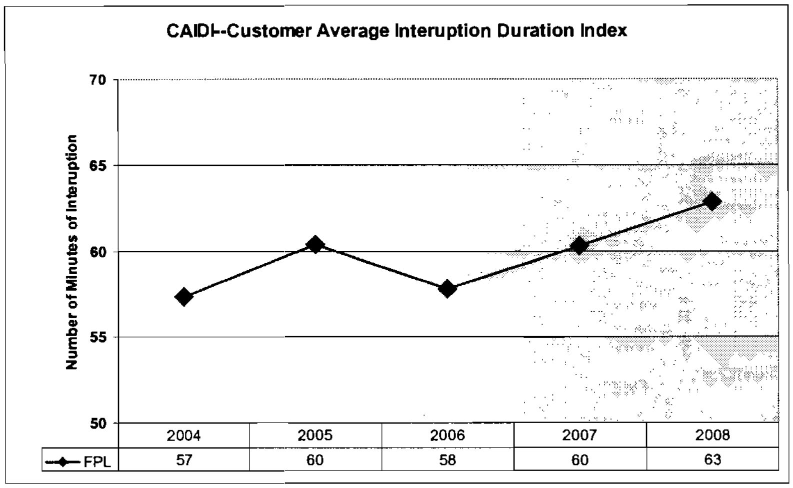


**Figure 3. CAIDI**

The SAIDI index includes the other indices of SAIFI and CAIDI. SAIDI for FPL's entire distribution system is trending downward. This is a good indication that the length of time a customer experiences an outage is decreasing and in 2008 SAIDI had decreased to 67 minutes.

Based on the above, we find that the quality and reliability of the electric service provided by FPL is adequate. We make this determination based on an analysis of customer complaints, an analysis of the distribution system metrics that include SAIDI, SAIFI, CAIDI, and the analysis of the metrics for the transmission system – System Average Restoration Index (SARI) and SAIDI. We note, however, that outages and momentary power interruptions caused by vegetation do appear to be increasing, and we expect our staff to continue to monitor that trend.

## DEPRECIATION STUDY

### Capital recovery schedules

Under the capital recovery schedule mechanism, the investment and associated reserve of installations facing near-term retirement are separated out as sub-accounts, and the unrecovered net amounts are amortized over the period of their remaining service to the public. The mechanism is in our depreciation rule, and is the standard practice of this Commission.[7]

FPL's proposed capital recovery schedules address the unrecovered costs associated with the near-term (2010-2013) retirement of the Cape Canaveral and Riviera steam plants, the St. Lucie and Turkey Point nuclear uprate projects, and the meters made obsolete by the new AMI

[7] 2005 Settlement Order; Order No. PSC-99-0073-FOF-EI, issued January 8, 2009, in Docket No. 971660-EI, In re: 1997 depreciation study by Florida Power & Light Company; and Order No. PSC-94-1199-FOF-EI, issued September 30, 1994, in Docket No. 931231-EI, In re: Request for change in Depreciation Rates by Florida Power and Light Company.

technology. FPL asserted that the use of capital recovery schedules ensures that recovery of retired equipment occurs close to, or before, their retirement. The proposed recovery period of four years coincides with the period between depreciation studies, and closely matches the remaining period the associated assets will be providing service.

OPC did not dispute the need for capital recovery schedules, but did dispute how the costs should be recovered. OPC witness Pous proposed that: (1) the unrecovered costs associated with the retirement of the Cape Canaveral and the Riviera power plants be offset by a portion of FPL's identified reserve surplus for the steam production investment; (2) the unrecovered costs associated with the nuclear uprates be offset by a portion of FPL's identified reserve surplus for the nuclear production investment; and (3) the unrecovered costs associated with obsolete meters retiring due to AMI technology be offset by a portion of FPL's identified reserve surplus existing in the distribution function. This would eliminate the capital recovery schedule expense and reduce the reserve surplus.

If recovery is not afforded for these identified net unrecovered near-term retirements during their remaining period of service, a negative reserve component will result relating to plant no longer providing service. We agree with OPC that a portion of the reserve surplus can and should be used for the immediate recovery of these costs. This action will reduce the test year depreciation expense as well as the reserve surplus.

SFHHA proposed that: (1) FPL's identified unrecovered costs associated with the near-term planned retiring Cape Canaveral and Riviera facilities should be added to the capital costs of the new repowered generating units; (2) the remaining net book value of the retired nuclear assets should be added to the uprated units for continued depreciation over the lives of those units; and (3) the remaining net book value, including removal costs of the retired meter investment, should be depreciated at the same rate as approved for the meter investment. SFHHA witness Kollen contended that:

- FPL's revenue requirement already includes the cost of advanced meters, so there is no need to accelerate the depreciation of old non-AMI investment;
- FPL's AMI deployment is the cause for the retirements of the existing non-AMI meters; therefore, it is reasonable to reclassify the existing non-AMI meters as a regulatory asset;
- FPL's proposal would require ratepayers to pay for existing non-AMI meter investment and the new AMI meter investment at the same time; and
- Since the existing non-AMI meters will be replaced at one time over a four-year period, FPL's four-year amortization proposal would "double-up" recovery for meters during that period.

FPL witness Davis asserted that he agreed that nuclear uprate costs relating to plant additions should increase the plant investment and be depreciated over the life of the related group of assets. However, witness Davis disagreed that the net book value of the identified nuclear uprate retirements and associated removal costs should be deferred and recovered over the remaining licensed life of each nuclear unit. Regarding the replacement of obsolete meters with new AMI meters, witness Davis disagreed that FPL is "doubling up," as SFHAA suggested.

The purpose of depreciation is to match expenses to the period the assets associated with those expenses are providing service to the public. Under group depreciation, it is recognized that some assets within the group will experience a life shorter than the average, while others will experience a life longer than the average. However, if there is a group of assets planned for near-term retirement that now have a significantly shorter life than the overall group life, the associated investments should be withdrawn from the group and recovered over their expected life as provided by our rules. This is the principle of matching expenses to consumption.

If assets retire earlier than the average life of the group without recovery being afforded, a negative reserve component is created. The negative reserve component translates into a positive rate base element. From the Company's standpoint, it will continue to earn a return on this non-existent plant over the life of the group. From the ratepayers' standpoint, they will continue paying for plant no longer providing service until the situation is corrected. Negative reserve amounts are non-life related net investments[8] that we have historically corrected as fast as practicable to remedy the existing intergenerational inequity.[9]

SFHHA's proposal would create a negative reserve component, the exact situation the capital recovery schedule mechanism avoids. Moreover, deferring recovery is simply mortgaging the future. Ratepayers should pay their fair share of costs associated with plant from which they are receiving service. Unrecovered amounts associated with non-existent plant do not benefit ratepayers. Contrary to SFHHA's assertions, recovery of the identified unrecovered costs associated with planned near-term retirements over a period that matches the remaining period the related assets will provide service ensures intergenerational equity. We disagree that such recovery is "accelerated" as FPL, FIPUG, and SFHHA contended. Recovery that matches the service life is not accelerated; it reflects the matching principle. Finally, offsetting FPL's identified unrecovered costs provides immediate recovery and reduces test year depreciation expense, thus alleviating SFHHA's concerns.

Based on the foregoing, we hereby approve the capital recovery schedules contained in Table 1, on the following page. A portion of FPL's existing reserve surplus shall be used to offset the recovery schedule expenses, as discussed in further detail below.

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[8] Non-life related net investments refer to unrecovered costs associated with plant that is no longer providing service to the public. Because the related plant has retired, there is no life over which to recover the costs. Thus, they are non-life related costs.

[9] Order No. PSC-09-0229-PAA-GU, issued April 13, 2009, in Docket No. 080548-GU, In Re: 2008 depreciation study by Florida Public Utilities Company, p. 3; Order No. PSC-03-0260-PAA-GU, issued February 24, 2003, in Docket No. 010906-GU, In re: Request for approval of depreciation study for five-year period 1996 through 2000 by Sebring Gas System, Inc., p. 3; Order No. PSC-02-1492-PAA-GU, issued October 31, 2002, in Docket No. 010383-GU, In re: Application for approval of new depreciation rates by Tampa Electric Company d/b/a Peoples Gas System, p. 3; Order No. PSC-01-2270-PAA-EI, issued November 19, 2001, in Docket No. 010669-EI, In re: Request for approval of implementation date of January 1, 2002, for new depreciation rates for Marianna Electric Division by Florida Public Utilities Company, p. 2.

Table 1

| Steam Plant Retirements | Estimated Investment 12/31/2009 | Estimated Reserve 12/31/2009 | Estimated Cost of Removal | Total Unrecovered costs |
|---|---|---|---|---|
| **Cape Canaveral Common** | | | | |
| 311 Structures & Improvements | 14,150,126 | 12,611,980 | | 1,538,146 |
| 312 Boiler Plant Equipment | 1,849,558 | 674,585 | | 1,174,973 |
| 314 Turbogenerator Units | 1,022,283 | 537,299 | | 484,984 |
| 315 Accessory Euqipment | 727,205 | 400,288 | | 326,917 |
| 316 Misc. Equipment | 649,164 | 635,515 | | 13,649 |
| **Total Cape Canaveral Common** | 18,398,336 | 14,859,667 | | 3,538,669 |
| **Cape Canaveral Unit 1** | | | | |
| 311 Structures & Improvements | 1,699,261 | 1,185,805 | | 513,456 |
| 312 Boiler Plant Equipment | 58,317,673 | 49,045,408 | | 9,272,265 |
| 314 Turbogenerator Units | 29,691,699 | 17,501,297 | | 12,190,402 |
| 315 Accessory Euqipment | 4,575,178 | 3,411,278 | | 1,163,900 |
| 316 Misc. Equipment | 454,247 | 446,053 | | 8,194 |
| **Total Cape Canaveral Unit 1** | 94,738,058 | 71,589,841 | | 23,148,217 |
| **Cape Canaveral Unit 2** | | | | |
| 311 Structures & Improvements | 1,460,458 | 1,476,474 | | (16,016) |
| 312 Boiler Plant Equipment | 49,029,068 | 45,864,642 | | 3,164,426 |
| 314 Turbogenerator Units | 18,405,448 | 12,974,004 | | 5,431,444 |
| 315 Accessory Euqipment | 4,980,181 | 4,984,124 | | (3,943) |
| 316 Misc. Equipment | 516,363 | 476,595 | | 39,768 |
| **Total Cape Canaveral Unit 2** | 74,391,518 | 65,775,839 | | 8,615,679 |
| **Riviera Common** | | | | |
| 311 Structures & Improvements | 9,194,438 | 93,788,335 | | (84,593,897) |
| 312 Boiler Plant Equipment | 651,151 | 580,853 | | 70,298 |
| 314 Turbogenerator Units | 1,221,674 | 1,115,841 | | 105,833 |
| 315 Accessory Euqipment | 2,048,442 | 2,056,365 | | (7,923) |
| 316 Misc. Equipment | 838,293 | 765,531 | | 72,762 |
| **Total Riviera Common** | 13,953,998 | 13,897,425 | | 56,573 |
| **Riviera Common Unit 3** | | | | |
| 311 Structures & Improvements | 323,577 | 169,948 | | 153,629 |
| 312 Boiler Plant Equipment | 26,644,720 | 24,867,091 | | 1,777,629 |
| 314 Turbogenerator Units | 20,348,570 | 16,753,158 | | 3,595,412 |
| 315 Accessory Euqipment | 2,480,171 | 2,404,136 | | 76,035 |
| 316 Misc. Equipment | 117,897 | 57,070 | | 60,827 |
| **Total Riviera Common Unit 3** | 49,914,935 | 44,251,403 | | 5,663,532 |
| **Riviera Common Unit 4** | | | | |
| 311 Structures & Improvements | 107,740 | 105,392 | | 2,348 |
| 312 Boiler Plant Equipment | 20,735,379 | 18,833,063 | | 1,902,316 |
| 314 Turbogenerator Units | 15,546,279 | 14,814,063 | | 732,216 |
| 315 Accessory Euqipment | 3,401,126 | 2,156,145 | | 1,244,981 |
| 316 Misc. Equipment | 47,438 | 45,433 | | 2,005 |
| **Total Riviera Common Unit 4** | 39,837,962 | 35,954,479 | | 3,883,483 |
| **Total Steam Plant Retirements** | 291,234,807 | 246,328,654 | | 44,906,153 |

Table 1

| | Estimated Investment 12/31/2009 | Estimated Reserrve 12/31/2009 | Estimated Cost of Removal | Total Unrecovered costs |
|---|---|---|---|---|
| **Nuclear Uprates** | | | | |
| **St. Lucie Unit 1** | | | | |
| 322 Reactor Plant Equipment | 3,089,857 | 1,285,383 | 2,171,874 | 3,976,348 |
| 323 Turbogenerator Units | 46,415,739 | 23,026,980 | 11,780,444 | 35,169,203 |
| 324 Accessory Euqipment | 108,098 | 107,964 | 1,675,065 | 1,675,199 |
| **Total St. Lucie Unit 1** | 49,613,694 | 24,420,327 | 15,627,383 | 40,820,750 |
| **St. Lucie Unit 2** | | | | |
| 322 Reactor Plant Equipment | 8,170,947 | 5,445,563 | 788,236 | 3,513,620 |
| 323 Turbogenerator Units | 68,116,907 | 47,503,584 | 12,173,427 | 32,786,750 |
| 324 Accessory Euqipment | 444,059 | 280,915 | 984,302 | 1,147,446 |
| **Total St. Lucie Unit 2** | 76,731,913 | 53,230,062 | 13,945,965 | 37,447,816 |
| **Turkey Point Common** | | | | |
| 322 Reactor Plant Equipment | 254,355 | 26,072 | | 228,283 |
| 323 Turbogenerator Units | 2,065,043 | 144,410 | | 1,920,633 |
| **Total Turkey Point Common** | 2,319,398 | 170,482 | | 2,148,916 |
| **Turkey Point Unit 3** | | | | |
| 321 Structures & Improvements | 541,965 | 440,388 | 289,308 | 390,885 |
| 322 Reactor Plant Equipment | 13,326,530 | 12,658,412 | 15,309,927 | 15,978,045 |
| 323 Turbogenerator Units | 37,480,833 | 22,160,888 | 12,054,706 | 27,374,651 |
| 324 Accessory Euqipment | 371,220 | 366,648 | 183,116 | 187,688 |
| **Total Turkey Point Unit 3** | 51,720,548 | 35,626,336 | 27,837,057 | 43,931,269 |
| **Turkey Point Unit 4** | | | | |
| 321 Structures & Improvements | 192,250 | 192,250 | 290,492 | 290,492 |
| 322 Reactor Plant Equipment | 13,393,985 | 13,120,597 | 15,326,786 | 15,600,174 |
| 323 Turbogenerator Units | 40,012,223 | 24,247,736 | 12,047,391 | 27,811,878 |
| 324 Accessory Euqipment | 314,044 | 314,044 | 183,694 | 183,694 |
| **Total Turkey Point Unit 4** | 53,912,502 | 37,874,627 | 27,848,363 | 43,886,238 |
| **Total Nuclear Uprates** | 234,298,055 | 151,321,834 | 85,258,768 | 168,234,989 |
| **Meters** | | | | |
| 370 Obsolete by AMI | 249,077,327 | 171,613,059 | 23,617,590 | 101,081,858 |
| **Total Capital Recovery Schedules** | 774,610,189 | 569,263,547 | 108,876,358 | 314,223,000 |

Remaining life calculation

For the reasons explained below, we are of the opinion that FPL's calculation of remaining life[10] leads to questionable results. Accordingly, we approve a remaining life calculation based on using the average age of the given account with the selected survivor curve.[11] The remaining lives we approve below are based on this calculation.

OPC disputed FPL's use of a truncated Iowa curve[12] in its life analysis for the production plant accounts. This argument relates to the way in which FPL accounted for interim retirements in its life determinations. Since this is more an issue with an input to the development of remaining life, rather than a calculation issue, we address OPC's arguments in the following section.

As part of its remaining life calculation, FPL allocated the actual book reserve for a given account to the individual surviving balances based on the theoretical or calculated reserve. OPC witness Pous took issue with two aspects of this allocation process. First, the process limited the allocated book reserve to the surviving balance of an individual vintage so that the reserve for the vintage did not exceed the total vintage original cost less net salvage.[13] Second, the impact of net salvage parameters was recognized in the remaining life calculation rather than after the calculation. Witness Pous used an industry standard remaining life calculation, which is the same one that Progress Energy Florida, Inc. (PEF) used in Docket No. 090079-EI.

Regarding his criticisms, witness Pous demonstrated that FPL's remaining life calculation ignored the fact that vintages to which no reserve was allocated were still in service and still accruing depreciation. Moreover, witness Pous explained that in group depreciation,[14] some items of plant are assumed to retire before the average service life while others will retire after the average service life. On average, however, depreciation expenses over the life of the group will equal the total investment adjusted for net salvage. Witness Pous demonstrated that if the book reserve is allocated to all vintages as it should be, different vintage remaining lives result.

FPL explained that it determined the remaining life annual depreciation expense for each vintage by dividing the future book expenses (original cost less book reserve) by the average remaining life of the vintage. The average remaining life for each vintage was a directly

[10] The remaining life is the period of years remaining, on average, that the group of assets being studied is expected to provide service to the public.
[11] A survivor curve is a graphical picture of the amount of property (in dollars), that exists at each age (in years), throughout the life of a property group.
[12] Iowa curves, published by Iowa State College in 1935, were developed by analyzing the ages at which industrial property had retired. An Iowa curve, when used in conjunction with other inputs, provides the remaining life. A truncated Iowa curve means that no vintage will survive past the estimated date of final retirement.
[13] Net salvage is gross salvage less cost of removal. Gross salvage is the amount received from trade-in or sale of the asset. Cost of removal relates to the costs incurred for the removal and disposal of the retired asset. Net salvage can be either positive where gross salvage exceeds cost of removal, or negative in cases where cost of removal is greater than gross salvage.
[14] Group depreciation assumes that some items of plant will retire before the average service life while others will retire after the average service life.

weighted average derived from the estimated future survivor curve. FPL witness Clarke testified that the remaining life calculated for each vintage took into account that a portion of each vintage will retire before the average service life and a portion will retire after the average service life, consistent with group depreciation concepts. Moreover, by limiting depreciation expenses only to vintages that are not fully accrued, expenses were calculated only for those vintages that had future costs remaining to recover. Witness Clarke contended that this resulted in a composite annual depreciation rate that is appropriate for the plant balances going forward and resulted in the appropriate amount of needed depreciation expenses.

We do not agree with FPL that its remaining life calculation is consistent with FPL's actual practice. FPL does not maintain its plant account reserves by vintage; they are maintained on a total account basis. Also, depreciation rates are not applied to individual vintages; the rates are applied to the total account balance. Allocating the book reserve to individual vintages based on a theoretical reserve calculation is not necessarily a concern. However, in its allocation, FPL determined that the reserve for any given vintage could not exceed the survivors for that vintage less net salvage. For example, in reviewing the calculation presented for Account 396.1, Power Operated Equipment, no reserve was allocated to the 1986-2000 vintages because the allocation of the reserve indicated that these vintages were fully accrued. That is because the most allocated to any given vintage was the surviving investment for that vintage less net salvage. These vintages represent more than 36 percent of the plant account investment. We believe this is a significant amount of investment that has no remaining life. Looking at Account 396.8, Other Power Operated Equipment, FPL uses an L0.5 Iowa curve and 9-year life combination. The average age of the account is 7.5 years. Using the method endorsed by OPC, the remaining life of the account is 5.2 years, compared to the Company's calculation of zero. While this account has an existing reserve surplus, that should not deter from the fact that it does indeed have a remaining life using FPL's proposed curve and life combination.

FPL did not dispute that net salvage impacts its calculation of remaining life. Net salvage impacts the remaining life depreciation rate, not the average remaining life itself.[15] Unfortunately, because FPL's calculation assumes that no vintage can have more reserve allocated than the surviving investment less net salvage, as net salvage varies, so does the remaining life. For all the foregoing reasons, FPL's remaining life calculation leads to questionable results. Accordingly, the remaining lives we address below are calculated by applying the average age of the account to the selected survivor curve. This is similar to OPC's calculation of remaining life and PEF's calculation in its depreciation study in Docket No. 090079-EI. The remaining lives we approve below use this calculation.

<u>Depreciation parameters for production plant</u>

FPL proposed depreciation rates for its plant investment through December 31, 2009. In addition, FPL proposed depreciation rates for production plants projected to become operational after the test year. The depreciation rates for "Future Units" will be implemented at the time of commercial operation.

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[15] Remaining Life Rate = (100-Net Salvage-Reserve)/Average Remaining Life. Rule 25-6.0436 (1)(e), F.A.C.

The remaining life rate is designed to recover the remaining unrecovered balance (investment less net salvage less reserve) over the remaining life of the associated investment. The formula for the remaining life rate is the plant investment (represented as 100 percent) minus net salvage percent minus reserve percent divided by the average remaining life in years. The reserve represents the portion of the investment accumulated through depreciation expense to date unless restated to another level. Rule 25-6.0436, F.A.C.

FPL used the life span technique in studying its production plants. This technique requires that a date of final retirement be estimated for each production unit. The technique also requires estimation of the level of interim retirements that will occur before the final retirement of the generating unit.[16] The Company used an interim retirement survivor curve[17] to account for expected interim retirements. The curve was developed by performing a statistical analysis that analyzed historical retirements and incorporated judgment and industry information. The economic retirement date of a facility affected each year of installation for the facility by truncating the interim survivor curve for each installation year at the year of expected retirement. The life span[18] for each account was based on the make-up of the property within the given account, experience in the industry, current forecasted life spans, the Company's resource plan, and information from Company personnel. FPL noted that the estimated retirement dates were established for depreciation purposes and did not commit FPL to actually retiring any production units on those dates.

The parties disagreed with the life spans FPL assumed in the depreciation study. The intervenors asserted that FPL's proposed life spans were too short. OPC also disagreed with FPL's level of interim retirements and interim net salvage.

Net salvage is the amount received from gross salvage less cost of removal. Gross salvage is the amount received from sale, reuse, or sometimes the reimbursement from retired property. Cost of removal relates to costs incurred in the removal and disposing of retired plant. Net salvage is positive when gross salvage exceeds cost of removal and negative when cost of removal is greater than gross salvage. Net salvage associated with production plant is associated with the interim retirements expected to retire prior to the retirement date of the generating facility.

1. Life Spans

FPL proposed a 40-year life span for its Scherer and SJRPP coal-fired plants. For the remainder of FPL's steam-fired facilities, FPL proposed a retirement date of mid-2020, resulting in the two newer stations, Martin and Manatee, having life spans ranging from 39 to 44 years, and low 50-year to mid 60-year life spans for the remaining stations. For its combined cycle units, FPL proposed a life span of 25 years.

[16] As an example, interim retirements for a building would consist of assets such as plumbing, heating, doors, windows, and roofs.
[17] A survivor curve graphically depicts the amount of property (in dollars) existing at each age (in years) throughout the life of a group of property.
[18] A life span is the time period when a unit goes into commercial operation and the estimated date of retirement.

OPC witness Pous proposed a 60-year life span for FPL's Scherer and SJRPP coal-fired generating stations. For FPL's Manatee and Martin plants, OPC witness Pous proposed a 50-year life span. The witness did not propose an adjustment to FPL's assumed 25-year life span for combined cycle units even though he asserted that 25 years was artificially short. The witness proposed that FPL be directed to perform a detailed analysis demonstrating why its combined cycle facilities cannot be expected to operate for 35 years or longer, and present the study in its next depreciation study filing. However, the witness suggested that a life span of 30 or 35 years would represent an initial step in bringing FPL's life spans more in line with reasonable expectations.

FIPUG witness Pollock proposed a life span of 55 years for FPL's coal units. For combined cycle units, FIPUG witness Pollock proposed a life span of at least 35 years. FIPUG based its proposed life spans on life spans determined in other regulatory proceedings throughout the country, life spans used by other utilities, and the actual life spans of some of FPL's units.

SFHHA witness Kollen did not address the life span of FPL's coal units, but proposed a life span of 40 years for FPL's combined cycle plants. SFHHA reasoned that if the Putnam combined cycle plant could experience a life span of 42 to 43 years, there was no reason to assume a shorter 25-year life span for other combined cycle units. As additional support for its proposal, SFHHA referred to the experience of other utilities that use a 40-year life span for combined cycle units. Finally, SFHHA asserted that FPL had not demonstrated that it would conclusively operate these units for only 25 years.

In support of its position, OPC asserted that FPL had demonstrated through actual operation that its oil- and gas-fired generating facilities can operate for more than 60 years. OPC witness Pous and FIPUG witness Pollock noted that other utilities and regulatory commissions have recognized 50 to 60 year or longer life spans for steam generating facilities. Moreover, OPC witness Pous referenced the Energy Information Administration of the Department of Energy's database that contains data on generating units demonstrating longer life spans than FPL proposed. Finally, the witness stated that FPL had not provided any economic analysis that demonstrated that its facilities could not operate for longer periods than it had proposed.

FPL contended that the intervenors' reliance on industry statistics from other electric utilities in making their proposals did not consider any of the unique circumstances related to the operations, design life, cycling, or maintenance practices of its production plants. While this may be true, we believe that FPL's actual operations are compelling.

For FPL's coal plants, Scherer and SJRPP, we believe a 50-year life span is appropriate to use in this proceeding. This life span reflects a compromise position between the life spans proposed by FPL and the longer life spans proposed by OPC and FIPUG, and recognizes uncertainties regarding environmental and climate change legislation. For the Manatee and Martin steam plants, we believe that OPC's proposed 50-year life span is reasonable. For the Port Everglades plant, we believe a 60-year life span is appropriate. We also believe that FPL's life span of 59 years for the Sanford plant, 66 years for the Cutler plant, and 53 years for the Turkey Point plant are reasonable.

When combined cycle plants are operating for more than 25 years, this indicates that a 25-year life span is no longer appropriate for depreciation purposes. While FIPUG and SFHHA recommend life spans of 35 or 40 years for combined cycle plants, OPC suggested that 30 to 35 years would be a step in the right direction. Accordingly, we will use a minimum 30-year life span at this time. For those units where FPL has assumed life spans longer than 30 years, no party disagreed. In FPL's next depreciation study, the Company shall provide specific information supporting a shorter life span, if it believes that to be appropriate.

No party disputed FPL's proposed life spans of 60 years for its nuclear units, except OPC believed that the life spans should match the actual license termination date of each unit. We agree. Also, no party disputed FPL's proposed life spans for its combustion turbines. Accordingly, we believe that they are appropriate.

2. Interim Retirements

OPC witness Pous agreed that interim retirements should be included in the calculation of production plant lives, but disagreed with FPL's approach in estimating interim retirements. OPC proposed constant interim retirement rates based on a method sponsored by the California Public Utilities Commission[19] and recognized by the National Association of Regulatory Utility Commissioners (NARUC).[20] The witness explained that he developed interim retirement ratios based on actual FPL historical retirements for each production account.

On the other hand, FPL contended that a constant interim retirement rate approach did not accurately estimate expected interim activity because the approach assumes a constant level of retirements throughout the group of investment's life rather than increased retirements as the property ages. Moreover, FPL asserted that OPC's interim retirement rates were only based on a single observed data point, rather than multiple data points as OPC claimed. FPL claimed that OPC's constant retirement rate calculation was mathematically incorrect and ignored later data points that have experienced higher levels of retirements. Finally, FPL contended that a constant retirement rate assumed that future interim retirement activity will be the same as past retirement activity, which is unlikely. FPL noted that things such as cap-and-trade legislation could require large investments in new technologies and lead to associated retirements to meet future regulatory requirements.

We have previously found that a generating station, or a generating unit, can be looked at as a box containing an assortment of various types of assets which can be expected to experience varied lives.[21] Prior to this current depreciation study, FPL utilized its mechanized property record system to provide in-depth stratified information for the assets in an account at a specific

[19] Determination of Straight-Line Remaining Life Depreciation Accruals Standard Practice U-4.
[20] Public Utility Depreciation Practices.
[21] Order No. PSC-99-0073-FOF-EI, issued January 8, 1999, in Docket No. 971660-EI, In re: 1997 depreciation study by Florida Power & Light Company, p. 4.

unit.[22] The life of the account was then arrived at by compositing expectations of the various strata.

In the current study, FPL did not use a stratified approach in determining production plant lives, but rather used a curve-life combination to depict interim retirements. In our opinion, such an approach leads to much more subjectivity than the stratification approach. Also, FPL's method of estimating interim retirements in its current depreciation study is not simpler than its previously used approach, especially given that the stratified information is contained in FPL's mechanized property record system. However, with any stratification, we recognize that the degree of disaggregation should be tempered by the associated costs.

We note that both FPL's method and OPC's method of determining interim retirements are industry acceptable practices. We agree with FPL's criticism that OPC's use of a constant retirement rate assumes that retirements in the future will mirror those of the past. However, it also appears that FPL based its selected life and curve combinations on a statistical analysis of historical data. The evidence does not indicate how, if at all, future expectations were considered in FPL's curve selections.

Based on the record evidence presented, we calculated a constant retirement rate based on the data provided in FPL's original observed data for each account. The interim retirement rates we use in this proceeding are contained in Table 2, on the following page.

[22] Stratification is the determination that a given account at a specific generating unit contains a certain amount of investment in such things as pumps, piping, rotors, or structures, with each strata expected to have a certain service life.

| Table 2: Commission Approved Interim Retirement Rates | |
|---|---|
| Account | Interim Retirement Rate |
| Steam Production | |
| 311 – Structures & Improvements | 0.0032 |
| 312 – Boiler Plant Equipment | 0.0094 |
| 314 – Turbogenerator Units | 0.0120 |
| 315 – Accessory Electric Equipment | 0.0052 |
| 316 – Misc. Power Plant Equipment | 0.0071 |
| Nuclear Production | |
| 321 – Structures & Improvements | 0.0028 |
| 322 – Reactor Plant Equipment | 0.0056 |
| 323 – Turbogenerator Units | 0.0138 |
| 324 – Accessory Electric Equipment | 0.0012 |
| 325 – Misc. Power Plant Equipment | 0.0032 |
| Other Production | |
| 341 – Structures & Improvements | 0.0023 |
| 342 – Fuel Holders, Producers & Accessories | 0.0095 |
| 343* - Prime Movers | 0.0057 |
| 344 – Turbogenerator Units | 0.0016 |
| 345 – Accessory Electric Equipment | 0.0013 |
| 346 – Misc. Power Plant Equipment | 0.0026 |

* An interim retirement rate of 0.1565 is recommended for capitalized spare parts.

We applied the interim retirement rate to the overall life span of the generating unit to determine an average service life and average remaining life. Our approved average remaining lives are contained in Table 3, below.

3. Interim Net Salvage

OPC witness Pous claimed that FPL's proposed interim net salvage parameters were excessively negative. OPC witness Pous contended that FPL failed to determine whether any activity in any particular year of its analysis was representative of the remaining investment. The witness proposed adjustments for two steam production accounts, two nuclear accounts, and five other production accounts.

In contrast to OPC's proposed interim net salvage proposals, FPL asserted that interim net salvage was developed for each account using a combination of historical data and informed judgment. The Company averred that, because interim net salvage did not pertain to all of the property, it adjusted the net salvage percent based on the percentage of plant that will be retired as interim retirements.

3a. Account-Specific Net Salvage Analysis

3a1. Steam Production

Account 311 – Structures and Improvements

FPL's currently approved interim net salvage for this account is negative 9 percent. FPL proposed net salvage of negative 15 percent, adjusted to negative 5 percent for interim retirements. Witness Clarke asserted that the historical data had averaged negative 15 percent with recent cost of removal increasing.

OPC proposed interim net salvage of negative 5 percent, reduced to zero for interim retirements. Witness Pous contended that FPL ignored recent activity indicating about negative 10 percent net salvage to a positive net salvage. Additionally, he noted that a disproportionate share of the historical retirements in this account have been piping, and replacement of a retaining wall and a cooling pond underdrain system, that may not be indicative of the future. Because piping comprised only 16 percent of the account's investment, the OPC witness asserted that it was given too much weight in FPL's analysis.

Based on the record evidence, we believe a negative 10 percent net salvage is reasonable. Adjusted for interim retirements, we approve the interim net salvage values shown in Table 3, below.

Account 312 – Boiler Plant Equipment

The currently approved interim net salvage for this account is negative 6 percent. FPL asserted that cost of removal had increased over the past few years indicating the need to increase the negative net salvage. Historical salvage data for the 1986-2007 period averaged negative 27 percent, with the 2005-2007 band averaging negative 15 percent. The Company proposed a net salvage of negative 15 percent, adjusted to negative 11 percent for interim retirements. Based on the record evidence, we believe FPL's net salvage proposal is reasonable. Adjusted for interim retirements, we approve the interim net salvage values shown in Table 3 below.

Account 314 – Turbogenerator Units

FPL's currently approved interim net salvage for this account is negative 6 percent. FPL proposed an interim net salvage of zero, noting that salvage data had been erratic.

OPC proposed positive 10 percent net salvage, adjusted to 1.67 percent for interim retirements. OPC contended that FPL's approach to this account was inconsistent with its approach in other accounts because it did not recognize that this account has historically averaged 8 percent positive net salvage, or that the five-year band of data reflected positive 9 percent.

Salvage activity has historically averaged positive 8 percent. The most recent two-year band averaged negative 11 percent. We agree with FPL that the data is erratic. Net salvage has ranged from negative 264 percent to positive 218 percent. Given that such wide variances do not indicate a consistent pattern, we approve the interim net salvage values shown in Table 3.

Account 315 – Accessory Electric Equipment

The currently approved interim net salvage for this account is negative 6 percent. FPL proposed increasing the negative net salvage to negative 20 percent to recognize increased costs of removal. The five-year band of salvage data averaged negative 28 percent with a number of years over 30 percent. Adjusted for interim retirements, FPL proposed negative 12 percent net salvage. OPC did not address FPL's proposal.

Net salvage has historically averaged negative 19 percent, with the most recent three-year and four-year bands average negative 28 percent. Based on the record evidence, we believe the Company's proposed net salvage value is reasonable. Adjusted for interim retirements, we approve the interim net salvage values shown in Table 3.

Account 316 – Miscellaneous Equipment

The currently approved interim net salvage for this account is zero percent. FPL noted that while the net salvage amounts were not large, cost of removal tended to be greater than realized gross salvage. Accordingly, FPL proposed negative 5 percent net salvage, adjusted to negative 4 percent for interim retirements. OPC did not address FPL's net salvage proposal for this account.

Historically, net salvage for this account has averaged negative 5 percent with the most recent five years average negative 8 percent. This account has not experienced sufficient retirements on which to rely. For this reason, we approve the interim net salvage values shown in Table 3.

3a2. Nuclear Production

Account 321 – Structures and Improvements

The currently approved interim net salvage for this account is negative 1 percent. Historically, net salvage averaged positive 8 percent, with some years being positive and some years being negative. FPL proposed a zero net salvage based on the erratic behavior of the data. OPC did not address FPL's proposal. Based on the account activity, we approve the Company's proposed net salvage.

Account 322 – Reactor Plant Equipment

The currently approved interim net salvage for this account is negative 2 percent. FPL proposed net salvage of negative 5 percent, adjusted to negative 4 percent for interim retirements.

OPC proposed retaining the current negative 2 percent interim net salvage. OPC explained that FPL recognized that the currently approved interim net salvage appeared justified, absent recent years in which there were some large retirements that distorted the activity. Nonetheless, the Company proposed an increase in the interim net salvage until more data was available. OPC contended that FPL's reasoning for its proposed net salvage was inconsistent with its approach in other accounts that also indicated positive net salvage, where FPL selected zero until a pattern was established.

Historically, net salvage has averaged negative 11 percent with recent years being more negative, in part due to the retirements associated with the uprate project. Discounting those years, net salvage has averaged slightly negative. Based on the record evidence, we are hesitant to approve a higher negative net salvage. Accordingly, we approve the currently approved net salvage of negative 2 percent.

Account 323 – Turbogenerator Units

The currently approved interim net salvage is negative 4 percent. FPL proposed a zero percent net salvage. The Company explained that the historical data showed positive net salvage in some years and negative net salvage in other years. Large retirements in recent years realized both high gross salvage and high removal costs. Until it is determined whether this type of activity will continue, FPL proposed zero percent net salvage. Based on the data for this account, we approve zero percent net salvage.

Account 324 – Accessory Electric Equipment

The currently approved interim net salvage for this account is negative 2 percent. FPL proposed increasing net salvage to negative 20 percent, adjusted to negative 18 percent for interim retirements. The Company stated that retirements had been fairly consistent with cost of removal always exceeding gross salvage. Historical data averaged negative 19 percent with the past five years of net salvage data averaging negative 41 percent.

OPC proposed negative 2 percent negative net salvage, adjusted to negative 0.06 percent for interim retirements. OPC asserted that the most recent five-year band of data represented less than 1 percent of retirement activity, rendering the results meaningless. We agree and, therefore, approve the currently approved interim net salvage of negative 2 percent.

Account 325 – Miscellaneous Power Plant Equipment

The currently approved net salvage for this account is negative 1 percent. FPL proposed zero interim net salvage based on the fact that historical data indicated positive net salvage with only the past couple of years showing cost of removal exceeding gross salvage. Based on the record evidence, we find that FPL's proposal is reasonable.

3a3. Other Production

Account 341 – Structures & Improvements

The currently approved interim net salvage for this account is negative 2 percent. FPL proposed increasing net salvage to negative 25 percent to reflect increasing removal costs. Adjusting for interim retirements, a negative 12 percent interim net salvage resulted.

OPC proposed interim net salvage of zero. OPC asserted that while FPL recognized increased removal costs, it discounted the 2007 positive net salvage as an anomaly without any investigation.

Historical net salvage for this account has averaged negative 20 percent, with the most recent five-year band averaging positive 9 percent. There was no indication from FPL why the removal costs incurred in 2005 should not be considered an anomaly. We approve the negative 2 percent interim net salvage for this account until more data is available.

Account 342 – Other Production Fuel Holders

The currently approved interim net salvage for this account is zero percent. FPL proposed interim net salvage of negative 5 percent to reflect increased removal costs. Adjusting for interim retirements resulted in negative 3 percent interim net salvage. The Company asserted that the account retirements have been erratic. However, when retirements have occurred, cost of removal with little gross salvage was experienced.

OPC proposed interim net salvage of zero. OPC viewed FPL's proposal as unwarranted given the lack of retirement data.

Based on the record evidence, this account shows insufficient retirements upon which to draw a meaningful conclusion. Accordingly, we approve the currently approved zero percent interim net salvage.

Account 343 – Other Production Prime Movers

The currently approved interim net salvage for this account is zero. FPL proposed interim net salvage of negative 10 percent adjusted to negative 2 percent for interim retirements. FPL asserted that historical net salvage averaged negative 24 percent, with the most recent five years averaging negative 14 percent. The Company averred that this data warranted an increase in negative net salvage.

OPC proposed interim net salvage of zero. OPC asserted that FPL's data included two large negative gross salvage amounts. This data caused the historical information to be excessively negative and produced illogical results. OPC averred that if this data is removed as an anomaly, there is no basis for changing the currently approved interim net salvage.

We agree with OPC that negative gross salvage amounts are illogical. We also agree with FPL that even ignoring these amounts, net salvage has been negative. FPL proposed zero net salvage in its 2005 depreciation study when the data showed negative net salvage. Therefore, we are hard pressed to approve a net salvage more negative when nothing has essentially changed since the 2005 depreciation analysis. We therefore approve the currently prescribed zero percent interim net salvage.

Account 344 – Other Production Generators

The currently approved interim net salvage for this account is negative 1 percent. FPL proposed a negative 100 percent net salvage based on the most recent five years of data, adjusted to negative 11 percent for interim retirements.

OPC proposed zero net salvage. OPC asserted that FPL had not adequately explained or supported its proposal.

Historical net salvage has averaged negative 98 percent, with the most recent five years of data averaging negative net salvage in excess of 100 percent. We note that retirements during the past five years account for more than 60 percent of all retirements recorded during the 1987-2007 period. We also note that until the last five years, cost of removal as well as retirements had generally been negligible. FPL did not explain what caused the sudden increase in activity, so we are unable to verify if its proposed net salvage is appropriate. Under the circumstances, we approve the currently approved interim net salvage of negative 1 percent.

Account 345 – Other Production Accessory Electric Equipment

The currently approved interim net salvage for this account is negative 1 percent. FPL proposed increasing net salvage to negative 10 percent, adjusted to negative 3 percent for interim retirements. The Company states that its proposal is in line with the historical net salvage experience of the account.

OPC proposed zero percent interim net salvage. OPC asserted that the retirement activity during the past five years represented less than 0.4 percent of the account's investment, and 79 percent of that activity was associated with items such as batteries and battery chargers that represented less than 5 percent of the account's investment. Thus, OPC contended that FPL's proposed interim negative net salvage was overstated.

Historical net salvage has averaged negative 7 percent with the most recent five-year band of data averaging negative 14 percent. FPL contended that OPC's argument was flawed because the account's retirements reflect the types of property that will likely be retired interimly and not necessarily the same investment mix. However, FPL did not explain other types of investments subject to interim retirement or the type of salvage they were likely to incur. It is difficult to assume that past activity is indicative of the future if the past is not representative of the type of activity being estimated. For this reason, we approve the currently prescribed negative 1 percent interim net salvage.

Account 346 – Miscellaneous Power Plant Equipment

The currently approved interim net salvage is zero percent, which FPL proposed retaining. Historical net salvage as well has the most recent five years of data have averaged negative 2 percent. Retirements have been minimal. Based on the record evidence, we find FPL's proposal reasonable.

4. Amortizations

In accord with Rule 25-6.0142, F.A.C., FPL amortizes investments in the miscellaneous power plant accounts that represent minor investments of numerous items that are too numerous to track or trace. Each vintage year's additions associated with each account is amortized over a like period of time. FPL proposed no change to these amortizations and none of the intervenors disputed them.

5. Conclusion

The approved depreciation parameters and resulting depreciation rates for production plant are shown on Table 3, on the following pages. The reserve positions shown incorporate the effects of the approved reserve allocations addressed below.

Table 3: Production Depreciation Components and Resulting Rates

| | COMMISSION APPROVED | | | |
|---|---|---|---|---|
| Account Number and Description | Average Remaining Life | Net Salvage | Theoretical Reserve | Remaining Life Rate |
| | (yrs.) | (%) | (%) | (%) |
| **<u>CUTLER PLANT</u>** | | | | |
| **Cutler Common** | | | | |
| 311.0 Structures & Improvements | 10.3 | (2.00) | 84.49 | 1.7 |
| 312.0 Boiler Plant Equipment | 9.9 | (7.00) | 85.38 | 2.2 |
| 314.0 Turbogenerator Units | 9.8 | 0.00 | 78.22 | 2.2 |
| 315.0 Accessory Electric Equip. | 10.2 | (6.00) | 86.69 | 1.9 |
| 316.0 Misc. Power Plant Equip. | 10.1 | 0.00 | 80.94 | 1.9 |
| **Cutler Unit 5** | | | | |
| 311.0 Structures & Improvements | 10.3 | (2.00) | 84.49 | 1.7 |
| 312.0 Boiler Plant Equipment | 9.9 | (7.00) | 85.38 | 2.2 |
| 314.0 Turbogenerator Units | 9.8 | 0.00 | 78.22 | 2.2 |
| 315.0 Accessory Electric Equip. | 10.2 | (6.00) | 86.69 | 1.9 |
| 316.0 Misc. Power Plant Equip. | 10.1 | 0.00 | 80.94 | 1.9 |
| **Cutler Unit 6** | | | | |
| 311.0 Structures & Improvements | 10.3 | (2.00) | 84.49 | 1.7 |
| 312.0 Boiler Plant Equipment | 9.9 | (7.00) | 85.38 | 2.2 |
| 314.0 Turbogenerator Units | 9.8 | 0.00 | 78.22 | 2.2 |
| 315.0 Accessory Electric Equip. | 10.2 | (6.00) | 86.69 | 1.9 |
| 316.0 Misc. Power Plant Equip. | 10.1 | 0.00 | 80.94 | 1.9 |

Table 3: Production Depreciation Components and Resulting Rates

| | COMMISSION APPROVED | | | |
|---|---|---|---|---|
| Account Number and Description | Average Remaining Life | Net Salvage | Theoretical Reserve | Remaining Life Rate |
| | (yrs.) | (%) | (%) | (%) |
| **MANATEE PLANT** | | | | |
| **Manatee Common** | | | | |
| 311.0 Structures & Improvements | 17 | (1.00) | 64.47 | 2.1 |
| 312.0 Boiler Plant Equipment | 16.1 | (2.00) | 60.95 | 2.6 |
| 314.0 Turbogenerator Units | 15.7 | 0.00 | 58.68 | 2.6 |
| 315.0 Accessory Electric Equip. | 16.7 | (5.00) | 65.15 | 2.4 |
| 316.0 Misc. Power Plant Equip. | 16.4 | (1.00) | 61.56 | 2.4 |
| **Manatee Unit 1** | | | | |
| 311.0 Structures & Improvements | 17 | (1.00) | 64.47 | 2.1 |
| 312.0 Boiler Plant Equipment | 16.1 | (2.00) | 60.95 | 2.6 |
| 314.0 Turbogenerator Units | 15.7 | 0.00 | 58.68 | 2.6 |
| 315.0 Accessory Electric Equip. | 16.7 | (5.00) | 65.15 | 2.4 |
| 316.0 Misc. Power Plant Equip. | 16.4 | (1.00) | 61.56 | 2.4 |
| **Manatee Unit 2** | | | | |
| 311.0 Structures & Improvements | 17 | (1.00) | 64.47 | 2.1 |
| 312.0 Boiler Plant Equipment | 16.1 | (2.00) | 60.95 | 2.6 |
| 314.0 Turbogenerator Units | 15.7 | 0.00 | 58.68 | 2.6 |
| 315.0 Accessory Electric Equip. | 16.7 | (5.00) | 65.15 | 2.4 |
| 316.0 Misc. Power Plant Equip. | 16.4 | (1.00) | 61.56 | 2.4 |

Table 3: Production Depreciation Components and Resulting Rates

| | COMMISSION APPROVED | | | |
|---|---|---|---|---|
| Account Number and Description | Average Remaining Life | Net Salvage | Theoretical Reserve | Remaining Life Rate |
| | (yrs.) | (%) | (%) | (%) |
| **MARTIN PLANT** | | | | |
| **Martin Common** | | | | |
| 311.0 Structures & Improvements | 21 | (1.00) | 55.87 | 2.1 |
| 312.0 Boiler Plant Equipment | 19.4 | (5.00) | 54.08 | 2.6 |
| 314.0 Turbogenerator Units | 18.8 | 0.00 | 50.53 | 2.6 |
| 315.0 Accessory Electric Equip. | 20 | (5.00) | 57.27 | 2.4 |
| 316.0 Misc. Power Plant Equip. | 19.9 | 0.00 | 52.62 | 2.4 |
| **Martin Pipeline** | | | | |
| 312.0 Boiler Plant Equipment | 19.4 | (5.00) | 54.08 | 2.6 |
| **Martin Unit 1** | | | | |
| 311.0 Structures & Improvements | 21 | (1.00) | 55.87 | 2.1 |
| 312.0 Boiler Plant Equipment | 19.4 | (5.00) | 54.08 | 2.6 |
| 314.0 Turbogenerator Units | 18.8 | 0.00 | 50.53 | 2.6 |
| 315.0 Accessory Electric Equip. | 20 | (5.00) | 57.27 | 2.4 |
| 316.0 Misc. Power Plant Equip. | 19.9 | 0.00 | 52.62 | 2.4 |
| **Martin Unit 2** | | | | |
| 311.0 Structures & Improvements | 21 | (1.00) | 55.87 | 2.1 |
| 312.0 Boiler Plant Equipment | 19.4 | (5.00) | 54.08 | 2.6 |
| 314.0 Turbogenerator Units | 18.8 | 0.00 | 50.53 | 2.6 |
| 315.0 Accessory Electric Equip. | 20 | (5.00) | 57.27 | 2.4 |
| 316.0 Misc. Power Plant Equip. | 19.9 | 0.00 | 52.62 | 2.4 |

Table 3: Production Depreciation Components and Resulting Rates

| Account Number and Description | COMMISSION APPROVED | | | |
|---|---|---|---|---|
| | Average Remaining Life | Net Salvage | Theoretical Reserve | Remaining Life Rate |
| | (yrs.) | (%) | (%) | (%) |
| **PT EVERGLADES PLANT** | | | | |
| **Pt Everglades Common** | | | | |
| 311.0 Structures & Improvements | 10.3 | (2.00) | 82.90 | 1.9 |
| 312.0 Boiler Plant Equipment | 9.9 | (6.00) | 83.19 | 2.3 |
| 314.0 Turbogenerator Units | 9.8 | 0.00 | 77.21 | 2.3 |
| 315.0 Accessory Electric Equip. | 10.2 | (5.00) | 84.40 | 2.0 |
| 316.0 Misc. Power Plant Equip. | 10.1 | (2.00) | 80.98 | 2.1 |
| **Pt Everglades Unit 1** | | | | |
| 311.0 Structures & Improvements | 10.3 | (2.00) | 82.90 | 1.9 |
| 312.0 Boiler Plant Equipment | 9.9 | (6.00) | 83.19 | 2.3 |
| 314.0 Turbogenerator Units | 9.8 | 0.00 | 77.21 | 2.3 |
| 315.0 Accessory Electric Equip. | 10.2 | (5.00) | 84.40 | 2.0 |
| 316.0 Misc. Power Plant Equip. | 10.1 | (2.00) | 80.98 | 2.1 |
| **Pt Everglades Unit 2** | | | | |
| 311.0 Structures & Improvements | 10.3 | (2.00) | 82.90 | 1.9 |
| 312.0 Boiler Plant Equipment | 9.9 | (6.00) | 83.19 | 2.3 |
| 314.0 Turbogenerator Units | 9.8 | 0.00 | 77.21 | 2.3 |
| 315.0 Accessory Electric Equip. | 10.2 | (5.00) | 84.40 | 2.0 |
| 316.0 Misc. Power Plant Equip. | 10.1 | (2.00) | 80.98 | 2.1 |
| **Pt Everglades Unit 3** | | | | |
| 311.0 Structures & Improvements | 10.3 | (2.00) | 82.90 | 1.9 |
| 312.0 Boiler Plant Equipment | 9.9 | (6.00) | 83.19 | 2.3 |
| 314.0 Turbogenerator Units | 9.8 | 0.00 | 77.21 | 2.3 |
| 315.0 Accessory Electric Equip. | 10.2 | (5.00) | 84.40 | 2.0 |
| 316.0 Misc. Power Plant Equip. | 10.1 | (2.00) | 80.98 | 2.1 |
| **Pt Everglades Unit 4** | | | | |
| 311.0 Structures & Improvements | 10.3 | (2.00) | 82.90 | 1.9 |
| 312.0 Boiler Plant Equipment | 9.9 | (6.00) | 83.19 | 2.3 |
| 314.0 Turbogenerator Units | 9.8 | 0.00 | 77.21 | 2.3 |
| 315.0 Accessory Electric Equip. | 10.2 | (5.00) | 84.40 | 2.0 |
| 316.0 Misc. Power Plant Equip. | 10.1 | (2.00) | 80.98 | 2.1 |

Table 3: Production Depreciation Components and Resulting Rates

| | COMMISSION-APPROVED | | | |
|---|---|---|---|---|
| Account Number and Description | Average Remaining Life | Net Salvage | Theoretical Reserve | Remaining Life Rate |
| | (yrs.) | (%) | (%) | (%) |
| **SANFORD PLANT** | | | | |
| **Sanford Unit 3** | | | | |
| 311.0 Structures & Improvements | 10.3 | (2.00) | 82.54 | 1.9 |
| 312.0 Boiler Plant Equipment | 9.9 | (6.00) | 82.68 | 2.4 |
| 314.0 Turbogenerator Units | 9.8 | 0.00 | 76.67 | 2.4 |
| 315.0 Accessory Electric Equip. | 10.2 | (5.00) | 84.00 | 2.1 |
| 316.0 Misc. Power Plant Equip. | 10.1 | (2.00) | 80.54 | 2.1 |

Table 3: Production Depreciation Components and Resulting Rates

| | COMMISSION APPROVED | | | |
|---|---|---|---|---|
| Account Number and Description | Average Remaining Life | Net Salvage | Theoretical Reserve | Remaining Life Rate |
| | (yrs.) | (%) | (%) | (%) |
| **SCHERER PLANT** | | | | |
| **Scherer Coal Cars** | | | | |
| 312.0 Boiler Plant Equipment | 26 | (5.00) | 36.75 | 2.6 |
| **Scherer Common (Site)** | | | | |
| 311.0 Structures & Improvements | 28 | (1.00) | 40.83 | 2.1 |
| 312.0 Boiler Plant Equipment | 26 | (5.00) | 36.75 | 2.6 |
| 314.0 Turbogenerator Units | 25 | 0.00 | 34.21 | 2.6 |
| 315.0 Accessory Electric Equip. | 27 | (4.00) | 40.18 | 2.4 |
| 316.0 Misc. Power Plant Equip. | 27 | (1.00) | 36.07 | 2.4 |
| **Scherer Common 3 & 4** | | | | |
| 311.0 Structures & Improvements | 28 | (1.00) | 41.23 | 2.2 |
| 312.0 Boiler Plant Equipment | 26 | (5.00) | 37.10 | 2.7 |
| 314.0 Turbogenerator Units | 25 | 0.00 | 34.21 | 2.6 |
| 315.0 Accessory Electric Equip. | 27 | (4.00) | 40.57 | 2.4 |
| **Scherer Unit 4** | | | | |
| 311.0 Structures & Improvements | 28 | (1.00) | 40.83 | 2.1 |
| 312.0 Boiler Plant Equipment | 26 | (5.00) | 36.75 | 2.6 |
| 314.0 Turbogenerator Units | 25 | 0.00 | 34.21 | 2.6 |
| 315.0 Accessory Electric Equip. | 27 | (4.00) | 40.18 | 2.4 |
| 316.0 Misc. Power Plant Equip. | 27 | (1.00) | 36.07 | 2.4 |

Table 3: Production Depreciation Components and Resulting Rates

| | COMMISSION APPROVED | | | |
|---|---|---|---|---|
| Account Number and Description | Average Remaining Life | Net Salvage | Theoretical Reserve | Remaining Life Rate |
| | (yrs.) | (%) | (%) | (%) |
| **SJRPP PLANT** | | | | |
| **SJRPP Coal Cars** | | | | |
| 312.0 Boiler Plant Equipment | 26 | (5.00) | 36.75 | 2.6 |
| **SJRPP Coal & Limestone** | | | | |
| 311.0 Structures & Improvements | 28 | (1.00) | 40.83 | 2.1 |
| 312.0 Boiler Plant Equipment | 26 | (5.00) | 36.75 | 2.6 |
| 315.0 Accessory Electric Equip. | 27 | (4.00) | 40.18 | 2.4 |
| 316.0 Misc. Power Plant Equip. | 27 | (1.00) | 36.07 | 2.4 |
| **SJRPP Common** | | | | |
| 311.0 Structures & Improvements | 27 | (1.00) | 42.98 | 2.1 |
| 312.0 Boiler Plant Equipment | 25 | (5.00) | 39.38 | 2.6 |
| 315.0 Accessory Electric Equip. | 26 | (4.00) | 42.55 | 2.4 |
| 316.0 Misc. Power Plant Equip. | 26 | (1.00) | 38.48 | 2.4 |
| **SJRPP Gypsum & Ash** | | | | |
| 311.0 Structures & Improvements | 27 | (1.00) | 42.98 | 2.1 |
| 312.0 Boiler Plant Equipment | 25 | (5.00) | 39.38 | 2.6 |
| 314.0 Turbogenerator Units | | 0.00 | 36.84 | 2.6 |
| 315.0 Accessory Electric Equip. | 26 | (4.00) | 42.55 | 2.4 |
| 316.0 Misc. Power Plant Equip. | 26 | (1.00) | 38.48 | 2.4 |
| **SJRPP Unit 1** | | | | |
| 311.0 Structures & Improvements | 27 | (1.00) | 42.98 | 2.1 |
| 312.0 Boiler Plant Equipment | 25 | (5.00) | 39.38 | 2.6 |
| 314.0 Turbogenerator Units | 24 | 0.00 | 36.84 | 2.6 |
| 315.0 Accessory Electric Equip. | 26 | (4.00) | 42.55 | 2.4 |
| 316.0 Misc. Power Plant Equip. | 26 | (1.00) | 38.48 | 2.4 |
| **SJRPP Unit 2** | | | | |
| 311.0 Structures & Improvements | 27 | (1.00) | 42.98 | 2.1 |
| 312.0 Boiler Plant Equipment | 25 | (5.00) | 39.38 | 2.6 |
| 314.0 Turbogenerator Units | 24 | 0.00 | 36.84 | 2.6 |
| 315.0 Accessory Electric Equip. | 26 | (4.00) | 42.55 | 2.4 |
| 316.0 Misc. Power Plant Equip. | 26 | (1.00) | 38.48 | 2.4 |

Table 3: Production Depreciation Components and Resulting Rates

| | COMMISSION APPROVED | | | |
|---|---|---|---|---|
| Account Number and Description | Average Remaining Life | Net Salvage | Theoretical Reserve | Remaining Life Rate |
| | (yrs.) | (%) | (%) | (%) |
| **TURKEY POINT PLANT** | | | | |
| **Turkey Point Common** | | | | |
| 311.0 Structures & Improvements | 10.3 | (2.00) | 80.56 | 2.1 |
| 312.0 Boiler Plant Equipment | 9.9 | (6.00) | 81.01 | 2.5 |
| 314.0 Turbogenerator Units | 9.8 | 0.00 | 74.87 | 2.6 |
| 315.0 Accessory Electric Equip. | 10.2 | (5.00) | 82.21 | 2.2 |
| 316.0 Misc.Power Plant Equip. | 10.1 | (2.00) | 78.59 | 2.3 |
| **Turkey Point Unit 1** | | | | |
| 311.0 Structures & Improvements | 10.3 | (2.00) | 80.56 | 2.1 |
| 312.0 Boiler Plant Equipment | 9.9 | (6.00) | 81.01 | 2.5 |
| 314.0 Turbogenerator Units | 9.8 | 0.00 | 74.87 | 2.6 |
| 315.0 Accessory Electric Equip. | 10.2 | (5.00) | 82.21 | 2.2 |
| 316.0 Misc.Power Plant Equip. | 10.1 | (2.00) | 78.59 | 2.3 |
| **Turkey Point Unit 2** | | | | |
| 311.0 Structures & Improvements | 10.3 | (2.00) | 80.56 | 2.1 |
| 312.0 Boiler Plant Equipment | 9.9 | (6.00) | 81.01 | 2.5 |
| 314.0 Turbogenerator Units | 9.8 | 0.00 | 74.87 | 2.6 |
| 315.0 Accessory Electric Equip. | 10.2 | (5.00) | 82.21 | 2.2 |
| 316.0 Misc.Power Plant Equip. | 10.1 | (2.00) | 78.59 | 2.3 |

Table 3: Approved Production Depreciation Components and Resulting Rates

| | COMMISSION APPROVED | | | |
|---|---|---|---|---|
| Account Number and Description | Average Remaining Life | Net Salvage | Theoretical Reserve | Remaining Life Rate |
| | (yrs.) | (%) | (%) | (%) |
| **ST LUCIE PLANT** | | | | |
| **St Lucie Common** | | | | |
| 321.0 Structures & Improvements | 32 | 0.00 | 42.86 | 1.8 |
| 322.0 Reactor Plant Equipment | 30 | (2.00) | 42.00 | 2.0 |
| 323.0 Turbogenerator Units | 27 | 0.00 | 34.15 | 2.4 |
| 324.0 Accessory Electric Equip. | 33 | (2.00) | 43.97 | 1.8 |
| 325.0 Misc.Power Plant Equip. | 32 | 0.00 | 41.82 | 1.8 |
| **St Lucie Unit 1** | | | | |
| 321.0 Structures & Improvements | 26 | 0.00 | 53.57 | 1.8 |
| 322.0 Reactor Plant Equipment | 25 | (2.00) | 52.00 | 2.0 |
| 323.0 Turbogenerator Units | 22 | 0.00 | 46.34 | 2.4 |
| 324.0 Accessory Electric Equip. | 26 | (2.00) | 56.28 | 1.8 |
| 325.0 Misc.Power Plant Equip. | 25 | 0.00 | 54.55 | 1.8 |
| **St Lucie Unit 2** | | | | |
| 321.0 Structures & Improvements | 32 | 0.00 | 42.86 | 1.8 |
| 322.0 Reactor Plant Equipment | 30 | (2.00) | 42.00 | 2.0 |
| 323.0 Turbogenerator Units | 27 | 0.00 | 34.15 | 2.4 |
| 324.0 Accessory Electric Equip. | 33 | (2.00) | 43.97 | 1.8 |
| 325.0 Misc.Power Plant Equip. | 32 | 0.00 | 41.82 | 1.8 |

Table 3: Approved Production Depreciation Components and Resulting Rates

| | COMMISSION APPROVED | | | |
|---|---|---|---|---|
| Account Number and Description | Average Remaining Life | Net Salvage | Theoretical Reserve | Remaining Life Rate |
| | (yrs.) | (%) | (%) | (%) |
| **TURKEY POINT PLANT** | | | | |
| **Turkey Point Common** | | | | |
| 321.0 Structures & Improvements | 23 | 0.00 | 58.93 | 1.8 |
| 322.0 Reactor Plant Equipment | 22 | (2.00) | 58.00 | 2.0 |
| 323.0 Turbogenerator Units | 19.9 | 0.00 | 51.46 | 2.4 |
| 324.0 Accessory Electric Equip. | 23 | (2.00) | 61.55 | 1.8 |
| 325.0 Misc.Power Plant Equip. | 23 | 0.00 | 58.18 | 1.8 |
| **Turkey Point Unit 3** | | | | |
| 321.0 Structures & Improvements | 23 | 0.00 | 58.93 | 1.8 |
| 322.0 Reactor Plant Equipment | 22 | (2.00) | 58.00 | 2.0 |
| 323.0 Turbogenerator Units | 19.9 | 0.00 | 51.46 | 2.4 |
| 324.0 Accessory Electric Equip. | 23 | (2.00) | 61.55 | 1.8 |
| 325.0 Misc.Power Plant Equip. | 23 | 0.00 | 58.18 | 1.8 |
| **Turkey Point Unit 4** | | | | |
| 321.0 Structures & Improvements | 23 | 0.00 | 58.93 | 1.8 |
| 322.0 Reactor Plant Equipment | 22 | (2.00) | 58.00 | 2.0 |
| 323.0 Turbogenerator Units | 19.9 | 0.00 | 51.46 | 2.4 |
| 324.0 Accessory Electric Equip. | 23 | (2.00) | 61.55 | 1.8 |
| 325.0 Misc.Power Plant Equip. | 23 | 0.00 | 58.18 | 1.8 |

Table 3: Production Depreciation Components and Resulting Rates

| | COMMISSION APPROVED | | | |
|---|---|---|---|---|
| Account Number and Description | Average Remaining Life | Net Salvage | Theoretical Reserve | Remaining Life Rate |
| | (yrs.) | (%) | (%) | (%) |
| **FT MYERS PLANT** | | | | |
| **Ft Myers Common** | | | | |
| 341.0 Structures & Improvements | 23 | (2.00) | 21.10 | 3.5 |
| 342.0 Fuel Holders, Prod. & Access. | 21 | 0.00 | 19.23 | 3.8 |
| 343.0 Prime Movers | 13.9 | 0.00 | 18.71 | 5.8 |
| 344.0 Turbogenerator Units | 23 | (1.00) | 23.57 | 3.4 |
| 345.0 Accessory Electric Equipment | 23 | (1.00) | 23.57 | 3.4 |
| 346.0 Misc. Power Plant Equipment | 23 | 0.00 | 20.69 | 3.4 |
| **Ft Myers Unit 2** | | | | |
| 341.0 Structures & Improvements | 22 | (2.00) | 24.62 | 3.5 |
| 342.0 Fuel Holders, Prod. & Access. | 20 | 0.00 | 23.08 | 3.8 |
| 343.0 Prime Movers | 18 | 0.00 | 25.00 | 4.2 |
| 344.0 Turbogenerator Units | 22 | (1.00) | 26.93 | 3.4 |
| 345.0 Accessory Electric Equipment | 22 | (1.00) | 26.93 | 3.4 |
| 346.0 Misc. Power Plant Equipment | 22 | 0.00 | 24.14 | 3.4 |
| **Ft Myers Unit 3 (Simple Cycle)** | | | | |
| 341.0 Structures & Improvements | 23 | (2.00) | 21.10 | 3.5 |
| 342.0 Fuel Holders, Prod. & Access. | 21 | 0.00 | 19.23 | 3.8 |
| 343.0 Prime Movers | 15.5 | 0.00 | 18.85 | 5.2 |
| 344.0 Turbogenerator Units | 23 | (1.00) | 23.57 | 3.4 |
| 345.0 Accessory Electric Equipment | 23 | (1.00) | 23.57 | 3.4 |
| 346.0 Misc. Power Plant Equipment | 23 | 0.00 | 20.69 | 3.4 |
| **Ft Myers GTs** | | | | |
| 341.0 Structures & Improvements | 10.4 | (2.00) | 77.89 | 2.3 |
| 342.0 Fuel Holders, Prod. & Access. | 9.9 | 0.00 | 73.24 | 2.7 |
| 343.0 Prime Movers | 8.7 | 0.00 | 72.81 | 3.1 |
| 344.0 Turbogenerator Units | 10.4 | (1.00) | 77.66 | 2.2 |
| 345.0 Accessory Electric Equipment | 10.4 | (1.00) | 77.66 | 2.2 |
| 346.0 Misc. Power Plant Equipment | 10.3 | 0.00 | 76.59 | 2.3 |

Table 3: Production Depreciation Components and Resulting Rates

| Account Number and Description | COMMISSION APPROVED Average Remaining Life | Net Salvage | Theoretical Reserve | Remaining Life Rate |
|---|---|---|---|---|
| | (yrs.) | (%) | (%) | (%) |
| **LAUDERDALE PLANT** | | | | |
| **Lauderdale Common** | | | | |
| 341.0 Structures & Improvements | 13.3 | (2.00) | 55.22 | 3.5 |
| 342.0 Fuel Holders, Prod. & Access. | 12.6 | 0.00 | 51.54 | 3.8 |
| 343.0 Prime Movers | 8.9 | 0.00 | 47.02 | 6.0 |
| 344.0 Turbogenerator Units | 13.3 | (1.00) | 56.22 | 3.4 |
| 345.0 Accessory Electric Equipment | 13.4 | (1.00) | 55.89 | 3.4 |
| 346.0 Misc. Power Plant Equipment | 13.2 | 0.00 | 54.48 | 3.4 |
| **Lauderdale Unit 4** | | | | |
| 341.0 Structures & Improvements | 13.3 | (2.00) | 55.22 | 3.5 |
| 342.0 Fuel Holders, Prod. & Access. | 12.6 | 0.00 | 51.54 | 3.8 |
| 343.0 Prime Movers | 11.2 | 0.00 | 51.30 | 4.3 |
| 344.0 Turbogenerator Units | 13.3 | (1.00) | 56.22 | 3.4 |
| 345.0 Accessory Electric Equipment | 13.4 | (1.00) | 55.89 | 3.4 |
| 346.0 Misc. Power Plant Equipment | 13.2 | 0.00 | 54.48 | 3.4 |
| **Lauderdale Unit 5** | | | | |
| 341.0 Structures & Improvements | 13.3 | (2.00) | 55.22 | 3.5 |
| 342.0 Fuel Holders, Prod. & Access. | 12.6 | 0.00 | 51.54 | 3.8 |
| 343.0 Prime Movers | 11.5 | 0.00 | 52.08 | 4.2 |
| 344.0 Turbogenerator Units | 13.3 | (1.00) | 56.22 | 3.4 |
| 345.0 Accessory Electric Equipment | 13.4 | (1.00) | 55.89 | 3.4 |
| 346.0 Misc. Power Plant Equipment | 13.2 | 0.00 | 54.48 | 3.4 |
| **Lauderdale GTs** | | | | |
| 341.0 Structures & Improvements | 10.4 | (2.00) | 79.43 | 2.2 |
| 342.0 Fuel Holders, Prod. & Access. | 9.9 | 0.00 | 74.62 | 2.6 |
| 343.0 Prime Movers | 8.9 | 0.00 | 73.82 | 2.9 |
| 344.0 Turbogenerator Units | 10.4 | (1.00) | 79.12 | 2.1 |
| 345.0 Accessory Electric Equipment | 10.4 | (1.00) | 79.12 | 2.1 |
| 346.0 Misc. Power Plant Equipment | 10.3 | 0.00 | 77.61 | 2.2 |

Table 3: Production Depreciation Components and Resulting Rates

| | COMMISSION APPROVED | | | |
|---|---|---|---|---|
| Account Number and Description | Average Remaining Life | Net Salvage | Theoretical Reserve | Remaining Life Rate |
| | (yrs.) | (%) | (%) | (%) |
| **Pt Everglades GTs** | | | | |
| 341.0 Structures & Improvements | 10.4 | (2.00) | 79.43 | 2.2 |
| 342.0 Fuel Holders, Prod. & Access. | 9.9 | 0.00 | 74.62 | 2.6 |
| 343.0 Prime Movers | 8.2 | 0.00 | 71.72 | 3.4 |
| 344.0 Turbogenerator Units | 10.4 | (1.00) | 79.12 | 2.1 |
| 345.0 Accessory Electric Equipment | 10.4 | (1.00) | 79.12 | 2.1 |
| 346.0 Misc. Power Plant Equipment | 10.3 | 0.00 | 77.61 | 2.2 |
| **MANATEE PLANT** | | | | |
| **Manatee Unit 3** | | | | |
| 341.0 Structures & Improvements | 25 | (2.00) | 14.07 | 3.5 |
| 342.0 Fuel Holders, Prod. & Access. | 23 | 0.00 | 11.54 | 3.8 |
| 343.0 Prime Movers | 20 | 0.00 | 13.04 | 4.3 |
| 344.0 Turbogenerator Units | 25 | (1.00) | 16.83 | 3.4 |
| 345.0 Accessory Electric Equipment | 25 | (1.00) | 16.83 | 3.4 |
| 346.0 Misc. Power Plant Equipment | 25 | 0.00 | 13.79 | 3.4 |

Table 3: Production Depreciation Components and Resulting Rates

| Account Number and Description | COMMISSION APPROVED | | | |
|---|---|---|---|---|
| | Average Remaining Life | Net Salvage | Theoretical Reserve | Remaining Life Rate |
| | (yrs.) | (%) | (%) | (%) |
| **MARTIN PLANT** | | | | |
| **Martin Common** | | | | |
| 341.0 Structures & Improvements | 14.2 | (2.00) | 52.06 | 3.5 |
| 342.0 Fuel Holders, Prod. & Access. | 13.5 | 0.00 | 48.08 | 3.8 |
| 343.0 Prime Movers | 12.0 | 0.00 | 47.83 | 4.3 |
| 345.0 Accessory Electric Equipment | 14.4 | (1.00) | 52.52 | 3.4 |
| 346.0 Misc. Power Plant Equipment | 14.2 | 0.00 | 51.03 | 3.4 |
| **Martin Pipeline** | | | | |
| 342.0 Fuel Holders, Prod. & Access. | 13.5 | 0.00 | 48.08 | 3.8 |
| **Martin Unit 3** | | | | |
| 341.0 Structures & Improvements | 14.2 | (2.00) | 52.06 | 3.5 |
| 342.0 Fuel Holders, Prod. & Access. | 13.5 | 0.00 | 48.08 | 3.8 |
| 343.0 Prime Movers | 12.5 | 0.00 | 47.92 | 4.2 |
| 344.0 Turbogenerator Units | 14.3 | (1.00) | 52.86 | 3.4 |
| 345.0 Accessory Electric Equipment | 14.4 | (1.00) | 52.52 | 3.4 |
| 346.0 Misc. Power Plant Equipment | 14.2 | 0.00 | 51.03 | 3.4 |
| **Martin Unit 4** | | | | |
| 341.0 Structures & Improvements | 14.2 | (2.00) | 52.06 | 3.5 |
| 342.0 Fuel Holders, Prod. & Access. | 13.5 | 0.00 | 48.08 | 3.8 |
| 343.0 Prime Movers | 12.4 | 0.00 | 48.33 | 4.2 |
| 344.0 Turbogenerator Units | 14.3 | (1.00) | 52.86 | 3.4 |
| 345.0 Accessory Electric Equipment | 14.4 | (1.00) | 52.52 | 3.4 |
| 346.0 Misc. Power Plant Equipment | 14.2 | 0.00 | 51.03 | 3.4 |
| **Martin Unit 8** | | | | |
| 341.0 Structures & Improvements | 25 | (2.00) | 14.07 | 3.5 |
| 342.0 Fuel Holders, Prod. & Access. | 23 | 0.00 | 11.54 | 3.8 |
| 343.0 Prime Movers | 20 | 0.00 | 13.04 | 4.3 |
| 344.0 Turbogenerator Units | 25 | (1.00) | 16.83 | 3.4 |
| 345.0 Accessory Electric Equipment | 25 | (1.00) | 16.83 | 3.4 |
| 346.0 Misc. Power Plant Equipment | 24 | 0.00 | 17.24 | 3.4 |

Table 3: Production Depreciation Components and Resulting Rates

| Account Number and Description | COMMISSION APPROVED | | | |
|---|---|---|---|---|
| | Average Remaining Life | Net Salvage | Theoretical Reserve | Remaining Life Rate |
| | (yrs.) | (%) | (%) | (%) |
| **PUTNAM PLANT** | | | | |
| **Putnam Common** | | | | |
| 341.0 Structures & Improvements | 10.4 | (2.00) | 75.48 | 2.6 |
| 342.0 Fuel Holders, Prod. & Access. | 9.9 | 0.00 | 71.71 | 2.9 |
| 343.0 Prime Movers | 7.7 | 0.00 | 67.92 | 4.2 |
| 344.0 Turbogenerator Units | 10.4 | (1.00) | 75.38 | 2.5 |
| 345.0 Accessory Electric Equipment | 10.4 | (1.00) | 75.38 | 2.5 |
| 346.0 Misc. Power Plant Equipment | 10.3 | 0.00 | 74.25 | 2.5 |
| **Putnam Unit 1** | | | | |
| 341.0 Structures & Improvements | 10.4 | (2.00) | 75.48 | 2.6 |
| 342.0 Fuel Holders, Prod. & Access. | 9.9 | 0.00 | 71.71 | 2.9 |
| 343.0 Prime Movers | 7.9 | 0.00 | 68.40 | 4.0 |
| 344.0 Turbogenerator Units | 10.4 | (1.00) | 75.38 | 2.5 |
| 345.0 Accessory Electric Equipment | 10.4 | (1.00) | 75.38 | 2.5 |
| 346.0 Misc. Power Plant Equipment | 10.3 | 0.00 | 74.25 | 2.5 |
| **Putnam Unit 2** | | | | |
| 341.0 Structures & Improvements | 10.4 | (2.00) | 76.13 | 2.5 |
| 342.0 Fuel Holders, Prod. & Access. | 9.9 | 0.00 | 71.71 | 2.9 |
| 343.0 Prime Movers | 8.6 | 0.00 | 71.33 | 3.3 |
| 344.0 Turbogenerator Units | 10.4 | (1.00) | 75.99 | 2.4 |
| 345.0 Accessory Electric Equipment | 10.4 | (1.00) | 75.99 | 2.4 |
| 346.0 Misc. Power Plant Equipment | 10.3 | 0.00 | 74.88 | 2.4 |

Table 3: Production Depreciation Components and Resulting Rates

| | COMMISSION APPROVED | | | |
|---|---|---|---|---|
| Account Number and Description | Average Remaining Life | Net Salvage | Theoretical Reserve | Remaining Life Rate |
| | (yrs.) | (%) | (%) | (%) |
| **SANFORD PLANT** | | | | |
| **Sanford Common** | | | | |
| 341.0 Structures & Improvements | 22 | (2.00) | 24.62 | 3.5 |
| 342.0 Fuel Holders, Prod. & Access. | 20 | 0.00 | 23.08 | 3.8 |
| 343.0 Prime Movers | 17.8 | 0.00 | 19.09 | 4.5 |
| 345.0 Accessory Electric Equipment | 22 | (1.00) | 26.93 | 3.4 |
| 346.0 Misc. Power Plant Equip. | 22 | 0.00 | 24.14 | 3.4 |
| **Sanford Unit 4** | | | | |
| 341.0 Structures & Improvements | 23 | (2.00) | 21.10 | 3.5 |
| 342.0 Fuel Holders, Prod. & Access. | 21 | 0.00 | 19.23 | 3.8 |
| 343.0 Prime Movers | 16.8 | 0.00 | 20.00 | 4.8 |
| 344.0 Turbogenerator Units | 23 | (1.00) | 23.57 | 3.4 |
| 345.0 Accessory Electric Equipment | 23 | (1.00) | 23.57 | 3.4 |
| 346.0 Misc. Power Plant Equip. | 23 | 0.00 | 20.69 | 3.4 |
| **Sanford Unit 5** | | | | |
| 341.0 Structures & Improvements | 22 | (2.00) | 24.62 | 3.5 |
| 342.0 Fuel Holders, Prod. & Access. | 20 | 0.00 | 23.08 | 3.8 |
| 343.0 Prime Movers | 18.1 | 0.00 | 24.58 | 4.2 |
| 344.0 Turbogenerator Units | 22 | (1.00) | 26.93 | 3.4 |
| 345.0 Accessory Electric Equipment | 22 | (1.00) | 26.93 | 3.4 |
| 346.0 Misc. Power Plant Equip. | 22 | 0.00 | 24.14 | 3.4 |

Table 3: Production Depreciation Components and Resulting Rates

| | COMMISSION APPROVED | | | |
|---|---|---|---|---|
| Account Number and Description | Average Remaining Life | Net Salvage | Theoretical Reserve | Remaining Life Rate |
| | (yrs.) | (%) | (%) | (%) |
| **TURKEY POINT** | | | | |
| **Turkey Point Unit 5** | | | | |
| 341.0 Structures & Improvements | 27 | (2.00) | 7.03 | 3.5 |
| 342.0 Fuel Holders, Prod. & Access. | 24 | 0.00 | 7.69 | 3.8 |
| 343.0 Prime Movers | 15.9 | 0.00 | 9.66 | 5.7 |
| 344.0 Turbogenerator Units | 27 | (1.00) | 10.10 | 3.4 |
| 345.0 Accessory Electric Equipment | 27 | (1.00) | 10.10 | 3.4 |
| 346.0 Misc. Power Plant Equip. | 27 | 0.00 | 6.90 | 3.4 |

Table 3: Production Depreciation Components and Resulting Rates

| | COMMISSION APPROVED | | | |
|---|---|---|---|---|
| Account Number and Description | Average Remaining Life | Net Salvage | Theoretical Reserve | Remaining Life Rate |
| | (yrs.) | (%) | (%) | (%) |
| **WEST COUNTY PLANT** | | | | |
| **West County Unit 1** | | | | |
| 341.0 Structures & Improvements | 30 | 0.00 | 2.56 | 3.3 |
| 342.0 Fuel Holders, Prod.& Access, | 30 | 0.00 | 2.56 | 3.3 |
| 343.0 Prime Movers | 30 | 0.00 | 3.50 | 3.3 |
| 344.0 Turbogenerator Units | 30 | 0.00 | 2.50 | 3.3 |
| 345.0 Accessory Electric Equip. | 30 | 0.00 | 3.50 | 3.3 |
| **West County Unit 2** | | | | |
| 341.0 Structures & Improvements | 30 | 0.00 | 2.56 | 3.3 |
| 342.0 Fuel Holders, Prod.& Access, | 30 | 0.00 | 2.56 | 3.3 |
| 343.0 Prime Movers | 30 | 0.00 | 3.50 | 3.3 |
| 344.0 Turbogenerator Units | 30 | 0.00 | 2.50 | 3.3 |
| 345.0 Accessory Electric Equip. | 30 | 0.00 | 3.50 | 3.3 |
| **West County Unit 3** | | | | |
| 341.0 Structures & Improvements | 30 | 0.00 | 0.00 | 3.3 |
| 342.0 Fuel Holders, Prod.& Access, | 30 | 0.00 | 0.00 | 3.3 |
| 343.0 Prime Movers | 30 | 0.00 | 0.00 | 3.3 |
| 344.0 Turbogenerator Units | 30 | 0.00 | 0.00 | 3.3 |
| 345.0 Accessory Electric Equip. | 30 | 0.00 | 0.00 | 3.3 |

Table 3: Production Depreciation Components and Resulting Rates

| | COMMISSION APPROVED | | | |
|---|---|---|---|---|
| Account Number and Description | Average Remaining Life | Net Salvage | Theoretical Reserve | Remaining Life Rate |
| | (yrs.) | (%) | (%) | (%) |
| SOLAR | | | | |
| Desoto Solar Energy Center | 30 | 0 | 0 | 3.3 |
| Spacecoast Solar Energy Center | 30 | 0 | 0 | 3.3 |
| Martin Solar Energy Center | 30 | 0 | 0 | 3.3 |

Table 3: Production Depreciation Components and Resulting Rates

| Account Number and Description | COMMISSION APPROVED Average Remaining Life | Net Salvage | Theoretical Reserve | Remaining Life Rate |
|---|---|---|---|---|
| | (yrs.) | (%) | (%) | (%) |
| **STEAM PRODUCTION - AMORTIZABLE** | | | | |
| 316.3 Misc. Power Plant Equipment | 3 Year Amortization | | | |
| 316.5 Misc. Power Plant Equipment | 5 Year Amortization | | | |
| 316.7 Misc. Power Plant Equipment | 7 Year Amortization | | | |
| **NUCLEAR PRODUCTION - AMORTIZABLE** | | | | |
| 325.3 Misc. Power Plant Equipment | 3 Year Amortization | | | |
| 325.5 Misc. Power Plant Equipment | 5 Year Amortization | | | |
| 325.7 Misc. Power Plant Equipment | 7 Year Amortization | | | |
| **OTHER PRODUCTION - AMORTIZABLE** | | | | |
| 346.3 Misc. Power Plant Equipment | 3 Year Amortization | | | |
| 346.5 Misc. Power Plant Equipment | 5 Year Amortization | | | |
| 346.7 Misc. Power Plant Equipment | 7 Year Amortization | | | |

Depreciation parameters and resulting rates: Transmission, Distribution, and General Accounts

In the discussion below, we address the depreciation rates for the mass property accounts, i.e., the transmission, distribution, and general accounts. Our approved depreciation parameters include the remaining life (in years), net salvage percent, and reserve percent, all of which are used to calculate the remaining life depreciation rate.[23] The reserve and any reallocations are addressed below. Based on the record, we find that adjustments to depreciation parameters in certain accounts are warranted.

For each account, FPL provided a proposal for a curve and average service life (ASL), both of which are used in the calculation of the remaining life. OPC provided proposals for curves as well as ASLs for specific accounts. Curves are denoted by a letter that describes when retirements are more likely to occur. An L curve implies that retirements tend to occur prior to the ASL, while an R curve implies that retirements tend to occur after the ASL. The average service life denotes the average number of years that the plant within a particular account is expected to live. While the ASL may be based, at least in part on historical data, it is prospective in its outlook and implementation. The remaining life is the average number of in-service years left for plant that is currently in service. The net salvage, based on historical data but also prospective in outlook, is gross salvage minus cost of removal. The reserve percent is calculated by dividing the book reserve by the original cost of plant.

OPC and FPL disagreed on how a curve should be fitted and whether certain types of retirements should be included in the data analysis. These disagreements are found throughout the account-by-account analysis. In order to avoid repetition, these disagreements will be discussed in this part of our analysis.

OPC used visual curve fitting in its technique. OPC witness Pous asserted that data points which "reflect the most significant level of plant exposed to retirement events [exposures] —are more important . . . than others." For example, in his analysis of Account 353, Station Equipment, witness Pous contended that his proposed curve is a better fit through the first 16.5 years of age than FPL's curve, and a comparable fit to FPL's curve from 16.5 years through about 23.5 years. According to witness Pous, FPL's curve is a better fit between 23.5 and 36 years. OPC witness Pous asserted that the level of exposures is approximately $1.3 billion through the early years; however, it drops to approximately $500 million by 16.5 years of age. According to witness Pous, FPL's interpretation of the actuarial analysis is "erroneous" because it places greater significance on the end of the curve, rather than the top or head of the curve where the level of exposures is much higher.

FPL used visual curve fitting and mathematical (statistical) matching in its technique. FPL witness Clarke averred that the emphasis in curve fitting should be placed on the middle years, basing his methodology on Bulletin 125 by Robley Winfrey, "considered the dean of

[23] Both FPL and OPC recognize that depreciation involves estimates. For this reason, there is little reason to be as precise as a hundredth of a year for remaining lives. Our approved lives reflect the rounding of lives over 20 years to the nearest whole year and lives less than 20 years to the tenth of a year.

depreciation and life analysis."[24] Mr. Winfrey's recommendation is to give more weight to the middle portion of the curve, between 80 and 20 percent surviving, because this section "is the result of greater numbers of retirements and also it covers the period of most likely the normal operation of the property." Even so, according to FPL, "if the average service life and the survivor curve combination was not reasonable, experience and judgment were needed." FPL witness Clarke asserted that OPC witness Pous proposed "exactly the opposite" of what Mr. Winfrey recommends.

The disagreement on curve fitting between FPL and OPC only serves to emphasize the need for judgment. Based on the evidence, we believe that FPL's method of curve estimation, as described in the record, is appropriate because it relied on visual and mathematical curve fitting, as well as classic depreciation theory.

There is significant disagreement between FPL and OPC on whether certain data should be included or excluded when analyzing retirements and their associated cost of removal and gross salvage. When analyzing data for retirements, cost of removal, and gross salvage, FPL witness Clarke included recurring retirements that were reimbursed by outside parties. Witness Clarke, however, removed reimbursed retirements that he considered to be nonrecurring, for example, relocations required by the Department of Transportation and the installation of the new Metrorail line. Witness Clarke also removed data related to hurricanes. According to witness Clarke, hurricanes "are unexpected events that are not indicative of the future activity for an account."

OPC witness Pous did not distinguish between recurring and nonrecurring reimbursed retirements. He contended that FPL witness Clarke "removed the impact of reimbursed retirements from the analyses, even though such events occur on an annual basis . . . ." Witness Pous asserted that these reimbursed retirements "cannot legitimately be considered outliers."

In our opinion, it is reasonable to remove data related to nonrecurring events, such as hurricane effects and nonrecurring reimbursed retirements, from the analysis because the data can skew the results of the analysis. At the same time, we feel it is reasonable to include recurring data.

OPC proposed depreciation parameters for the aircraft accounts. However, there is no need at this time for us to order depreciation rates for these accounts because FPL removed aviation costs from rate base. If, in the future, FPL wishes to include aviation investment and depreciation expense in rate base for establishing revenue requirements, it will need to file a new depreciation study.

[24] Bulletin 125 was originally printed in 1935 by Iowa State University. It was revised by Harold A. Cowles, renamed the "Statistical Analyses of Industrial Property Retirements," and reprinted in April 1967.

1. Account-Specific Analysis: Transmission Plant

Account 350.20 – Easements

FPL proposed no change to its current S4 curve, 50-year average service life, and 0 percent net salvage. OPC proposed an increase in the average service life from 50 to 95 years.

OPC argued that FPL relied on "suggestive" industry data for its ASL proposal. OPC also argued that it is difficult to obtain easements for new transmission lines. This difficulty, in OPC's view, results in FPL's continued reliance on existing easements. OPC witness Pous characterized his proposal as "conservative." Witness Pous pointed out in his testimony that FPL does not have plans to retire easements.

FPL's plans are to continue to use existing easements "as it replaces transmission investment that currently occupies the easement." Although not all of FPL's easements are perpetual, FPL indicated that its "policy is to obtain perpetual rights easements (no expiration) everywhere that is available."

FPL witness Clarke asserted that there were "not many retirements in this account;" consequently, the "results of the statistical analysis were poor." According to witness Clarke, the industry range is 40-60 years, and with the present ASL of 50, "[t]here is no reason to warrant a change from the current approved [average service life of 50]." Witness Clarke characterized OPC's proposal of a 95-year ASL as "absurd." Witness Clarke averred that the maximum life of the equipment on the easements, e.g., poles, would be one half of the life of the easement.

We believe that a 50-year average service life for easements is too short, based on the evidence. OPC's arguments, for the most part, are convincing; however, not all of FPL's easements are perpetual. Therefore, we believe that a reasonable compromise is an average service life of 75 years.

Account 352.00 – Structures and Improvements

FPL proposed a change in curve from S4 to R3, an increase in the ASL from 47 to 60 years, and a decrease in net salvage from (10) percent to (15) percent. None of the intervenors offered any proposal for this account.

According to FPL witness Clarke, both his actuarial analysis and industry data suggest a life of 50 – 60 years. Witness Clarke also asserted that both his proposed curve and ASL "are reasonable for structure of this nature, produce the best results in the life analysis and are consistent with the estimates used by other electric utilities." Both the S4 and R3 curves, with a 60-year ASL, result in approximately the same remaining life.

Witness Clarke asserted that cost of removal has increased recently; however, gross salvage is "negligible." After reviewing the data, we agree that gross salvage is negligible. Between 2000 and 2007, cost of removal ranged from 0 percent (2000) to 387 percent (2003).

Accordingly, we find that decreasing the net salvage from (10) to (15) percent appears reasonable in light of the data.

Account 353.00 – Station Equipment

FPL proposed no change in the current R1.5 curve, a two-year increase in the ASL from 36 to 38 years, and a decrease in net salvage from five percent to (10) percent. OPC proposed an L1 curve, 43-year ASL, and 0 percent net salvage.

OPC argued that FPL's curve and ASL proposal "relies on a poor and inappropriate interpretation of the results of its actuarial analysis . . . ." Witness Pous contended that his proposed curve is a better fit through the first 16.5 years, where there are the greatest level of exposures (plant available for retirement). According to FPL witness Clarke, FPL's curve was the "best fitting curve mathematically." As discussed above, we believe that FPL's curve fitting technique is the appropriate technique. Accordingly, we will use the R1.5 curve.

OPC witness Pous also asserted that with regard to the ASL, FPL witness Clarke was incorrect when he asserted that an ASL of 38-39 years is "typical." According to OPC witness Pous, an ASL of 38-39 years falls at the low end of industry data. Witness Pous contended that, based on FPL's industry data, a "typical" ASL would be 45 or 50 years. Witness Pous also asserted that although FPL claimed it recognized the trend toward longer lives, it "did not follow through." We agree with OPC that the ASL should be longer than the 38 years proposed by FPL. However, an increase from 36 to 43 years is too large an increase at one time. Therefore, based on the record evidence, we will use a compromise ASL of 40 years.

For net salvage, OPC argued that FPL's proposal is "inappropriate." According to OPC witness Pous, there are "atypical values" in FPL's data that "drive" FPL's proposal to decrease net salvage from five to (10) percent. Witness Pous also contended that FPL's proposal "fails to analyze the relationship of investment mix versus retirement mix . . . ." Witness Pous asserted that the trend of increases in the cost of removal is "significantly driven by retirements during 2007."

FPL witness Clarke asserted that OPC witness Pous "claims to have investigated these [unusual] values, but the results of his 'investigation' are in some ways bizarre." According to FPL witness Clarke, witness Pous claimed that 2007's large cost of removal "is driven by the retirement of a building with a high level of asbestos." According to witness Clarke, the type of building referred to by OPC is in another account.

While the cost of removal should be decreased, a decrease from five percent to (10) percent is too drastic. Therefore, we approve a compromise of (2) percent net salvage.

Account 353.10 – Station Equipment – Generator Step-Up Transformers

FPL proposed a change in the curve from S3 to R2, a decrease in the ASL from 35 to 33 years, and a decrease in net salvage from five to 0 percent. OPC proposed a change in the curve from S3 to S0.5 and an increase in the ASL from 35 to 44 years.

OPC argued that FPL's approach to determining an ASL is "simplistic and flawed." OPC witness Pous contended that it is "illogical and inconsistent with the historical practices for the industry" to propose a shorter life for step-up transformers than for the rest of the generation plant to which the investment in this account is "directly tied." Witness Pous also asserted that a significant retirement occurred at age zero that should have been removed from the analysis.

FPL witness Clarke's rebuttal was brief. Witness Clarke asserted that his curve and ASL proposals were based on statistical analysis. He further asserted that the "statistical analysis was good and showed a good fit . . . both graphically and mathematically." Witness Clarke contended that removing the retirement that occurred at year zero did not impact his analysis.

As discussed above, we believe that FPL's curve fitting technique is appropriate; therefore, we will use the R2 curve. We disagree with FPL's shortening of the ASL; however, we do not believe the record supports an increase in average service life. Therefore, we will use an ASL of 35 years.

Account 354.00 – Towers and Fixtures

FPL proposed no change to the existing R5 curve, 45-year ASL, and (15) percent net salvage. OPC proposed a small change in the curve from R5 to R4, an increase in the ASL from 45 to 60 years, and an increase in net salvage from (15) percent to 0 percent.

OPC argued that FPL admitted that the results of its actuarial analysis are "poor." OPC witness Pous asserted that OPC's "recommendation is logically derived from Company specific data, and is also reflective of what Mr. Clarke and his firm have recommended in other depreciation studies." According to witness Pous, the basis for OPC's recommendation for an R4 curve and 60-year ASL is primarily that FPL has "substantial" investment 35 years old or older and that there have been few retirements. With few retirements, OPC placed "greater reliance" on information from the industry. OPC argued that, using FPL's industry data, 63 years is the average ASL.

FPL witness Clarke contended that there was insufficient information to recommend a change to the ASL. Witness Clarke also asserted that OPC provided no evidence that the industry data results in an "appropriate comparison with FPL." Additionally, witness Clarke asserted that OPC was "wrong" about FPL having plant close to the maximum age. According to witness Clarke, the maximum life for the R5 curve with 45-year ASL is over 60 years; the oldest FPL plant is 49 years old as of December 31, 2009.

In our opinion, limited retirements lend credence to OPC's proposal for a longer life. However, we believe that 60 years is too long. Accordingly, we will use the R5 curve with a 52-year ASL.

With regard to net salvage, OPC argued that FPL's proposal "is based on its failure to properly analyze the data upon which it relied." OPC witness Pous primarily based his arguments on what he viewed as data manipulation, including the 2006 data. According to FPL witness Clarke, OPC witness Pous contended that reimbursed retirements should have been included. FPL witness Clarke contended that OPC's argument about discrepancies in 2006 data is related to hurricane-related retirements, which FPL removed from the data. As discussed above, we believe that FPL's approach with regard to reimbursed retirements and the effects of hurricanes is reasonable. Therefore, we approve a net salvage of (15) percent.

Account 355.00 – Poles and Fixtures

FPL proposed no change to the R2 curve, an increase in the ASL from 41 to 44 years, and no change to the (50) percent net salvage. OPC proposed that the net salvage be increased from the current (50) percent to (30) percent.

OPC witness Pous contended that FPL's "manipulation of its actual historical data is suspect." By this, OPC meant that FPL removed reimbursed retirements and hurricane related data. As discussed above, we believe that FPL's approach with regard to reimbursed retirements and the effects of hurricanes is reasonable.

OPC witness Pous also contended that FPL ignored more recent data with reduced negative net salvage. OPC argued that FPL did not consider economies of scale. OPC further argued that although FPL expected increased negative net salvage because of preservatives on the poles, FPL "admitted" that the majority of transmission poles are concrete. Witness Clarke responded to OPC's contention that FPL ignored recent data by explaining that "a more detailed look at the history of this account reveals that there is more of a cyclical trend . . . ." With regard to economies of scale, witness Clarke referred to an earlier discussion where he pointed out that for economies of scale to be pertinent, large numbers of retirements need to occur in close proximity.

We believe that FPL's removal of nonrecurring reimbursed retirements and hurricane data is appropriate; otherwise, this data might skew the results. After reviewing the data, we believe that the data is probably more cyclical in nature than not. While some economies of scale might be present, they are probably small once hurricane data is excluded. Accordingly, we find that (50) percent net salvage is appropriate.

Account 356.00 – Overhead Conductors and Devices

FPL proposed no change in the R1.5 curve, an increase in the ASL from 44 to 47 years, and a decrease in net salvage from (45) to (50) percent. OPC proposed an S0 curve, an increase in the ASL to 51 years, and an increase in net salvage from (45) to (40) percent.

OPC witness Pous contended that his curve fitting technique provides a "somewhat better overall fit" than FPL's technique. As discussed above, we believe FPL's curve fitting technique is appropriate. Therefore, we will use the R1.5 curve.

OPC witness Pous asserted that the process of upgrading lower voltage transmission lines to higher voltage lines "artificially shortened the overall life expectancy of the previously retired investment." Thus, according to witness Pous, a longer ASL is indicated. Witness Pous contended that another reason for an increased ASL is the "not in my backyard" or "NIMB" syndrome.

FPL witness Clarke discounted OPC's arguments by asserting that the "data for this account is excellent and fits the Iowa curve selection very nicely." We believe that FPL has made the more persuasive case in its proposal to increase the ASL from 44 to 47 years.

With regard to net salvage, OPC argued that FPL manipulated the database by removing reimbursed retirements. As discussed above, we are of the opinion that FPL's approach on reimbursed retirements and hurricane effects is reasonable. Therefore, we approve a net salvage of (50) percent.

Account 357.00 – Underground Conduit

FPL proposed a change in curve from S3 to R4, an increase in the ASL from 46 to 60 years, and no change to the net salvage of 0 percent. None of the intervenors offered any proposal for this account.

According to FPL witness Clarke, actuarial data and industry data support an increase in the ASL and a change to a "higher mode" curve. We note that whether the S3 or R4 curve is used with the ASL of 60 years, the remaining life differs by less than one year. With "limited" data, witness Clarke asserted that a net salvage "close to 0 percent is appropriate since underground conduits are generally abandoned in place." We believe that the R4 curve, and 60-year ASL are appropriate. We approve a net salvage of 0 percent.

Account 358.00 – Underground Conductors and Devices

FPL proposed a change in curve from S3 to L3, an increase in the ASL from 35 to 60 years, and a decrease in net salvage from 0 to (10) percent. None of the intervenors offered any proposal for this account.

According to FPL witness Clarke, the actuarial analysis results in life indications of 50 to 60 years, with industry data ranging between 30 and 60 years. Witness Clarke asserted that, "[g]enerally, the cost of removing wire from underground conduit is expected to be greater than its salvage value, thus net salvage of 0 or less is reasonable." According to witness Clarke, industry data suggest net salvage between 0 and (20) percent. Witness Clarke asserted that, for FPL, salvage data is "sporadic" for some years.

Using an S3 curve or an L3 curve with a 60-year ASL results in almost the same remaining life (difference of less than one year). We believe that the change in curve is reasonable. With regard to net salvage, there has been no gross salvage since 2000, while cost of removal has experienced considerable variance (e.g., 37 percent in 2006 and 509 percent in 2005). Overall, net salvage appears to be decreasing; therefore, we find that the decrease in net salvage to (10) percent is reasonable.

Account 359.00 – Roads and Trails

FPL proposed no change to the current curve, no change in the 50-year ASL, and a decrease in net salvage from 0 to (10) percent. OPC proposed that the ASL be increased to 65 years.

According to FPL witness Clarke, there is "very little activity in this account." Witness Clarke concludes, based in part on industry data, that a range of 50 to 70 years "would be consistent with the industry range." Witness Clarke decreased the net salvage because "there is [sic] some removal costs preparing to restore to pristine condition." According to witness Clarke, the cost of removal rates are (41) percent for the 20-year band and (48) percent for the 5-year band.

OPC argued that investments in this account can and will last longer than the 50 years proposed by FPL. According to OPC witness Pous, "limited level of retirement activity . . . is indicative of longer life spans for such investments." OPC witness Pous also compared FPL witness Clarke's proposal in this docket with proposals he made in other states. FPL witness Clarke opined that there is "no justification" for extending the life; furthermore, he asserted that witness Pous provided "no valid justification" for his proposal. Witness Clarke disagreed with OPC witness Pous that what witness Clarke proposed in other states is relevant in this case.

We agree with OPC that limited retirement activity lends support to an increase in life. Accordingly, we believe that a 65-year ASL for this account is reasonable.

2. Account-Specific Analysis: Distribution Plant

Account 361.00 – Structures and Improvements

FPL proposed a change in curve from L3 to R3, an increase in the ASL from 45 to 60 years, and no change to the net salvage of (15) percent. None of the intervenors offered any proposal for this account.

According to FPL witness Clarke, the actuarial analysis supports a change in curve and an increase in life. Industry lives for this account range from 30 to 65 years. Changing the curve from L3 to R3 with a 60-year ASL results in remaining lives that are less than one year apart. According to witness Clarke, cost of removal is increasing, but gross salvage is "negligible." We believe that the R3 curve, and 60-year ASL are appropriate. We approve a net salvage of (15) percent.

Account 362.00 – Station Equipment

FPL proposed no change in the R1.5 curve, an increase in the ASL from 38 to 41 years, and no change in the (10) percent net salvage. OPC proposed a change in the curve from R1.5 to S0 and an increase in the ASL from 38 to 48 years.

OPC argued that its curve fitting technique, which places greater emphasis on the level of exposures, is appropriate. As discussed above, we believe that FPL's technique is appropriate; therefore, we will use the R1.5 curve. OPC witness Pous also contended that FPL's industry average is 46 years. FPL witness Clarke disagreed with OPC's proposed increase in the ASL to 48 years. However, we believe that a modest increase in life beyond FPL's is warranted. Therefore, we increase the life to 43 years.

Account 364.00 – Poles, Towers, and Fixtures

FPL proposed a slight change in the curve, from R1.5 to R2, an increase in the ASL from 34 to 37 years, and a decrease in net salvage from (40) percent to (125) percent. OPC proposed the curve remain at R1.5, an increase in the ASL from 34 to 41 years, and a decrease in net salvage from (40) percent to (60) percent.

OPC witness Pous contended that his proposed curve and ASL are a "superior fit" compared to FPL's proposal. Witness Pous asserted that FPL's statements that "most poles in the system are concrete poles is incorrect;" the "vast majority" of poles are wood poles. According to witness Pous, FPL recognized, but did not appear to incorporate, programs to extend the life of wood poles. Witness Pous averred that industry data supports an ASL longer than the 37 years proposed by FPL. FPL witness Clarke asserted that FPL is "not sure" how many wood poles will be replaced with concrete poles. Witness Clarke contended that his ASL proposal extends the life, but to increase it even more "is not justified at this time." Additionally, according to witness Clarke, using the average life in the industry is "incorrect." We believe it is reasonable to extend the ASL further; however, we believe that a compromise ASL of 39 years is appropriate based on the record. We also believe that the R2 curve is appropriate.

FPL proposed to decrease net salvage from (40) to (125) percent because of a "large increase in removal costs." OPC proposed a much smaller decrease in net salvage from (40) to (60) percent. OPC argued that FPL's proposal is the "most aggressive depreciation practice presented by the Company." OPC witness Pous contended that a review of the data indicates FPL "has significantly manipulated the historical results" by removing reimbursed retirements. Witness Pous also asserted that while FPL "has raised concerns" about the disposal of treated wood poles, FPL "fails to note" the level of investment of concrete poles (18 percent), and that FPL is adding concrete poles at a faster rate than wood poles.

As discussed above, we believe that FPL's approach on reimbursed retirements is reasonable. A review of the data shows that cost of removal is increasing and gross salvage is decreasing. We believe it would be a useful exercise for FPL to perform an analysis to determine why this is occurring and whether it is possible for FPL to make internal changes that might mitigate this trend. We are of the opinion that FPL's proposed decrease in net salvage is too large and may well be premature. OPC's proposed net salvage of (60) percent represents a moderate decrease in net salvage, yet it still reflects FPL's actual experience. Accordingly, we approve (60) percent net salvage.

Account 365.00 – Overhead Conductors and Devices

FPL proposed a slight change in curve, from S0.5 to S0, an increase in the ASL from 35 to 40 years, and a decrease in net salvage from (50) to (100) percent. OPC proposed the S0 curve, an increase in the ASL to 43 years, and no change in net salvage of (50) percent.

OPC argued that its proposed 43-year ASL is the "only credible recommendation in the record." OPC witness Pous contended that if FPL had used the 20-year experience band, the ASL "would have to be increased" to 46 years instead of 40 years. Additionally, according to witness Pous, industry information would support an ASL in the "mid 40s." FPL witness Clarke contended that his statistical analysis was "good" and his proposal was a "good fit both graphically and mathematically." Witness Clarke asserted that witness Pous did not explain why a 20-year band should be used. Since both parties made good arguments, a compromise on the ASL is reasonable. Therefore, we will use an S0 curve and 41-year life.

FPL proposed a net salvage of (100) percent, in effect doubling the negative net salvage. OPC witness Pous contended that FPL's proposal was made "without adequate or reasonable justification for its position." According to witness Pous, FPL did not investigate a "significant anomaly," a large negative gross salvage in 2006. FPL responded that it considered the amount an outlier. FPL witness Clarke contended that assuming an "average" salvage in 2006, the net salvage would have been over (90) percent. According to OPC witness Pous, the "disproportionate retirement level of switches in the historical database is skewing" FPL's proposal. FPL witness Clarke responded that he looked at all retirements, not just the 10 percent of retirements comprised of switches. Part of OPC's argument refers to reimbursed retirements.

As discussed above, we believe that FPL's approach to reimbursed retirements is reasonable. However, such a large decrease in net salvage is without adequate support. A review of the data shows that cost of removal is increasing. We believe it would be a useful exercise for FPL to perform an analysis to determine why the cost of removal is increasing and whether it is possible for FPL to make internal changes that might mitigate this trend. A modest decrease in net salvage, reflecting the data, is appropriate. Accordingly, we approve (60) percent net salvage.

Account 366.60 – Underground Conduit, Duct System

FPL proposed a small change in the curve, from S3 to S1.5, an increase in the ASL from 48 to 70 years, and an increase in the net salvage from (10) percent to (5) percent. OPC proposed a net salvage of 0 percent.

OPC argued that FPL's proposed increase in net salvage is "inadequate." OPC witness Pous asserted that the 5-year salvage band results support a 0 percent net salvage; however, the 3-year bands are positive. According to witness Pous, "[I]f reimbursed retirements are recognized, the historical database turns *positive* overall." As discussed above, we believe that FPL's approach on reimbursed retirements is reasonable. However, after an evaluation of the data, the record supports an increase in the net salvage somewhat more than FPL's proposal. We find that a net salvage of (2) percent is appropriate.

Account 366.70 – Underground Conduit, Direct Buried

FPL proposed a change in curve from S3 to R4, an increase in the ASL from 41 to 50 years, and no change in the 0 percent net salvage. None of the intervenors offered any proposal for this account.

According to FPL witness Clarke, the results of the actuarial analysis were "poor." Lives in the industry range from 35-80 years. Witness Clarke asserted that the S3 curve is "too short" and the ASL should be increased. According to witness Clarke, the "cost of removal and [gross] salvage percents are all over the place for this account;" therefore, his proposal is to retain the net salvage. We will use the R4 curve, and 50-year ASL. We approve a net salvage of 0 percent.

Account 367.60 – Underground Conductors and Devices Duct System

FPL proposed to retain the S0 curve, 38-year ASL, and (5) percent net salvage. OPC proposed a curve change from S0 to L1, an increase in the ASL from 38 to 40 years, and an increase in net salvage from (5) percent to 0 percent.

OPC argued that the L1 curve is a better fit through the first 12 to 13 years. As discussed above, we believe that FPL's curve fitting technique is appropriate. Therefore, we will use the S0 curve. OPC witness Pous contended that tree retardant cable, which comprises over 22 percent of the investment, provides support for a longer ASL. FPL witness Clarke responded that he was unaware that there was an established industry life for tree retardant cable longer than 38 years. We believe FPL's argument persuasive; therefore, we will use an S0 curve and 38-year ASL.

For net salvage, OPC based its proposal, in part, on reimbursed retirements. As discussed above, we believe that FPL's approach on reimbursed retirements is reasonable. We find that 0 percent net salvage is appropriate based on the data.

Account 367.70 – Underground Conductors Devices Direct Buried

FPL proposed a change in curve from R2.5 to R2, an increase in the ASL from 34 to 35, and no change in the 0 percent net salvage. OPC proposed a change in curve from R2.5 to S0.5 and an increase in the ASL from 34 to 43 years.

OPC argued that its "presentation of a better curve fit was unrebutted." OPC witness Pous asserted that his proposed curve is a better fit than FPL's during different periods. As discussed earlier, we believe that FPL's curve fitting technique is appropriate; therefore, we approve the R2 curve. OPC witness Pous contended that the slowing of retirements in the last six years would support an increased ASL beyond FPL's proposal. According to FPL witness Clarke, while retirements had slowed down, they have begun to increase again. We believe that a 35-year ASL is reasonable and supported by the evidence.

Account 368.00 – Line Transformers

FPL proposed a change in curve from L2 to L1.5, an increase in the ASL from 31 to 32, and an increase in net salvage from (35) percent to (25) percent. OPC proposed the L1.5 curve, an ASL of 34 years, and an increase in net salvage to (20) percent.

OPC argued that its proposed curve is a better fit for ages less than 24.5 years. As discussed above, we believe that FPL's curve fitting technique is appropriate; therefore, we will use the L1.5 curve. OPC witness Pous asserted that his ASL recommendation of 34 years is closer to the industry average ASL than FPL's. Although FPL witness Clarke mentioned OPC's discussion of industry averages, witness Clarke did not refute the use of averages; rather, he contended that the statistical analysis was "good" and that his proposed curve and life "fit good both graphically and mathematically." According to witness Clarke, the industry range is 26-45 years. We believe that an increase in the ASL to 33 years is reasonable and appropriate.

FPL witness Clarke asserted that his proposed increase in net salvage is based on a decline in the cost of removal with almost no gross salvage. OPC argued that FPL's proposal is insufficient. Witness Clarke contended that OPC has "no facts" for increasing the net salvage compared to what FPL proposed. After reviewing the data, we find that an increase in net salvage from (35) to (25) percent is reasonable.

Account 369.10 – Services, Overhead

FPL proposed a small change in the curve, from R1.5 to R1, an increase in the average service life, from 36 to 48 years, and a decrease in the net salvage, from (60) percent to (125) percent. OPC proposed that the net salvage be decreased from (60) percent to (85) percent.

OPC provided several arguments against decreasing the net salvage. First, OPC witness Pous asserted that FPL's current net salvage is "already more negative than the industry average by a significant level." Second, witness Pous contended that FPL's accounting practices are "suspect." Third, according to witness Pous, FPL's proposed net salvage would produce $4.2 million of negative net salvage, an amount that is "almost *four* times the average level of negative net salvage the Company has experienced throughout its historical database . . . ." Additionally, OPC argued that FPL's proposal was made "without any consideration of what causes it to be so much more negative than the industry."

According to FPL witness Clarke, net salvage has been more than (200) percent in some recent years. Witness Clarke asserted that a "direct comparison of FPL to the companies in my industry group would not be an 'apples to apples' comparison." This is because of the "many factors" that influence FPL's data, including "accounting policies, Operation and Maintenance (O&M) practices, management policies, etc."

It is clear from a review of the data that cost of removal is increasing. We believe it would be a useful exercise for FPL to perform an analysis to determine why the cost of removal is increasing and whether it is possible for FPL to make internal changes that might mitigate this trend. We are also of the opinion that decreasing net salvage from (60) to (125) percent is far too drastic. Accordingly, we approve decreasing net salvage from (60) to (85) percent because this is a moderate change that, nonetheless, recognizes what is occurring in this account.

Account 369.70 – Services, Underground

FPL proposed no change in the R2 curve, 34-year ASL, and (10) percent net salvage. OPC proposed a change in curve from R2 to S0.5, an increase in the ASL from 34 to 41 years, and an increase in net salvage from (10) percent to (5) percent.

OPC witness Pous contended that its proposed curve is an "excellent" fit through the first 13.5 years of age. As discussed above, we believe that FPL's curve fitting technique is appropriate; therefore, we will use the R2 curve. According to witness Pous, FPL did not state that the average ASL for its industry database is 39 years, five years longer than FPL's proposed ASL, while OPC's proposal is two years higher. According to FPL witness Clarke, retirements in this account are "very small compared to the exposures." We believe that an ASL of 38 is both moderate and reasonable, taking into account what appears to be longer living plant.

OPC argued that the "only credible evidence in the record supports" OPC's net salvage proposal. Witness Pous averred that there appears to be a correlation between quantity retired and cost of removal, such that economies of scale had an impact. FPL witness Clarke alleged that witness Pous "attempts to confuse the record." We disagree. We find that an increase in net salvage to (5) is appropriate based on data and the record.

Account 370.00 – Meters

FPL proposed a change in curve from S2 to R2.5, an increase in the ASL from 34 to 36 years, and a decrease in net salvage from (30) percent to (55) percent. OPC proposed a curve of S1.5, an ASL of 38, and net salvage of (10) percent.

According to OPC witness Pous, his visual curve fitting technique produces a better fit through the first 22.5 years. As discussed above, we believe that FPL's curve fitting technique is appropriate; therefore, we will use the R2.5 curve. OPC argued that based on actuarial analysis, an ASL of 38 years is warranted. FPL expects to retire approximately 4.3 million meters in the next five years, to be replaced with AMI meters (Account 370.10). We believe that increasing the ASL beyond 36 years is premature because of the planned replacements of meters.

OPC argued that FPL did not establish that its historical net salvage "is indicative of what will transpire in the future . . . ." OPC witness Pous asserted that FPL did not refer to industry data when discussing this account because if it had, "it would have become patently clear that the Company's proposal falls so far outside reasonable bounds as to lack credibility." According to OPC witness Pous, the industry database upon which FPL relied shows an average net salvage of (3) percent, with the most negative net salvage at (25) percent. OPC witness Pous based his recommendation on a cost of removal estimate of $5.63 per meter, taken from a case in Texas. Witness Pous applied $5.63 to FPL's 4.3 million meters that will be retired in the next five years, yielding an approximate net salvage of (10) percent. FPL witness Clarke contended that retiring 4.3 million meters will have "no bearing" on the contents of this account. Witness Clarke asserted that his proposed net salvage relates to those meters not being replaced with AMI meters because meters removed due to the AMI program will be moved to a capital recovery schedule.

We are troubled by such a high proposed cost of removal. Although the data may appear to support a higher cost of removal, FPL did not provide an analysis of why the cost of removal is high. Accordingly, we believe it would be a useful exercise for FPL to investigate and determine the reasons for the high cost of removal in this account. We believe it is premature to increase the cost of removal. At the same time, the data indicates a net salvage less than OPC's proposal. Therefore, we approve a net salvage of (30) percent.

Account 370.10 – Meters – AMI

This is a new subaccount, containing AMI meters. FPL proposed a curve of R2.5, an ASL of 20 years, and (55) percent net salvage. OPC proposed a net salvage of (10) percent.

FPL based its curve on the curve for Account 370.00, Meters, and its proposed ASL on the manufacturer's suggested 20-year life. We believe that this is reasonable.

With regard to net salvage, FPL witness Clarke noted that AMI meters are "new and no historical information is available." FPL witness Clarke asserted that there is no reason to use a different net salvage for this account than for Account 370.00, Meters. Therefore, he recommended the same net salvage percent that he recommended for Account 370.00, Meters. OPC argued that its recommendation also relies on its recommendation for Account 370.00, Meters.

At this time, we agree that the net salvage for this account should be the same as the net salvage for Account 370.00, Meters. Therefore, based on the discussion in Account 370.00, Meters, we find that a net salvage of (30) percent is appropriate.

Account 371.00 – Installations on Customer's Premises

FPL proposed a slight curve change, from L1 to L0, an increase in the ASL from 15 to 30 years, and a decrease in net salvage from (15) to (25) percent. None of the intervenors offered any proposal for this account.

Most additions to this account occurred within the last 30 years. Industry lives range from 10 to 30 years, averaging 22 years. According to FPL witness Clarke, the current L1 curve and 15-year life are "low for this type of equipment and within the industry range." We believe that the L0 curve and 30-year ASL are reasonable.

Witness Clarke asserted that the cost of removal increased in the last five to six years, while gross salvage has decreased. According to witness Clarke, the industry range is from 0 to (40) percent. Witness Clarke's proposed decrease in net salvage derives from the last five years. We believe a decrease in net salvage is reasonable; however, a change from (15) to (25) percent is too drastic based on the evidence. We believe that a more moderate change is appropriate. Accordingly, we find that a net salvage of (20) percent is appropriate.

Account 373.00 – Street Lighting and Signal Systems

FPL proposed a change in curve from S-0.5 to R0.5, an increase in the ASL from 20 to 30 years, and an increase in net salvage from (35) to (20) percent. OPC proposed an L0 curve with a 35-year life.

OPC witness Pous asserted that his curve fitting technique is a better fit through the first 10.5 years. As discussed above, we believe that FPL's curve fitting technique is appropriate; therefore, we will use the R0.5 curve.

OPC argued that FPL "failed to consider the technological changes" that have occurred to this account's investment. OPC witness Pous asserted that the changes in technology in this account have led to shorter ASLs (for existing plant). Therefore, according to witness Pous, OPC's recommended 35-year life is a "conservative estimate at this point in time," because FPL has not identified any new technologies. According to FPL witness Clarke, FPL did not identify any changes in the near future; therefore, witness Clarke asserted that he did not believe that OPC had a "valid basis" for its prediction. We do not believe the record supports an increase in the ASL from 20 to 35 years. Therefore, we believe that a 30-year ASL is appropriate.

Account 390.00 – Structures and Improvements

FPL proposed a change in curve from S1 to R1.5, an increase in the ASL from 38 to 50 years, and a decrease in net salvage, from 0 percent to (10) percent. OPC proposed an L0 curve, an increase in the ASL to 56 years, and an increase in net salvage from 0 to 25 percent.

OPC witness Pous contended that his curve is a better fit through the first 10.5 years of life. As discussed above, we believe that FPL's curve fitting technique is appropriate; therefore, we will use the R1.5 curve.

OPC argued that its proposal to increase the ASL to 56 years is "conservative." According to OPC witness Pous, FPL "understates the realistic and reasonable ASL for this account." Witness Pous contended that because this account contains ten buildings comprising approximately 64 percent of the investment, an ASL longer than FPL's proposed ASL is "well warranted." OPC witness Clarke asserted that the ten buildings "also include ancillary components such as roofs, air conditioning, lighting systems, etc." We agree that the ASL should be increased and we believe that an increase to 50 years is moderate and supportable.

With regard to net salvage, OPC argued that over 40 percent of the investment is in FPL's two largest office complexes, and that the trend in commercial real estate is capital appreciation, not depreciation. OPC witness Pous asserted that the negative net salvage derives from retirements of building components, such as roofs. FPL witness Clarke asserted that assets such as roofs are what FPL expects to retire in the future. Witness Clarke contended that "substantial appreciation" in real estate has not occurred in Florida since 2005. Witness Clarke also asserted that if FPL were to retire any of these buildings, they would "probably be worthless as-is, without improvements." Only the land would have value, according to witness Clarke; however, the land is owned by shareholders who do not receive return of their capital through rates. We believe that FPL makes a more persuasive case; however, FPL's view of the net salvage for this account is unnecessarily bleak. Accordingly, we approve a net salvage of (5) percent.

Account 392.10 – Transportation – Automobiles

FPL proposed a small change in the curve, from L3 to L2, a decrease in average service life from eight to six years, and an increase in net salvage from 10 to 15 percent. None of the intervenors offered a proposal for this account.

According to FPL witness Clarke, FPL personnel "mentioned the lives of automobiles were getting shorter in recent years," and Company records confirmed that, showing "automobiles were sold after 6 years." Also, according to witness Clarke, the cost of removal is 0 while salvage is "around 15 percent," representing an increase in salvage. We believe that the L2 curve, and six-year ASL are appropriate, and we find that a 15 percent net salvage is reasonable.

Account 392.20 – Transportation – Light Trucks

FPL proposed a change in curve from S3 to L3, no change in the nine-year ASL, and no change to the 15 percent net salvage. None of the intervenors offered a proposal for this account.

FPL witness Clarke's actuarial analysis resulted in lives of around eight and one half to nine years. FPL personnel confirmed that eight to nine years is the life for light trucks. According to witness Clarke, the curve "should be changed to reflect the life analysis results." Witness Clarke asserted that although the gross salvage showed a "slight increase," the net salvage (cost of removal is 0) should remain at 15 percent because the increase may result from "one year of suspect data."

After reviewing the salvage data, we agree that the indicated increase in salvage may be the result of bad data. Even if the increase is not because of bad data, it is premature to increase the net salvage. Therefore, we believe that the L3 curve, and nine-year ASL are appropriate, and we find that a 15 percent net salvage is reasonable.

Account 392.30 – Transportation – Heavy Trucks

FPL proposed no change in the S3 curve, an increase in the ASL from 11 to 12 years, and an increase in net salvage from 10 percent to 15 percent. None of the intervenors offered a proposal for this account.

FPL witness Clarke based his increased life proposal on both actuarial analysis and information from FPL personnel. According to witness Clarke, a salvage analysis showed increasing salvage and no cost of removal. We believe that it is reasonable to retain the S3 curve, and to increase the ASL to 12 years, and we find that it is appropriate to increase the net salvage to 15 percent.

Account 392.40 – Transportation – Tractor Trailers

FPL proposed a change in curve from S2 to L2.5, a decrease in the ASL from 11 to nine years, and a decrease in net salvage from 15 to 0 percent. None of the intervenors offered a proposal for this account.

According to witness Clarke, actuarial analysis showed a nine-year life, which was confirmed by FPL personnel. Witness Clarke asserted that an L2.5 curve and a nine-year life "better reflect [the] life analyses." No cost of removal or gross salvage has been recorded for this account since 2000; therefore, witness Clarke recommended a net salvage of 0 percent.

We believe that the L2.5 curve and a nine-year ASL are reasonable. We find that decreasing the net salvage from 15 to 0 percent is appropriate since there has not been any cost of removal or gross salvage recorded since 2000.

Account 392.90 – Transportation – Trailers

FPL proposed a small change in the curve, from L2 to L1, an increase in the average service life from 18 to 20 years, and a decrease in net salvage from 30 to 15 percent. None of the intervenors offered any proposal for this account.

According to FPL witness Clarke, FPL personnel informed him that these trailers last between 15 to 25 years. The actuarial analysis showed lives of about 20 years, with a low order curve. We believe that an L1 curve and ASL of 20 years are reasonable.

Witness Clarke's net salvage proposal stems from an analysis that showed "very little salvage and no removal costs being recorded in the past few years." Witness Clarke averred that the "estimate of 30 percent net salvage is too high and should be decreased." We note that gross salvage has varied widely since 2001. We believe it is premature to reduce the net salvage; therefore, we approve a 30 percent net salvage.

Account 396.10 – Power Operated Equipment – Transportation

FPL proposed a small change in curve, from L0 to L0.5, an increase in the ASL from nine to 10 years, and no change in the 20 percent net salvage. None of the intervenors offered any proposal for this account.

FPL witness Clarke proposed the increase in the ASL based on the actuarial analysis and information from FPL personnel. Witness Clarke testified that there is no cost of removal; however, gross salvage data "does not look good for [the] last five years." Prior to the last five years, gross salvage averaged around 20 percent. Witness Clarke's proposal is to retain the current 20 percent net salvage. We agree that the salvage data is problematic; thus, we find that retaining 20 percent net salvage is reasonable. We also believe that the L0.5 curve and 10-year ASL are reasonable.

Account 396.80 – Other Power Operated Equipment

FPL proposed a change in curve from S1 to L0.5, no change in the nine-year ASL, and no change in the 20 percent net salvage. None of the intervenors offered any proposal for this account.

Witness Clarke proposed the curve change based on his actuarial analysis. According to witness Clarke, no cost of removal or salvage data has been recorded since 2000. Witness Clarke proposed that this account use the same net salvage as Account 396.1, Power Operated Equipment, i.e., 20 percent, "[u]ntil the data is reviewed." The current net salvage for this account is 20 percent. We believe that the L0.5 curve, and nine-year ASL are reasonable. We find that a 20 percent net salvage is reasonable.

Account 397.80 – Communications Equipment – Fiber Optics

FPL proposed no change in the L0 curve, no change in the 10-year ASL, and a decrease in net salvage from five to 0 percent. None of the intervenors offered any proposal for this account.

According to FPL witness Clarke, there was "insufficient data to perform an actuarial life analysis." Witness Clarke noted that the fiber optic equipment in this account was "spun off" in 2000; the remaining investment is the electronics equipment. Therefore, witness Clarke recommended no change in the curve or average service life. Witness Clarke asserted that the data for the salvage analysis is "erratic and missing many years." He recommended ignoring the salvage data and using 0 percent net salvage "until data is revised."

After reviewing the cost of removal and salvage data, we agree with witness Clarke that the data should be ignored. We agree with FPL's proposal; therefore, the net salvage shall be reduced to 0 for this account. We believe that it is reasonable to retain the L0 curve and 10-year ASL.

3. Amortizations

General Accounts

Pursuant to Rule 25-6.04361(5)(f), F.A.C., certain General Plant Accounts may use an amortization schedule. FPL proposed to amortize these accounts in accordance with the rule. Under FPL's proposal, there will be no change to the depreciation accrual. None of the intervenors offered a proposal for these accounts. The approved amortizations are shown in Table 4:

Table 4: General Account Amortizations

| Account No. | Account Name | Amortization Period (Years) |
|---|---|---|
| 391.10 | Office Furniture | 7.0 |
| 391.20 | Office Accessories | 5.0 |
| 391.30 | Office Equipment | 7.0 |
| 391.40 | Duplicating & Mailing Equipment | 7.0 |
| 391.50 | EDP Equipment | 5.0 |
| 391.70 | PC Equipment (ECCR) | 3.0 |
| 391.90 | Personal Computer Equipment | 3.0 |
| 392.70 | Transportation Equipment – Marine | 5.0 |
| 393.10 | Stores Equipment – Handling Equipment | 7.0 |
| 393.20 | Stores Equipment – Storage Equipment | 7.0 |
| 394.20 | Shop Equipment – Portable Handling | 7.0 |
| 395.20 | Lab Equipment – Portable | 7.0 |
| 395.60 | Laboratory Testing Equipment (LMS) | 5.0 |
| 397.20 | Communications Equipment – Other 7-Yr Amrt | 7.0 |
| 397.30 | Communications Equipment – Official | 7.0 |
| 397.40 | Communication Equipment (ECCR) | 5.0 |
| 398.00 | Miscellaneous Equipment | 7.0 |

Other Accounts

Pursuant to Order No. PSC-05-0902-S-EI, issued on September 14, 2005, in Docket No. 050188-EI, four other amortizations were permitted. The other amortizations are contained in Table 5:

Table 5: Amortizations for Other Accounts

| Account No. | Account Name | Amortization Period (Years) |
|---|---|---|
| 362.90 | Substation Equipment – LMS | 5.0 |
| 367.50 | UG Conduct & Dev., Cable Injection–20+ Years | 29.0(*) |
| 367.90 | UG Conduct & Dev., Cable Injection–10 Years | 10.0 |
| 371.20 | Residential Load Management | 5.0 |

*Per Order No. PSC-94-1199-FOF-EI, issued on September 30, 1994, in Docket No. 931231-EI, the 20-year guaranteed cable injection is to be recovered over the remaining life of the cable. The remaining life shown is the approved remaining life.

In this proceeding, FPL proposed to continue using the previously-approved amortizations. None of the intervenors offered any proposal for these accounts. The only change to the depreciation accrual will be for Account 367.50, which, by our prior order, is tied to the remaining life of the cable. Therefore, we approve the amortizations contained in Tables 4 and 5.

In conclusion, we approve the remaining life, net salvage percent, allocated reserve percent, amortizations, and resulting rates for each transmission, distribution, and general plant account contained in Table 6, on the following pages.

Table 6: Transmission, Distribution, and General Plant Depreciation Components and Resulting Rates

| Account Number and Description | COMMISSION APPROVED Average Remaining Life | Net Salvage | Theoretical Reserve | Remaining Life Rate |
|---|---|---|---|---|
| | (yrs.) | (%) | (%) | (%) |
| **TRANSMISSION PLANT** | | | | |
| 350.2 Easements | 58 | 0.00 | 22.67 | 1.3 |
| 352.0 Structures & Improvements | 47 | (15.00) | 24.92 | 1.9 |
| 353.0 Station Equipment | 29 | (2.00) | 28.05 | 2.6 |
| 353.1 Station Equipment - Step-Up | 25 | 0.00 | 28.57 | 2.9 |
| 354.0 Towers & Fixtures | 34 | (15.00) | 39.81 | 2.2 |
| 355.0 Poles & Fixtures | 33 | (50.00) | 37.50 | 3.4 |
| 356.0 OH Conductors & Devices | 35 | (50.00) | 38.30 | 3.2 |
| 357.0 Underground Conduit | 40 | 0.00 | 33.33 | 1.7 |
| 358.0 Undg. Conductors & Devices | 40 | (10.00) | 36.67 | 1.8 |
| 359.0 Roads & Trails | 47 | (10.00) | 30.46 | 1.7 |
| **DISTRIBUTION PLANT - DEPRECIABLE** | | | | |
| 361.0 Structures & Improvements | 50 | (15.00) | 19.17 | 1.9 |
| 362.0 Station Equipment | 33 | (10.00) | 25.58 | 2.6 |
| 364.0 Poles, Towers & Fixtures | 27 | (60.00) | 49.23 | 4.1 |
| 365.0 Overhead Conductors & Devices | 30 | (60.00) | 42.93 | 3.9 |
| 366.6 Undg. Conduit, Duct | 59 | (2.00) | 16.03 | 1.5 |
| 366.7 Undg.Conduit, Direct Buried | 40 | 0.00 | 20.00 | 2.0 |
| 367.6 Undg. Conductors & Devices, Duct | 29 | 0.00 | 23.68 | 2.6 |
| 367.7 Undg. Conductors & Devices, Buried | 18.4 | 0.00 | 47.43 | 2.9 |
| 368.0 Line Transformers | 22 | (25.00) | 41.67 | 3.8 |
| 369.1 Services, Overhead | 36 | (85.00) | 46.25 | 3.9 |
| 369.7 Services, Underground | 26 | (5.00) | 33.16 | 2.8 |
| 370.0 Meters | 24 | (30.00) | 43.33 | 3.6 |
| 370.1 AMR Meters | 19.2 | (30.00) | 5.20 | 6.5 |
| 371.0 Installations on Customer's Premises | 22 | (20.00) | 32.00 | 4.0 |
| 373.0 Street Lighting & Signal Systems | 22 | (20.00) | 32.00 | 4.0 |
| **GENERAL PLANT - DEPRECIABLE** | | | | |
| 390.0 Structures & Improvements | 36 | (5.00) | 29.40 | 2.1 |
| 392.1 Transportation - Automobiles | 3 | 15.00 | 42.50 | 14.2 |
| 392.2 Transportation - Light Trucks | 4.6 | 15.00 | 41.56 | 9.4 |
| 392.3 Transportation - Heavy Trucks | 5 | 15.00 | 49.58 | 7.1 |
| 392.4 Transportation - Tractor-Trailers | 2.6 | 0.00 | 71.11 | 11.1 |
| 392.9 Transportation - Trailers | 11.9 | 30.00 | 28.35 | 3.5 |
| 396.1 Power Operated Equipment (Transp.) | 6.3 | 20.00 | 29.60 | 8.0 |
| 396.8 Other Power Operated Equipment | 5.2 | 20.00 | 33.78 | 8.9 |
| 397.8 Commun. Equipment - Fiber Optics | 7.7 | 0.00 | 23.00 | 10.0 |

Table 6: Amortization Items

| Account Number and Description | COMMISSION APPROVED | | | |
|---|---|---|---|---|
| | Average Remaining Life | Net Salvage | Theoretical Reserve | Remaining Life Rate |
| | (yrs.) | (%) | (%) | (%) |
| **DISTRIBUTION - AMORTIZABLE** | | | | |
| 362.9 Substation Equipment - LMS | 5 Year Amortization | | | |
| 367.5 UG Cable Injection - 20+ Year | 29 Year Amortization | | | |
| 367.9 UG Cable Injection - 10 year | 10 Year Amortization | | | |
| 371.2 Residential Load Management | 5 Year Amortization | | | |
| **GENERAL PLANT - AMORTIZABLE** | | | | |
| 391.1 Office Furniture | 7 Year Amortization | | | |
| 391.2 Office Accessories | 5 Year Amortization | | | |
| 391.3 Office Equipment | 7 Year Amortization | | | |
| 391.4 Duplicating & Mailing Equipment | 7 Year Amortization | | | |
| 391.5 EDP Equipment | 5 Year Amortization | | | |
| 391.7 PC Equipment (ECCR) | 3 Year Amortization | | | |
| 391.9 Personal Computer Equipment | 3 Year Amortization | | | |
| 392.7 Transportation Equip. - Marine | 5 Year Amortization | | | |
| 393.1 Stores Equip. - Handling Equip. | 7 Year Amortization | | | |
| 393.2 Stores Equip. - Storage Equipment | 7 Year Amortization | | | |
| 394.2 Shop Equip. - Portable Handling | 7 Year Amortization | | | |
| 395.2 Lab Equipment - Portable | 7 Year Amortization | | | |
| 395.6 Lab. Testing Equip. (LMS) | 5 Year Amortization | | | |
| 397.2 Comm. Equip. - Other 7-Yr Amort | 7 Year Amortization | | | |
| 397.3 Comm. Equipment - Official | 7 Year Amortization | | | |
| 397.4 Communication Equip. (ECCR) | 5 Year Amortization | | | |
| 398.0 Miscellaneous Equipment | 7 Year Amortization | | | |

Reserve Imbalance

The theoretical reserve is the calculated balance that would be in the reserve if the life and salvage estimates now considered appropriate had always been applied. The book reserve is the amount actually recovered to date. The difference between the theoretical reserve and the book reserve is a reserve imbalance. If the calculated theoretical reserve is more than the book reserve, the imbalance is a reserve deficit. If the calculated theoretical reserve is less than the book reserve, the imbalance is a reserve surplus.

Applying its proposed depreciation life and salvage parameters, FPL calculated a reserve surplus of $1.245 billion. OPC calculated a reserve surplus of $2.75 billion based on its proposed depreciation formula. The formula for the prospective theoretical reserve is provided in Rule 25-6.0436(4)(k), F.A.C. Using this formula and the life and salvage components approved above, we calculate a reserve surplus of $1,208.8 million, as shown in Table 7 below:

| Table 7: Reserve Imbalance | |
|---|---|
| | ($000,000) |
| Steam Production | 353.1 |
| Nuclear Production | 127.0 |
| Other Production | 119.6 |
| Transmission | 12.1 |
| Distribution | 555.6 |
| General | 41.4 |
| | |
| **Total Reserve Imbalance** | 1,208.8 |

Corrective reserve measures

Having determined above that there is a theoretical reserve surplus, the parties asked us to determine what, if any, corrective measures should be taken. The crux of the parties' dispute was whether the reserve imbalance should be corrected over the remaining life of the assets or over a shorter period of time. FPL argued that the surplus should be addressed through the remaining life rate design of its plant (22 years), rather than "accelerating" the recovery over a short period of time as suggested by the intervenors. FPL contended that the remaining life approach to resolve reserve imbalances is the norm and there is no reason to deviate. OPC, FIPUG, and FRF asserted that the magnitude of the reserve imbalance warranted a corrective approach shorter than the normal remaining life depreciation approach. SFHHA did not address the magnitude of the surplus, but asserted that it should be amortized over a short period of time.

FPL argued that a short amortization of the reserve surplus would have "the direct and unavoidable effect of rapidly increasing rate base, the required return on rate base, and future depreciation expense – all of which will have to be borne by future customers." FPL suggested that a middle path would be to transfer a portion of the reserve surplus to offset the expenses associated with its proposed capital recovery schedules. FPL argued that this action could provide "a measure of shorter-term relief for customers without doing as much damage to regulatory practices and future customers' pocketbooks." AIF supported FPL's position.

While OPC witness Pous calculated a reserve surplus of $2.75 billion using his proposed life and salvage values, he recommended that only FPL's identified reserve surplus of $1.25 billion be amortized over four years. OPC and FIPUG proposed that $314.3 million of FPL's reserve surplus should be first applied to offset the unrecovered costs associated with FPL's proposed capital recovery schedules for near-term retirements. OPC asserted that a four year amortization of the remaining balance of $894.6 million would reduce test year depreciation expense, thereby lowering FPL's revenue requirements. OPC submitted that amortizing the reserve surplus represented the most appropriate remedy to eliminate the intergenerational inequity the surplus created. FRF supported the OPC position that $1.25 billion of the reserve surplus be amortized over four years. SFHHA suggested that we require FPL to amortize its calculated reserve surplus of $1.245 billion over a five-year period. SFHHA asserted that the calculated surplus demonstrated that FPL's past depreciation rates were excessive, considering present expectations regarding depreciation parameters.

FIPUG witness Pollock proposed a slightly different approach to correct the remaining $894.6 million surplus. The witness proposed that FPL continue to record the $125 million annual credit to depreciation expense until the next depreciation study review.

Amortization of the reserve surplus will serve to decrease the reserve over the amortization period, thus increasing rate base. At the time of FPL's next depreciation review, its reserve positions will be lower, thereby resulting in higher depreciation rates, all other things remaining equal. Indeed, OPC recognized that depreciation rates in the instant proceeding are higher due to the lower reserve position resulting from the $500 million depreciation credit the Company recorded during the years 2005-2009, in accord with the 2005 Settlement Order. However, as noted by witness Pous, FPL's calculated theoretical reserve is lower by $500 million.

OPC argued that a reserve imbalance violated the matching principle.[25] The intervenors claimed that the existence of FPL's reserve imbalance indicates that past and current customers have paid more than their fair share of depreciation expenses and that future customers will therefore pay less than their fair share. In contrast, FPL contended that intergenerational inequity concerns are mitigated by the fact that customer rates were not increased during the time when the reserve surplus accumulated.

OPC contended that whether the remaining life methodology was adequate to address reserve imbalances depended on the magnitude of the imbalance and the time frame over which it would be corrected. The relative adequacy of the reserve causes the remaining life rate formula to self-adjust for historic over- or under-recovery, as well as for changes in projected life or salvage parameters. A reserve imbalance indicates a failure of the matching principle. The

[25] The matching of the period of time over which depreciation expense is collected with the service life of the group of assets is called the matching principle. Customers benefitting from the assets should be those who pay for the assets.

depreciation expenses of the past were misstated, so correction should be made now to reduce the misstatement into the future. Correction of the imbalance will result in a return to the matching principle. In this case, OPC argued that FPL's reserve imbalance was so great that recovery over the remaining life (22 years) was inadequate.

We believe that the very presence of a reserve imbalance indicates the existence of intergenerational inequity. Based on what is known today, the life estimates of yesterday are now viewed as being too short. FPL has lengthened the life span estimates for its production plants. Net salvage estimates have changed. This does not mean however, that past life and salvage estimates were wrong. Disregarding the fact that settlements were reached in 2002[26] and 2005[27] that addressed depreciation and many other matters, the last time this Commission actually conducted a thorough review and analysis of FPL's depreciation parameters was in Order No. PSC-99-0073-FOF-EI, issued January 8, 1999, in Docket No. 971660-EI, In re: 1997 depreciation study by Florida Power & Light Company. Conditions, Company plans, and regulatory requirements change. OPC witness Pous acknowledged that depreciation parameters change over time simply because depreciation is a projection of anticipated events in the future. FRF recognized in its brief that in a depreciation study review, a goal has been to align the actual and theoretical reserve positions for all accounts.

We agree with FPL witness Deason and OPC witness Pous that it is unlikely there would ever be a time when there is no reserve imbalance, simply because as time passes, more information is known and better estimates of life and salvage can be determined. However, that is not a reason to defer taking some action to correct reserve imbalances, where possible, either through reserve transfers or an amortization. The magnitude of the reserve imbalance should also dictate what action is taken. The matching principle argues for a quick correction of any surplus; the quicker the better so that the ratepayers who may have overpaid would have a chance of benefitting.

We agree with FPL that current and future customers will receive the benefit of the existing reserve surplus through lower depreciation rates. If the reserve surplus is reduced, the depreciation reserve will increase, thereby, all things remaining equal, causing depreciation rates and future revenue requirements to naturally increase.[28] At the present time, it can be argued that the current reserve surplus results in prospective depreciation rates that are artificially low. This is the beauty or the beast of the remaining life rate methodology. A surplus means that under present expectations more than enough has been recovered, so there is a smaller amount left to be recovered over the average remaining life. Conversely, the presence of a reserve deficit means that not enough has been recovered to date, so the depreciation rate must increase to make up the difference in the future.

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[26] Order No. PSC-02-0501-AS-EI, issued April 11, 2002, in Docket Nos. 001148-EI, In re: Review of the retail rates of Florida Power & Light Company, and 020001-EI, In re: Fuel and purchased power cost recovery clause with generating performance incentive factor. (2002 Settlement)

[27] Order No. PSC-05-0905-S-EI, issued September 14, 2005, in Docket Nos. 050045-EI, In re: Petition for rate increase by Florida Power & Light Company, and 050188-EI, In re: 2005 comprehensive depreciation study by Florida Power & Light Company. (2005 Settlement)

[28] About $300 million of FPL's current base rate increase is due to the $125 million annual depreciation expense credit that was recorded in accord with the 2005 FPL Rate Case Settlement Order.

The remaining life rate typically carries the burden of correcting any reserve imbalance. A significant reserve imbalance can distort resulting depreciation rates. For example, an account with a 40-year average service life, 20-year average remaining life, zero percent net salvage, and 80 percent reserve would result in an average remaining life rate of 1.0 percent. This is due to the fact that the reserve should theoretically be 50 percent rather than 80 percent. The surplus in the reserve results in a remaining life depreciation rate being lower than it otherwise would be to correct the surplus over the remaining life. If the account reserve is restated to its theoretically correct level, the resulting depreciation rate is 2.5 percent. Thus, the presence of the reserve surplus depresses the resulting depreciation rate from 2.5 percent to 1.0 percent. The more significant the reserve surplus, the more depressed the resulting remaining life rate will be.

The intervenors contended that our past orders support a position that reserve imbalances have historically been recovered over a period of time that is shorter than the average remaining life. FPL, on the other hand, contended that the orders referenced by the intervenors are not applicable to FPL's circumstances. FPL witness Davis also asserted that none of the actions in the referenced orders had any impact on customer rates.

In the 1990s, we allowed FPL to record additional depreciation expense to reduce the potential for stranded investments. In 1995, we authorized FPL to record $126 million in additional depreciation expenses to the reserve for nuclear production. Also, for 1996 and 1997, we permitted FPL to record an additional $30 million in expense to the reserve for nuclear production, and to record an additional depreciation expense based on differences between actual and forecasted revenues.[29] We allowed FPL to continue the recording of these additional expenses in 1998 and 1999 by Order No. PSC-98-0027-FOF-EI.[30] We found that it was good regulatory policy to eliminate these types of items when the funds are available to do so without raising customer rates.

Subsequently, in the FPL 1999 Revenue Sharing Agreement approved by Order No. PSC-99-0519-AS-EI, we granted FPL, among other things, the discretion to record up to $100 million of additional depreciation expense each year of the three-year settlement period to reduce nuclear and/or fossil production plant in service.[31] As part of this settlement, customer rates were reduced by $350 million and a revenue cap and revenue sharing plan was established.

As a result of the FPL 2002 Settlement, approved in Order No. PSC-02-0501-AS-EI, FPL received the discretionary ability to record a depreciation expense credit of up to $125 million annually for 2002-2005.[32] The amounts recorded first went to offset the $170.3 million bottom

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[29] Order Nos. PSC-95-0672-FOF-EI, issued May 31, 1995, and PSC-96-0461-FOF-EI, issued April 2, 1996, in Docket No. 950359-EI, In re: Petition to establish amortization schedule for nuclear stranded investment by Florida Power & Light Company.

[30] Order No. PSC-98-0027-FOF-EI., issued January 5, 1998, in Docket No. 970410-EI, In re: Proposal to extend plan for recording of certain expenses for years 1998 and 1999 for Florida Power & Light Company.

[31] Order No. PSC-99-0519-AS-EI, issued March 17, 1999, in Docket No. 990067-EI, In re: Petition by the Citizens of the State of Florida for a full revenue requirements rate case for Florida Power & Light Company.

[32] Order No. PSC-02-0501-AS-EI, issued April 11, 2002, in Docket Nos. 001148-EI, In re: Review of the retail rates of Florida Power & Light Company, and 020001-EI, In re: Fuel and purchased power cost recovery clause with generating performance incentive factor. (2002 Settlement)

line amortization recorded pursuant to Order No. PSC-99-0519-AS-EI, with any additional amounts recorded to a bottom line reserve to be allocated to specific accounts in the next FPL depreciation study after the term of the settlement. Among other things, the settlement reduced FPL's customer rates by $250 million and continued a revenue cap and revenue sharing plan. FPL acknowledged that it had overdepreciated its plant and a depreciation expense credit offered through the settlement would help correct the situation.

In the 2005 Settlement Order, FPL was again authorized to amortize up to $125 million annually as a credit to depreciation expense and a debit to the bottom line depreciation reserve for years 2006-2009.[33] FPL recorded $500 million in accord with the agreement.

FRF argued in its brief that our declared policy with respect to reserve imbalances is to correct them as soon as possible without adversely impacting a company's ability to earn a fair and reasonable return.[34] FRF noted that we have also targeted overearnings in the past to book additional depreciation expense, thereby lowering reported earnings and bringing them in line with the allowed rate of return. In the instant proceeding, we are setting a new rate of return for FPL. In deciding whether to amortize the reserve imbalance as the intervenors proposed, we should also consider any negative impacts such an amortization would have on FPL's financial integrity.

OPC's proposed adjustment to address the reserve imbalance would reduce FPL's revenue requirement by approximately $311 million per year. Because rate base would be higher as a result of this adjustment, the reduction to FPL's cash flow would be offset by approximately $20 million of additional return earned on this incremental rate base. Thus, the net impact of the proposed adjustment would be a reduction to cash flow of approximately $291 million.

FRF asserted that OPC's proposed amortization would not deny FPL recovery of any capital dollars, but would only affect the timing of the collection of those dollars. Further, FRF argued that OPC's proposed amortization would not affect FPL's earnings or earned rate of return. FRF stated that metrics used to analyze financial integrity generally include measures of debt, cash flow, and interest coverage requirements.

FRF asserted that the coverage ratios (the number of times FPL's generated cash flow covers debt service) were important indicators of financial integrity. FRF stated that FPL's financial strength is such that FPL's cash flow would be sufficient to amortize $1.25 billion of the reserve surplus identified by OPC witness Pous and maintain coverage ratios that warrant an "A" rating by Standard & Poors (S&P).

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[33] Order No. PSC-05-0905-S-EI, issued September 14, 2005, in Docket Nos. 050045-EI, In re: Petition for rate increase by Florida Power & Light Company, and 050188-EI, In re: 2005 comprehensive depreciation study by Florida Power & Light Company. (2005 Settlement)

[34] Order No. PSC-01-2270-PAA-EI, issued November 19, 2001, in Docket No. 060699-EI, In re: Request for approval of implementation date of January 1, 2002, for new depreciation rates for Marianna Electric Division by Florida Public Utilities, p. 2.

The financial metrics affected by the proposed adjustment are the cash from operations to interest ratio (CFO/Interest) and the cash from operations to debt ratio (CFO/Debt). The debt to total capital ratio is unaffected by the proposed adjustment. FPL's corporate credit rating is single A flat from S&P, single A1 from Moody's Investor Service (Moody's), and single A flat from Fitch Ratings (Fitch). Pursuant to S&P's rating methodology, FPL's business profile is rated as excellent and its financial profile is rated as intermediate. Based on these designations, the ratings criteria published by S&P and Moody's for FPL's current credit ratings include the following cash flow metric standards.

Table 8

| | S&P A rating | Moody's A rating |
|---|---|---|
| CFO/Interest | 3.0x – 4.5x | 4.5x – 6.0x |
| CFO/Debt | 25% – 45% | 22% – 30% |

OPC witness Lawton testified that, while the proposed adjustment to address the reserve imbalance will decrease FPL's cash flow metrics, he did not believe it will harm the Company's financial integrity. Witness Lawton demonstrated that FPL's CFO/Interest ratio will decrease from 6.7x to 5.9x and the Company's CFO/Debt ratio will decrease from 45 percent to 40 percent. That said, this analysis does not take into account additional adjustments that will impact cash flow. However, witness Lawton argued that even if all of OPC's proposed adjustments were made, there is no basis to conclude that FPL's credit rating would fall below investment grade. FPL witness Pimentel agreed that even a two-notch downgrade for FPL would still result in a triple B plus rating, which would remain firmly investment grade. Moreover, none of the rating agencies have indicated that they would downgrade FPL's credit rating even if we denied the entire rate increase.

In this case, FPL's net reserve imbalance is a $1.2 billion surplus. The reserve surplus is of such a magnitude that its existence results in abnormal depreciation rates. Where significant reserve surpluses and deficits exist, corrective reserve transfers between accounts or amortization of the reserve imbalance should be considered. Whether the reserve imbalance is a surplus or a deficit, it violates the matching principle and represents a subsidy, and thus should be corrected.

As mentioned above, we calculated a theoretical reserve for each account within each production unit, and each transmission, distribution, and general plant account. Comparing the theoretical reserve to the book reserve resulted in various account surpluses and deficits that we netted to a bottom-line reserve surplus amount of $1.2 billion. As a result of this netting, each account's reserve is placed at its theoretically correct position. The theoretically correct reserve position is reflected in the depreciation rates contained in Table 3 and Table 6 above.

FPL, FIPUG, and OPC suggested that we transfer a portion of the reserve surplus to offset the expenses associated with its proposed capital recovery schedules. We agree. Accordingly, $314.2 million of the reserve surplus shall be transferred to offset the unrecovered costs associated with FPL's proposed capital recovery schedules. This reduces the reserve imbalance to an $894.6 million surplus.

FPL argued that amortization of the remaining reserve surplus over any time period other than the remaining life results in intergenerational unfairness to the ratepayers of yesterday versus those of tomorrow. OPC, on the other hand, argued that the existence of a reserve imbalance indicates that there are intergenerational inequities in that current and past customers paid more than they should have, thereby subsidizing future customers. We agree with OPC's position that intergenerational unfairness already exists, as witnessed by the existence of such a significant reserve imbalance. Therefore, we are of the opinion that amortizing the remainder of the reserve surplus is the most appropriate remedy to eliminate the intergenerational inequity the surplus created. The only question remaining is how long it should take to correct the situation.

Accordingly, we find that the remaining reserve surplus amount of $894.6 million shall be amortized over a four-year period. This is consistent with our policy with respect to reserve imbalances, which has been to correct them as soon as possible without adversely impacting the company's ability to earn a fair and reasonable return.[35] We find that there is substantial evidence in the record to show that the company's ability to earn a fair and reasonable return will not be adversely affected. Furthermore, our decision is consistent with past orders in which we have amortized reserve imbalances over periods shorter than the remaining life.[36] And we note that we will be reviewing FPL's depreciation reserve again when FPL files its next depreciation study.

In conclusion, each account's book reserve shall be brought to its calculated theoretically correct level. Of the $1,208.8 million bottom-line reserve surplus, $314.2 million shall be used to offset the unrecovered costs associated with the capital recovery schedules of near-term retiring investments. The remaining reserve surplus of $894.6 million shall be amortized over a 4-year period, beginning January 1, 2010. As part of FPL's next depreciation study, to be filed no later than March 16, 2013, FPL's reserve position will be reviewed and assessed for any other necessary action.

<u>Implementation date for revised depreciation rates, capital recovery schedules and amortization schedules</u>

FPL proposed an implementation date of January 1, 2010. All the parties, except SFHHA, agreed with FPL's proposed implementation date. SFHHA argued that the implementation date for revised depreciation rates, capital recovery schedules, and amortization schedules should correspond with the implementations of rates resulting from this proceeding. We disagree with SFHHA's proposed implementation date. The implementation date for the

[35] Order No. PSC-01-2270-PAA-EI, issued on November 19, 2001, in Docket No. 010699-EI, <u>In re: Request for approval of implementation date of January 1, 2002, for new depreciation rates for Marianna Electric Division by Florida Public Utilities</u>, p. 2.
[36] Order No. PSC-96-0461-FOF-EI, issued on April 2, 1996, in Docket No. 950359-EI, <u>In Re: Petition to establish amortization schedule for nuclear generating units to address potential for stranded investment by Florida Power & Light Company</u>; Order No. PSC-06-0307-FOF-TP, issued April 20, 2006, in Docket No. 041269-TP, <u>In re: Petition to establish generic docket to consider amendments to interconnection agreements resulting from changes in law, by BellSouth Telecommunications, Inc.</u>; and Order No. PSC-98-1723-FOF-EI, issued on December 18, 1998, in Docket No. 971570-EI, <u>In re: 1997 Depreciation Study by Florida Power Corporation</u>.

revised depreciation rates, capital recovery schedules, and amortization schedules shall be January 1, 2010, because FPL data and related calculations abut the January 1, 2010 date.

## FOSSIL DISMANTLEMENT COST STUDY

### Annual dismantlement provision

FPL's 2008 fossil dismantlement study filed in this proceeding indicates there is a need to adjust FPL's current annual fossil dismantlement accrual, which is currently set at $15,321,113. The current dismantlement study represents an update of FPL's base dismantlement costs, contingency, and inflation forecasts. FPL contends an annual accrual of $20,180,368 is required to meet its fossil dismantlement needs. We analyze and critique FPL's 2008 fossil dismantlement study below.

The current-approved annual dismantlement provision shall be revised to reflect the Company's updated base cost estimates of dismantlement, inflation rates, and contingency costs. Any revised annual fossil dismantlement accrual shall take effect January 1, 2010. Table 9 on the following page details FPL's fossil dismantlement cost by plant site.

Table 9

| FOSSIL DISMANTLEMENT COST ESTIMATES | | |
|---|---|---|
| | **2007 Study Current Costs** | **2008 Study Current Costs** |
| | ($) | ($) |
| Cape Canaveral | 12,953.491 | 16,642,848 |
| Cutler | 8,035,610 | 10,424,803 |
| Fort Lauderdale | 18,956,572 | 25,524,535 |
| Ft. Myers | 22,877,762 | 29,598,540 |
| Manatee | 53,698,856 | 65,118,814 |
| Martin | 57,337,705 | 76,887,456 |
| Port Everglades | 52,594,168 | 61,149,529 |
| Putnam | 9,403,254 | 11,146,862 |
| Riviera | 13,583,544 | 15,070,232 |
| Sanford | 28,650,916 | 35,681,288 |
| Scherer | 37,391,063 | 43,744,940 |
| St. Johns River Power Park | 19,548,345 | 24,802,975 |
| Turkey Point | 18,323,729 | 25,825,396 |
| West County Energy Center | - | 22,707,813 |
| DeSoto Solar | - | 1,365,069 |
| Space Coast Solar | - | 724,875 |
| St. Lucie Wind Turbines | - | 584,770 |
| **Total*** | **353,355,015** | **467,000,745** |

* Cost estimate totals were subject to rounding for some of the plant site/units.

<u>Corrective reserve measures</u>

FPL's 2008 fossil dismantlement study contains proposed adjustments to correct reserve imbalances that exist for certain units. These imbalances arise when there are discrepancies between the actual dismantlement reserve and the theoretical reserve indicated in the dismantlement study. FPL proposed that reserve surpluses for the Cape Canaveral and Riviera plants be transferred to the Cutler, Manatee, Martin, Port Everglades, Sanford, Scherer, St. Johns River and Turkey Point plants. Although FPL did not file updated reserve transfers, we were able to calculate the appropriate transfer amounts, which are shown in Table 10, including the companies updated inflation figures.

We have consistently approved reserve transfers in fossil dismantlement studies. FPL's last reserve transfers were approved by Order No. PSC-08-0095-PAA-EI, issued on February 14, 2008, in Docket No. 070378-EI, In Re: Petition for approval of revised fossil dismantlement accrual by Florida Power & Light Company. We have reviewed FPL's proposed reserve transfers, and consistent with our precedent, we believe they are reasonable. However, FPL's dismantlement cost estimates shall be updated to reflect the February 2009 Global Insight inflation forecasts. Accordingly, we approve the corrective reserve reallocations shown in Table 10 below.

Table 10

| THEORETICAL RESERVE RE-ALLOCATIONS FOR JANUARY 1, 2010 | | | | |
|---|---|---|---|---|
| **Site** | **Actual Reserves December 31, 2009** | **Theoretical Reserves** | **Reserve Transfers** | **Restated Reserve for 1/1/2010** |
| Cape Canaveral | $17,654,087 | $16,970,239 | $(1,269,977) | $16,384,110 |
| Cutler | 11,429,097 | 13,168,448 | 144,749 | 11,573,846 |
| Manatee | 36,930,092 | 46,480,891 | 794,816 | 37,724,908 |
| Martin | 35,623,068 | 39,988,999 | 363,331 | 35,986,399 |
| Port Everglades | 54,604,976 | 74,237,570 | 1,301,674 | 55,906,650 |
| Riviera | 18,943,435 | 15,349,799 | (3,593,636) | 15,349,799 |
| Sanford | 5,987,502 | 6,267,665 | 23,315 | 6,010,817 |
| Scherer | 30,939,801 | 42,933,155 | 998,085 | 31,937,886 |
| St. Johns River | 18,825,872 | 27,761,363 | 743,609 | 19,569,481 |
| Turkey Point | 17,216,106 | 23,152,609 | 494,034 | 17,710,140 |
| **Total Reserves*** | **$248,154,036** | **$306,310,738** | **$0** | **$248,154,036** |

* Reserve transfers were subject to rounding for some of the plant site/units.

Annual provision for dismantlement

By Order No. 24741,[37] we established the methodology for accruing the costs for dismantlement of fossil-fueled production plants. The methodology, codified in Rule 25-6.04364, F.A.C., is dependent on three factors: estimated base costs for dismantlement, projected inflation, and a contingency factor. Electric companies are required to file site-specific dismantlement studies at least once every four years from the submission date of the previous study unless otherwise required by Commission order.

FPL filed its last updated dismantlement cost study with associated annual accrual proposals in 2007. We approved this study and associated fossil dismantlement accruals by Order No. PSC-08-0095-PAA-EI.[38] In this order, we also directed FPL to file its next fossil fuel dismantlement study concurrently with its comprehensive depreciation study on or about March 17, 2009.

[37] Order No. 24741, issued July 1, 1991, in Docket No. 890186-EI, In Re: Investigation of the Ratemaking and Accounting Treatment for the Dismantlement of Fossil-Fueled Generating Stations.
[38] Order No. PSC-08-0095-PAA-EI, issued February 14, 2008, in Docket No. 070378-EI, In re: Petition for approval of revised fossil dismantlement accrual by Florida Power & Light Company.

The dismantlement cost estimates in the current study are based on site-specific analysis and reflect an increase of approximately 32 percent from the 2007 cost estimates. The major drivers of the increase in cost include: (1) addition of new plant, (2) increases in the equipment rental component of labor rates, and (3) increased fuel oil tank removal costs. The dismantlement costs for Martin Solar, Desoto Solar, and Space Coast Solar plants will be recovered through the ECRC.

Dismantlement accruals are based on current cost estimates, escalated to future costs of the estimated date of dismantlement. The future costs, less accumulated dismantlement reserves, are discounted over the remaining life of each plant and plant site. We established the methodology for calculating annual accruals for the dismantlement fossil-fueled production plants by Order No. 24741. FPL's fossil dismantlement study as filed contained August 2008 inflation factors and assumed dismantlement of plants will begin five years after retirement. Inflation rates are used to escalate the current costs to the expected future amount that will be needed to pay for dismantlement. We requested, and were provided, updated inflation factors to reflect current market rates. The updated inflation rates are from the February 2009 Global Insight edition.

Our approved levelized annual accrual of $18,468,387 (including solar) is based on FPL's site-specific dismantlement cost estimates and a 16 percent contingency factor, with two modifications. First, we used the February 2009 inflation factors published by Global Insight for 2010 though 2013. Second, our analysis incorporated changes in the retirement dates of certain units in accord with our decisions above. We applied the jurisdictional separation factors for 2010 to the levelized annual accrual of $18,014,571 that excludes the solar units. Our approved retail annual accrual amount for 2010 is $17,660,832 (excluding solar), which reflects an increase of $2,640,568 over the amounts from FPL's last dismantlement study. Our calculations of the retail annual accrual amounts and incremental increase are shown in Table 11. FPL's 2008 site-specific dismantlement costs are shown in Table 12. Accordingly, this change to the fossil dismantlement annual accrual impacts the 2010 and 2011 accumulated depreciation and depreciation expense as set forth below.

Table 11
2010 Projected Test Year – Commission Approved

| Functional Description | 2007 Current Accrual | Required Increase in Cost of Service | Commission Approved 2010 Annual Accrual |
|---|---|---|---|
| **Fossil** | $8,966,504 | $755,421 | $9,741,745 |
| **Other Production excluding Solar** | $6,354,609 | $1,918,216 | $8,272,825 |
| **Total Excluding Solar** | $15,321,113 | $2,693,457 | $18,014,570 |
| **Jurisdictional Separation Factor** | | 98.036379% | 98.036379% |
| **Retail Annual Accrual Amounts** | | **$2,640,568** | **$17,660,832** |

Table 12

| FLORIDA POWER AND LIGHT COMPANY<br>EFFECTIVE ACCRUAL JANUARY 1, 2010 | | | |
|---|---|---|---|
| **Plant Site** | **2007 Current Annual Accrual**** | **Commission Final Approved Annual Accrual** | **Final Change in Annual Accrual** |
| | ($) | ($) | ($) |
| Cape Canaveral | 434,779 | 252,203 | -182,576 |
| Cutler | 216,262 | 333,801 | 117,539 |
| Fort Lauderdale | 985,269 | 1,251,191 | 265,922 |
| Fort Myers | 1,161,985 | 1,317,305 | 155,320 |
| Manatee | 2,255,726 | 2,559,415 | 303,689 |
| Martin | 2,327,547 | 2,533,098 | 205,551 |
| Port Everglades | 2,566,987 | 2,802,360 | 235,373 |
| Putnam | 339,106 | 405,297 | 66,191 |
| Riviera | 321,232 | 89,182 | -232,050 |
| Sanford | 1,374,909 | 1,493,396 | 118,487 |
| Scherer | 1,755,506 | 1,634,157 | -121,349 |
| St. Johns River Power Park | 807,788 | 869,586 | 61,798 |
| Turkey Point | 774,017 | 1,111,193 | 337,176 |
| Martin Solar | 0 | 346,160 | 346,160 |
| West County Energy Center | 0 | 1,332,348 | 1,332,348 |
| St Lucie Wind Turbines | 0 | 30,038 | 30,038 |
| DeSoto Solar | 0 | 72,712 | 72,712 |
| Space Coast Solar | 0 | 34,944 | 34,944 |
| **Total Dismantlement Provision** | ***15,321,113** | ***18,468,387** | **3,147,274** |
| **Less accrual for solar units recovered through the ECRC clause** | | | 453,817 |
| **Increase in cost of service due to increase in non-solar dismantlement accrual** | | | ***** 2,693,457** |

* Annual accruals were subject to rounding for some of the plant site/units.

** Annual accrual per approved by Order No. PSC-08-0095-PAA-EI, issued on February 14, 2008, in Docket No. 070378-EI, In Re: Petition for approval of revised fossil dismantlement accrual by Florida Power & Light Company.

***Net increase in fossil dismantlement accrual.

In conclusion, the appropriate system annual provision for dismantlement is $18,468,387 (including solar), and the retail annual accrual amounts for 2010 is $17,660,832 (excluding solar). This reflects an increase of $2,640,568 over the amounts from FPL's last dismantlement study. These accruals reflect current estimates of dismantlement costs on a site-specific basis, inflation estimates as of February 2009, a 16 percent contingency factor, and changes in retirement dates in accordance with this Order.

Greenfield status

In his testimony, OPC witness Pous objected to the extent of FPL's fossil dismantlement approach. He contended that FPL's dismantlement assumptions "assumed a 100% probability of the worst case scenario, that being full demolition and site restoration." Witness Pous asserted that FPL is not legally required to restore its plant sites to a "greenfield" condition. During cross-examination, FPL witness Ousdahl stated she believed that site restoration in terms of greenfield means "park-like." She cited the Company's dismantlement of its Palatka plant as an instance where site remediation was to greenfield status. AIF supported FPL's position. In its brief, AIF stated that FPL witness Ousdahl clearly described the cost components included in FPL's 2008 fossil dismantlement study. AIF stated that intervenor witnesses Pous and Pollock provided no basis for the disallowance of FPL's 2008 fossil dismantlement study as presented, including site restoration to greenfield status upon retirement.

Rule 25-6.04364, F.A.C., is our dismantlement rule. Of particular interest to this issue are subparts 2 (b) and (c):

> (2)(b) "Dismantlement." The process of safely managing, removing, demolishing, disposing, or converting for reuse the materials and equipment that remain at the fossil fuel generating unit following its retirement from service and restoring the site to a marketable or useable condition.
>
> (2)(c) "Dismantlement Costs." The costs for the ultimate physical removal and disposal of plant and site restoration, minus any attendant gross salvage amount, upon final retirement of the site or unit from service.

We find that FPL's site restoration assumptions in its 2008 study comport with both our rule and Commission precedent in previous dismantlement proceedings. Accordingly, we find that the assumptions FPL made in its 2008 dismantlement study with regards to site restoration site restoration assumptions by definition are reasonable.

Dismantlement studies

By Order No. 24741, issued July 1, 1991, in Docket No. 890186-EI, In Re: Investigation of the Ratemaking and Accounting Treatment for the Dismantlement of Fossil-Fueled Generating Stations (Order No. 24741), we established the methodology for accruing the costs for dismantlement of fossil-fueled production plants. The methodology, codified in Rule 25-6.04364, F.A.C., is dependent on three factors: estimated base costs for dismantlement, projected inflation, and a contingency factor. As explained above, electric companies are required to file site-specific dismantlement studies at least once every four years from the submission date of the previous study unless otherwise required by our order.

FPL's fossil dismantlement study contains two types of assumptions. First, the study includes general assumptions that are applicable to all units and sites, such as provisions for site security and management personnel. Second, for each unit, the study includes site-specific assumptions, which are intended to capture unique characteristics of an individual plant site. Examples of site-specific assumptions may also include such things as the extent of asbestos abatement required for a given unit, and whether controlled blasting of chimneys can be done.

We find that FPL's dismantlement study complies with our dismantlement rule and is in accord with prior dismantlement studies. Based on our review of the study and its supporting documentation, we believe that the company adequately takes into consideration factors that are unique to specific units when estimating dismantlement costs. As such, it appears that FPL has considered alternative demolition techniques and incorporated them into the study. FPL should continue to consider whether alternative demolition approaches are reasonable in future studies, as it has in the past. Absent specific references, it is unclear what aspects of FPL's study OPC believes are deficient or unsupported. Accordingly, at this time we do not believe the record supports the need to require FPL to file analyses of alternative demolition approaches.

## RATE BASE

### Calculation of working capital allowance

According to FPL witness Ousdahl, our current practice for clause over- and under-recoveries is not equitable. She testified that:

> The Commission has not permitted FPL to remove the liability from working capital even though FPL compensates customers by paying interest on the over-recovery through the cost recovery clauses. This is inconsistent with the treatment of underrecoveries, where the Commission has previously required FPL to remove the asset from working capital.

Witness Ousdahl argued that this Commission should acknowledge that base rates should never include the cost of capital associated with clause over- or under-recoveries, as such costs are already provided for in the clause rate itself. She further argued that the regulatory liability associated with projected over-recoveries should be removed from working capital.

OPC stated that over-recoveries represent funds the Company owes customers and if they excluded from working capital, customers would be providing interest the company returned in the clause. OPC further stated that the under-recoveries are collected from the customers at the commercial paper rate. In addition, if a clause under-recovery is included in base rates, the company will receive a double return on the under-recovery.

OPC argued that the Commission's practice has been to exclude fuel under-recoveries, which are assets, from Working Capital, and to include over-recoveries, which are liabilities. Furthermore, the rationale for including over-recoveries as a reduction to working capital is to provide the Company with an incentive to make its projections for the cost recovery clause as accurate as possible and avoid large over-recoveries.[39]

We agree with the assessment of OPC as to how we have handled fuel over-recoveries in calculating the working capital allowance in prior rate case proceedings. In the Company's last rate proceeding, its fuel over-recovery was included in the calculation of the working capital allowance. There is no compelling evidence in the record that indicates our policy should be changed. Utilities should strive to reasonably project expenses so as to avoid over-collecting from customers. Therefore, the over-recovery that shall be included in the calculation of the working capital allowance for 2010 is $101,971,000.

Advanced Metering Infrastructure (AMI)

FPL plans to install smart meters over a five year period. The meters will have more capabilities than the meters currently installed. The new meters will be equipped with two-way communications, remote reading, connection, and disconnection capabilities and will be able to collect data regarding consumption at predetermined intervals. The installation will be for residential and small/medium business accounts. The meters will provide both operational and service improvements. The operational improvements include a reduced need for meter readers. The service improvements include more customer usage information and reductions in the number of calls to the company. The meters have a life expectancy of 20 years.

Below is Table 13 that summarizes the number of meters being installed, capital costs, O&M costs, O&M savings and net O&M savings.

Table 13

| **Deployment** | **2009** | **2010** | **2011** | **2012** | **2013** | **Total** |
|---|---|---|---|---|---|---|
| **Meters (Thousands)** | 170 | 1,128 | 1,099 | 1,076 | 873 | 4,346 |
| | | | | | | |
| **Capital (Millions)** | $43.7 | $168.5 | $158.7 | $151.5 | $122.5 | $645 |
| | | | | | | |
| **O&M (Thousands)** | $2,274 | $6,883 | $8,910 | $11,882 | $10,458 | |
| **Savings (Thousands)** | ($167) | ($418) | ($4,700) | ($18,203) | ($30,401) | |
| | | | | | | |
| **Net O&M (Thousands)** | $2,106 | $6,465 | $4,210 | ($6,321) | ($19,943) | |

[39] Order No. 12663, issued November 7, 1983, in Docket No. 830012-EU, In re: Petition of Tampa Electric Company for an increase in rates and charges and approval of a fair and reasonable rate of return, pp. 14-15; and Order No. PSC-93-0165-FOF-EI, issued March 29, 1993, in Docket No. 920324-EI, In re: Application for a rate increase by Tampa Electric Company, p. 38.

FPL witness Santos testified that the implementation of AMI will help to modernize the grid. The implementation of AMI will have $645 million in capital costs and once fully implemented will have an annual cost savings of $36.9 million. Beginning in 2012, the O&M savings are greater than the O&M costs associated with AMI. Beginning 2013, the net O&M savings exceed $30 million annually. Witness Santos testified that the savings from smart meters are not directly proportional to the installations. Witness Santos testified that AMI is a long-term project in which savings are realized after several complex, interdependent components and processes are fully developed, tested and implemented and deployment at the FPL regional work area is achieved.

SFHHA witness Kollen testified that the savings from the meters and the costs should be aligned. Witness Kollen proposed including 16.9 percent of the estimated $36 million in savings into the test year. The witness further testified that it is unreasonable to have the ratepayers pay 16.9 percent of the total expenditures for AMI in the test year while only receiving 1.2 percent of the projected savings.

We believe SFHHA's arguments are unfounded. While we agree the savings are not in the test year, it would be inappropriate to move costs or savings from outside of the test year into the test year. This project spans several years, and FPL plans to make significant investments outside of the test year. FPL has not front loaded costs for this project. AMI implementation will ultimately give customers more control over their energy usage.

Accordingly, we find that the costs for AMI implementation are appropriate and have properly been included in rate base for the test year. As seen in the chart above, the Company will continue making investments outside of the test year. The project will lead to increased savings. The investment will help modernize the grid and help the Company provide better service to its customers. If the savings become too great, and the Company earns a return outside its authorized rate, we may call FPL in for an earnings review.

FPL shall provide annually a progress report on implementation of smart meters in the Energy Conservation Cost Recovery docket. The report shall include a detailed description of how FPL intends to utilize smart meters to allow customers to better manage their energy consumption, including new programs or rate offerings associated with smart meters.

Levels of plant in service

We were asked to address whether FPL's requested $28,288,080,000 levels of plant in service was appropriate. As explained below, we do not find that it is. FPL agreed with OPC's position to remove the long-term transmission service contracts. OPC witness Brown provided revised adjustments. However, in some instances her calculations were less than FPL's adjustments as shown in Exhibit 378. OPC chose to adopt the adjustments of FPL provided by witness Ender as proper adjustments to be made to rate base, operating revenues, and expenses.

SFHHA witness Kollen's calculations established the 2009 total reduction of 19 percent or $529 million, by annualizing the actual decrease of the first four months of capital expenditures in the amount of $170 million. Witness Kollen did not provide any supporting documentation to substantiate annualizing only four months of data for capital expenditures. There were no comparative analyses of historical data to add credibility to SFHHA's proposed overstatement of 2009 through 2011 capital expenditures. FPL outlined its capital expenditures by business units rather than by FERC accounts. SFHHA used the annualization based on business units without obtaining the necessary documentation from FPL that would have linked the reductions to the functional accounts in the MFRs. Therefore, we find that SFHHA's adjustments for 2009 through 2011 using the first four months of 2009 capital expenditures were not supported by adequate documentation.

FPL witness Ousdahl provided a schedule in her rebuttal testimony that identified additional Company adjustments as stated below. In addition, she provided a late filed exhibit that identified the applicable plant account/function the adjustments would impact.

(1) Item 21 of Exhibit 358 identified the jurisdictional adjustment to transmissions services for the removal of the long-term transmission service contracts as a reduction to plant in service in the amount of $386,896,000.

(2) Item 4 of Exhibit 358 reflected an adjustment for anticipated capital expenditures expected by DOE in 2010 due to the nuclear fuel settlement agreement. This resulted in a jurisdictional reduction in the amount of $25,866,000 for 2010.

(3) Item 12 of Exhibit 358 reflected a reduction to plant in service for a correction of an error related to the Customer Information System III (CIS) in the amount of $3,301,000 for 2010.

As discussed below, a reduction was made to aircraft expenditures for plant in service in the amount of $53,268,205 for 2010.

During the cross-examination of FPL witness Barrett, he was asked whether the deferred projects listed on Exhibit 418 were included in the $91 million reduction as shown in Exhibit 386. He stated that the projects were deferred from the 2010 projected test year. He further clarified that "Exhibit 418 reflected plant in service, accumulated depreciation, Construction Work In Progress (CWIP), and depreciation for the delayed substations." The deferred substation projects show a reduction to plant in service for 2010 in the amount of $7,276,000.

As discussed above, a capital recovery schedule, as shown in Table 1, was established for the near-term retirements of Cape Canaveral and Riviera power plants, the St. Lucie and Turkey Point nuclear uprate projects, and the AMI meter project. The total estimated investment of the near-term retirements as of December 31, 2009 is shown as $774,610,189. In addition to the capital recovery schedule, a corresponding reduction shall be made to plant in service and accumulated depreciation to remove the estimated investment for the planned near-term retirements. Therefore, plant in service and accumulated depreciation for the 2010 test year shall be reduced by $774,610,189.

As shown in Table 14 below, we identified all the adjustments to plant in service for 2010 as provided in the record. Based on a review of the parties' positions and adjustments, plant in service shall be reduced for the 2010 test year by $1,251,217,394.

TABLE 14

| 2010 Plant In Service Adjustments | | | | |
|---|---|---|---|---|
| Description | FPL | OPC | SFHHA | Commission |
| Issue 15 SLB-26 Revised-Jurisdictional Separation Factor–Transmission Services | | ($373,423,000) | | |
| EXH 358-Issue 4-DOE Settlement | ($25,866,000) | 0 | | ($25,866,000) |
| EXH 358-Issue 12 CIS III | ($3,301,000) | 0 | | ($3,301,000) |
| EXH 358-Item 21-Transmission Services–jurisdictional factor | ($386,896,000) | 0 | 0 | ($386,896,000) |
| EXH 418-Deferred Projects | 0 | 0 | 0 | ($7,276,000) |
| Issue 94 Aviation Costs | ($53,268,205) | 0 | | ($53,268,205) |
| Issue 50: SFHHA Capital Expenditures | 0 | | ($784,000,000) | 0 |
| Issue 19A: Table 1 | | | | ($774,610,189) |
| Total Reductions | ($469,331,205) | ($373,423,000) | ($784,000,000) | ($1,251,217,394) |

In summary, based on the reductions reflected in Table 14 above, the appropriate level of plant in service for the 2010 test year is $27,036,862,606.

Levels of accumulated depreciation

We examined accumulated depreciation records of the Company for 2010 to determine the appropriate projected test year amount. We made several adjustments, including those agreed to by FPL and the parties, issues relating to the 2009 depreciation study, fossil dismantlement study, reserve surplus, GBRA, deferred/delayed projects, aviation, and changes based on the jurisdictional separation of long-term transmission contracts.

As shown in Table 15 on the following page, we identified all the adjustments to accumulated depreciation for 2010 as provided in the record.

TABLE 15

| 2010 PROJECTED TEST YEAR-ACCUMULATED DEPRECIATION | | | |
|---|---|---|---|
| Description | FPL's proposed | OPC's proposed | Commission approved |
| Accum. Depreciation Per FPL Filing | $12,590,521,000 | $12,590,521,000 | $12,590,521,000 |
| Issue 15 SLB-26 Revised-Jurisdictional Separation Factor–Transmission Services | | | |
| EXH 358-Issue 4-DOE Settlement | ($252,000) | 0 | ($252,000) |
| EXH 358-Issue 12 CIS III | ($130,000) | 0 | ($130,000) |
| EXH 358 Issue 16 Account 354 correction | ($1,734,000) | | ($1,734,000) |
| EXH 358-Item 21-Transmission Services–jurisdictional factor | ($144,299,000) | 0 | ($144,299,000) |
| EXH 418-Deferred Projects | 0 | 0 | ($114,000) |
| Issue 94 Aviation Costs | ($27,853,907) | 0 | ($27,853,907) |
| Issue 19C and 19D: Depreciation Study | | | ($41,367,500) |
| Issue 19E: Reserve Surplus | | | ($111,848,000) |
| Issue 42: Fossil Dismantlement Study | | | $1,320,284 |
| Issue 50: Near-term Investment for Retirements | | | ($774,610,189) |
| Total Reductions | ($174,268,907) | ($414,924,000) | ($1,100,888,312) |
| Accumulated Depreciation Levels | $12,416,252,000 | $12,175,597,000 | $11,489,632,688 |

Accordingly, the appropriate adjustment for the 2010 test year is $1,100,888,312.

Adjustment to CWIP

FPL proposed an adjustment to CWIP for the 2010 projected test year for the Florida EnergySecure Line (gas pipeline). The Company's proposed adjustment is not appropriate. On October 6, 2009, we denied FPL's petition to determine need for the gas pipeline. We determined that FPL had not adequately shown that the proposed gas pipeline was the most cost-effective option.[40] Accordingly, we ordered FPL to revise its request for proposals based on its identified gas transportation needs and provide a copy to our staff for review prior to its issuance. Based on these actions, the capital expenditures for the gas pipeline shall not be reflected through CWIP - AFUDC nor reported to this Commission on the Company's Monthly Earning Surveillance reports.

[40] Order No. PSC-09-715-FOF-EI, issued October 28, 2009, in Docket No. 090172-EI, In re: Petition to determine need for Florida EnergySecure Pipeline by Florida Power & Light Company.

Levels of Construction Work in Progress (CWIP)

FPL stated that the appropriate level of CWIP for the 2010 projected test year, including the adjustments from Exhibit 358 (KO-16), should be $691,380,000. OPC stated that the appropriate levels of CWIP should reflect the adjustments provided in Exhibit 248 (SLB-26 Revised) regarding the appropriate jurisdictional factors. OPC further stated that the appropriate jurisdictional amount for 2010 should be $692,754,000.

We agree with the Company's calculations for the impact of the jurisdictional separation factors as shown in Item 21-Transmission Services. FPL witness Ousdahl provided additional adjustments in Exhibit 358 (KO-16) which impacted CWIP as identified in Table 16 below, including (1) Item 4-DOE Settlement nuclear spent fuel agreement), and (2) Item 12-CIS Plant III for an error in projection to plant in service. However, witness Barrett's late-filed exhibit was entered into the record, which included projects deferred from the 2010 test year. Witness Barrett explained that Exhibit 418 (2010-2011 Deferred Projects) included deferred projects which resulted in reductions to the 2010 test year to plant in service, accumulated depreciation, CWIP, and depreciation expense. This exhibit included a reduction in CWIP for 2010 in the amount of $4,565,000. The overall adjustments are provided in Table 16 below.

TABLE 16

| CONSTRUCTION WORK IN PROGRESS -2010 ADJUSTMENTS | | | |
|---|---|---|---|
| Description | Company proposed | OPC proposed | Commission Approved |
| Exhibit 358-Item 21-Transmission Services | ($18,623,000) | ($14,777,000) | ($18,623,000) |
| Exhibit 358-Item 4-DOE Settlement | (828,000) | 0 | (828,000) |
| Exhibit 358-Item 12-CIS Plant III | 3,301,000 | 0 | 3,301,000 |
| Exhibit 418-Deferred Projects | 0 | | (4,565,000) |
| Total deductions | ($16,150,000) | ($14,777,000) | ($20,715,000) |

We find that the appropriate level of CWIP for the 2010 projected test year is $686,815,000, which is a reduction of $20,715,000 from FPL's requested level.

Levels of Property Held for Future Use

As discussed earlier in this Order, OPC stated that Exhibit 378 reflected the proper adjustments to be made to rate base, operating revenues and expenses. We compared OPC witness Brown's Exhibit 248 with FPL witness Ender's Exhibit 378 and saw there were differences in some of the adjustments. Even though there are differences in the parties adjustments, OPC chose to use FPL witness Ender's adjustments. The overall rate base reduction for 2010 is $261,720,000. Exhibit 378 shows that the Company reduced property held for future use for 2010 in the amount of $4,200,000.

We find that the appropriate level of property held for future use for 2010 is $70,302,000. Accordingly, the proposed level of property held for future use for 2010 shall be reduced by $4,200,000.

Accrual of Nuclear End of Life Materials and Supplies

Order No. PSC-02-0055-PAA-EI addresses (1) FPL's petition for the approval of annual accruals for nuclear decommissioning; (2) FPL's accumulated amortization; and (3) the appropriate method of recovery for the last core of nuclear fuel for FPL. The order explained FPL's position on end-of-life material and supplies inventories and last core as follows:

> FPL believes EOL M & S (end of life material and supplies) inventories should be considered part of nuclear decommissioning since the costs relate to the time each nuclear site will cease operation. Further, FPL asserts that the annual expense/reserve accruals associated with the EOL M & S inventories represent the recovery of amounts that will have already been expended during the operating life of each nuclear unit and thus do not require a cash outlay at the time of decommissioning. Therefore, FPL concludes that there is no need to fund these amounts.
>
> FPL considers the Last Core cost to be a result of final shut down of the nuclear reactor, equating to an unrecovered cost remaining at the end of the unit's life.

The order also addressed our request that FPL address the amortization status of end of life material and supplies and last core costs in subsequent decommissioning studies so the related annual accruals could be revised, if warranted. The order further stated that "in the event of industry restructuring, treatment of the Last Core unfunded reserve should follow the same treatment afforded nuclear decommission." Based on this order, we find that this base rate proceeding is not the appropriate docket within which to address the increase for end of life nuclear fuel last core and material and supplies.

In conclusion, we find that the 2010 accrual of nuclear end of life materials and supplies and last core nuclear fuel is appropriate based on the 2005 Settlement Order. However, the additional expense for 2010 and 2011 in the amount of $6 million for end-of-life nuclear fuel last core and $137,000 end of life materials and supplies shall be removed from the applicable accounts of this base rate proceeding and addressed when the Company files its 2010 Nuclear Decommissioning Study.

Nuclear fuel included in rate base

FPL included the nuclear fuel balance in net plant and, therefore, included in the calculation of rate base. Based on the change in accounting rules, the benefit of off-balance sheet financing is no longer available, and the nuclear fuel balance is a part of FPL's consolidated balance sheet. Further, bond rating agencies now include the debt that financed the nuclear fuel as part of FPL's overall debt. Finally, including nuclear fuel in rate base is analogous to including fuel inventory in working capital and, therefore, in rate base. For these reasons, we approve FPL's proposed treatment of nuclear fuel. Accordingly, the nuclear fuel assets shall be capitalized and included in rate base for the 2010 projected test year.

We recognize that this treatment increases the revenue requirement in comparison to the previous (leasing) treatment. This is because the nuclear fuel assets are financed at the overall cost of capital instead of the specific debt rate for commercial paper.

Levels of Nuclear Fuel

Based on our review of OPC Exhibit 248, we found that OPC's net Nuclear Fuel reduction for the 2010 test year was $39,000. We made a similar review of FPL's Exhibits 358 and Exhibit 378 (JAE-11), and found that FPL's net nuclear fuel reduction for the 2010 projected test year was $3,771,000. As discussed above, OPC agreed with FPL's final reductions. Therefore, we agree with both parties that FPL's reduction for the 2010 test year is appropriate. Accordingly, the appropriate level of nuclear fuel for 2010 is $370,962,000. This results in a reduction of $3,771,000.

Unamortized balance of Glades Power Park

FPL contended that the unamortized balance of the FPL Glades Power Park (FGPP) should be included in rate base. The Company stated that in Order No. PSC-09-0013-PAA-EL, issued on January 5, 2009, in Docket No. 070432-EI, we granted FPL recovery of the FGPP costs and provided for amortization of the $34.1 million of costs over a five-year period beginning on January 1, 2010.[41] The other parties to the rate case proceeding took no position on this issue.

We agree with the Company. Accordingly, the unamortized balance of FGPP in the amount of $34.1 million shall be included in rate base and amortized over five years.

Levels of working capital

In Table 17 below, we list all of the adjustments to working capital as provided by FPL and OPC. As discussed above, FPL's adjustments were identified in Exhibit 358 (KO-16) and are shown in the table as a $7,777,000 increase to working capital. Item 21-Transmission Services jurisdictional factor was discussed above, and the table reflects the applicable portion of the $261,720 million reduction which impacted working capital. Each adjustment represents a correction of an error to rate base by the Company. OPC contended that the 2010 adjustment to working capital should be $41,763,000. However, FPL argued that the adjustment to 2010 working capital should be an increase of $7,777,000. We believe that the net over-recovery that was removed by FPL, as discussed above, should be included in the calculation of the working capital allowance. The inclusion of over-recoveries in working capital is an ongoing practice of this Commission. Therefore, the 2010 calculation of the working capital allowance shall be increased by $101,971,000. Also, as we discuss below, rate case expense shall be removed from working capital for the 2010 test year in the amount of $2,948,000. Accordingly, the overall effect results in reductions for the 2010 test year in the amount of $97,194,000, as reflected in Table 17 below.

[41] Order No. PSC-09-0013-PAA-EI, issued January 5, 2009, in Docket No. 070432-EI, In re: Petition for authority to use deferral accounting and for creation of a regulatory asset for prudently incurred preconstruction costs associated with development of clean coal project by Florida Power & Light.

TABLE 17

| 2010 Working Capital Adjustments | | | |
|---|---|---|---|
| Description | FPL | OPC | Commission |
| Item 8 - Bad Debt (EXH 358) | $584,000 | 0 | $584,000 |
| Item 13 - Storm Liability (EXH 358) | 1,809,000 | 0 | 1,809,000 |
| Item 14 - Fuel Inventory | 1,685,000 | 0 | 1,685,000 |
| Item 21 - Transmission Services | 3,700,000 | ($41,763,000) | 3,700,000 |
| Issue 46 - Over-Recovery | 0 | 0 | (101,971,000) |
| Issue 122 - Rate Case Expense | | | (2,948,000) |
| Total Working Capital Reduction | $7,777,000 | ($41,763,000) | ($97,141,000) |

In summary, as reflected in Table 17 above, the appropriate reduction for the 2010 working capital allowance is $97,141,000. Therefore, the appropriate level of working capital for the 2010 test year is $112,121,000.

Requested rate base

We find that the appropriate 2010 projected test year rate base is $16,787,429,918, which is a reduction of $276,156,082 from FPL's requested level, as shown below in Table 18 below.

TABLE 18

| Jurisdictional Amount for 2010 Rate Base | | | | |
|---|---|---|---|---|
| | FPL | OPC | SHHA | Commission |
| Utility Plant-In-Service | 27,818,749,000 | 27,914,655,000 | 27,504,000,000 | 27,036,862,606 |
| Accumulated Depreciation | 12,416,252,000 | 12,175,597,000 | | 11,489,632,688 |
| Net Plant-In Service | 15,402,497 | 15,739,058,000 | | 15,547,229,918 |
| CWIP | 691,380,000 | 692,754,000 | | 686,815,000 |
| Property Held for Future Use | 70,302,000 | 70,432,000 | | 70,302,000 |
| Nuclear Fuels | 370,962,000 | 374,772,000 | | 370,962,000 |
| Net Utility Plant | 16,535,141,000 | 16,877,016,000 | | 16,675,308,918 |
| Working Capital | 217,040,000 | 167,502,000 | | 112,121,000 |
| Total Rate Base | 16,752,180,637 | 17,044,518,000 | 16,511,586,000 | 16,787,429,918 |

## COST OF CAPITAL

Accumulated deferred taxes

As defined in Order No. PSC-09-0283-FOF-EI[42] issued in the recently completed Tampa Electric Company rate case:

> ADITs [Accumulated Deferred Income Taxes] represent the income tax component resulting from the application of the income tax rate to temporary differences at each balance sheet date. Deferred tax expense reflects the period to period change in ADITs. Because the financial statements reflect accrual accounting, the income tax expense calculation must reflect the liability for income taxes payable in the future as a result of transactions recorded in the current financial statements. Deferred income taxes are generated when ratepayers pay income tax expenses in rates prior to the Company actually being required to make those payments to the U.S. Treasury. Deferred income taxes are included in capital structure because these funds are used by the Company in the provision of utility electric service and should be reflected in the utility's regulated capital structure. The purpose of deferred income tax accounting is to reflect in the financial statements the tax effects (both current and deferred) of assets, liabilities, revenues, and expenses recorded on the financial statements. In the regulated environment, the process of recording deferred income taxes on temporary differences is often referred to as "normalization." Recognizing zero cost deferred taxes in the capital structure (normalization) reduces the overall rate of return charged to ratepayers. In ratemaking, the ADIT balance is a zero cost source of capital in the cost of capital computation, thereby sharing the benefit of the reduced financing costs with ratepayers.

Financial Accounting Standards Board (FASB) Statement No. 109 (SFAS 109)[43] requires a company to recognize a deferred tax liability or asset for the deferred tax consequences of temporary differences. The correct amount of ADITs is the result of various adjustments to the original MFR Schedules.

FPL's original MFR Schedules showed a jurisdictional ADITs balance of $2,723,327,000 for 2010. As a result of "bonus depreciation" made available by the American Recovery and Reinvestment Act of 2009, FPL's balance of jurisdictional ADITs increased to $2,886,174,000 for 2010. The Company's revised MFR Schedule D-1a reflected a balance of jurisdictional ADITs of $2,890,553,000 for 2010. This additional adjustment in the amount of ADIT was the

[42] Order No. PSC-09-0283-FOF-EI, issued April 30, 2009, in Docket No. 080317-EI, In re: Petition for rate increase by Tampa Electric Company.

[43] Accounting for Income Taxes, Statement of Financial Accounting Standards No. 109 (Financial Accounting Standards Board, 1992) Cross Reference: Income Taxes, FASB ASC 740 (Topic 740 of the Financial Accounting Standards Board Accounting Standards Codification). The Codification is the single source of authoritative nongovernmental U.S. generally accepted accounting principles (US GAAP) effective for interim and annual periods ending after September 15, 2009.

result of subsequent rate base and cost of capital adjustments made by the Company related to the removal of aviation expenses.

FPL witness Ousdahl recommended certain adjustments to the balance of ADITs originally proposed by the Company for the 2010 projected test year. FPL proposed an adjustment to tax depreciation for 2009 to reflect the impact of the Stimulus Bill of the American Recovery and Reinvestment Act of 2009. The Stimulus Bill allowed businesses to immediately depreciate 50 percent of the cost of a depreciable property purchased and placed in service in 2009. (26 USC §168(k)) Consistent with the IRC §168(k),[44] FPL utilized the special depreciation allowance in addition to Modified Accelerated Cost Recovery System (MACRS) tax depreciation allowed on its federal tax returns. FPL increased the tax depreciation by $884 million in 2009. However, in addition to recognizing the bonus depreciation adjustment, FPL also corrected an error that resulted in a decrease in the accumulated deferred income tax liability. The net result of these adjustments increased the balance of ADITs to $2,890,553,000 for 2010.

SFHHA witness Kollen recommended that the appropriate amount of ADITs was $3,313,373,000 for the projected 2010 test year. Witness Kollen offered reasons why the balance of ADITs should be increased. First, witness Kollen asserted that the Company inappropriately reduced the balance of ADITs included in the proposed capital structure by $168,598,000 for the effects of FASB Interpretation No. 48 (FIN 48).[45]

FIN 48 is an interpretation of FASB SFAS 109 that clarifies the accounting for uncertainty in income taxes. FIN 48 requires a company to establish a "reserve" for future income tax audit adjustments that may increase the Company's income tax liability and thus reduce the balance of ADITs recorded on its accounting books. Per FIN 48, a liability recognized as a result of applying this interpretation shall not be classified as a deferred tax liability unless it arose from a taxable temporary difference. FPL witness Ousdahl testified that FPL had included the deferred taxes associated with the temporary differences related to the FIN 48 liabilities in the Company's balance of ADITs rather than with long-term liabilities in rate base. She stated that this practice was consistent with the treatment of the deferred taxes and FIN 48 liabilities for FERC reporting.

Witness Kollen also contended that FPL had improperly diluted the low-cost capital provided by customer deposits and the cost-free capital provided by ADITs by allocating pro rata adjustments over these capital components. However, FPL witness Ousdahl stated that allocating pro rata adjustments over only investor sources of capital would result in an inappropriate double counting of the low cost customer deposits and cost-free deferred income tax capital structure components. To support the Company's position on the issue, witness

[44] 26 USC §168(k) (2009)

[45] Accounting for Uncertainty in Income Taxes, Statement of Financial Accounting Standards No. 48, §18 (Financial Accounting Standards Board, 2006). Cross Reference: Unrecognized Tax Benefits, FASB ASC 740-10-45-12 (Paragraph 740-10-45-12 of the Financial Accounting Standards Board Accounting Standards Codification). The Codification is the single source of authoritative nongovernmental U.S. generally accepted accounting principles (US GAAP) effective for interim and annual periods ending after September 15, 2009.

Ousdahl cited to some of our previous orders and demonstrated the effects of the double counting.

We are concerned that the double counting of deferred income taxes might result in a violation of tax normalization rules. Per IRC§168(i)(9),[46] tax normalization requires any ratemaking adjustment with respect to a utility's deferred income tax reserves to be consistently applied with respect to rate base, depreciation expense, and income tax expense. Pursuant to IRC §168(f)(2),[47] the consequence of violating the normalization method of accounting is the loss of the ability to claim accelerated depreciation for income tax purposes. Such a normalization violation would result in the loss of the ability to use accelerated tax methods of depreciation. Consistent with prior PSC orders, tax normalization rules, and as discussed in greater detail below, FPL has properly allocated pro-rata adjustments to all sources of capital.

Based on the foregoing, we find that the methodology used by FPL to calculate ADITs is proper and is consistent with SFAS 109, FIN 48, and Internal Revenue Code covering the projected test year. After making adjustments, the appropriate amount of accumulated deferred taxes to include in FPL's capital structure is $2,892,247,084 for the projected 2010 test year. This amount represents the adjustments proposed by FPL in its testimony, which were incorporated along with our own adjustments to depreciation expense and accumulated depreciation.

Unamortized investment tax credits

In its initial filing, FPL recorded a balance of $56,983,000 of jurisdictional investment tax credits (ITCs) in the Company's capital structure for the projected 2010 test year. After its initial filing, the Company revised some of its specific adjustments to long-term debt and deferred income taxes, and accordingly adjusted the balance of ITCs. In its original filing, FPL removed solar plant amounts from rate base for clause recovery but did not remove solar-related ITCs from the capital structure. In a later filing, FPL corrected its error which resulted in a decrease to the balance of ITCs of $51,565,000 in 2010. The Company's revised MFR Schedule D-1a reflected a jurisdictional ITC balance of $5,426,000 for 2010. An additional adjustment was made as a result of rate base and cost of capital adjustments made by the Company related to the removal of aviation expenses.

FPL and OPC disagreed over the methodology for calculating the ITC cost rate. FPL's methodology for calculating the ITC cost rate was to apply the respective cost rates to the respective balances of common equity, preferred stock (none), and long-term debt. OPC's methodology for determining the ITC cost rate was to apply the respective cost rates to all of FPL's investor sources of capital, including short-term debt. We find that the investments that qualify for ITCs are those that are financed with long-term investor sources of capital. Accordingly, we find that FPL's methodology for calculating the balance of and cost rate for ITCs is appropriate and is in accordance with IRS requirements.

[46] 26 USC §168(i)(9) (2009)
[47] 26 USC §168(f)(2) (2009)

While we agree that FPL's methodology for calculating the cost rate for ITCs is correct, we disagree with FPL's proposed cost rate. FPL proposed a 9.74 percent cost rate for 2010 based on the Company's proposed return on equity of 12.50 percent and long-term debt cost rate of 5.55 percent applied to the relative percentages of these sources of capital. OPC proposed a cost rate for ITCs of 7.41 percent for 2010. The OPC proposed cost rate was based on the return on equity and long-term debt cost rate recommended by OPC witness Woolridge. Accordingly, we recalculated the 2010 ITC cost rate based on the approved 10.00 percent ROE and the approved long-term debt cost rate of 5.49 percent. This resulted in a cost rate for ITC's of 8.19 percent. Based on the foregoing, the appropriate jurisdictional balance of unamortized ITCs to include in FPL's capital structure is $5,429,401 at a cost rate of 8.19 percent for the projected 2010 test year.

Cost rate for short-term debt

We heard testimony and received record evidence for a 2010 weighted average short-term debt cost rate ranging from .60 percent to 2.96 percent. FPL proposed a cost rate for short-term debt of 2.96 percent for 2010. OPC asserted that the appropriate short-term debt cost rate for 2010 was 2.27 percent. SFHHA supported a short-term debt cost rate of .60 percent which reflected the 3-month London Interbank Offered Rate (LIBOR) rate as of June 30, 2009.

FPL's proposed cost rate for short-term debt of 2.96 percent included both interest charges related to commercial paper borrowings based on the 30-day forward LIBOR curve as of November 30, 2008 and fixed costs related to maintaining back-up credit facilities to support FPL's commercial paper program. FPL witness Pimentel testified that it was appropriate to recover the $1,536,000 in annual commitment fees associated with FPL's use of short-term debt in the cost rate.

FPL's 2.96 percent cost rate for short-term debt was comprised of an assumed commercial paper borrowing rate of 2.12 percent, plus an allowance for commitment fees associated with accessing its credit facility of 0.84 percent. The following Table 19 shows FPL's 2008-2011 short-term debt balances, the annual credit facility commitment fees, fees as a percentage of short-term debt, short-term debt cost rates, and the total short-term debt cost rate.

Table 19

| Year | (1) Short-term Debt Balance | (2) Annual Credit Facility Fees | (3) Annual Credit Facility Fee Percentage (2)/(1) | (4) Short-term Debt Cost Rate | (5) Total Short Term Debt Cost Rate (3)+(4) |
|---|---|---|---|---|---|
| 2008 | $353,370,000 | $1,993,000 | .56% | 1.96% | 2.52% |
| 2009 | $242,016,000 | $1,536,000 | .63% | 1.64% | 2.27% |
| 2010 | $181,615,000 | $1,536,000 | .84% | 2.12% | 2.96% |
| 2011 | $83,370,000 | $1,536,000 | 1.84% | 2.77% | 4.61% |

As shown in Table 19 above, the annual credit facility fees were calculated as a percentage of the short-term debt balance.

Witness Pimentel testified that forward LIBOR curves best represent market expectations regarding future interest rates and thus it would not be appropriate to use historical rates or a rate from a specific point in time. In addition, witness Pimentel viewed the current low rates as a market anomaly, and did not expect this trend to continue.

OPC witness Woolridge asserted that the appropriate short-term debt cost rate for 2010 was 2.27 percent. Witness Woolridge testified that a 2009 short-term debt cost rate of 2.27 percent was more appropriate than the Company's proposed 2.96 percent for 2010. Witness Woolridge asserted that his recommended cost rate reflected current market interest rates and was not based on speculative forecasts of interest rates. Witness Woolridge testified that the LIBOR peaked in the third quarter of 2008 at 4.75 percent, and since then declined to below 1.0 percent as the short-term credit markets opened up and Treasury rates remained low. In addition, witness Woolridge proposed an increase in the relative balance of the short-term debt reflected in the capital structure to reflect the higher relative percentage of short-term debt maintained in the past.

SFHHA witness Baudino supported a short-term debt cost rate of .60 percent which reflected the 3-month LIBOR rate as of June 30, 2009. Additionally, SFHHA witness Kollen recommended that the annual facility and administrative fees for the Company's credit term loan facilities be included as an expense in the determination of the revenue requirement. Witness Baudino also supported an increase in the relative amount of the short-term debt as a percentage of the capital structure.

SFHHA's proposed short-term cost rate of .60 percent derived from the actual 3-month LIBOR as of June 30, 2009, is not an appropriate short-term cost rate since the cost rate should incorporate the annual credit facility fee charges. In addition, the SFHHA adjustment to include the facility and administrative fee associated with the Company's credit term loan facilities as an operating expense is not appropriate in this instance. These fees are a true cost of issuing short-term debt and shall be included in the cost of debt.

OPC's proposed short-term cost rate of 2.27 percent taken from FPL's MFR Schedule D-3 actual 2009 calculation is not appropriate in this instance. The use of OPC witness Woolridge's short-term cost rate overstates FPL's cost rate for 2010 since OPC's rate is historical and does not factor in more current projections. We also disagree with FPL's recommendation to use a dated 30-day forward LIBOR curve as of November 30, 2008. Instead of the November 30, 2008 LIBOR curve, the appropriate short-term cost rate shall be calculated utilizing an interpolated percentage of the more recent 30-day LIBOR curve projection as of July 28, 2009. In addition, an average of the annual credit facility fee percentages from 2008-2010 of .68 percent will sufficiently compensate the Company for these annual fees.

Accordingly, we find that the appropriate cost rate for short-term debt is 2.11 percent for the projected 2010 test year. We arrived at this cost rate by utilizing a methodology similar to that used by FPL and OPC but we relied on more current information from the hearing record to make our computation. We used an interpolated percentage of the 30-day forward LIBOR curve as of July 28, 2009, to obtain a more current projected interest rate of 1.43 percent for 2010. We added 68 basis points for the average cost of credit facility fees to the interpolated borrowing rate of 1.43 percent for a total short-term debt cost rate of 2.11 percent.

Cost rate for long-term debt

We received record evidence for a 2010 weighted average long-term debt cost rate ranging from 5.14 percent to 5.55 percent. Both OPC and FPL used the same methodology of calculating the long-term debt cost rate, but OPC witness Woolridge applied FPL's 2009 long-term debt cost rate of 5.14 percent to the 2010 projected test year. Witness Woolridge stated that the long-term debt cost rate should be based on current market interest rates, not based on speculative forecasts of interest rates.

FPL proposed a 5.55 percent cost rate for long-term debt for 2010. This proposed rate was based on the weighted average cost rate of the Company's existing debt and projected debt offerings in 2009 and 2010 based on the Blue Chip Financial Forecast (Blue Chip) consensus forecast of December 1, 2008. FPL's proposed cost rate for long-term debt took into account the actual cost of debt on all of the Company's billions of dollars of outstanding long-term debt as well as projected future costs of incremental long-term debt to be issued in the future, for which forecasted interest rates were considered.

FPL witness Pimentel explained that FPL's MFRs had been predicated on its expectation to issue $300 million of three year debt in January 2009 at an interest rate of 3.3 percent. However, the debt was not issued at that time and FPL instead issued $500 million of 30-year bonds at 5.96 percent in March 2009. Witness Pimentel stated that the additional funds raised would reduce the October and December 2009 projected issuances to keep the total amount of debt raised in 2009 issuance at $1 billion.

FPL witness Pimentel disagreed with OPC witness Woolridge's recommended cost rate for long-term debt of 5.14 percent. Witness Pimentel stated that he did not agree with witness Woolridge's use of the overall embedded long-term debt cost rate for 2009 as the long-term debt cost rate for 2010. Witness Pimentel argued that for the 2010 long-term debt cost rate to remain at the 2009 embedded cost rate of 5.14 percent, FPL would need to issue long-term debt in 2009 and 2010 at an average rate of 3.70 percent. Witness Pimentel stated that the Company's actual weighted average cost of long-term debt for 2009, excluding storm recovery bonds, was 5.43 percent.

FPL provided a revised MFR Schedule D-4a to correct some calculation errors and to update the schedule to reflect actual issuances that did not take place as projected due to market conditions. FPL witness Pimentel asserted that the actual debt that the Company issued in the first quarter of 2009 along with the updated interest rate projections from the June 2009 Blue Chip Financial forecast for projected debt issuances were considered together, it would result in a slightly higher interest rate than the rate proposed in FPL's original MFR Schedule D-4a.

FPL maintained that it would be unreasonable and erroneous to adopt a lower long-term cost of debt for FPL in this proceeding based upon the more recent Blue Chip projections of interest rates - i.e. taking this one data point out of context - without also taking into account the updated facts testified to by witness Pimentel. We agree with FPL that updated information in the record should be incorporated in the revisions. Conversely, we disagree with FPL that it is inappropriate to use an updated forecast when determining the appropriate long-term cost rates as well as revising any errors in the original filing.

We calculated the long-term rate for 2010 based on updated information and updated revisions from the record before us. We determined that FPL made an error of including a nonexistent AAA- credit rating in its interpolation of the Company's A+ credit rating positioned between AAA and BBB. This error had the effect of overestimating the long-term cost of debt for FPL. In addition, we applied the more recent October 2009 Blue Chip forecast and the June 2009 Blue Chip forecast (Biannual edition) to update FPL's projected long-term coupon rates. Table 20 below shows FPL's originally proposed interest rates based on the December 2008 Blue Chip Financial forecast and our estimated rates based on FPL's methodology updated for forecasts from the June and October 2009 editions of Blue Chip, correcting for the interpolation error, and recognizing the other adjustments FPL made in its revised MFR Schedule D-4a.

Table 20

| Estimated Coupon Rate Calculation | Blue Chip Financial Forecast Edition(s) | S&P Credit Rating | 2009 Estimated Coupon Rate | 2010 Estimated Coupon Rate |
|---|---|---|---|---|
| FPL | December 2008 | A+ | 7.11% | 6.88% |
| Commission | June & October 2009 | A+ | 5.95% | 6.29% |

To calculate the appropriate embedded cost of long-term debt, we made adjustments to FPL's revised MFR Schedule D-4a for 2010. For the specific debt issuances projected by FPL, we substituted FPL's estimated coupon rates of 7.11 percent for 2009 and 6.88 percent for 2010 with the updated estimated coupon rates of 5.95 percent and 6.29 percent, respectively, based on updated interest forecasts from more current Blue Chip forecasts. In addition, the 3-year notes that were not actually issued in January 2009 and the storm securitization bonds have been removed from this calculation. The net effect of the above adjustments results in a six basis point decrease in the cost rate for long-term debt for 2010 from 5.55 percent to 5.49 percent. Based on the foregoing, the appropriate cost rate for long-term debt is 5.49 percent.

Reconciliation of rate base and capital structure

We next turned to the determination of whether adjustments made by FPL to rate base have been appropriately reconciled to the capital structure. In making this determination, we first determined whether certain specific adjustments were appropriately made. We then evaluated whether certain pro rata adjustments should be reconciled over all sources of capital or over investor sources of capital only. MFR Schedule D-1b listed the specific and pro rata adjustments that FPL made to the Company's proposed capital structure for the 2010 projected test year. FPL made specific adjustments to the balances of common equity, long-term debt, investment tax credits (ITCs), and accumulated deferred income taxes (ADITs). After FPL made specific adjustments to specific components in the capital structure, all other adjustments were made pro rata over all sources of capital.

FPL witness Ousdahl asserted that a significant portion of FPL's pro rata adjustments reflected the removal of clause-related plant and Allowance for Funds Used During Construction (AFUDC)-eligible CWIP from FPL's retail rate base. Witness Ousdahl testified that these rate base items were removed because they earned their own return outside of base rates. Additionally, witness Ousdahl stated that the clause items earned a Commission-approved rate of return that was calculated over all sources of capital, including ADITs, customer deposits, and ITCs. Moreover, witness Ousdahl stated that when these items are removed from rate base, it is appropriate to make the necessary reconciling adjustment to the capital structure on a pro rata basis over all sources of capital in order to avoid double-counting the benefit of zero cost deferred taxes and low cost customer deposits.

OPC argued that specific adjustments should be made to the balances of customer deposits, ADITs and ITCs based on corresponding rate base adjustments, and no further pro rata adjustments to these accounts should be made to reconcile the Company's capital structure to rate base. SFHHA also stated that the balances of customer deposits, ADITs and ITCs should not be reduced for pro rata adjustments to reconcile the Company's capitalization to rate base. SFHHA witness Kollen argued that FPL had improperly diluted the low-cost capital provided by customer deposits and the cost-free capital provided by ADITs by allocating pro rata adjustments over these capital components. Witness Kollen explained that capital amounts should be directly assigned to ratepayers in the same manner as if the amounts had been used to reduce rate base. Witness Kollen maintained that customer deposits and ADITs were not used to finance the amounts that comprised the total of FPL pro rata adjustments.

FPL argued that making the adjustment in the manner it proposed was the easiest way to avoid a potential violation of the Internal Revenue Service (IRS) tax normalization rules and avoid the risk of losing the IRS tax benefit of accelerated depreciation. FPL witness Ousdahl explained that reconciling rate base over all sources of capital also matched the way FPL expended cash in the normal course of its operations. FPL funds its operations from a pool of funds that is generated from all sources of capital - including deferred taxes, customer deposits and investment tax credits.

In support of its position, FPL cited our treatment of Tampa Electric Company's (TECO) method of reconciling adjustments approved in Order No. PSC-09-0571-FOF-EI.[48] However, in that order we identified seven additional orders in which the incremental adjustment to rate base was made through pro rata adjustments over investor sources of capital only.[49] In addition, we

[48] Order No. PSC-09-0571-FOF-EI, issued August 21, 2009, in Docket No. 080317-EI, In re: Petition for rate increase by Tampa Electric Company.

[49] Order No. PSC-09-0375-PAA-GU, issued May 27, 2009, in Docket No. 080366-EI, In re: Petition for rate increase by Florida Public Utilities Company; Order No. PSC-08-0436-PAA-GU, issued July 8, 2008, in Docket No. 070592-GU, In re: Petition for rate increase by St. Joe Natural Gas Company, Inc.; Order No. PSC-04-1110-PAA-GU, issued November 8, 2004, in Docket No. 040216-GU, In re: Application for rate increase by Florida Public

stated in Order No. PSC-09-0571-FOF-EI, "Our decision on this point is specific to the record in this case and shall not be considered precedent regarding our position on this or similar issues in future proceedings." That said, FPL did not furnish the information we requested concerning adjustments by plant to the balances of ADITs and ITCs. The following passage is the response by FPL to a discovery request to identify the balances of ADITs and ITCs by plant:

> For the forecast period, the Company did not specifically identify accumulated deferred income taxes or investment tax credits by plant. The Company forecasts the temporary differences for each annual period and identifies the change in deferred income taxes applicable to those temporary differences for each period. The temporary differences during the forecast period are not specifically identified to a specific plant. The amounts are provided in the aggregate in the determination of the taxable income and the accumulated deferred income taxes applicable to a specific plant item have not been separated by temporary differences in the accumulated deferred taxes balance. To determine the deferred income taxes related to CWIP for a specific item, a close out schedule for temporary differences would be required to reflect the transfer of temporary difference from CWIP to plant in service and the related allocation of book depreciation to the various forecasted basis (temporary) differences. For the test year 2010 and the subsequent year, 2011, the amount of deferred tax liabilities forecasted to be generated relating to CWIP were approximately $176 million and $143 million, respectively. During these same periods, deferred income tax liabilities related to plant in service decreased for 2010 by $17 million and increased by $4 million for 2011. Related to the investment tax credits, the Company calculated the estimated amount of investment tax credits to be generated from solar and reported the amounts in the applicable year; it also provided for the amortization beginning on the estimated in-service date. The amortization of investment tax credits is not tracked by plant and is combined by rate on the balance sheet.

We agree with SFHHA witness Kollen that it has been our practice to make specific adjustments where possible and to prorate other rate base adjustments over investor sources only.[50] If an adjustment does not involve plant, then it is likely that the account in question did not produce deferred taxes or ITCs. Absent a showing that specifically identifies ADITs and ITCs associated with a non-plant related adjustment, all adjustments for amounts unrelated to plant shall continue to be removed from the capital structure through a pro rata adjustment over investor sources of capital only.

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Utilities Company; Order No. PSC-04-0128-PAA-GU, issued February 9, 2004, in Docket No. 030569-GU, In re: Application for rate increase by City Gas Company of Florida; Order No. PSC-01-1274-PAA-GU, issued June 8, 2001, in Docket No. 001447-GU, In re: Request for rate increase by St. Joe Natural Gas Company, Inc.; and Order No. PSC-01-0316-PAA-GU, issued February 5, 2001, in Docket No. 000768-GU, In re: Request for rate increase by City Gas Company of Florida.

[50] Order No. PSC-02-0787-FOF-EI, issued June 10, 2002, in Docket No. 010949-EI, In re: Request for rate increase by Gulf Power Company; Order No. PSC-08-0327-FOF-EI, issued May 19, 2008, in Docket No. 070304-EI, In re: Petition for rate increase by Florida Public Utilities Company; Order No. PSC-08-0436-PAA-GU, issued July 8, 2008, in Docket No. 070592-GU, In re: Petition for rate increase by St. Joe Natural Gas Company, Inc.

FPL did not follow our practice in this rate case; however, we will permit FPL to make the pro rata adjustments as it proposed. In this particular instance, there are three reasons why we are permitting FPL to make pro rata adjustments over all sources of capital. First, FPL has made a compelling argument regarding the plant items that earn an AFUDC rate and clause items that earn a Commission-approved rate of return. The AFUDC return is calculated over all sources of capital, including deferred taxes, customer deposits, and investment tax credits. When these items are removed from rate base, it is appropriate to make the necessary reconciling adjustment to the capital structure on a pro rata basis over all sources of capital to avoid double-counting the benefit of zero cost deferred taxes and low cost customer deposits. Second, FPL asserted that to avoid a potential violation of IRS tax normalization rules,[51] the rate of return for clause-related plant and AFUDC-eligible CWIP removed from the rate base should be calculated using the same methodology as the rate of return for the jurisdictional rate base so that adjustments to ADITs are applied consistently. We are concerned about the potential loss of deferred income tax treatment by violation of IRS tax normalization rules. Third, as shown below in Table 21, we have calculated the relative difference in the overall cost of capital resulting from the two methodologies of reconciling rate base and capital structure. This difference does not justify the negative consequence of a normalization violation.

Table 21

| | Pro rata adjustment over all sources of capital | Pro rata adjustment over investor sources only | Difference |
|---|---|---|---|
| 2010 Weighted Average Cost of Capital | 7.00% | 6.92% | 8 basis points |

Overall, we are concerned about symmetry in the treatment of reconciling rate base and capital structure. But the proper venue (to address the appropriate methodology for reconciling

[51] As defined in Order No. PSC-09-0571-FOF-EI, issued August 21, 2009, in Docket No. 080317-EI, In re: Petition for rate increase by Tampa Electric Company; Normalization requirements are outlined in Section 168 of the Internal Revenue Code (IRC). In pertinent part, Section 168 permits the use of accelerated depreciation methods. However, accelerated depreciation is permitted with respect to public utility property only if the taxpayer uses a normalization method of accounting for ratemaking purposes. Under a normalization method of accounting, a utility calculates its ratemaking tax expense using depreciation that is no more accelerated than its ratemaking depreciation (typically straight-line). In the early years of an asset's life, this results in ratemaking tax expense that is greater than actual tax expense. The difference between the ratemaking tax expense and the actual tax expense is added to a reserve (the accumulated deferred income tax reserve, or ADIT). The difference between ratemaking tax expense and actual tax expense is not permanent and reverses in the later years of the asset's life when the ratemaking depreciation method provides larger depreciation deductions and lower tax expense than the accelerated method used in computing actual tax expense. This accounting treatment prevents the immediate flowthrough to utility ratepayers of the reduction in current taxes resulting from the use of accelerated depreciation. Instead, the reduction is treated as a deferred tax expense that is collected from current ratepayers through utility rates, and thus is available to utilities as cost-free investment capital. When the accelerated method provides lower depreciation deductions in later years, only the ratemaking tax expense is collected from ratepayers and the difference between the actual tax expense and ratemaking tax expense is charged to ADIT, depleting the utility's stock of cost-free capital. (http://edocket.access.gpo.gov/2003/03-4885.htm)

the capital structure to rate base) is a generic docket to address the issue, since it would affect all IOUs, not just FPL. The appropriate method to reconcile rate base to capital structure is to make adjustments to the class of capital in the capital structure that correspond to the adjustments made to related accounts in rate base. For example, adjustments made to rate base from accounts that do not generate deferred taxes or investment tax credits should not be reconciled over deferred taxes or investment tax credits in the capital structure. Accordingly, we will open a generic docket to address this issue on a prospective basis.

In this docket, FPL did not provide the information necessary to itemize specific adjustments to the balances of ADITs and ITCs for the amounts removed from rate base. The record shows that FPL did not specifically identify its sources of capital and trace its funding usage. The omission of information should not inure to the benefit of the party responsible for providing that information. However, we find that the risk of losing the benefit on accumulated deferred income taxes in the determination of customer rates due to a tax normalization violation outweighs our concern in this instant case. Based upon the foregoing, after making certain specific adjustments, we find that for the sole purpose of setting rates in this rate case only, rate base and capital structure have been reconciled appropriately.

Equity ratio

The goal of an appropriate equity ratio and capital structure is to minimize the overall weighted average cost of capital and to maintain consistent access to capital under reasonable terms. This is an important consideration in that it is the overall cost of capital that is used to determine revenue requirements and ultimately customer rates.

To reach our decision of the appropriate equity ratio and capital structure, we start with a review of whether FPL has appropriately described the actual 59.6 percent equity ratio that it proposed to use for ratemaking purposes as an "adjusted 55.8 percent equity ratio" on the basis of imputed debt associated with FPL's purchased power contracts. This question involves the different ways FPL's test year equity ratio has been presented for purposes of this proceeding.

A company's capitalization can be expressed in a number of ways. For purposes of financial reporting, a company will report its capitalization in accordance with Generally Accepted Accounting Principles, often referred to as on a "GAAP" basis. GAAP prescribes specific requirements for how a company's book capital structure will be presented. Another way a company's capitalization ratios can be expressed is from the perspective of the rating agencies. For their own analytical purposes, rating agencies often make adjustments to a company's capitalization ratios to include certain items that are not recorded on the balance sheet and to remove other items that are recorded on the balance sheet pursuant to GAAP. A third way of expressing a company's capitalization, if the company in question is a regulated utility, is on a Commission-adjusted basis. These adjustments are made to capital structure and rate base primarily to account for the removal of rate base items that are recovered outside of base rates.

Due to differences between GAAP requirements, rating agency adjustments, and regulatory requirements, it is common for a company's reported equity ratio to vary. The table below shows FPL's projected 2010 test year equity ratio as a percentage of investor capital expressed on a GAAP, Standard & Poors' (S&P), and Commission (PSC) basis.

Table 22

| | GAAP | S&P | PSC |
|---|---|---|---|
| Equity Ratio | 55.6% | 55.8% | 59.6% |

Annual reports for shareholders as well as filings made with the Securities and Exchange Commission (SEC) are prepared in accordance with GAAP. On a GAAP basis, FPL's capitalization will include the storm recovery bonds issued in 2007 to finance storm restoration costs and replenish the storm reserve.[52] The annual reports and filings with the SEC will not, however, reflect imputed debt associated with FPL's purchased power agreements in the balance sheet and income statement. The capitalization ratios reflected in the GAAP statements are expressed on a year end basis.

S&P routinely makes adjustments to the financial statements of companies for purposes of its own analytical review. S&P will make an adjustment to FPL's capitalization to remove the storm recovery bonds because these bonds are non-recourse to the Company. S&P will also impute debt in FPL's capitalization ratios to reflect the fixed payment obligation associated with FPL's purchased power agreements. These "adjusted" financial statements are also on an annual basis.

From a regulatory perspective, we require certain adjustments that also impact FPL's capitalization ratios. For purposes of this proceeding, FPL made adjustments to long-term debt to remove the storm recovery bonds that are recovered through a separate line charge and to remove nuclear fuel capital leases that are recovered through the fuel cost recovery clause. With the exception of the adjustment recognized pursuant to the 2005 Stipulation negotiated between the parties to settle PEF's 2005 rate case approved in Order No. PSC-05-0945-S-EI,[53] base rate-related filings with us do not reflect imputed debt associated with purchased power agreements. For ratemaking purposes, FPL's financial statements are expressed on a 13-month average basis.

As demonstrated above, FPL was technically correct from a GAAP and S&P basis when it described its proposed equity ratio for purposes of this proceeding as approximately 55 percent. However, we do not set rates for FPL based on its GAAP or S&P adjusted equity ratios. We determine FPL's overall cost of capital, and therefore its revenue requirements, based on FPL's regulatory adjusted equity ratio. Accordingly, while the Company's GAAP and S&P equity ratios may be expressed as 55.6 and 55.8 percent, respectively, the equity ratio reflected in FPL's original MFR filing for purposes of determining revenue requirements in this proceeding is appropriately described as 59.6 percent.

[52] Order Nos. PSC-06-0464-FOF-EI, issued May 30, 2006, and PSC-06-0626-FOF-EI, issued July 21, 2006, collectively known as the Financing Order, in Docket No. 060038-EI, In re: Petition for issuance of a storm recovery financing order, by Florida Power & Light Company.
[53] Order No. PSC-05-0945-S-EI, issued September 28, 2005, in Docket No. 050078-EI, In re: Petition for rate increase by Progress Energy Florida, Inc., (2005 Stipulation).

Having determined that FPL has appropriately described its equity for purposes of this proceeding, we next address what is the appropriate equity ratio that we will use for ratemaking purposes in this case. All witnesses that testified on this issue were in agreement that we should approve a rate of return for FPL that maintains its financial integrity and allows the Company continued access to the capital markets under reasonable terms. The disagreement between the witnesses concerned the relative magnitude of the equity ratio recognized for purposes of determining revenue requirements that is necessary to achieve these results. FPL proposed that for purposes of setting its revenue requirements, we recognize its equity ratio as a percent of investor capital of 59.6 percent. OPC recommended that we adopt an equity ratio of 54.4 percent. FIPUG suggested the equity ratio be reduced to 50.2 percent and SFHHA recommended an equity level of 53.5 percent.

FPL witness Pimentel testified that it is critical for FPL to maintain its financial strength as it confronts the challenges of meeting significant infrastructure investment requirements during this period of financial uncertainty as the nation comes out of the global economic recession. He noted that FPL's strong balance sheet has provided continuous access to both short-term liquidity and long-term capital throughout extreme events such as the 2004 and 2005 storm seasons, the spike in natural gas prices, and the disruption in the financial markets in the fall of 2008. Witness Pimentel testified that FPL's current equity ratio provides for the liquidity requirements and financial flexibility necessary to be in a position to fund future storm restoration activities, hedge fuel price volatility, and fund substantial infrastructure investment.

FPL witness Avera acknowledged that FPL's requested equity ratio is at the upper end of the range of equity ratios for both the companies in his proxy group as well as the investor-owned utilities (IOUs) they own. However, he testified that it is appropriate for FPL to maintain this level of equity given the risks and challenges that the Company faces. Witness Pimentel testified that FPL has consistently maintained this relative equity position, on an adjusted basis, since the we approved the 1999 Revenue Sharing Agreement in Order No. PSC-99-0519-AS-EI.[54] He also noted that FPL's "adjusted" equity ratio of 55.8 percent has been and continues to be viewed as adequate and appropriate by the investment community.

In evaluating the adequacy of the capital structure of a company, witness Pimentel testified that rating agencies will take into account major financial commitments that are not reflected on the balance sheet such as long-term purchased power agreements. FPL witness Avera testified that FPL must be mindful of how the investment community views the Company's capital structure. He also stressed that, unlike TECO[55] and PEF,[56] FPL is not requesting that imputed equity be included in its regulatory capital structure. Because rating agencies and the investment community consider the impact of such fixed obligations when assessing the Company's financial position, both witnesses Pimentel and Avera testified that we

[54] Order No. PSC-99-0519-AS-EI, issued March 17, 1999, in Docket No. 990067-EI, In re: Petition by the Citizens of the State of Florida for a full revenue requirements rate case for Florida Power & Light Company, (1999 Agreement).
[55] Order No. PSC-09-0283-FOF-EI, issued April 30, 2009, in Docket No. 080317-EI, In re: Petition for rate increase by Tampa Electric Company, pages 36–42.
[56] Docket No. 090079-EI, In re: Petition for increase in rates by Progress Energy Florida, Inc., staff recommendation filed November 30, 2009, pages 146–149.

should consider these obligations when evaluating the reasonableness of FPL's proposed equity ratio.

OPC witness Woolridge testified that the 59.6 percent equity ratio as a percentage of investor capital reflected in the Company's filing "is well in excess of the common equity ratios of electric utility companies." He noted that there is a direct correlation between the relative amount of equity in the capital structure and the revenue requirements the customers are called upon to bear. Witness Woolridge testified that if the proportion of equity is too high, rates will be higher than they need to be. For this reason, he recommended that FPL pursue a capitalization strategy that strikes a more appropriate balance of equity and debt in the capital structure.

OPC recognized that FPL is not proposing to impute equity in its capital structure for purposes of setting rates in this proceeding, but stressed that the "actual adjusted" equity ratio of 55.8 percent is not the equity ratio that the Company has employed to calculate its revenue requirements. Because FPL's proposed capital structure ratios do not reflect the actual capitalization of FPL or FPL Group, Inc. (FPL Group) and because the proposed equity ratio is much higher than the equity ratios of other electric utilities, witness Woolridge recommended we recognize a lower equity ratio for ratemaking purposes.

Witness Woolridge recommended an equity ratio of 54.4 percent as a percentage of investor capital. This equity ratio was based on the average of FPL's projected year end capitalization ratios for 2009 and 2010. Because these year end balances differ from the 13-month average balances reported on MFR Schedule D-1a, accomplishment of witness Woolridge's recommended equity ratio would entail adjustments that decrease the relative amount of common equity and increase the relative amounts of long-term and short-term debt. Because his recommended capital structure was based on Company book figures, witness Woolridge testified that his equity ratio more accurately reflected the Company's equity ratio as viewed by investors.

FIPUG witness Pollock challenged the testimony of FPL witnesses that it is necessary for us to consider the impact of imputed debt associated with purchased power agreements. He noted that, due to our approval of purchased power agreements and the full and direct recovery of firm energy and purchased power capacity payments through the fuel and capacity cost recovery clauses, there is minimal recovery risk associated with purchased power agreements in Florida. Thus, consideration of imputed debt is unnecessary in assessing the reasonableness of FPL's capital structure. Witness Pollock testified that, at an equity ratio approaching 60 percent, FPL would be one of the least leveraged regulated electric utilities in the nation.

Witness Pollock recommended an equity ratio of 50.2 percent as a percentage of investor capital. This equity ratio was based on the average equity ratio for single A-rated electric utilities followed by SNL Financial for the period 2006 through the first quarter of 2009. Because FPL is rated single A1 by Moody's Investors Service (Moody's) and single A flat by both Fitch Ratings (Fitch) and S&P, he recommended that the Company's equity ratio should be adjusted to be more comparable to the average equity ratio of other comparably-rated electric utilities.

SFHHA witness Baudino recommended that FPL's equity level be reduced to 50.0 percent on an adjusted basis to conform with the high end of S&P's debt-to-total capital range consistent with a single A rating. He stated that his recommended adjusted equity ratio equates to a ratemaking equity ratio of 53.5 percent. He suggested that this adjustment be accomplished, in part, through an increase in the balance of short-term debt of $600 million to be consistent with the Company's short-term debt levels over the last few years. Witness Baudino concluded that his proposed capital structure strikes an appropriate balance between the interests of Company shareholders and customers, results in an equity ratio consistent with a single A rating, and is supportive of FPL's credit quality.

Witness Baudino testified that approval of an "excessive" equity ratio for FPL could result in customers subsidizing FPL Group's unregulated affiliate operations. S&P employs a consolidated rating methodology whereby it generally assigns a rating to each entity in an organization based upon the credit profile of the consolidated entity. Witness Baudino argued that FPL Group could not maintain a single A rating on a consolidated basis without the support of an excessive FPL equity ratio. He noted the higher debt leverage maintained at the funding vehicle for FPL Group's unregulated operations (FPL Group Capital) and by FPL Group on a consolidated basis relative to the debt leverage maintained at FPL. He also referred to a February 12, 2009 report on FPL wherein S&P cautioned that FPL's rating could be pressured if FPL Group failed to manage significant risks in its merchant energy and energy marketing and trading operations. Because the level of equity for ratemaking purposes should reflect the risk associated with regulated operations, not to offset higher debt leverage at the consolidated level, witness Baudino recommended that the Company's equity ratio be reduced.

Since the approval of the 1999 Agreement, FPL has consistently maintained the proposed relative level of equity capitalization. For the period 1999 through 2008, FPL earned approximately $8.0 billion in net income. Over this period, approximately $4.1 billion was retained by FPL Group and $3.9 billion was invested in FPL in order to maintain the relative balance of debt and equity in its capital structure that it has proposed be recognized for purposes of this proceeding.

Unlike the filings by TECO and PEF, FPL is not requesting any adjustment to its regulatory capital structure to offset the impact of imputed debt associated with purchased power agreements. The Company witnesses have testified that, from the rating agencies' perspective, purchased power agreements represent a debt-like obligation that we should consider when evaluating the reasonableness of the capital structure maintained by FPL. In addition to the impact purchased power agreements have on the Company's financial flexibility, witness Pimentel also urged us to consider the challenges faced by FPL when determining the appropriate capital structure. These challenges include having the financial strength and flexibility to fund potentially significant storm restoration efforts, to hedge fuel price volatility, and to maintain the ability to raise capital under reasonable terms even during periods of economic uncertainty and market volatility.

SFHHA witness Baudino raised the concern that if an "excessive" equity ratio is approved for FPL, it could result in inappropriate cross subsidization through the cost of capital. We take concerns regarding cross subsidization between regulated and unregulated operations of a consolidated entity very seriously. As in all cases that come before us, we are prohibited from setting rates to make up for losses or inadequate returns of affiliated companies. FPL witness Pimentel explained that intervenor witnesses made inappropriate comparisons between FPL's equity ratio and the equity ratio supporting FPL Group's unregulated operations. After considering rating agency adjustments for non-recourse project debt and hybrid capital instruments supporting the unregulated operations, debt leverage at FPL Group Capital and FPL Group on a consolidated basis, while still higher than for FPL, is not as pronounced as a comparison of their respective book capitalizations might suggest. Moreover, to the extent we approve an equity ratio for FPL that represents the high end of the range of ratios for other, comparably situated electric utilities, this lower financial risk position is recognized with our setting of FPL's authorized return on equity (ROE) in this proceeding.

FPL's position of financial strength has served it and its customers by holding down the Company's cost of capital. During the recent volatility in the capital markets, many companies experienced sharp spikes in their cost to borrow. In some instances, companies had to accept rates as high as 10 percent to issue bonds. In the case of FPL, however, due to its strong financial position it was able to sell 30-year bonds at rates under 6 percent during 2008 and 2009 despite the significant disruption in the credit markets.

In its original filing, FPL requested an overall cost of capital of 8.00 percent for 2010. FPL lowered its requested overall cost of capital to 7.85 percent for 2010 principally due to the recognition of additional zero cost accumulated deferred income taxes in the capital structure. The net impact of the net increase in the balance of accumulated deferred income taxes and decrease in the balance of investment tax credits discussed earlier in this order lowered FPL's Commission-adjusted equity ratio as a percentage of investor capital from 59.6 percent to 59.1 percent for 2010.

Based on the foregoing, we approve the capital structure shown on Schedule 2, attached to this order. This capital structure reflects an equity ratio as a percentage of investor capital of 59.1 percent for 2010. While this relative level of equity is near the top of the range of equity ratios of the IOUs owned by the companies in witness Avera's proxy group, it is still within the range of equity ratios of comparably rated IOUs. In addition, this equity ratio is consistent with the relative level of equity FPL has maintained, on an adjusted basis, over the past decade.

Capital Structure for purposes of setting rates

FPL proposed specific adjustments to long-term debt, common equity, and deferred income taxes in its original capital structure as shown in MFR Schedule D-1a. FPL made a specific downward adjustment to the balance of long-term debt in the amount of ($907,863,000). This amount of ($907,863,000) was comprised of ($374,898,000) in nuclear fuel capital leases, ($1,110,000) for prepayment interest on commercial paper, and ($531,855,000) for storm bonds. FPL witness Ousdahl explained that FPL Fuels, Inc. was established for the purpose of financing the acquisition of nuclear fuel and then subsequently leasing the fuel to FPL. However, the rating agencies no longer give off-balance sheet treatment to commercial paper issued by FPL Fuels, Inc. and changes in accounting rules now require FPL to consolidate FPL Fuels, Inc. into its financial statements, so there is no longer any benefit to maintain a separate fuel company.

Therefore, for the reasons above FPL intended to dissolve FPL Fuels, Inc. on or before January 1, 2010.

FPL proposed a specific net downward adjustment to deferred taxes in the amount of ($259,006,000) comprised of ($332,507,000) for storm deficiency recovery and $73,501,000 for accumulated provision for property and storm insurance. Additionally, FPL proposed making a specific downward adjustment to remove nonutility property from common equity in the amount of ($9,519,000).

Subsequent to its original filing, the Company revised its specific adjustments to long-term debt and deferred income taxes, and proposed a new adjustment to investment tax credits as we discussed regarding unamortized tax credits. FPL's proposed adjustment to remove solar plant amounts from base rates for clause recovery did not include the removal of the related investment tax credits from the capital structure. Correction of this error resulted in a decrease to the balance of investment tax credits in the amount of $51,565,000 in 2010. In addition, a proposed adjustment to reflect the impact of the Stimulus Bill that were not known at the time of the original filing resulted in an increase in the balance of accumulated deferred income taxes in the amount of $288,261,000 in 2010. Finally, FPL inadvertently excluded the impact to accumulated deferred income taxes resulting from the company adjustment to include the impact of the change in depreciation rates specified by its depreciation filing. Correction of this error resulted in a decrease in the balance of accumulated deferred income taxes in the amounts of $16,508,000 in 2010.

We approve the Company's the proposed specific adjustments to long-term debt, common equity, deferred income taxes, and investment tax credits as detailed on Schedule 2. Accordingly, we find that the appropriate capital structure for the purpose of setting rates in this proceeding is based on FPL's projected 2010 capital structure with certain adjustments as discussed above. The appropriate capital structure for 2010 is shown on Schedules 2.

Return on equity

We were presented testimony and evidence supporting a range of return on equity (ROE) from 7.6 percent to 13.9 percent. Four witnesses testified in this proceeding regarding the appropriate ROE for FPL. FPL witness Avera testified that a reasonable ROE for FPL is in the range of 12.0 percent to 13.0 percent. FPL witness Pimentel, while not conducting his own independent analysis of the appropriate ROE for FPL, recommended the midpoint of witness Avera's recommended range, or 12.5 percent, as the appropriate ROE for FPL for purposes of this proceeding. OPC witness Woolridge recommended an ROE of 9.5 percent. SFHHA witness Baudino recommended an ROE of 10.4 percent. As expressly stated in the 2005 Settlement, FPL does not currently have an authorized ROE.[57] However, for purposes other than reporting or assessing earnings (such as cost recovery clauses and AFUDC), the 2005 Settlement Order provided for FPL to use an ROE of 11.75 percent.

[57] Order No. PSC-05-0902-S-EI, issued September 14, 2005, in Docket No. 050045-EI, In re: Petition for rate increase by Florida Power & Light Company, p. 3, (2005 Settlement).

The statutory principles for determining the appropriate rate of return for a regulated utility are set forth by the U.S. Supreme Court in its Hope and Bluefield decisions.[58] These decisions define the fair and reasonable standards for determining rate of return for regulated enterprises. Namely, these decisions hold that the authorized return for a public utility should be commensurate with returns on investments in other companies of comparable risk, sufficient to maintain the financial integrity of the company, and sufficient to maintain its ability to attract capital under reasonable terms.

While the logic of the legal and economic concepts of a fair rate of return are fairly straightforward, the actual implementation of these concepts is controversial. Unlike the cost rate on debt that is fixed and known due to its contractual terms, the cost of equity is a forward-looking concept and must be estimated. Financial models have been developed to estimate the investor-required ROE for a company. Market-based approaches such as the Discounted Cash Flow (DCF) model, Capital Asset Pricing Model (CAPM), and ex ante Risk Premium (RP) model are generally recognized as being consistent with the market-based standards of a fair return enunciated in the Hope and Bluefield decisions.

Three witnesses used the DCF model to estimate the investor-required ROE for FPL. Because FPL is a wholly-owned subsidiary of FPL Group, Inc. (FPL Group), its common stock is not publicly traded. To apply the model, each witness had to select a group of companies with publicly traded stock to serve as a proxy for FPL.

FPL witness Avera applied the DCF model to two proxy groups he determined to be comparable in risk to FPL. To select his first group of companies, witness Avera started with all electric utilities followed by Value Line Investment Survey (Value Line). From this initial sample, he eliminated all companies that did not have at least a triple B plus corporate credit rating from Standard & Poors' (S&P), a Value Line safety rank of 1 or 2, a Value Line financial strength rating of B++ or better, and at least two published earnings per share (EPS) growth projections from Value Line, Thomson I/B/E/S (IBES), First Call Corporation (First Call), and Zacks Investment Research (Zacks). Based on these selection criteria, witness Avera identified a proxy group of 19 utility companies (the Utility Proxy Group) that he testified reflect the risks and prospects associated with FPL's jurisdictional utility operations. To select his second proxy group, witness Avera started with all companies followed by Value Line. From this sample, he eliminated all companies that did not pay a dividend, had a Value Line safety rank less than 1, had a financial strength rating less than A, did not have an investment grade credit rating from S&P, and that did not have at least two published EPS growth projections from Value Line, IBES, First Call, and Zacks. Based on these selection criteria, witness Avera identified a proxy group of 66 non-utility companies (the Non-Utility Proxy Group). Considering the various measures of business and financial risk for the two proxy groups, witness Avera concluded that investors would likely view the overall investment risk of FPL to be comparable to the investment risks of the companies in both proxy groups.

[58] Federal Power Commission v. Hope Natural Gas Company, 320 U.S. 591 (1944); and Bluefield Water Works & Improvement Company v. Public Service Commission of West Virginia, 262 U.S. 679 (1923).

Witness Avera used the constant growth DCF model to estimate the cost of equity for FPL. He derived the expected dividend yields from information published in December 2008 editions of Value Line. The dividend yields for the companies in the Utility Proxy Group ranged from 2.8 percent to 6.4 percent and averaged 6.0 percent for the group. The dividend yields for the companies in the Non-Utility Proxy Group ranged from 0.55 percent to 13.60 percent and averaged 3.52 percent for the group. He relied on security analyst EPS growth projections from Value Line, IBES, First Call, and Zacks as of January 2009 and the expected growth rate as measured by the sustainable growth approach to estimate the growth rate used in his DCF analysis. The growth rates for the companies in the Utility Proxy Group ranged from 0.0 percent to 12.0 percent. The growth rates for the companies in the Non-Utility Proxy Group ranged from (1.2) percent to 18.9 percent. The average of the growth rates used in his DCF analyses were 6.3 percent for the Utility Proxy Group and 10.1 percent for the Non-Utility Proxy Group. In evaluating the results of his DCF analyses, he determined it was appropriate to eliminate cost of equity estimates that were determined to be "extreme outliers." After eliminating "illogical low- and high-end values," the average results of witness Avera's DCF analysis applied to the Utility Proxy Group ranged from 10.6 percent to 11.5 percent. After applying the DCF model to the Non-Utility Proxy Group in the same manner, the average indicated returns ranged from 12.9 percent to 13.4 percent.

To select his group of comparable companies, OPC witness Woolridge started with all electric and combination electric and gas utilities followed by Value Line and AUS Utility Reports (AUS). From this initial sample, he removed all companies that did not have an investment grade bond rating from Moody's Investors Service (Moody's) and/or S&P, and a three year history of paying dividends. He further narrowed his proxy group by focusing on companies with annual operating revenues of at least $5 billion and that generate at least 70 percent of their operating revenues from regulated electric operations. Based on these selection criteria, witness Woolridge identified a group of 10 comparable companies for use in his analysis.

Witness Woolridge used the constant growth DCF model. He relied on dividend yields for the six month period ended July 2009 and for the month of July 2009 as reported by AUS Utility Reports. The expected dividend yield used in his analysis was 4.83 percent. He relied on Value Line's historical and projected growth rate estimates for EPS, dividends per share (DPS), and book value per share (BVPS). In addition, he used the average EPS growth rate forecasts from First Call, Zacks, and Reuters and the expected growth rate as measured by the earnings retention method. The average growth rate used in his analysis was 5.50 percent. The indicated return from witness Woolridge's DCF analysis was 10.33 percent.

To select his group of comparable companies, SFHHA witness Baudino started with all electric companies followed by AUS with at least a single A rating from Moody's and S&P. From this initial sample, he selected companies that generated at least 50 percent of their revenues from regulated electric operations and that had EPS growth forecasts from Value Line and either Zacks or First Call. He further narrowed his proxy group by removing all companies that had recently cut or eliminated dividends, were recently or currently involved in merger activities, or had recent experience with significant earnings fluctuations. Based on these selection criteria, witness Baudino identified a group of 14 companies that he believed had a risk profile that is reasonably similar to FPL.

Witness Baudino used the constant growth DCF model. He derived the dividend yields used in his analysis based on information for the six month period ended June 2009 as reported by Yahoo! Finance. The monthly average dividend yields for the group ranged from 4.75 percent to 5.66 percent. The average expected dividend yield used in his analysis was 5.45 percent. He relied on Value Line projected EPS and DPS growth rate estimates. In addition, he used EPS growth rate forecasts from Zacks and First Call. Witness Baudino ran his DCF model under three slightly different growth rate assumptions. In method 1, he calculated the average of all growth rates from Value Line, Zacks, and First Call. In method 2, he calculated the median growth rate for his proxy group. In method 3, he omitted double digit growth rates and growth rates that were less than 1 percent from the calculation of the averages. The expected growth rates produced by all three methods fell in the range of 3.75 percent to 6.25 percent. Method 1 produced an indicated cost of equity range of 9.72 percent to 11.64 percent with an average of 11.01 percent and a midpoint of 10.68 percent. Method 2 produced an indicated cost of equity range of 9.10 percent to 11.66 percent with an average of 10.80 percent and a midpoint of 10.38 percent. Method 3 produced an indicated cost of equity range of 10.49 percent to 11.43 percent with an average of 11.13 percent and a midpoint of 10.96 percent. Based on this analysis, witness Baudino testified that his DCF analysis indicated a range of returns of 10.38 percent to 11.13 percent and he recommended we adopt an ROE of 10.40 percent for FPL.

All three witnesses used the same constant growth version of the DCF model. And with the exception of witness Avera's Non-Utility Proxy Group, all three witnesses used relatively similar estimates of dividend yields. The primary reason for the difference in the indicated DCF returns is attributed to differences in their respective estimates of the growth rate to include in the DCF model.

Both witnesses Woolridge and Baudino testified that the results of witness Avera's DCF analysis based on the Non-Utility Proxy Group is not appropriate to estimate the ROE for the regulated operations of FPL. Witness Woolridge testified that, because the companies in the Non-Utility Proxy Group are large and successful, have lines of business vastly different from the electric utility business, and do not operate in a highly regulated environment, "the non-utility group is not an appropriate proxy for FPL, and therefore the equity cost rate results for this group should be ignored." Witness Baudino testified that non-utility companies have higher overall risk structures than a low-risk electric utility like FPL and will have higher required returns from their shareholders. Given the greater degree of business risk for the non-utility companies, he stated that it should be expected that witness Avera's DCF results for his Non-Utility Proxy Group would be substantially higher than the results for his Utility Proxy Group. Witness Baudino concluded that "using higher required returns from a group of unregulated companies is obviously unjustified, inflates FPL's required ROE, and should be rejected by the Commission."

Witness Avera countered that his Non-Utility Proxy Group was screened to have corresponding risk indicators with FPL and is comprised of 66 of the best known and most stable corporations in America. He stated that the Hope and Bluefield decisions dictate that the allowed return be consistent with returns on investments of comparable risk but that neither decision restricted consideration to only utilities. Because utilities compete with unregulated companies for capital and his Utility and Non-Utility Proxy Groups are comparable in risk, witness Avera argued our consideration of the results of both DCF analyses is consistent with the regulatory standard established by Hope and Bluefield.

Three witnesses also performed a CAPM analysis. For the reason discussed earlier, the witnesses used their respective proxy groups for certain inputs to their CAPM analysis.

FPL witness Avera performed an ex ante, or forward-looking, CAPM analysis. For the estimate of the risk-free rate, he used the average yield on 20-year Treasury bonds for December 2008 of 3.2 percent. For the estimate of the company-specific risk, or beta, he used the average beta for his two proxy groups. The average beta for the Utility Proxy Group was .73 and the average beta for the Non-Utility Proxy Group was .84. Witness Avera relied on Value Line for his estimates of beta. He derived a market risk premium of 10.0 percent based on a DCF analysis of the dividend paying companies in the S&P 500. Witness Avera's CAPM analyses indicated returns of 10.5 percent for the Utility Proxy Group and 11.5 percent for the Non-Utility Proxy Group.

OPC witness Woolridge also performed an ex ante CAPM analysis. For the risk-free rate, he used an estimate of the forward-looking yield on 30-year U.S. Treasury bonds of 4.50 percent. For beta, he used the average Value Line beta for his group of proxy companies of .70. He determined an expected risk premium of 4.36 percent based on the results of various studies of historical risk premium, ex ante risk premium studies, and equity risk premium surveys. Witness Woolridge's CAPM analysis indicated an ROE of 7.6 percent.

SFHHA witness Baudino performed both an ex ante and an ex post, or historical, CAPM analysis. For the estimate of the risk-free rate, he used both the average yield on 5-year Treasury notes and 20-year Treasury bonds for the 6 months ended June 2009 of 2.00 percent and 3.94 percent, respectively. For the estimate of beta, he used the average beta for his proxy group of .69 as reported by Value Line. Witness Baudino derived a market risk premium range of 6.47 percent (based on the yield on 20-year Treasury bonds) to 8.41 percent (based on the yield on 5-year Treasury notes) for purposes of his ex ante CAPM. For purposes of his ex post CAPM, he relied on historical, earned returns from Ibbotson Associates to determine a market risk premium range of 4.40 percent to 5.97 percent. Witness Baudino's analysis indicated a range of returns of 7.77 percent to 8.38 percent for the ex ante CAPM and 6.96 percent to 8.03 percent for the ex post CAPM.

With the exception of witness Baudino's ex post CAPM analysis, all three witnesses used the ex ante CAPM model. Witness Woolridge testified that witness Avera's CAPM analysis overstated the required return for FPL because of its application to a non-utility proxy group and its reliance on an excessive market risk premium. For the same reasons discussed above in the section on the DCF model, witness Woolridge testified that witness Avera's group of non-utility companies is not an appropriate proxy to estimate the required return for FPL. Witness Woolridge also testified that witness Avera's estimate of a market risk premium of 10.0 percent is well in excess of the equity premium demanded by the market.

Witness Baudino testified that witness Avera's CAPM analysis overstated the required return for the market, and by extension, the market risk premium. Witness Avera estimated a market return of 13.2 percent and a market risk premium of 10.0 percent based on his "market" of the 346 dividend paying stocks in the S&P 500. Witness Baudino argued that if witness Avera had used a broader "market," such as the Value Line universe of companies as he had done, witness Avera's analysis would have produced results closer to the estimated market return of 10.4 percent and market risk premium of 6.5 percent reflected in witness Baudino's analysis.

Witness Avera testified that the CAPM cost of equity estimates of witnesses Woolridge and Baudino are "significantly downward biased." He also disputed their testimony regarding his methodology, stating that "the forward-looking estimate of the market rate of return used in my CAPM analysis is entirely consistent with the requirements of this approach and there is no basis to claim that it is overstated."

In addition to the DCF and CAPM analyses, FPL witness Avera also performed an Expected Earnings Approach. He testified that reference to rates of return available from alternative investments of comparable risk can provide an important benchmark in assessing the return necessary to assure confidence in the financial integrity of a company and its ability to attract capital. He also stated that the Expected Earning Approach is consistent with the standards for a fair rate of return while avoiding the complexities and limitations of the equity cost models discussed above. As reported in the relevant November and December 2008 editions of Value Line, the expected returns on equity for the companies in his Utility Proxy Group ranged from 8.1 percent to 15.9 percent and averaged 11.7 percent for the group. Witness Avera also noted that Value Line projected an average return on equity for the entire electric industry of 11.5 percent for 2009 and over its 2011 – 2013 forecast horizon.

Both OPC witness Woolridge and SFHHA witness Baudino challenged the reasonableness of this approach for estimating the investor required ROE for FPL. Witness Woolridge testified that witness Avera's Expected Earnings Approach "is fundamentally flawed." He stated that many of the companies in witness Avera's Utility Proxy Group have significant unregulated operations and therefore the results of this approach are unduly influenced by the profits associated with these unregulated operations. Witness Woolridge also noted that because witness Avera did not evaluate the market-to-book ratios for these companies, he cannot determine whether the past and projected returns on book equity are above or below investor required returns. To the extent the market-to-book ratios for these companies are above 1.0, witness Woolridge testified that the indicated return from this approach would exceed investors' required return.

Witness Baudino testified that all witness Avera did in this approach was report Value Line's forecasted return on book equity for 2009 and the period 2011 – 2013. He stated that forecasted returns on book equity may have nothing whatsoever to do with investors' required returns in the market place. Witness Baudino testified that we should reject this approach and recommended we utilize the range of returns produced by the DCF model in setting FPL's ROE in this proceeding.

Witness Avera countered that the Expected Earnings Approach he used is consistent with both sound regulatory policy and the legal standards set forth in the Hope and Bluefield decisions. He also testified that there is no clear link between market-to-book ratios for electric utilities and allowed returns. Finally, witness Avera stated that neither witness demonstrated how the criterion of revenues from electric operations translated into differences in the investment risk perceived by investors.

FPL witness Avera testified that the results of his various analyses indicated that the cost of equity for FPL was in the range of 11.0 percent to 13.0 percent. In addition to the results of these quantitative analyses, he stressed that it was important for us to consider additional factors such as FPL's need to remain financially strong so it will have the ability to absorb potential financial shocks due to storm damage, fuel price volatility, and disruptions in energy supply. He also noted the challenging capital market environment and FPL's need to finance significant infrastructure investment as factors we should consider when setting FPL's ROE.

Witness Avera also testified that when a company raises equity through the sale of common stock, there are costs incurred. These flotation costs include services such as legal, accounting, and printing as well as other fees paid to brokers. He stated that, while debt issuance costs are recorded on the books of the company, amortized over the life of the issue, and recovered through the cost of debt, there is no similar accounting treatment to ensure equity flotation costs are recorded and ultimately recognized. He cautioned that unless some provision is made to recognize these issuance costs, a company's revenue requirements will not fully reflect all of the costs incurred for the use of investors' funds. For this reason, witness Avera recommended incorporating a 25 basis point adjustment in determining a reasonable ROE range for FPL.

Witness Avera testified that, based on the need to remain financially strong as well as the need to recognize a 25 basis point adjustment for flotation costs, a reasonable ROE for FPL fell in the range of 12.0 percent to 13.0 percent. In light of FPL's "exemplary management," he recommended that it would be "entirely consistent with regulatory economics and past incentive mechanisms approved by the FPSC" to consider this performance when establishing a fair ROE for FPL in this range.

Finally, FPL witness Pimentel testified that there are several risk factors that are unique to FPL that should be considered by us in the determination of the Company's ROE. From the viewpoint of investors, witness Pimentel argued that FPL is more risky than other IOUs due to its geographic location, capital expenditure program, fuel supply and mix, nuclear generation, and Florida's economy. He testified that witness Woolridge's and witness Baudino's recommended returns are inconsistent with the authorized ROE of 11.25 percent recently awarded to TECO.[59] Because FPL is exposed to significantly greater risk in a number of areas when compared to TECO, witness Pimentel concluded that FPL "warrants a strong financial position and higher return on equity to meet our obligations to serve our customers."

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[59] Order No. PSC-09-0283-FOF-EI, issued April 30, 2009, in Docket No. 080317-EI, In re: Petition for rate increase by Tampa Electric Company, p. 48.

OPC witness Woolridge testified that it is not necessary to make an upward adjustment to the cost of equity for the recovery of flotation costs. He stated that FPL has not identified any actual flotation costs for the Company. In addition, because electric utilities have market-to-book ratios in excess of 1.0x, he testified that there should be a flotation cost reduction (and not increase) to the equity cost rate. Finally, he argued that investors also incur transaction costs when they purchase shares. If these transaction costs are taken into account, the price of shares would be higher. If these transaction costs were included in the DCF analysis, the higher effective stock prices paid for stocks would have led to lower dividend yields. This would have resulted in a downward adjustment to the DCF equity cost rate. For these reasons, witness Woolridge testified that it is unnecessary to recognize a specific adjustment for flotation costs in the determination of the investor-required ROE.

SFHHA witness Baudino also testified that an adjustment for flotation costs is inappropriate. He stated that, since witness Avera failed to provide any specific information on flotation costs incurred by FPL, his recommended adjustment is not tied to any actual costs incurred by the Company either now or in the past. Witness Baudino testified that flotation costs are already accounted for in the current stock prices and that adding an adjustment for flotation costs amounted to double recovery. For these reasons, he recommended we reject witness Avera's proposed flotation cost adjustment.

Witness Baudino testified that, while the financial markets did undergo one of the most serious periods of volatility and uncertainty in history, economic conditions have begun to stabilize. He stressed that even through the height of the financial crisis in 2008, FPL Group did not experience problems in accessing capital markets. He believes FPL's recommended ROE of 12.5 percent results in a burdensome cost of capital that is too expensive for customers to maintain. Moreover, witness Baudino testified that the cost of equity should be based on the investor-required return. He concluded that it would be inappropriate to inflate the authorized return by an arbitrary adjustment for exemplary management.

The intervenors also challenged the testimony of Company witnesses that FPL is more risky than TECO. Because TECO is rated triple B by all three rating agencies and FPL is rated single A by the same agencies, SFHHA argued that "it is unreasonable and inconsistent with investor perceptions that a company with an "A" bond rating is more risky than a company with a "BBB" bond rating like TECO, and would therefore require a higher ROE." In addition, it was noted that TECO Energy's stock price increased by 8 percent and trading volume more than doubled following the announcement of our staff's recommended ROE of 10.75 percent for TECO. FRF concluded that, because investors looked favorably on an ROE of 10.75 percent, this "lends additional support to basing the rates for FPL, which is stronger financially than Tampa Electric, on a substantially lower ROE than requested by FPL."

Each of the witnesses recognized that the generally accepted models used for estimating ROE are based on a number of restrictive assumptions. Under normal economic circumstances, the relaxation of these assumptions for the practical application of the models is generally understood. And while the state of the economy has improved since the market disruption in the fall of 2008, the economic recovery is still somewhat tenuous. This realization does not mean the models no longer have value, rather, it is particularly important at this point in time to exercise informed judgment in the application of the models.

OPC witness Woolridge and SFHHA witness Baudino both argued that FPL witness Avera made certain assumptions in the application of his DCF analysis that overstated the investor-required ROE for FPL. In turn, witness Avera argued that witnesses Woolridge and Baudino made certain assumptions in the application of their respective DCF analyses that understated the investor-required ROE for FPL. As discussed earlier, all three witnesses used the same constant growth version of the DCF model. And with the exception of witness Avera's Non-Utility Proxy Group, all three witnesses used relatively similar estimates of dividend yields. The primary reason for the difference in the indicated DCF returns is attributed to differences in their respective estimates of the growth rate to include in the DCF model.

OPC witness Woolridge used an average growth rate of 5.50 percent based on the average of growth forecasts for EPS, DPS, BVPS, and the internal growth rate. The growth rates in SFHHA witness Baudino's analysis ranged from 3.75 percent to 6.25 percent and averaged 5.53 percent. These growth rates are based on growth forecasts for EPS and DPS. The average growth rates used in FPL witness Avera's DCF analysis ranged from 5.66 percent to 6.90 percent and averaged 6.32 percent. These growth rates are primarily EPS growth rates but he also included an estimate of growth based on the earnings retention method.

Because the estimated return produced by the DCF model used by the witnesses is determined by the sum of the growth rate and the dividend yield, the higher the growth rate the higher the indicated return, all else held constant. As a result, the decision regarding which DCF result is more indicative of the investor-required return for FPL comes down to which witness' estimate of growth is believed to be more appropriate.

FPL witness Avera testified that neither OPC witness Woolridge or SFHHA witness Baudino demonstrated how the criterion of revenues from electric operations translated into differences in the investment risk perceived by investors. However, a comparison of the inputs to the witnesses' respective DCF analyses provides some insight into this debate.

Both witnesses Woolridge and Baudino testified that nonregulated companies are subject to greater risk than regulated electric companies and therefore nonregulated companies will have different return requirements than regulated companies. As noted above, while the average growth rates for the respective witnesses' utility proxy groups ranged from 5.50 percent to 6.32 percent, the average growth rate for witness Avera's Non-Utility Proxy Group was 10.1 percent. While this differential in growth rates is partially offset by the relative difference in average dividend yields between the utility and non-utility proxy companies, it is clear investment analysts, and by extension investors, have a very different view of the projected earnings growth for regulated companies compared to nonregulated companies.

The existence of higher expected earnings growth for the unregulated operations versus the regulated operations of the companies included in utility proxy groups was also highlighted by the intervenor witnesses. The companies in witness Woolridge's proxy group rely on regulated electric revenues for approximately 85 percent of their revenues. In contrast, the companies in witness Avera's proxy group rely on regulated electric revenues for approximately 62 percent of their revenues. In addition, at least three of the companies in witness Avera's Utility Proxy Group rely on regulated electric revenues for less than 25 percent of their revenues.

To illustrate the impact this distinction has on the DCF-indicated return, consider the three companies that operate vertically integrated investor owned utilities (IOUs) in Florida.[60] All three witnesses included FPL Group, the Southern Company, and Progress Energy in their respective utility proxy groups. Both the Southern Company and Progress Energy have divested nearly all of their unregulated operations and rely on regulated operations for essentially all of their revenues. In contrast, depending on the source,[61] FPL Group relies on unregulated operations for 25 to 30 percent of its revenues.

The difference in expected earnings growth between the three companies is telling. Progress Energy has expected earnings growth estimates ranging from 5.0 percent to 6.0 percent and the average of the expected earnings growth rates is 5.3 percent. The Southern Company has expected earnings growth estimates ranging from 5.2 percent to 5.8 percent and the average of the expected earnings growth rates is 5.5 percent. In contrast, FPL Group has expected earnings growth estimates ranging from 9.3 percent to 10.0 percent and the average of the expected earnings growth rates is 9.6 percent. This difference between the expected earnings growth for "pure plays" such as Progress Energy and the Southern Company and more diversified companies such as FPL Group is an important consideration in the determination of the ROE for FPL because the ROE authorized in this proceeding will only reflect the investor-required return for the regulated operations of FPL and not the required return for FPL Group, the consolidated entity.

In defense of his reliance on a Non-Utility Proxy Group to estimate the investor-required return for FPL, witness Avera testified that the Bluefield decision did not restrict consideration of comparable risk just to other utilities. He is correct. There is no expressed requirement in Bluefield that comparable companies be limited to utilities. However, as noted in the pertinent passage from the Bluefield decision that follows, the determination of a comparable company is not without limits:

> A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties, *but it has no constitutional right to such*

[60] We note that, while Tampa Electric Company also operates in Florida, none of the three witnesses included TECO Energy in their utility proxy group.

[61] AUS reports that FPL Group derives 70 percent of its revenues from regulated electric operations. S&P reports that FPL is responsible for 75 percent of FPL Group's consolidated credit profile. According to FPL Group's 2008 Annual Report to Shareholders, FPL accounted for 76 percent of FPL Group's consolidated revenues in 2007 and 71 percent of its consolidated revenues in 2008.

> *profits as are realized or anticipated in highly profitable enterprises or speculative ventures.*[62]

(emphasis added)

Witness Baudino testified that the bulk of witness Avera's results suggest a lower ROE, more in the range of 10.5 percent to 11.7 percent if the results of his Utility Proxy Group were used. Witness Baudino stated that only by considering the results of his Non-Utility Proxy Group can witness Avera support a return above 12.0 percent. Witness Baudino testified that non-utility companies have higher overall risk structures, and thus higher required returns, than low-risk utilities like FPL. Moreover, because FPL has one of the strongest bond ratings in the utility industry, he argued that FPL should have a lower required return than the average utility.

Both OPC witness Woolridge and SFHHA witness Baudino challenged the reasonableness of FPL witness Avera's Expected Earnings Approach for estimating the investor-required ROE for FPL. Witness Woolridge testified that many of the companies in witness Avera's Utility Proxy Group have significant unregulated operations and therefore the results of this approach are unduly influenced by the profits associated with these unregulated operations. Witness Baudino testified that forecasted returns on book equity may have nothing whatsoever to do with investors' required returns in the market place. Witness Avera countered that the Expected Earnings Approach he used is consistent with both sound regulatory policy and the legal standards set forth in the Hope and Bluefield decisions.

Witness Avera is correct that the Expected Earnings Approach is a generally recognized method for estimating ROE and is consistent with the "corresponding risk" standard of the Bluefield decision. However, witness Avera acknowledged that the expected returns shown in his analysis were based on the results of both the regulated and unregulated operations of the companies in his Utility Proxy Group. To the extent that the greater risk associated with unregulated operations exerted upward pressure on the expected returns for the consolidated companies, the indicated return from this approach overstates the investor-required return for the regulated operations of FPL.

Each of the witnesses made arguments for including and not including an allowance for the recovery of flotation costs in the determination of the ROE. While it has been our practice to recognize an adjustment for flotation costs in certain applications, the determination of an authorized ROE by a regulatory commission in an evidentiary proceeding very seldom involves the level of specificity that would permit the itemization of a specific allowance for flotation costs. In this context, the debate over whether to include or not include an allowance for flotation costs is similar to the debate over whether to use an annual or quarterly DCF model, or a blended growth rate or an earnings-only growth rate in the DCF analysis. The ROE we approved in this docket does not specifically recognize or exclude an allowance for flotation costs but rather represents a blend of the results of the witnesses' analyses.

[62] Bluefield Water Works & Improvement Company v. Public Service Commission of West Virginia, 262 U.S. 692–693 (1923).

Company witnesses testified that, due to risk factors unique to FPL, we should set an ROE for FPL higher than the return recently authorized for TECO. The ROE set in this proceeding is based on the record in this case. While the record in the TECO case was developed over the period from August 2008 through January 2009 and a decision was rendered in March 2009, the record in FPL's case was developed over the period March 2009 through October 2009 with a decision in January 2010. Conditions change over time and an ROE that was reasonable for a particular company at a particular point in time may or may not be relevant to the investor-required return for a different company at a different point in time.

As for the argument that FPL is so uniquely riskier than other IOUs that it requires an ROE well above the average ROE authorized for other IOUs, the record in this case does not bear this out. Other than the Company's geographic location, it was demonstrated that the majority of the companies in witness Avera's Utility Proxy Group were also exposed to the same or similar risk factors related to significant capital expenditure programs, issues related to fuel mix, managing O&M expense, owning and/or proposing nuclear generation, dealing with weather related service interruptions, and the need for a regulatory environment supportive of credit quality. Witness Avera testified that, to the extent that cost recovery clauses and other adjustment mechanisms are prevalent across the industry, the risk mitigation benefits of these mechanisms have already been reflected in the cost of equity estimates. Similarly, since the risk factors suggested by the Company are systemic to the industry and are not unique to FPL, investors' expectations regarding these risk factors have also been captured in the results of the cost of equity models. Moreover, the rating agencies conduct quantitative and qualitative assessments of the Company's business and financial risk position. FPL is one of the highest rated IOUs in the nation. Just as we have resisted certain proposed adjustments to the Company's capital structure that would exert downward pressure on the Company's financial position, it is equally important to resist efforts to overstate the Company's relative risk profile to justify a higher ROE.

Due to the reliance on the results of DCF and CAPM analyses applied to unregulated companies, the Company's requested ROE of 12.5 percent overstates the current investor-required ROE for FPL. Exhibit 462 reported the authorized ROEs set during 2009 for the electric utilities followed by Regulatory Research Associates (RRA). The ROEs set during 2009 ranged from a low of 8.75 percent to a high of 11.5 percent and averaged 10.51 percent for the group. While we do not believe the authorized ROE for FPL should be based upon the average return set by other Commissions during 2009, we do not believe returns significantly above or below this level are indicative of the investor-required return for FPL, either.

Finally, in making our decision, we are cognizant of the prevailing economic realities that Florida electric customers and the Company face right now. These difficult economic times must be faced by both the electric customers and the Company alike. We know from record testimony that FPL's customers in this market are experiencing economic hardship, as Florida residents are throughout the state. And yet again, we are conscious of the need to provide an equitable and fair rate of return for FPL. It is our responsibility as an economic regulatory agency, to be cognizant of the prevalent economic conditions and to establish a return on equity that will be fair to the company and fair to the customers alike.

Based on the foregoing, we approve an authorized ROE of 10.00 percent with a range of plus or minus 100 basis points. In arriving at this return, we weighed the identified strengths and weaknesses associated with the respective witness' analyses. We also took into account FPL's proposed construction program and its need to access the capital markets under reasonable terms. In addition, when determining the ROE, we considered the equity ratio. At an equity ratio of approximately 59 percent on a Commission-adjusted basis and approximately 56 percent on an S&P-adjusted basis, we find that an authorized ROE of 10.00 allows FPL the opportunity to earn a fair and reasonable return for the provision of regulated service.

Weighted average cost of capital

Each party's recommendation on the appropriate weighted average cost of capital is a mathematical computation based upon their recommendations on each of the prior issues regarding cost of capital. FPL originally proposed a weighted average cost of capital for 2010 of 8.00 percent. However, due to certain revisions, FPL amended its proposed weighted average cost of capital to 7.85 percent. OPC proposed a weighted average cost of capital of 6.14 percent for 2010. SFHHA proposed a weighted average cost of capital of 6.34 percent.

Our determination of the weighted average cost of capital is a result of our previous decisions regarding the cost of capital. Based upon the proper components, amounts, and cost rates associated with the capital structure for the test year ending December 31, 2010, the appropriate weighted average cost of capital for FPL for purposes of setting rates in this proceeding is 6.65 percent. Our decision is demonstrated in Schedule 2 attached to this order.

## NET OPERATING INCOME

Inflation and customer growth

We reviewed the inflation and customer growth rate projections for 2010 contained in MFR Schedule F-8. The 2010 inflation and customer growth rates were sponsored by FPL witness Morley and provided in MFR Schedule F-8. In her direct testimony, witness Morley testified that FPL incorporated several measures of inflation into its budgeting assumptions including the Consumer Price Index (CPI), the Producer Price Index (PPI), and the GDP Deflator. These budgeting assumptions were based upon input from Global Insight and other publically available sources. For 2009 and 2010, FPL projected inflation, as measured by the CPI, to increase at a two percent annual rate. The inflation projections contained in MFR F-8 are consistent with the projections of independent sources such as Global Insight and other publicly available sources. Therefore, the inflation assumptions contained in MFR F-8 are appropriate for the 2010 test year.

We also reviewed the forecast model and assumptions used to project customer growth rates through 2010. FPL's customer growth rates for 2009 and 2010 were derived from FPL's customer model. Based on the output of this model, FPL projected the number of customers to increase by 0.2 percent in 2009, and increase by 0.6 percent in 2010. These growth rates represent reasonable expectations of customer growth through 2010. Accordingly, we approve the inflation and customer growth factors for 2010 as provided in MFR Schedule F-8 as appropriate.

Capacity charges

FPL witness Ousdahl explained that the Company was requesting to transfer $56.9 million associated with St. Johns River Power Park (SJRPP) from base rates to the capacity clause. According to witness Ousdahl, the reason for this transfer was:

> . . . in order to be consistent with the recovery mechanism for other capacity arrangements and to comply with the Commission's decision in Order No. 25773, Docket No. 910794-EQ which stated in part "that capacity related purchased power costs not currently being recovered in any manner may be included in the capacity recovery factor. Those costs currently being recovered in base rates will remain in base rates until the utility's next general rate case. A net amount of $56.9 million was included for recovery in 1988 base rates as explained in FPSC Order No. PSC-94-1092-FOF-EI, Docket No. 940001-EI.

MFR Schedule B-2, for the projected 2010 test year, showed adjustments made to transfer costs associated with SJRPP from rate base to the capacity clause. Rate base was increased by $54,511,000 for 2010 on a jurisdictional basis.

MFR Schedule C-2, for the projected 2010 test year, showed the adjustments to net operating income related to the transfer of cost associated with SJRPP from base rates to the capacity clause. Net operating income was increased by $34,979,000 for 2010 on a jurisdictional basis.

We find that capacity charges associated with SJRPP shall be treated consistently with other capacity arrangements and shall be included in the capacity clause. This is the first general rate case in which we have had the opportunity to transfer these charges from base rates to the capacity clause. Accordingly, the adjustments made by FPL for the St. Johns River Power Park (SJRPP) from base rates to the capacity clause are approved.

Fuel Adjustment, Conservation, Capacity, and Environmental cost recovery clauses

FPL asserted that it made appropriate adjustments to remove revenues and expenses recoverable through the Fuel Adjustment, Conservation, Capacity, and Environmental Cost Recovery Clauses. FPL offered the testimony of witness Ousdahl, as well as MFRs and exhibits to support its position. FPL witness Ousdahl testified that ". . . Exhibit, KO-3 [hearing Exhibit 119] lists the MFRs that directly support the overall 2010 jurisdictional revenue requirement increase of $1.044 billion requested by FPL. Those MFRs include schedules that support adjusted jurisdictional rate base of $17.1 billion, adjusted jurisdictional net operating income of $726 million . . ." Exhibit 180 contained a complete set of FPL's MFRs, including those listed in Exhibit 119 mentioned in Witness Ousdahl's testimony above.

MFR Schedule B-2, for the projected 2010 test year, showed the adjustments to rate base that FPL made related to the transfer of cost associated with each of the aforementioned clauses from base rates to the appropriate clause. For the Fuel Adjustment Clause, rate base was decreased by $102,000 for 2010 on a jurisdictional basis. For the Conservation Cost Recovery Clause, rate base was decreased by $23,759, for 2010 on a jurisdictional basis. For the Environmental Cost Recovery Clause, rate base was decreased by $593,376,000 for 2010 on a jurisdictional basis. No adjustments to rate base were made for the Capacity Cost Recovery Clause.

MFR Schedule C-2, for the projected 2010 test year, showed the adjustments to net operating income that FPL made related to the transfer of cost associated with each of the aforementioned clauses from base rates to the appropriate clause. For the Fuel Adjustment Clause, net operating income was decreased by $1,262,000 for 2010 on a jurisdictional basis. For the Conservation Cost Recovery Clause, net operating income was decreased by $1,808,000 for 2010 on a jurisdictional basis. For the Capacity Cost Recovery Clause, net operating income was decreased by $32,323,000 for 2010 on a jurisdictional basis. For the Environmental Cost Recovery Clause, net operating income was decreased by $78,999,000 for 2010 on a jurisdictional basis.

We have reviewed the MFRs and discovery responses concerning the adjustments for each of the aforementioned clauses and find that they are correct. Accordingly, FPL's proposal to transfer revenue, expenses and investment associated with the fuel clause from base rates to the Fuel Adjustment Clause is approved. FPL's proposal to transfer revenue, expenses and investment associated with the conservation cost recovery from base rates to the Conservation Cost Recovery Clause is approved. FPL's proposal to transfer revenue, expenses and investment associated with capacity cost recovery from base rates to the Capacity Cost Recovery Clause is approved. FPL's proposal to transfer revenue, expenses and investment associated with the environmental cost recovery from base rates to the Environmental Cost Recovery Clause is approved.

Commercial/Industrial Demand Reduction Rider

FPL witness Ousdahl proposed adjustments to the Company's forecasted revenues for the 2010 test year to the Commercial/Industrial Demand Reduction (CDR). MFR Schedule C-2, for the projected 2010 test year, showed the adjustments to revenue and net operating income that FPL made related to the CDR. Revenue was reduced $10,306,000 and net operating income was decreased by $6,330,000 for 2010 on a jurisdictional basis. Witness Ousdahl explained that:

> CDR is a voluntary energy management program that provides customers bill credits, while helping FPL efficiently manage the supply of electricity by allowing the Company to unilaterally reduce power usage during peak demand periods, capacity shortages, or system emergencies. FPL records an offset to its base revenues for the benefits received by those customers who participate in the CDR program. FPL inadvertently excluded the debit to base revenues in its 2010 Test Year and 2011 Subsequent Year forecasts. Therefore, FPL has included a reduction in base revenues of $10.3 million for the 2010 Test Year and $10.6 million for the 2011 Subsequent Year.

We have reviewed the Company's forecast and it does reveal that the effects of the CDR were not originally included in the forecast by FPL witness Morley. The CDR was inadvertently excluded. Accordingly, FPL's adjustments to operating revenue for the 2010 test year to include the effects of the C/I Demand Reduction Rider Incentive Credits are approved.

Late payment fee revenues

In its forecasted revenues, FPL included a 30 percent reduction in late payment fees and a 2 percent increase in write-offs of late payment revenues due to the proposed increase in the late payment fee. FPL proposed a change in its revenues relating to late payment charges to recognize a proposed customer behavior modification plan which FPL argued would discourage customer late payments. FPL witness Santos described the Company's proposed change to its charge for late payments as follows:

> FPL currently charges 1.5% for late payments, but is proposing the greater of 1.5% or $10. Driven largely by the deteriorating economy, FPL has seen a steady increase in the number of customers making late payments. The percent of customers with late payments has increased from 21% in 2006 to 24% in 2008. This is an increase of 150,000 customers on average per month.

OPC witness Brown testified that FPL had understated its projected revenue from late payment.

> . . . in projecting the late payments fees for the test years, FPL has assumed that percentage of late paid accounts will remain at the same levels as the 2008 experience. In addition, the Company has offset the increased late payment fees by a 2% write-off rate and a 30% "behavior change" associated with accounts that would be subject to the minimum charge. These adjustments have resulted in an understatement of the late payment revenues under the revised structure.

According to witness Brown, FPL did not provide any justification for its assumption that the implementation of the $10 minimum late fee would cause 30 percent of the affected customers to pay their bills on time which would reduce the percent of late paid bills to pre-2007 levels.

OPC witness Brown recommended eliminating the two percent write-off adjustment, which should already be incorporated into the uncollectible accounts expense. She also recommended eliminating the 30 percent behavior modification adjustment and, instead, proposed using an average of the 2007 and 2008 late payments as a percentage of total bills. Under this approach, 20 percent of customer bills are assumed to be late which is less than the 22.3 percent level experienced in 2008.

OPC witness Brown's recalculated revenues from late payment fees was $25,024,251 greater than FPL's estimate for 2010.

FPL witness Santos testified in her rebuttal that:

> The purpose of changing the late payment charge to have a minimum of $10 is to change behavior and induce more timely payment. . . By minimizing the behavior change assumption of 30%, Ms. Brown effectively diminishes the impact that the late payment charge is specifically designed to achieve. . . FPL's use of an assumed behavior change of 30% is therefore quite conservative because it is less than half of the 65% change expected when applying the electricity demand elasticity.

We disagree with the Company's analysis of its customer behavior modification plan. The Company's analysis of behavior change based on the electricity demand elasticity suggested that there would be a behavior change of 65 percent. We believe this percentage to be extremely high and in our opinion makes the analysis somewhat suspect. We do not find it supportive of the Company's 30 percent behavior change. No analyses was presented for the 30 percent behavior change in FPL's original filing.

We agree with witness Brown's recommendation to eliminate the two percent write-off adjustment and to include the effects of uncollectibles in the uncollectible account. This approach is consistent with other revenue adjustments. We also agree with witness Brown's approach to recognize revenue associated with late payment fees based on the average of 2007 and 2008. Witness Brown's approach used actual late payments and still recognized a decrease in the number of customers paying late compared to 2008.

FPL proposed some additional changes to its late payment revenues based on corrections it discovered during the proceeding. FPL witness Ousdahl sponsored hearing Exhibit 358 in her rebuttal testimony and explained that during the course of the proceeding, FPL identified some additional adjustments to the Company's original filing. Exhibit 358 summarized the additional adjustments to rate base, net operating income, and capital structure that FPL made to its original filing. Items 6a and 10 of Exhibit 358 addressed some additional changes to FPL's proposed adjustment to net operating income for revenues associated with late payments.

Item 6a of Exhibit 358 showed FPL's proposed adjustments due to an over-statement of late payment revenue. According to FPL, late payment revenues were overstated because they were based on an older version of the revenue forecast than what was used to develop the final projections. Item 6a resulted in an adjustment to decrease late payment fee revenue by $7,386,000 for the 2010 test year.

Item 10 of Exhibit 358 showed FPL's proposed adjustments due to an under-statement of late payment revenue. According to FPL, late payment revenues were inadvertently reduced by expected bad debts on the full amount of late payment revenues rather than on the incremental change in late payment revenues. Item 10 resulted in an adjustment to increase late payment fee revenue by $751,895 for the 2010 test year.

We find that FPL's additional adjustments made in its Exhibit 358, which were made to correct its original filing, are reasonable and appropriate.

Based on the foregoing, we find that FPL's adjustments to correct the original forecast for Late Payment Revenue proposed in Item 6a and Item 10 of Exhibit 358 are appropriate and we approve those changes. We agree with OPC's proposal to adjust the forecast of late payment revenues based on 2007 and 2008 actual experience. Accordingly, we approve a net adjustment to net operating income to increase late payment revenue for the 2010 test year by $18,390,146.

Revenue Forecast

Our decision regarding the 2010 revenue forecast is a result of our discussion of several items in this Order. Our revenue forecast is based on our analysis and decisions regarding forecasts of customers for the 2010 test year, revenue responsibility for transmission investments, and late payment fee revenues. No further changes to our revenue forecast are necessary as the changes are captured in our discussions listed above and are reflected cumulatively in our calculation of net operating income totals listed below.

Total Operating Revenue

We were asked to determine if FPL's proposed $4,114,727,000 total operating revenue for 2010 was appropriate. Our decision regarding what FPL's appropriate total operating revenues for 2010 is a culmination of our other decisions in this Order. Based on our decisions, the appropriate total operating revenue is $4,136,478,146 for the 2010 projected test year and, is shown on Schedule 3, attached to this Order.

Charitable contributions

FPL witness Ousdahl sponsored Exhibit 117, which included MFR Schedule C-18 for the 2010 test year. This MFR was also contained in Exhibit 180. MFR Schedule C-18 required the Company to "Provide a schedule, by organization, of any expenses for lobbying, civic, political and related activities or for civic charitable contributions included for recovery in cost of service for the test year and the most recent historical year." FPL's response to MFR Schedule C-18 for the 2010 test year stated "Because of prior Commission decisions, the Company did not include any expenses for lobbying, civic, political and related activities, or for civic charitable contributions in determining Net Operating Income for 2010. All are accounted for "below the line."

We find that, with the exception of contributions to FPL's Historical Museum, FPL has followed our direction provided through past orders regarding the treatment of charitable contributions. FPL witness Ousdahl testified that it was not appropriate to adjust the test year expenses to remove the contributions made to the FPL Historical Museum by FPL. According to witness Ousdahl:

> The FPL Historical Museum is a subsidiary of FPL that is charged with maintaining records and artifacts associated with the Company's long history in the state of Florida. These activities are important to the preservation of the historically significant information about the Company and the industry from its beginning in the early 20th century until today. The FPL Historical Museum costs

> are incurred by FPL and recorded as legitimate FPL operating costs. Therefore, it is inappropriate to make an adjustment to move such costs below the line and treat them as charitable donations.

Witness Dismukes argued that the payments to the FPL Museum appear to be the same as charitable contributions and should be treated as such. She recommended an adjustment for the costs recorded above the line for the FPL Historical Museum, Inc. She stated that:

> I am recommending that the Commission reduce test year expenses by $45,470 in 2010 and $46,764 in 2011 for the contributions made by FPL to the Historical Museum. (Response to OPC Interrogatory 69 and AG Interrogatory 27.) According to FPL, the museum maintains records and artifacts concerning the electric industry as well as FPL historical records. (Supplemental Response to OPC Interrogatory 27.) The museum is a not-for-profit affiliate. FPL pays the operating costs of the museum and records them to FERC Account 930. These costs are reflected on the financial statements of the museum as a contribution. (Second Supplemental Response to OPC Interrogatory 69.)

The record reflects that FPL Historical Museum is a not-for-profit subsidiary of FPL. FPL pays the operating cost of the museum. However, the museum records these amounts as contributions. The true purpose of the Museum should dictate how its costs are recovered. According to FPL, the museum is responsible for "maintaining records and artifacts associated with the Company's long history" and "records and artifacts concerning the electric industry as well."

The minimum standards for the preservation of records of public utilities are described in great detail in the Code of Federal Regulations Part 125 (Code). The costs to maintain FPL's books and records, as described in the Uniform System of Accounts, are recorded as administrative and general expenses. The Code does not require that utilities maintain "records and artifacts concerning the electric industry."

FPL did not explain exactly what records were being maintained by the FPL Museum. Also, FPL did not explain why the responsibility "for maintaining records and artifacts" was established as a separate not-for-profit entity and named the FPL Historical Museum. It would appear that the FPL Museum is designed more for the enhancement of FPL's corporate image than mere records storage.

Based on the foregoing, we find that the payments to FPL Museum are charitable contributions. We have consistently held for many years now that such costs should be borne by stockholders of a company rather than by ratepayers, since the latter have no choice in the charity.[63] Accordingly, we reduce other expenses by $45,470 for the 2010 test year.

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[63] Order PSC-07-0671-PAA-GU, issued August 21, 2007, in Docket No. 070107-GU, In re: Investigation into 2005 earnings of the gas division of Florida Public Utilities Company.

Aviation costs

FPL removed the full amount of aviation costs for the 2010 test year from its rate increase request as a concession and to assist in the completion of the hearing. We approved FPL's motion to withdraw all aviation costs included in the 2010 test year. The Company's original MFRs are adjusted to show the effect of removing the Company's aviation costs as follows:

FPL's removal of aviation costs reduced operating expenses and depreciation expense by $1,633,916 and $2,092,009, respectively, for the 2010 test year. It also reduced plant in service and depreciation reserve by $53,268,205 and $27,853,907, respectively, for the 2010 test year. We approve those adjustments.

The removal of aviation costs had the effect of increasing FPL's originally requested net operating income before taxes by $3,725,925 for the 2010 test year. It also had the effect of reducing FPL's originally requested rate base by $25,414,298 for the 2010 test year.

Advanced Metering Infrastructure (AMI) meters included in net operating income

As noted above, FPL plans to install smart meters over a five year period. FPL contended that it appropriately included the cost savings for AMI meters in net operating income. FPL stated that the cost savings associated with AMI meters will only be realized after the meters are deployed and after all components and supporting processes are fully developed, tested, and implemented. According to FPL, the claims made by SFHHA to prorate the savings as the meters are installed would be unrealistic.

SFHHA argued that the savings should be proportional to the costs. SFHHA argued that the mismatch between savings and costs deprives FPL's ratepayers of the full operational savings to which they are entitled. SFHHA argued that net operating income should reflect 16.9 percent of the annualized O&M expense savings, or $6.084 million.

FPL Witness Santos testified that the savings from AMI will only happen after the completion of the entire AMI project. AMI savings will not happen in ratio to the implementation of the meters. Witness Santos testified that the savings will only occur after an integration of software, completion of new databases, implementation of cyber security, development of measures to maximize new functionality, and training on the new systems and processes is completed. The witness testified that the project could be deferred, but FPL believed that the technology was ready, and that FPL wanted to be able to help shape the market. Table 23 on the following page shows the capital expenditures and the associated savings from AMI implementation.

Table 23

| Deployment | 2009 | 2010 | 2011 | 2012 | 2013 | Total |
|---|---|---|---|---|---|---|
| Meters (Thousands) | 170 | 1,128 | 1,099 | 1,076 | 873 | 4,346 |
| | | | | | | |
| Capital (Millions) | $43.7 | $168.5 | $158.7 | $151.5 | $122.5 | $645 |
| | | | | | | |
| O&M (Thousands) | $2,274 | $6,883 | $8,910 | $11,882 | $10,458 | |
| Savings (Thousands) | ($167) | ($418) | ($4,700) | ($18,203) | ($30,401) | |
| | | | | | | |
| Net O&M (Thousands) | $2,106 | $6,465 | $4,210 | ($6,321) | ($19,943) | |

SFHHA witness Kollen testified that recognizing 1.2 percent of the savings and 16.9 percent of the capital expenditure in a test year was unreasonable. Witness Kollen testified that the meters, when installed, would realize immediate savings. The witness contended that the savings should be matched to the capital expenditures.

We decline to adjust net operating income in the test year for the future savings from AMI. The expenditure in AMI will lead to increased savings and should provide the customer with more information. The implementation of AMI will allow the Company to provide more service from a remote location. The delay of the implementation of AMI is not in the best interests of the Company or the ratepayers. Future savings from AMI can reduce the impact of future costs incurred by FPL.

Based on the foregoing, we find that the savings from smart meters have been appropriately included in rate base. It is unrealistic to assume that the savings from AMI implementation will happen as soon as the meters are installed. The AMI project is prudent and should not be delayed. We recognize that the project will have greater savings in the future, but we do not believe an adjustment is warranted. We direct the Company to bring us a program that will help customers take advantage of the potential energy savings from AMI.

<u>Bad debt expense</u>

We were asked to determine the appropriate amount of bad debt expense. FPL proposed bad debt expense of $29,903,552 for 2010, which included adjustments made by FPL in its Exhibit 358. OPC argued that the 2010 bad debt expense was $19,751,466. OPC argued that FPL overstated its bad debt expense. OPC witness Brown testified that:

> FPL used a regression analysis to forecast the uncollectible accounts expense using historical and projected data such as the real price of electricity, kWh sales, and unemployment. . . . the assumptions used in the regression model were apparently made prior to economic changes that were utilized by FPL in preparing other components of its filing. These assumptions would cause the overstatement of bad debt.

FPL witness Santos testified that:

> Ms. Brown correctly points out that the level of kwh sales and real price of electricity used in the regression model to predict bad debt are higher than those used for other purposes in FPL's final projection for the Test Years. However, she incorrectly concludes that the bad debt calculation would have been reduced significantly if later, lower estimates of kwh sales and real price of electricity had been used. . . . For consistency in FPL's filing, it is necessary to use all variables-- kWh sales, real price, and the other economic variables-- from the same vintage. . . . FPL is reflecting this increase in bad debt expense as part of FPL witness Ousdahl's Exhibit KO-16 [358], Identified Adjustments.

FPL witness Santos explained that FPL used regression analysis to forecast bad debt expense. According to witness Santos, projected bad debt expense was based on a model using historical and projected data such as the inflation adjusted price of electricity, kWh sales, and unemployment. She stated that:

> . . . we have found that there are two main drivers of a customer's ability to make payment, the dollar amount of the bill and the economic conditions currently impacting their ability to pay. These two variables are subject to changes overtime which may not be reflected in the historical write-off experience, especially during periods of economic instability.

OPC Witness Brown testified that the 2010 Test Year net write-offs should then be reduced by the impacts of additional automatic bill payments and the incremental avoided write-offs due to the remote connect switch (RCS).

FPL witness Santos explained that the regression model used to forecast bad debt expense included growth in automatic bill payments over the last few years. As a result, the model already assumed a rate of growth for automatic bill payments in 2010.

FPL witness Santos further explained that the RCS was a new technology in the meters that FPL was deploying as part of the AMI project. She noted that witness Brown's recommendation for a greater RCS write-off savings would require an earlier deployment of RCS than was planned.

FPL's proposed bad debt expense was adjusted to include corrections to the direct testimony and MFR filings. FPL witness Ousdahl sponsored hearing Exhibit 358 in her rebuttal testimony and explained that during the course of the proceeding, FPL identified appropriate additional adjustments to the Company's filing. Hearing Exhibit 358 summarized the additional adjustments to rate base, net operating income, and capital structure that FPL proposed be made to its original filing.

Item 6b of Exhibit 358 showed FPL's proposed adjustment to bad debt expense to correct an under-statement. According to Exhibit 358, FPL's bad debt expense was understated because it was based on an older version of the revenue forecast and economic variables than what was used to develop the final projections. Item 6b resulted in an adjustment to increase bad debt expense by $3,805,000 for the 2010 test year.

We find that the recommendation by OPC concerning the automatic bill payments has been incorporated into the adjusted forecast by FPL. We find that FPL's adjustments to correct the original forecast for bad debt expense proposed in Item 6b of Exhibit 358 is appropriate and we approve the same. It appears that OPC's proposed adjustment to reflect the impacts of additional automatic bill payments and the incremental avoided write-offs due to the RCS would require the Company to deploy the AMI project faster than planned. Accordingly, we decline to adopt OPC's proposed adjustment. Based on the foregoing, we increase bad debt expense by $3,805,000 for the 2010 test year, as proposed by FPL in Item 6b of Exhibit 358.

Clause revenue

FPL proposed to make an adjustment to net operating income to remove those portions of bad debt expense associated with clause revenue that are currently being recovered in base rates and include them as recoverable expenses in the respective recovery clauses. FPL witness Ousdahl explained that "the Company's 2010 and 2011 forecast includes an estimate of bad debt expense on its total revenues, including revenues generated from clauses, in accordance with current practice." However, the Company proposed an adjustment to remove estimated bad debt expense related to clause revenues from base rates and include them with the recovery clauses. Witness Ousdahl stated "including the clause bad debt as a clause recoverable cost ensures that the estimate is consistent with and related to the clause revenues that are not collected."

OPC witness Brown recommended that the uncollectible accounts expense remain in base rates for two reasons. First, FPL's proposed treatment creates an additional need for regulatory oversight and adjustments. Witness Brown testified that:

> In order to apply this process to the clauses, FPL would need to develop separate write-off rates and establish separate accrual provisions for each clause as the clause components of uncollectible accounts would vary by month and by customer. FPL has not proposed a process for recognizing the uncollectible accounts expenses through the various clauses.

Second, Witness Brown pointed out that the transfer of the uncollectible accounts expense to the clauses would increases the portion of FPL's revenue that was collected through clauses. She stated that "If 61% of the uncollectible accounts are simply passed through a clause, then FPL's incentive to continue its efforts to reduce uncollectible accounts is reduced."

We agree with OPC's reasoning. FPL's proposed treatment would create an additional need for regulatory oversight. Allocating a portion of bad debt to the clauses would create a disincentive to reduce bad debt and require additional regulatory vigilance. Perhaps the strongest reason not to move a portion of bad debt from base rates to several different clauses is found in FPL's own position that the rate of bad debt exposure is no different for a dollar of fuel revenue than for a dollar of base revenue. Accordingly, there is no compelling reason to move the bad debt expense to clause recovery. Our decision here is consistent with our recent Order No. PSC-

09-0411-FOF-GU,[64] wherein we denied Peoples Gas' proposal to move a portion of bad debt expense from base rates to the Purchased Gas Adjustment Clause (PGA).

Based on the foregoing, we hold that bad debt expense shall remain in base rate and that no portion of it will be allocated to the recovery clauses. Accordingly, bad debt expense is increased by $16,893,000 for the 2010 test year.

Payroll

For the 2010 test year, FPL projected it would have 11,111, employees consisting of 4,943 exempt (salaried) employees, 2,628 non-exempt (hourly) employees, and 3,540 union employees. However, we were presented with evidence showing that during the five years ending 2008, FPL's actual full-time equivalents ranged from a low of 1.71 percent below target in 2004 to a high of 2.48 percent below target in 2007, with an average of 2.08 percent below target over the 5-year period. We were asked to determine if any adjustments to FPL's payroll were necessary to reflect the historical average level of unfilled positions and jurisdictional overtime.

OPC contended that the dollars associated with unfilled positions should be removed because they would not be incurred in 2010. The record indicated that historically, FPL has consistently run under the number of budgeted employees. Therefore, it stands to reason that FPL's historical level of overtime included the time necessary to cover the work that would be performed by the unfilled positions.

To correct FPL's double counting, OPC witness Brown made changes to the actual unfilled historic data to eliminate discrepancies, and staffing changes that were disclosed in discovery. She then developed a factor that could be applied to the projected test years to produce a projected number of unfilled positions. She proposed an adjustment to reduce payroll and benefits based on a modified historical average of 1.59 percent. This percentage represented the difference between the budgeted numbers of employees compared to the expected number of actual employees that would be in place during the test year.

Witness Brown proposed an offsetting adjustment to increase overtime for the Nuclear and Transmission Business Units due to the unfilled positions. This offset was calculated to recognize that these business units based their overtime projections, in part, on the full budgeted staff levels.

Exhibit 236, page one, sponsored by Witness Brown, showed OPC's proposed adjustment to reduce payroll and associated benefits by the projected level of unfilled positions. The total jurisdictional adjustment to expenses was a $12,507,000 decrease for the 2010 test year.

[64]Order No. PSC-09-0411-FOF-GU, issued June 9, 2009, in Docket 080318-GU, In re: Petition for rate increase by Peoples Gas DOCKET NO. OS031S-GU System, p. 29.

Exhibit 236, page 2, sponsored by Witness Brown, showed OPC's proposed adjustment to increase overtime that offsets the adjustment for unfilled positions. Witness Brown testified that "[t]his offset to my adjustment was calculated to recognize that these business units based their overtime projections, in part, on budgeted staff levels. . . . FPL's other business units primarily used historical levels of overtime without adjustment for increased staffing levels." OPC's proposed adjustment for overtime increased jurisdictional expenses by $3,261,989 for the 2010 test year.

According to OPC witness Brown's testimony, except for the departments she specifically adjusted, FPL used the historical levels of overtime to project the overtime for the 2010 test year. This resulted in the time to perform the work of the unfilled positions being counted twice. First, the forecasted overtime included the time to perform work for unfilled positions based on historical averages. Second, the costs of the positions that would not be filled were included in the forecast.

We agree that OPC's witness Brown effectively showed that FPL's method in budgeting for payroll was flawed because it failed to accurately take into account unfilled positions and because by projecting overtime from historical data, FPL double counted its costs. It is clear from the record that FPL will not employ the number of positions that it forecasted for the 2010 test year. However, we do not believe that OPC's modified historical average was representative of the 2010 test year either. Prior to making its other adjustments, OPC took an average of the 5 years prior to and including the historic test year. That average was 2.08 percent below target. However, we find that the data from 2007 is more representative of the number of unfilled positions that FPL will have in 2010. We heard testimony from FPL indicating it was taking a more conservative approach to filling vacant positions since 2008. Accordingly, we find that 2007 data is most representative of the number of unfilled positions. Based on the foregoing, we reduce FPL's proposed O&M expense for payroll by $15,392,467, on a jurisdictional basis and taxes other than income taxes by $882,729, on a jurisdictional basis for the 2010 test year to reflect historically unfilled positions.

Productivity improvements

We were asked to consider whether we should reduce FPL's expenses for productivity improvements given the Company's lower historical rate of growth in payroll costs. SFHHA witness Kollen testified that "[t]he Company reflected significant increases in payroll costs, including inflation and merit increases and staffing increases, but did not explicitly reflect an offset against these proposed expense increases for productivity improvements." Witness Kollen explained that the Company achieved productivity through capital investment in assets that reduced maintenance requirements and allowed fewer employees to do more in less time. Witness Kollen also stated that FPL's adoption of best practices in managing processes should reduce expenses.

FPL disagreed. FPL witness Barrett stated:

> A better measure of the Company's productivity is payroll dollars per customer rather than payroll per hour. The Company's goal is to serve customers reliably at a reasonable cost, not to achieve a particular payroll cost per hour. . . . the projected increases in base pay per customer in 2010 and 2011 are lower than the average increase in that metric from 2006 to 2008.

We find that productivity is an important metric that should be tracked by utilities as a significant guide as to whether the utility is performing as it should from year to year. However, productivity can be measured in many ways and must be fully understood before conclusions can be drawn concerning its applicability to any given situation.

In this case, we agree that a Company's goal is to serve customers reliably at a reasonable cost. The Company has shown that its base pay per customer in 2010 is lower than the average increase in that metric from 2006 to 2008. While we do not approve a productivity adjustment based on the record in this case, we will continue to review productivity in the future. Based on the foregoing, we decline to make a productivity adjustment to expenses.

Forecasted operating and maintenance expenses

FPL proposed to increase its forecasted O&M expenses due to estimated needs for nuclear production staffing. FPL witness Stall testified that:

> It can take as long as eight to nine years to develop an operator candidate into an SRO [Senior Reactor Operator]. In general, the cost to FPL of training, examination development, and licensing of a single candidate who starts without a license to obtain an SRO license is approximately $160,000, not including payroll and benefits of each candidate, or the fees charged by the NRC for its review of the examination materials and oversight of the training and examination process. Additionally, FPL has been required to increase licensed operator class size (and hire additional training instructors to support such classes) to ensure adequate staffing in light of the competitive environment for nuclear professionals.

SFHHA disagreed and argued that the Company had already increased its staffing levels in recent years. Witness Kollen stated that the Company proposed an increase in nuclear staffing of 270 employees due primarily to employee attrition and training requirements. He said the Company cited this as one reason for the proposed $37.298 million in excess over the benchmark level proposed for nuclear production on MFR Schedule C-41.

SFHHA witness Kollen also noted that in response to discovery, the single largest reason for exceeding the benchmark identified by the Company was an increase in payroll costs to reflect a significant increase in staffing levels. The Company quantified the payroll expense effect of adding these employees at $18.5 million for the test year compared to 2008. Witness Kollen explained that the Company cited its apprenticeship program and operations training as the primary reasons for the proposed increases in staffing levels in the test year compared to year end 2008.

According to SFHHA witness Kollen, the Company had been systematically reducing nuclear staffing since September 2008. Witness Kollen stated that ". . . the Company's nuclear staffing peaked in September 2008 and had been steadily declining each month since then." In addition, SFHHA witness Kollen stated that the Company's proposed increase in staffing levels was inconsistent with the significant capital investments the Company has made to improve the performance at its nuclear facilities that should reduce staffing.

SFHHA witness Kollen recommended ". . . that the Commission reduce the Company's nuclear production O&M expense by $21.852 million to eliminate the Company's request for increased staffing . . ." This amount consisted of an $18.5 million reduction in O&M expense, a $1.194 million reduction in payroll taxes, and a $2.158 million reduction in employee fringe benefits.

FPL witness Stall testified in rebuttal that the 270 head count increase referred to by witness Kollen included 129 positions supporting non-O&M activities such as uprate, capacity clause, and affiliate support. . . . The O&M costs forecasted in the 2010 test year did not include costs associated with these non-base O&M positions."

FPL witness Stall went on to explain that "due to the specialized nature of requirements for nuclear experience, it was imperative that an experienced nuclear operator train its employees." In addition to the 8-9 years to develop a senior reactor operator, witness Stall added that other positions can take 1-3 years to train. He pointed out that in such a lengthy program, there is a fair amount of attrition along the way. "Incremental staffing is needed to assure that we have sufficient experienced nuclear operations personnel."

FPL witness Stall testified that "[c]laims that FPL is reducing nuclear staffing are not correct. FPL is hiring today to fill critical positions to ensure the safe and reliable operation of our nuclear plants."

FPL witness Stall explained that "the long-term capital investments provide improvements in long-term plant reliability and do not offset the need for plant staff." He stated that these investments do result in fuel savings and many of the capital investments were in response to the Nuclear Regulatory Commission (NRC) requirements.

SFHHA witness Kollen's recommendation to eliminate nuclear staffing cost was based on 270 full time positions. Kollen failed to recognize that 129 of these positions had no effect on FPL's 2010 test year expense, because the 129 position were supporting non-O&M activities such as uprate, capacity clause, and affiliate support.

The Company presented persuasive testimony that it is in an active hiring mode for its nuclear business unit and that positions are indeed needed. The Company made it clear that there is a national shortage of qualified nuclear power plant staff, that there is a long training period to qualify new staff, and that changes to NRC requirements have resulted in an increase in the number of staff required to run and maintain a nuclear power plant.

Based on the foregoing, the Company has met its burden with respect to the number of additional employees required for the 2010 test year for its nuclear production staffing.

Salaries and Employee Benefits

FPL requested $765,261,494 to be included in O&M expenses for salaries and employee benefits. Based upon our discussion and conclusions below, we find that FPL's request is unreasonable and inappropriate, and thus reduce FPL's request by $49,510,136. As reduced in this Order, we find that FPL's O&M expense for salaries and employee benefits is reasonable.

Part of FPL's petition to increase rates included the recovery of incentive compensation for its employees, both executive and non-executive. During the proceeding, we conducted discovery and cross-examined several witnesses to evaluate the prudence of these projected expenses, as well as the prudence of the overall amount of salaries and benefits included in O&M expenses. In our efforts to evaluate the employee compensation expenses, we obtained information regarding compensation amounts, including bonus and overtime pay for certain highly-compensated employees (for purposes of this Order, highly compensated employees are those receiving $165,000 or more annually). Because of disputes between this Commission and the Company regarding the application of the public records law to employee compensation information, we had difficulty in obtaining the detailed information we sought to help us evaluate this O&M expense which FPL proposed to charge to ratepayers. While we did receive the requested employee compensation information, the information received was claimed confidential by FPL and its employees, thus making cross-examination and discussion cumbersome.

Nevertheless, we learned that FPL's proposed O&M expense budget for employee compensation for the 2010 test year was $765,261,494. Of that amount, $48,471,915 was to be paid to FPL executive employees as an incentive program. The term executive(s) as defined by FPL for use in this rate case referred to 42 employees that are officers of FPL, FPL Group, or one of its affiliates. The executive incentive compensation did not include the additional amounts paid to executives for base pay, lump sum pay or other pay. FPL's proposed executive incentive compensation represented 4.5 percent of FPL's proposed gross pay for 2010. At the hearing, FPL reduced its amount of proposed executive incentive compensation to $16,457,087 which is 2.25 percent of FPL's proposed gross pay for 2010.

FPL provided its executive incentive compensation program in response to an interrogatory request of the AG. OPC provided a copy of that response as Exhibit SB-15 for our review. Witness Brown listed the types of factors considered in determining whether an employee merits a reward under the incentive program. Those factors primarily relate to shareholder value and improving FPL's financial position. In fact, OPC witness Brown testified that pursuant to FPL's proxy the primary objective for FPL Group's executives is to support the creation of long-term shareholder value. Furthermore, the record reflects that FPL Group's goals for long-term incentive programs were to "promote the identity of interests between shareholders of FPL Group and employees of FPL Group and its subsidiaries by encouraging and creating significant ownership of FPL Group common stock by officers and other salaried employees of FPL Group and its subsidiaries . . ." Witness Brown concluded that this incentive program caused her concern in three areas: 1) that while the incentive compensation program was tied to increasing shareholder value, shareholders do not share in the costs of the incentive program, 2) that while FPL says it is concerned about the state of the economy and its effect on its customers, the executive incentive compensation program shields FPL's executive employees from the negative impact of the current economy and allows those employees to continue receiving "gold plated" compensation at ratepayers expense, and that 3) the proposed executive compensation assumes attainment of performance at levels higher than the objectives.

Witness Brown testified that in 2008, FPL gave the financial matrix a weighted 50 percent in calculating the corporate performance factor for its named executives. The other 50 percent of the corporate performance factor, although based on operation factors, also included financial performance measures. The CEO factor of the performance factor was not disclosed to OPC but witness Brown testified that the CEO factor has historically been based on financial performance. We concur with witness Brown that the executive incentive program is tied to shareholder value. But we disagree with witness Brown's conclusion that only 50 percent of the costs should be born by shareholders while the remaining 50 percent should be included as an O&M expense in this rate case. We find that the entire executive incentive compensation program is designed to benefit the shareholders by creating long-term shareholder value. We find that the executive incentive compensation program is designed to place the interests of executives in the same light as that of shareholders, thus creating incentive to increase the value of FPL Group's shares. Because these programs are designed for the benefit of shareholders, those costs shall be borne exclusively by shareholders.

We also concur with Witness Brown that while FPL expressed its concern with the effect of the economy on its ratepayers, its proposed executive incentive compensation program is designed to shield FPL Groups shareholders from the negative impact of the current economy. For instance, if the company does not meet its financial performance targets, the incentive compensation payments can be reduced while the shareholders retain the revenues paid by ratepayers for those incentive compensation programs. If the Company exceeds its targets, shareholders will receive the benefits of exceeding financial targets. Ratepayers will not receive those benefits.

We note that several witnesses provided us with comparative compensation information, comparing FPL employees with the market. Witness Brown testified that Watson Wyatt, one of the human resource consulting firms utilized by FPL, took a survey of large companies to understand what effect the economy was having on other executive programs. Witness Brown testified that the results of Watson Wyatt's study was published and that the study concluded that "more than half of respondents have frozen executive salaries, ten percent have reduced executive salaries, and annual incentive plans are declining." Furthermore, in response to discovery requests, FPL provided a presentation which indicated that at least half to about three-fourths of responding companies were reducing salary spending and merit pay increases or were contemplating salary freezes due to the recent economic situations or cost pressures.

Contrary to the indications of a slowing economy, FPL proposed at a minimum, to maintain or in some cases increase its O&M expenses over that provided in 2008. This requested increase in compensation is despite FPL's own testimony reflecting reductions in sales and higher bad debt attributable to the bad economy. While most competitive businesses would seek avenues of decreasing costs in response to economic conditions, FPL is actually requesting an increase in its compensation costs.

An example of an area in which FPL's request for increased compensation is unreasonable in light of the current economy is in the number of highly compensated support group (non-operational) positions which appear to us to be redundant. FPL expressed a need to protect its nuclear division from poaching. We requested and received compensation information, in confidential format, for employees earning above $165,000 annually. Upon review of the actual amounts proposed to be paid to employees, FPL's reasoning was not supported. There were several director and vice-presidential positions in support group positions which appear to reflect a larger portion of the bonus and pay compensation than did the nuclear operational employees. In fact, of the employees listed in discovery responses as receiving more than $165,000 annually, only 66 percent of them were in the nuclear division. Moreover, we identified several positions in the highly compensated support group functions that appear redundant. While we believe that much of the compensation paid for those positions may reflect unreasonable and imprudent compensation, we find that at a minimum $300,000 of that compensation is unreasonable and inappropriate and thus disallow $300,000.

While we found that the executive incentive compensation was designed to benefit the value of shares, we are hesitant to conclude that one hundred percent of the non-executive incentive compensation benefited only shareholders. Accordingly, we concur with OPC witness Brown that 50 percent of the non-executive incentive compensation, after adjusting the payout ratio for stock-based compensation from 1.3 times to the target to 1.0 times the target, shall be excluded from O&M expense as unreasonable. The proposed reduction to limit the incentive remaining, after the adjustment for the payout ratio, to 50 percent was a reduction in jurisdictional O&M expenses of $3,538,246 for the 2010 test year. The total decrease in jurisdictional O&M expenses due to the non-executive incentive compensation reductions was $5,661,193 for the 2010 test year.

We calculated the employee incentive compensation based upon the target level of 1.0 percent as explained by OPC. OPC witness Brown explained that FPL had used a projected payout level of 1.4 times the target level for executives and 1.3 times the target level for non-executives. She stated:

> I am first recommending that the Commission reduce the levels of the executive Annual Incentive Compensation and Long-Term Incentive Pay to reflect a target payout ratio of one (1) times the target compensation. This is a reasonable assumption to make for a future test year, particularly a year in which the Company has represented that its return on equity will drop to 4.67% without the requested rate increase.

We agree that the payout ratio for the incentive awards shall be reduced to the target level and not set at 1.3 or 1.4 times the target. If the Company is consistently achieving 30 to 40 percent above the baseline year after year, then the incentive payments have essentially become base salary. Exhibit 242 showed the reductions in incentive compensation to executives proposed by OPC witness Brown. The proposed adjustment to reduce the payout ratios for executive incentive compensation to 1.0 resulted in a reduction in jurisdictional O&M expenses of $12,226,189 for the 2010 test year. OPC witness Brown recommended similar adjustments for FPL's non-executive incentive compensation. The proposed reduction to lower the payout ratio from 1.3 times the target to an amount equal to the target is a reduction in jurisdictional O&M expenses of $2,122,947 for the 2010 test year.

Finally, FPL proposed adjustments to its original filing. Among those adjustments, it removed executive bonuses in the amount of $757,282 for the 2010 test year. We approve this adjustment.

Based on the foregoing, we reduce FPL's O&M expenses by $757,282 to reflect FPL's concession to eliminate the executive raises. We reduce FPL's O&M expenses by $12,226,189 to reduce the payout ratio for executive incentive compensation from 1.4 times the target level to 1.0 times the target level. We reduce FPL's O&M expenses by $30,565,472, to reflect a 100 percent reduction in executive incentive compensation. We reduce O&M expense by $2,122,947 to reflect the change in the payout ratio for non-executive incentive compensation from 1.3 times the target level to 1.0 times the target level. We reduce O&M expenses by $3,538,246 to limit non-executive incentive compensation remaining after the adjustment for the payout ration to 50 percent. We reduce O&M expenses by $300,000 to reflect our determination that there are redundant highly compensated non-operational positions. The total reduction of FPL's O&M expenses for salaries and benefits is $49,510,136.

Pension Expense

We were asked to determine if any adjustments should be made to net operating income for pension expenses. We analyzed and reviewed the MFRs, discovery responses, testimony, and cross examination and determined that there shall be no adjustments for pension expense, except for the adjustments made by FPL in Exhibits 481 and 511. The pension amounts were estimated from an actuarial calculation for the 2010 FPL Group plan costs and related obligations using consistent methodologies and reasonable, supportable assumptions. We decline to make any additional adjustments for pension expense.

Environmental Insurance Refund

We were asked to determine if a test year adjustment was necessary to reflect FPL's receipt of an environmental insurance refund in 2008. OPC proposed a decrease in O&M expense to recognize FPL's receipt in 2008 of a refund for environmental insurance it had previously purchased. OPC witness Brown testified that FPL's rates included the costs for property insurance and, as such, any refunds should be provided to ratepayers. The adjustment proposed by OPC witness Brown, based on a five year amortization of the insurance refund, was a decrease in jurisdictional O&M expense of $8,685,682 for the 2010 test year and a decrease in jurisdictional O&M expense of $8,685,656 in the 2011 subsequent test year. The adjustment would also increase jurisdictional rate base by $39,085,569 for the 2010 test year.

The policy that created the refund was purchased in 1998, a non-base rate setting year, and was never included in the Company's Environmental Cost Recovery Clause (ECRC). This is not an accounting gain but an out-of-period expense reduction that was recorded in 2008, and was related to the period of 1998 through 2007. The expense associated with the purchase and the reduction in expense associated with the refund was properly reflected in the Company's surveillance reports.

Based on the foregoing, we decline to make any further adjustments for the environmental insurance refund in 2008.

Department of Energy Settlement

We were asked to address the treatment of an expected monetary settlement and whether it should be incorporated into FPL's books in the 2010 projected test year. The monetary settlement was the result of a lawsuit FPL filed against the United States Department of Energy (DOE) concerning the disposal of spent nuclear fuel. Two exhibits sponsored by FPL witness Kim Ousdahl summarized the test year adjustment for the DOE settlement funds FPL made for 2010.

FPL witness Ousdahl testified that FPL should make an updated adjustment to its 2010 Test Year revenue requirements to reflect new information from the DOE. She testified that:

> FPL's 2010 Test Year jurisdictional revenue requirements should be adjusted by $(6.9) million, representing the NOI impact and $(3.1) million, representing the rate base impact. These adjustments are based on the amount of capital and operations and maintenance expenses the Company has identified in its 2010 forecast that are expected to be reimbursed by the DOE, and apply the same recovery assumptions from FPL's settlement agreement with the DOE entered into on March 31, 2009 resolving FPL's damages incurred prior to 2008. FPL has calculated these adjustments to its 2010 revenue requirements associated with the expected reimbursement, and has included them as Items 3 and 4 of Exhibit KO-16 [358].

FPL witness Stall explained that FPL will incur capital and O&M expenditures to manage the DOE's failure to begin accepting spent nuclear fuel for disposal as required by law. He further stated:

> On-site storage capacity for spent fuel in the spent fuel pools is limited. As existing capacity is utilized, alternative methods for storing the spent fuel are required. Alternative storage is required as a prudent operational measure whenever the spent fuel pools can no longer accommodate a full-core offload. Maintaining a full-core offload capability is a prudent measure in the event that all of an entire core of reactor fuel must be offloaded to accomplish emergent repairs to the reactor.

We find that the test year adjustments presented in hearing Exhibit 358 and detailed in Exhibit 477 are appropriate to reflect the expected settlement received from the Department of

Energy. Accordingly, FPL's O&M expenses, depreciation expense and taxes other than income taxes are reduced by $6,084,000, $747,000, and $109,000, respectively, for the 2010 test year. Plant in service, depreciation reserve and CWIP are reduced by $25,866,000, $252,000, and $828,000, respectively, for the 2010 test year.

Transactions with affiliated companies

OPC witness Dismukes testified to the importance of our examining transactions between FPL and its affiliates. We reviewed the testimony and exhibits from FPL and OPC regarding FPL's transactions with its affiliates. Upon completion of our review we determined that for certain affiliate transactions, we needed additional information.

FPL witness Ousdahl provided an overview regarding the methods FPL used to charge costs to its affiliates including FPL's New England Division (FPL-NED). FPL-NED is a division of FPL, and not a separate affiliate. Witness Ousdahl described the controls in place to ensure that FPL's retail customers did not subsidize FPL's affiliates.

Witness Ousdahl testified that there are three ways that FPL charges costs of shared activities to its affiliates. Those are direct charges, service fees, and affiliate management fees (AMF). Direct charges are those costs of FPL resources used exclusively to provide service for the benefit of the affiliate company and are directly charged to that affiliate. Service fees are costs for ongoing services provided to one or more affiliates of FPL. AMF are costs associated with corporate staff infrastructure and governance costs that benefit both FPL and all the affiliates and are categorized into specific cost pools.

Regarding the third category, AMF, where distinct cost drivers may be determined, Witness Ousdahl stated that:

> . . . the cost of ongoing services shared jointly to support utility and affiliate operations are allocated using specific factors. Examples of these cost pools include corporate systems applications, support for computer mainframe operations, benefit programs, and corporate security. The drivers to allocate these costs are carefully selected in order to accurately allocate costs. Examples of commonly used drivers include number of personal computers, number of transactions, headcount and square footage . . .

Concerning the cost pools associated with the AMF, which do not have distinct cost drivers, Witness Ousdahl explained that these cost pools are:

> . . . allocated using the Massachusetts Formula, a methodology widely accepted by utility regulators as a fair and reasonable way to allocate common costs among affiliates. The Massachusetts Formula has three components: property, plant and equipment, revenue and payroll. . . . The use of a calculated average of property, plant and equipment, revenue and payroll appropriately considers the various factors affecting the use of common services. Examples of cost pools that do not

> have a specific driver include budgeting, and planning, external financial reporting, corporate communications, mail services, and shareholder services.

Witness Dismukes identified concerns with different FPL methodologies for charging its affiliates. She made recommendations for most of those concerns. Witness Dismukes argued that the Company's data was stale and needed updating. She felt that the factors inaccurately reflected the amounts that should be allocated to FPL. Witness Dismukes also testified that there were problems with FPL's use of the Massachusetts Formula. Witness Dismukes expressed concern regarding certain transactions between FPL and its affiliate FPLES. She also testified that FiberNet's charges to FPL overstated the cost of capital charged by FiberNet to FPL for FiberNet's services. Witness Dismukes also addressed her concerns regarding power monitor regulations.

Updates to Specific Drivers

Concerning the problem that she identified with the Company's use of allocation factors for specific drivers that need to be updated with more current data, OPC witness Dismukes recommended the following:

> First, to overcome the problem associated with the Company's use of stale allocation factors, I recommend that the Commission update the specific drivers to reflect the most recent information available. With respect to the Power Generation Division Fee I recommend that the Commission update the installed megawatts using the Company's disclosures in its 2008 annual report and testimony filed in this proceeding. . . . Second, . . . in instances where the Company did not project an increase for the projected test years, I recommend that the Commission increase the allocation drivers based upon recent growth. . . . I recommend that the Commission reduce test year expenses by $2.3 million in 2010 . . . .

FPL witness Ousdahl responded to the concerns raised about "stale" drivers for certain allocation factors in her rebuttal testimony. Witness Ousdahl stated that:

> Ms. Dismukes has made the incorrect assumption that all of the specific drivers used in the AMF will increase over time. To address Ms. Dismukes' concern that the drivers were not current, FPL has provided drivers updated in the first quarter of this year as a part of its normal billing process to compare to those included in the rate filing. The drivers used for the test year forecasts and the new drivers are shown on Exhibit [356] KO-14. The minor fluctuations between the two sets of drivers indicate that many of the new drivers actually decreased.

FPL witness Ousdahl also addressed the update to the installed megawatts:

> FPL again used the most current information available at the time to develop the allocation factors. Contrary to Ms. Dismukes' testimony, this information already included 1,219 MW related to FPL's West County Energy Unit 1 and 864 MW of

> wind capacity for NextEra for 2009. FPL updated MW information used for these calculations as of the second quarter of 2009. Exhibit 357 shows the current forecasted relative MW of capacity, which are minimally different from those included in the filing.

OPC's recommended adjustment for stale drivers, used for specific drivers of shared affiliate costs, assumes that allocation drivers to affiliates of FPL will always increase. This is not necessarily correct because the percentages representing the drivers are the relative size of one affiliate to another. The constant increase of allocation drivers to affiliates of FPL assumes that the affiliates are always going to grow faster than FPL itself. For example, the specific driver based on the number of personal computers owned by FPL and each affiliate, produces a percentage to allocate certain shared costs. The number of personal computers is not necessarily going to grow faster at the affiliates of FPL than FPL itself. If the specific drivers are growing faster for the affiliates of FPL versus FPL itself, then it would seem that the cost pool to support the growth in the affiliates would also need to be increased to account for the additional work load.

We find that the most current factors shall be used in projections, as long as there they are representative of the future and that no changes of an unusual nature have occurred from one measurement period to the next. However, this does not mean that there will always be an increase in the factors over an earlier period. FPL filed the latest available drivers in Exhibit 356. FPL also filed the latest relative MW capacity between NextEra and FPL available. These exhibits showed that there was not a material change in the specific drivers in the latest quarter of data available and that some drivers went down. Accordingly, we do not find that OPC's recommended adjustment to reduce expenses by $2.3 million for the 2010 test year is appropriate, and we decline to do so.

Massachusetts Formula:

OPC Witness Dismukes recommended two adjustments concerning problems she perceived with FPL's use of the Massachusetts Formula. The first problem she addressed, FPL's failure to update the components used in the calculation of the Massachusetts Formula, would only have affected the revenue requirements for the 2011 test year. Since we declined to approve a 2011 test year, we need not address this issue.

OPC witness Dismukes' other perceived problem with the Massachusetts Formula was that it did not account for the benefits that the non-regulated affiliates received from their association with FPL and FPL Group. Witness Dismukes stated that the Massachusetts Formula implicitly assumed that the larger the affiliate, the greater its received benefit from shared services. She recommended the following:

> To address the problems associated with the size-based nature of the allocation factor and the significant benefits the non-regulated affiliates derive from being associated with FPL and FPL Group, I recommend that the Commission distribute shared executive costs of the FPL Group between FPL and the non-regulated

> affiliates with 50% assigned to each. . . . As shown on Exhibit [201] KHD-11, the changes that I recommend concerning the allocation of the AMF reduce charges to the Company in the projected years by $7.9 million for 2010 . . . .

FPL witness Ousdahl addressed OPC witness Dismukes' concerns with the Massachusetts Formula's failure to reflect the benefits that FPL affiliates received from the shared services:

> The objective of performing cost allocations to affiliates is to recover the cost of the shared services that the affiliates use in order to ensure that FPL's customers are not paying any costs that would result in a subsidy to those affiliates. . . . Ms. Dismukes ignores the benefit that FPL and its customers receive from affiliate relationships. FPL has greater access to high quality resources without having to incur the full cost thereof. . . . While I agree that the Massachusetts Formula results in larger allocations for larger companies, this result is entirely appropriate. . . . To the extent we can identify a causal relationship between activities and support services, specific drivers are used to allocate costs. All of these allocations result in the larger companies receiving a larger share of costs. When a similar result occurs because of the application of the Massachusetts Formula for truly un-attributable costs, it neither is unexpected nor inappropriate. It is for this very reason the Massachusetts Formula has been so widely accepted in the utility industry as well as by this Commission. No adjustment is necessary to the Massachusetts formula results.

In her summary, Witness Ousdahl stated:

> Ms. Dismukes' recommended adjustments are based on inappropriate trending and 50/50 allocations, and ignore the use of specific drivers and the long standing Massachusetts formula employed by the Company. Her suggested use of trending is clearly inappropriate. She is forecasting the historic trajectory of the growth in affiliates into the 2010 and 2011 timeframe, which quite ignores the constraints faced today in the capital markets which will make it impossible for historical rates of growth to continue.

OPC's second proposed adjustment to the Massachusetts Formula was made to better reflect the benefits that the affiliates receive from their association with FPL and FPL Group. OPC recommended that the Massachusetts Formula be changed to distribute the shared executive costs of the FPL Group between FPL and the affiliates by assigning 50 percent to each. While we are not required to adhere to the Massachusetts Formula without question or examination of its results, the Massachusetts Formula was designed to fairly distribute un-attributable costs to insure that a regulated company does not subsidize its affiliates. This is why the Massachusetts Formula has been widely accepted in the utility industry and accepted by us in the past. We have reviewed the testimony and do not find a clear empirical reason to change the use of the Massachusetts Formula in this docket. Accordingly, we decline to adjust the Company's forecast based on the Massachusetts Formula, proposed by OPC.

FPL Energy Services:

Witness Dismukes also had concerns about the transactions between FPL Energy Services (FPLES) and FPL. FPLES is an affiliate of FPL that provides energy-related products and services and is not regulated by us. Witness Dismukes did not believe that the sale of FPL's natural gas contracts was at a reasonable price. She stated that she "developed [her] recommended adjustment by averaging the gross margin earned from these contracts over the five years preceding the sale." Her proposed adjustment was to recognize a gain on the sale of $1,090,753 for both the 2010 and 2011 test year.

FPL witness Santos testified concerning the January 1, 2006, sale of the natural gas business of FPL to FPLES. Witness Santos stated:

> As stated earlier, the matter related to the sale of the FPL gas contracts to FPLES was resolved per the Stipulation and Settlement Agreement. Since 2006, FPLES has been responsible for all activities related to the Gas Business and has assumed all related risk. FPL has not been involved in this business since that time. As such, the gross margins realized from the Gas Business are unrelated to FPL and its rate payers. No adjustment is necessary contrary to Ms. Dismukes' recommendation.

The gains or losses on the sale of the gas contracts to FPLES by FPL were completely explored and debated in the Company's last rate case, including direct and rebuttal testimony. That case was settled and we approved the stipulation in the 2005 Settlement Order.[65] The order stated "This Stipulation and Settlement will resolve all matters in these Dockets . . ."

The second concern over transactions between FPL and FPLES was discussed by Witness Dismukes:

> Clearly, if FPL is billing on its electric bills for services that FLPES provides to FPL's residential, commercial, and governmental customers, FPLES should compensate FPL for the use of its personnel, billing systems, collection systems, postage, paper and any other costs associated with billing the customer. OPC has issued additional discovery on these matters and intends to present additional information to the Commission on the subject.

FPL witness Santos also testified concerning FPL's billing on its electric bills for services of FPLES, stating that, "[f]or those FPLES programs that utilize the FPL bill, FPLES compensates FPL accordingly for billing, collection and any other related costs.

We share the concerns of witness Dismukes regarding FPLES's use of FPL's services for the benefit of FPLES programs. FPLES offers products to FPL's customers through FPL's bill inserts. FPL processes the cost of that on its bill. We are concerned whether there is cross-

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[65] Order No. PSC-05-0902-S-EI, issued September 14, 2005, in Docket No. 050045-EI, In re: Petition for rate increase by Florida Power & Light Company.

subsidization and whether it is really a level playing field to the extent competitors want to offer the same products as FPLES. Furthermore, we are concerned that products offered in this manner cause customer confusion; in addition we heard testimony regarding the limitations of these products. Accordingly, to explore our concerns, we find it appropriate to open a separate docket to investigate the relationship of and the appropriateness of FPLES offering products to FPL consumers.

FiberNet:

OPC witness Dismukes proposed lowering the charges from FiberNet to FPL by reducing the rate of return on FiberNet's assets. Witness Dismukes recommended lowering the return charged by FiberNet to that suggested by OPC witness Woolridge. This adjustment would reduce O&M expenses by $1,182,224 for the 2010 test year. Concerning the costs charged to FPL by FiberNet, an affiliate of FPL, OPC witness Dismukes testified:

> With respect to costs allocated from FiberNet, for the projected test year costs were allocated using fiber miles, fiber capacity, and DS3 capacity. I am recommending one modification to the methodology employed to allocate these costs to FPL. As shown on Exhibit 202, the allocation of costs to FPL is based upon the assets owned by FiberNet. A large portion of the costs allocated to FPL are based upon the return on the assets used by FPL. In developing the amount to charge FPL, the Company used a return on investment . . . I have modified this return to be consistent with the pre-tax overall cost of capital recommended by Dr. Woolridge. The Commission should reject the Company's request to use a rate of return that is substantially in excess of FPL's allowed rate of return and utilize the rate of return recommended by Mr. Woolridge. As shown on this exhibit, this change results in an estimated reduction to charges for the years 2010 and 2011 of $1,182,224 [each year].

FPL witness Avera's rebuttal Exhibit 363 (Rebuttal to Technical Arguments) stated that:

> . . . the risks and cost of capital for telecommunications services is generally regarded as higher than for electric utility services, particularly for competitive local exchange companies such as FiberNet. . . . A review of Exhibit JRW-18 reveals that the average beta for the Telecommunications Services industry was 1.43, versus the 0.88 beta value cited by Dr. Woolridge for the electric utility industry and a beta of 1.00 for the overall market.

In other words, FPL witness Avera believed this comparison indicated that the risks associated with FiberNet were higher than FPL. Witness Avera concluded that OPC witness Woolridge's recommended overall rate of return for FPL was entirely unrelated to the services provided by FiberNet.

FPL could own its own telecommunications equipment that would be used strictly for its own use. If this were the case, the assets would be a part of the Company's rate base and it would be allowed to earn the same return as the rest of its rate base assets. We find that FiberNet has higher risk as a separate affiliate, and that the ratepayers shall not be required to pay for this additional risk. The return payable to FiberNet from FPL ratepayers shall be that permitted to be earned by FPL. This adjustment decreases O&M expenses by $1,182,224.

Power Monitoring Revenue:

OPC recommended increasing miscellaneous revenue by $236,336 for the 2010 test year. These increases were to certain revenues excluded from revenue due to a mislabeling. FPL witness Ousdahl stated that the data was mislabeled in an informal discovery response as power monitoring revenues, and should have been labeled as regulation service revenues. She went on to say:

> This description change is supported by FPL's response to OPC's First Set of Interrogatories Question No. 55 where the same amounts are shown for 2006, 2007 and 2008 with a description of Regulation Service Revenues. Even though FPL misidentified the account description, it does not impact the amounts forecasted for Power Monitoring revenues, which are properly reflected in FPL's MFR's.

We find that this adjustment was unnecessary and that the revenues associated with this item were correctly shown in the Company's MFRs.

Forecast Updates:

FPL witness Ousdahl sponsored Exhibit 358 in her rebuttal testimony and explained that during the course of the proceeding, FPL identified appropriate adjustments to the Company's filing. Exhibit 358 summarized the adjustments to rate base, net operating income, and capital structure that FPL proposed to its original filing.

Item 5 of Exhibit 358 showed FPL's proposed adjustment due to an overstatement of affiliate payroll loadings. According to FPL, affiliate payroll loading was overstated because it was not based on the final payroll forecast from the business units. Item 5 resulted in an adjustment to decrease O&M expense and taxes other than income taxes by $3,373,000 for the 2010 test year. The forecast updates result in an adjustment to decrease O&M expense and taxes other than income taxes by $3,592,000.

Conclusion

Based on the foregoing, we find that: 1) the Company's proposed adjustment for the forecast data shall be accepted, and that O&M expense and taxes other than income taxes shall be decreased by $3,373,000; 2) that no adjustment shall be made for stale allocation drivers; 3) that no adjustment shall be made for the Massachusetts Formula; 4) that no adjustment shall be made for FPL Energy Services; 5) that adjustment to the charges from FiberNet to FPL shall be made resulting in an O&M expense reduction of $1,182,224 for the 2010 test year; 6) that no adjustment shall be made for the power monitoring revenue; and 7) that a generic docket shall be opened to investigate the relationship of and the appropriateness of FPLES offering certain products to FPL consumers. The total reduction in this docket for O&M expense and taxes other than income taxes is $4,774,224 for affiliate transactions.

Gains on sale of utility assets

We were asked to determine if an adjustment was necessary to reflect the gains on sale of utility assets sold to FPL's non-regulated affiliates. OPC witness Dismukes sponsored Exhibit 204, which showed that during 2007 and 2008 the Company sold several assets to its affiliates which resulted in a gain on sale. As shown on Exhibit 204, during 2007, the Company sold 15 assets which resulted in a total gain of $4.6 million. The largest gain resulted from the sale of a combustion turbine rotor to FPL Group, Inc. which resulted in a gain of $4.5 million. During 2008, the Company sold 14 assets which resulted in a gain of $877,706. The largest gain, $872,974, related to a transformer sold to Calhoun Company I, LLC. The total gains for both years amounted to $5.5 million.

According to OPC witness Dismukes, we have had several cases in which we ruled on the gain or loss on the sale of a utility asset. Witness Dismukes cited our recent decision regarding transaction and transition costs for Florida City Gas. Witness Dismukes recommended that we pass the gains on to customers and amortize them over five years. Her adjustment, shown in Exhibit 204, resulted in an increase in net operating income of $1.1 million for the 2010 test year.

FPL witness Ousdahl explained that our orders as cited by OPC witness Dismukes referred to transactions for the sale of entire gas systems and the sale of land. Witness Ousdahl stated:

> Ms. Dismukes cites FPSC Docket No. 060657-GU, Order No. PSC-07-0913-PAA-GU, issued November 7, 2007. This order relates to the sale of an entire gas plant. The order also includes an embedded reference to FPL Docket No. 830465-EI, Order No. 13537, issued July 24, 1984. This order discusses regulatory treatment for a gain on sale of land. These transactions represent sales of facilities and land, and Commission policy for the amortization of gains or losses on the sale of these entire systems and land parcels would be appropriate. However, Ms. Dismukes attempts to apply this Commission policy to FPL's sale of retirement units which were transacted in 2007 and 2008. Gains and losses that arise from the sale or interim retirement of retirement units of a utility are deferred to the balance sheet and accounted for in future depreciation. Specifically, for the FPL transactions analyzed by Ms. Dismukes in 2007 and 2008, when the FPL assets were sold, the original cost of the asset was debited to account 108 and credited to account 101. Then, as required by USOA and FPSC rules and practice, FPL recorded a debit to cash and a credit to account 108 for the sales proceeds at market in accordance with FPSC and FERC guidelines for retirement of plant in service retirement units. The customers will benefit from these gains through reduced return and decreased depreciation expense as is the requirement of the USOA and regulatory accounting practice for electric utilities.

We find that FPL applied the correct interpretation to the Uniform System of Accounts and applied the correct accounting to the gains referred to in this issue. The treatment recommended by OPC is appropriate for the sale of entire systems and land. Accordingly, no adjustment is necessary for gains on sale of utility assets sold to FPL's non-regulated affiliates.

Transfer of the FPL-NED Assets

We were asked to determine if we should order FPL to report the future transfer of the FPL-NED assets from FPL to a separate company under FPL Group Capital. OPC witness Dismukes made recommendations for safeguarding ratepayers from any risks related to the transfer of FPL-NED assets to a separate company under FPL Group Capital. Witness Dismukes testified that:

> The Commission should ensure that at the time of the transfer to this new company, the assets are transferred at the higher of cost or market as required by its affiliate transaction rules. In addition, the Commission should order that an independent appraisal be prepared as to the fair market value of these assets, as required by its rules on affiliate transactions.

FPL witness Ousdahl stated that the provision of our affiliate Rule 25-6.1351-3(d), F.A.C., does not apply to the situation of FPL-NED. Witness Ousdahl testified that:

> Section 3(d) of the affiliate rule applies the requirement that assets be transferred at the higher of net book value or market when an asset used in regulated operations is transferred from a utility to a nonregulated affiliate. This rule does not apply because FPL-NED assets have never been used in operation in any Florida retail jurisdiction regulated by the FPSC.

We agree with OPC. We direct FPL to notify us at the time FPL-NED assets are transferred to a separate company. At that time, FPL shall provide us with an independent appraisal as to the fair market value of the assets. We find that Rule 25-6.1351-3(d), F.A.C., applies to this transaction and that the assets transferred shall be at the higher of cost or market as required by our rules.

Storm Damage Reserve

FPL proposed an annual storm damage accrual of $150,000,000 per year with a target reserve level of $650,000,000. OPC, AG, FIPUG, FRF, and SFHHA disagreed with FPL and suggested that there be no accrual of storm damage reserve and that the target level of the reserve be $200,000,000, which has already been funded. We were asked to determine whether to adjust FPL's revenues to exclude all or a portion of FPL's proposed accrual.

FPL witness Pimentel described what he believed to be the key policy considerations underlying the storm cost recovery framework, as articulated in Orders Nos. PSC-93-0918-FOF-EI, PSC-95-0264-FOF-EI, and PSC-95-1588-FOF-EI. According to witness Pimentel, the key principles are:

> First, storm restoration is a cost of providing electric service in Florida and is therefore, properly recoverable through the rates and charges of the Company.

> While we cannot predict with certainty when storms will occur, we can predict with virtual certainty that tropical storms and hurricanes will affect our service territory and we will incur costs for restoring power. However, those costs are not reflected in the Company's base rates.
>
> Second, each "generation" of customers should contribute to the cost of storm restoration, even if no storm strikes in a particular year. Since storms will occur and only their timing is uncertain, the true cost of providing electric service should include an allowance for a level of restoration activity that approximates the expected annual storm costs.
>
> Third, "pre-funding" restoration costs sufficient to cover an extreme sub-period of storm activity (ie., building up a Reserve sufficient to cover virtually all storm restoration) is likely to be economically inefficient. Thus, some mechanism for recovery of the prudently incurred costs that exceed the Reserve is required.

FPL witness Pimentel went on to explain that since Hurricane Andrew, commercial insurance to cover storm cost has been unavailable. He described the framework he believes to be endorsed by us as consisting of three main parts: (1) an annual storm accrual; (2) a reserve adequate to accommodate most but not all storm years; and (3) a provision for utilities to seek recovery of costs that go beyond the reserve.

As a result of the 2004 storm season, costs incurred to restore electric service following Hurricanes Charley, Frances, and Jeanne, totaled \$890 million (net of insurance proceeds), completely depleting FPL's Reserve. In Order No. PSC-05-0937-FOF-EI,[66] we approved a surcharge of \$1.65 (per 1,000 kWh residential bill) which was intended to eliminate the deficit in the reserve.

Witness Pimentel then explained what happened to the Company's storm reserve as a result of the 2005 storm season. He testified that,

> In 2005, another very active storm season, four Hurricanes inflicted damage on FPL's system. Restoration costs associated with Hurricanes Dennis, Katrina, Rita and Wilma increased the Reserve deficiency by approximately \$816 million, leaving a deficit balance in the Reserve in excess of \$1.1 billion. The Storm Restoration Surcharge was designed to recover approximately \$300 million of that amount by February 2008, leaving approximately \$800 million to he recovered through another means, as well as the question of how best to restore the Reserve to a reasonable level going forward.

Next FPL witness Pimentel addressed the effects of Order No. PSC-06-0464-FOF-EI[67] approving the issuance of bonds to finance storm restoration costs:

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[66] Order No. PSC-05-0937-FOF-E1, issued September 21, 2005, in Docket No. 041291-E1, <u>In re: Petition for Authority to Recover Prudently Incurred Storm Restoration Cost Related to the 2004 Storm Season that Exceed the Reserve balance, by Florida Power & Light Company</u>.

[67] Order No. PSC-06-0464-FOF-EI, issued May 30, 2006, in Docket No. 060038-EI, <u>In re: Petition for issuance of a storm recovery financing order, by Florida Power & Light Company</u>.

> The Commission approved the issuance of Bonds in the amount of up to $708 million, provided the initial average retail cents per kWh for the Bonds would not exceed the average retail cents per kWh for the Storm Restoration Surcharge which was then in effect. The proceeds from the issuance of Bonds authorized by this Financing Order were required to be used by FPL to finance the after-tax equivalent of the following amounts: (1) approximately $199 million in unrecovered 2004 storm-recovery costs as of July 31, 2006 (estimated); (2) approximately $736 million in 2005 unrecovered storm-recovery costs (estimated); (3) replenishment of FPL's Reserve to the level of $200 million; and (4) $11.4 million in financing costs (estimated) associated with the Bonds. To the extent there were differences between the actual and estimated balances for unrecovered 2004 and 2005 storm restoration costs and between the actual and estimated financing costs, the differences were to be reflected through an adjustment to the Reserve.

FPL witness Pimentel explained that FPL commissioned studies to calculate the annual amount of expected windstorm losses, as well as the expected value of the Reserve given various funding levels. The studies were prepared by and were sponsored by FPL witness Harris of ABS Consulting.

Witness Harris summarized the results of the Reserve Performance Analysis:

> Reserve performance can be viewed in terms of the expected balance of the reserve and the likelihood of insolvency occurring in any year of the five-year periods. Based on the simulated loss distributions, there is some likelihood of the reserve having a negative balance for each of the annual accrual levels analyzed. Higher accrual levels will result in a lower probability of the reserve having a negative balance, and will have a higher probability of a positive reserve balance at the end of the five-year simulation period.

Witness Harris was asked if FPL's selection of a $650 million target level for the reserve is adequate. He answered that "[b]ased on the current value of FPL's T&D assets, a reserve balance of $650 million would be adequate to cover uninsured losses during most, but not all, storm seasons." Witness Harris was asked for his conclusion with respect to the $150 million annual level of accrual selected by FPL.

> . . . My analysis indicates that, with an expected annual loss of $153.3 million, an annual accrual of $150 million and the ability to recover any negative reserve balances over a two-year period, the balance of the reserve at the end of five years would grow from the initial $215 million to an expected balance of $382 million. . . .

In asking whether the Company should be allowed the proposed annual accrual of $150 million with a target reserve of $650 million, OPC witness Brown answered no:

> While Mr. Pimentel notes some key policy considerations, the balancing of generational ratepayer interests is extremely important in this case. FPL's

> customers are currently facing tough economic times. FPL's requested storm damage accrual of $150 million a year is over 14% of FPL's requested 27% increase in base rates. While it is not reasonable or feasible for customers to pay for storm costs in the year of occurrence and thus requires customers over several generations to provide revenues to cover such costs, the Commission must also recognize that current ratepayers are already paying a substantial amount to cover past storms, as well as replenishment of the storm reserve fund to over $200 million. In 2010, FPL anticipates storm recovery revenues of $93.957 million. Generational sharing of costs does not require pre-funding and may result in deferred cost recovery or securitization such as the current securitized bonds covered by the storm recovery surcharges.

We have balanced the need to make certain that FPL will be able to reliably provide electricity to its customers in the event of storms, with the need to set fair, just and reasonable rates. We are aware that when storm costs occur, customers will be called upon to pay those costs, either through a reserve fund or through a surcharge. Yet we are very aware and very concerned with the current economic times. We have been made aware, through testimony, that customers have difficulty paying their bills, without our adding an additional burden that could be deferred. Furthermore, customers are already paying a surcharge for past storm costs. Allowing the Company to begin collecting an annual accrual, in addition to the existing surcharge could have the same effect as double surcharges in the future. We have previously supported the process of building a storm cost reserve, and as a result the Company has funded a storm reserve. This funded reserve bears interest. We note that there are provisions for the protection of utilities to allow them to seek recovery of prudently incurred storm costs that go beyond the reserve level. Because these mechanisms are in place to recover storm costs, we choose at this time, not to place this additional burden on the ratepayers. Accordingly, FPL's O&M expenses are decreased by $148,666,500.

Rate Case Expense

FPL requested recovery of rate case expense of $3,657,000 over a three year amortization period. While the total rate case expense of $3,657,000 was a fair estimate of what rate case expense would have been without the subsequent 2011 test year and GBRA request, we disagree with certain aspects of FPL's proposal.

FPL included $450,000 for overtime and or bonuses for salaried employees in its original total rate case expense filing. We have historically disallowed recovery of additional pay or bonuses as a part of rate case expense.[68] In Order No. PSC-08-0327-FOF-E1,[69] we stated "Salaried Overtime Pay for Extraordinary Work Load" shall be disallowed because these employees and managers are paid a salary, not an hourly wage. Salaried employees are usually expected to work the hours required to complete their job duties without extra compensation.

[68] See Order No. PSC-08-0327-FOF-E1, issued May 19, 2008 in Docket No. 070304-EI, In re: Petition for rate increase by Florida Public Utilities Company.
[69] Id.

FPL requested that the unamortized balance of rate case expense be included in rate base. FPL witness Ousdahl stated that recovery of necessary rate case expenses was appropriate and has historically been included in the Company's revenue requirement. She testified that,

> Similar to FGPP cost recovery, the unamortized balance must be included in rate base in the Test Year in order to avoid an implicit disallowance. The Company has been prudent in limiting its incremental rate case expenses, while being mindful of the need to present and fully support its case in accordance with Commission requirements.

We do not agree with the Company that the unamortized balance of rate case expense should be included in rate base. Historically, the unamortized balance of rate case expense has been excluded from rate base to reflect a sharing of the rate case cost between the ratepayers and the shareholders.[70] Rate case expenses are recovered from ratepayers through the amortization process as a cost of doing business in a regulated environment. However, the unamortized balance of rate case expense has been excluded from rate base to reflect that an increase in rates is a benefit to the shareholders. The Company included $2,948,000 in working capital for the 2010 test year.

FPL requested that the rate case expense be amortized over three years. OPC suggested that recovery occur over 5 years. We shall permit rate case expense for FPL to be amortized over a four year period which is consistent with several of our recent decisions.[71] Four years is a more likely time period than three or five years for the Company's next filing.

Based on the foregoing, we reduce the Company's total rate case expense of $3,657,000, as originally filed, by the $450,000 for overtime and/or bonuses for salaried employees. Total rate case expense as adjusted is $3,207,000. Total rate case expense shall be amortized over a four year period at an amortization of $801,750 per year. The unamortized balance of rate case expense shall be excluded from working capital. We reduce rate case amortization expense by $217,250 for the 2010 test year. We also reduce jurisdictional working capital by $2,948,000 for the 2010 test year.

<u>Energy Conservation Cost Recovery Clause</u>

FPL witness Ousdahl testified that:

> This company adjustment applies payroll loadings consistent with the payroll dollars recovered through the energy conservation cost recovery (ECCR) clause. Currently, FPL makes an adjustment to the ECCR clause to reduce total payroll

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[70] Order No. 14030, issued January 25, 1985, in Docket No. 840086-EI, <u>In Re: Application of Gulf Power Company for authority to increase its rates and charges</u>; Order No. 16313, issued July 8, 1986, in Docket No. 850811-GU, <u>In Re: Petition of Peoples Gas System, Inc. for authority to increase its rates and charges in Hillsborough County</u>; Order No. 23573, issued October 3, 1990, in Docket No. 891345-EI, <u>In Re: Application of Gulf Power Company for a rate increase</u>.

[71] <u>See</u> Order No. PSC-09-0283-FOF-EI, issued April 30, 2009, in Docket No. 080317-EI, <u>In re: Petition for rate increase by Tampa Electric Company</u>.

> loadings related to compensation associated with conservation employees by the amount of loadings for FICA and unemployment taxes. This adjustment has been required due to a finding in Docket No. 850002-PU that these items were already included in base rates at that time. FPL is proposing to remove $1.6 million for 2010 and $1.5 million for 2011 for the FICA and unemployment taxes remaining in base rates, in order to facilitate recovery of fully loaded ECCR payroll costs through the ECCR clause beginning in 2010. The amount of these loadings varies directly with payroll costs charged to the ECCR clause, so it is appropriate that they be recovered via that mechanism.

The Company's adjustment would shift more cost to the recovery clauses. As the Company noted, we required that the loadings on payroll recovered through the ECCR remain in base rates in Docket No. 850002-PU. The Company has presented no compelling reason to shift these costs from base rates to the ECCR clause.

Accordingly, the Company's proposed adjustment to remove FICA and unemployment taxes, associated with payroll through the ECCR, from base rates and to recover those cost through the ECCR clause is denied. Based on the foregoing, O&M expenses are increased by $1,582,000.

FPL proposed that payroll loadings on incremental security costs, currently included in base rates be recovered through the Capacity Cost Recovery Clause. Several intervening parties opposed this change and we were asked to determine if those payroll loadings should be moved from rate base to the Capacity Cost Recovery Clause.

FPL witness Ousdahl testified that:

> This company adjustment applies payroll loadings consistent with the payroll dollars recovered through the capacity clause. Currently, FPL has not been including payroll taxes related to compensation associated with incremental security through the capacity clause. FPL proposes to remove $430 thousand from base rates in the 2010 Test Year and $506 thousand from the 2011 Subsequent Year for payroll taxes related to compensation associated with incremental security, in order to facilitate recovery of fully loaded incremental security payroll costs through the capacity clause beginning in 2010. These loadings are incremental and vary directly with incremental security payroll costs charged to the capacity clause.

We find that the Company's adjustment would shift more cost to the recovery clauses and that the Company presented no compelling reason to do so. Based on the foregoing, the Company's proposed adjustment to remove FICA and unemployment taxes, associated with payroll recovered through the capacity clause, from base rates and to recover those cost through the capacity clause is denied. O&M expenses are increased by $427,000 for the 2010 test year.

Incremental Hedging Costs Recovered through the Fuel Cost Recovery Clause

FPL proposed to move incremental hedging costs to rate base. "Incremental" hedging costs are administrative costs such as labor cost, as opposed to "actual" hedging costs which are the prudently-incurred gains and losses from fuel price hedging activities. Actual hedging costs are charged to the fuel cost recovery clause pursuant to Order No. PSC-02-1484-FOF-EI.[72] In addition, actual hedging costs are much larger than incremental hedging costs.

Witness Ousdahl testified that:

> Incremental hedging costs of $715,000 for 2010 primarily consisted of the labor costs associated with the trading, back office, and middle office staff employed in support of the Company's Commission-sanctioned fuel hedging program. In accordance with Order No. PSC-02-1484-FOF-EI, issued October 30, 2002, in Docket No. 011605-EI, incremental costs associated with the Company's hedging program were recoverable as a part of the fuel clause until the earlier of 2006 or the establishment of new base rates in the Company's next base rate case. FPL's clause recovery of its incremental hedging costs was extended in Docket No. 050001-EI, Order No. PSC-05-1252-FOF-EI, issued on December 23, 2005, through at least December 31, 2009 and thereafter until FPL's next base rate proceeding. At this time, it is appropriate to include these costs in the current base rate revenue requirements calculations.

Consistent with our prior orders, we move incremental hedging costs into base rates. The incremental hedging costs are administrative costs and properly belong in base rates, not in fuel factors.

Exhibit 180, MFR Schedule C, showed adjustments to increase jurisdictional expenses by $702,000 for the 2010 test year. FPL made several corrections to its original filing, including corrections to its inclusion of incremental hedging costs in rate base. FPL witness Ousdahl sponsored Exhibit 358 which summarized the adjustments to rate base, net operating income, and capital structure that FPL proposed we make to its original filing. Item 20 of Exhibit 358 showed FPL's proposed adjustment due to an over-statement of O&M cost associated with hedging cost. In its original filing the Company overstated the increase in O&M cost by $52,000. Based on the foregoing, the Company's proposal to move $650,000 ($702,000 - $52,000) of incremental hedging costs into rate base for the 2010 test year is approved.

O&M Expenses

We were asked to determine if FPL's proposed O&M expenses were appropriate, with the adjustments made by FPL. This is a fallout issue and its determination is based on our decisions above. However, FPL proposed one additional adjustment to its filings for O&M expenses. FPL witness Ousdahl sponsored Exhibit 358, which summarized the adjustments to

[72] Order No. PSC-02-1484-FOF-EI, issued October 30, 2002, in Docket No. 011605-EI, In re:Review of investor-owned electric utilities' risk management policies and procedures.

rate base, net operating income, and capital structure that FPL proposed to its original filing. Item 2 of Exhibit 358 showed FPL's proposed adjustment due to the possibility that poor investment performance in 2008 might affect Nuclear Electric Insurance Limited's (NEIL) ability to make future distributions. FPL witness Ousdahl testified that "In early 2009, when the 2008 performance became known, the Company should have revised its forecast to reflect the expectation of no distributions in 2010 and 2011 prior to filing its MFRs. This adjustment corrects that oversight."

Unlike most of the adjustments to the Company's filing shown in Exhibit 358, Item 2 is not a correction of an error but an update to one item of expense in the Company's entire forecast. This adjustment is based on a possible elimination of distributions based on information that became known to the Company in early 2009 after it had filed its case. First, we do not believe it is appropriate to update one item of expense in the Company's entire forecast without updating all items of revenue and expense. Second, the Company has not had any communication with NEIL wherein it was communicated that there would definitely be no distributions in 2010 and future years. NEIL has made distribution for many years without interruption. Accordingly, we deny FPL's proposed adjustment shown on Item 2 of Exhibit 358. Based on the foregoing, the appropriate level of O&M - Other expense is $1,475, 020,037 for the 2010 projected test year, and is shown on Schedule 3 of this Order.

Customer Information System

FPL acknowledged that it should not be permitted to collect depreciation expense for its new Customer Information System before its implementation date. FPL contended that its proposed depreciation expense was overstated by $0.4 million in 2010. In rebuttal testimony, FPL witness Ousdahl stated that there was a problem with FPL's projection of plant in service and depreciation expense for the Customer Service Information (CIS III) replacement project. The error was not detected until the Company responded to SFHHA's Tenth Set of Interrogatories, question number 288. Witness Ousdahl further stated that rate base was understated by $2.0 million due to the accumulated depreciation in 2010. Witness Ousdahl testified that the applicable adjustments and the revenue requirement impacts were shown in her Exhibit 358 Items 11 and 12.

We reviewed the adjustments made by FPL in Items 11 and 12 of Exhibit 358 and concur. The adjustments corrected the depreciation expense error for the CIS III replacement project. Item 11 of Exhibit 358, reduced the 2010 expenses by $435,000. Item 12 of Exhibit 358, adjusted the impact of the CIS III error correction for accumulated depreciation and was discussed above. Accordingly, we reduce the 2010 depreciation expense by $435,000.

Capital Expenditure Reductions

We reviewed the proposed depreciation expense adjustments for 2010 as reflected in FPL's exhibits. The capital expenditure reductions that corresponded to Exhibit 358 were the DOE Settlement, the customer information system, the transmission services, and error corrections to Account 354. The depreciation expense reductions for 2010, as reflected in FPL's exhibits, totaled $14,936,000. As we discussed above regarding levels of plant in service, capital expenditure reductions were provided for aviation costs and deferred or delayed projects with the corresponding depreciation expense for 2010 in the amount of $2,303,009. When discussing levels of plant in service, we also reviewed SFHHA's proposal of an annualized adjustment for 2010 plant in service in the amount of $784,000,000 and declined to make that adjustment. Based on the foregoing, the total capital expenditure reductions for 2010 is $17,239,009. These reductions for depreciation expense are included with all other depreciation reductions in Table 24 on the following page.

Depreciation expense adjustment

We were asked to determine what adjustments, if any, should be made to depreciation expense. Our decision on what adjustments is a culmination of our other decisions in this docket. As shown in the table below, we identified all of the adjustments to depreciation expense that we have made. Each adjustment for depreciation expense corresponds to adjustments we made for: jurisdictional separation; depreciation study, capital recovery schedules and reserve surplus; fossil dismantlement study; plant in service; aviation costs; customer information system-CIS3; and correction of errors by the Company. In addition, based on the results of the depreciation study, we developed the composite depreciation rates that were used for the 2010 test year depreciation expense calculation.

**TABLE 24**

| **2010 Adjustments to Depreciation Expense** | | | |
|---|---|---|---|
| Description | FPL | OPC | Commission |
| Issue 15 SLB-26 Revised-Jurisdictional Separation Factor–Transmission Services | | | |
| Issue 108: EXH 358-Item 4-DOE Settlement | ($747,000) | 0 | ($747,000) |
| Issue 129: EXH 358-Item 12 CIS III | ($435,000) | 0 | ($435,000) |
| EXH 358 Issue 16 Account 354 correction | ($3,419,000) | | ($3,419,000) |
| Issue 15: EXH 358-Item 21-Transmission Services–jurisdictional factor | ($10,335,000) | 0 | ($10,335,000) |
| Issue 50: EXH 418-Deferred Projects | 0 | 0 | ($211,000) |
| Issue 94: Aviation Costs | ($2,092,009) | 0 | ($2,092,009) |
| Issue 19C and 19D: Depreciation Study | 0 | | ($82,735,000) |
| Issue19E and 19F: Allocation of Reserve Surplus | | | ($223,695,000) |
| Issue 121: Fossil Dismantlement Study | | | $2,640,568 |
| Total Reductions | ($17,028,009) | ($560,659,000) | ($321,028,441) |

Accordingly, based on the adjustments reflected in the table above, the appropriate adjustment to depreciation expense for 2010 shall be a reduction of $321,028,441. The effect of the adjustments for the 2010 test year is a depreciation expense of $753,236,559.

Taxes other than income taxes

FPL witness Ousdahl sponsored Exhibit 358 in her rebuttal testimony, which summarized the additional adjustments to rate base, net operating income, and capital structure that FPL proposed to its original filing. Item 9 of Exhibit 358, showed FPL's proposed adjustment to reflect an increase in state unemployment tax rates that were inadvertently excluded from the Company's MFRs. This adjustment increased jurisdictional taxes other than income taxes by $972,000 for 2010. FPL's corrections to its original filing presented in Exhibit 358 were not challenged and appear to be reasonable. Accordingly, we accept FPL's adjustment of $972,000. Based on the other adjustments made in this Order, in addition to this adjustment, we find that taxes other than income taxes are $344,962,130.

The American Recovery and Reinvestment Act (Stimulus Bill)

We reviewed whether an adjustment should be made to reflect any test year revenue requirement impacts of the Stimulus Bill signed into law by the President on February 17, 2009. On August 6, 2009, FPL submitted a grant application to the United States Department of Energy for the Smart Grid Investment Grant. The maximum award for the grant was $200 million. As of the end of this proceeding, FPL had not received a response on its DOE Smart Grid Investment Grant application.

FPL witness Santos testified that the grant would be used for incremental projects. Witness Santos testified that the DOE was looking for new projects that would stimulate the economy. Witness Santos testified that FPL would likely begin to receive the grant money during the 2010-2011 timeframe. FPL asserted it would use the grant money on projects it had not planned on doing in the areas of transmission, distribution, and home area networks. The grant would also allow FPL to install smart meters in the industrial class, which was not something that was a part of FPL's original rate forecast. Witness Santos testified that the grant money, when received, would be applied like a contribution in aid of construction. The money would reduce the future plant in service balance.

SFHHA stated that the receipt of the grant for Smart Grid would allow FPL to realize extra savings, and therefore we should reduce rate base by $20 million. SFHHA also argued that the stimulus act has allowed FPL to accumulate an additional $884 million dollars in tax benefits.

SFHHA witness Kollen testified that revenue requirement should be reduced by at least $20 million. The witness further testified that the grants and other savings associated with the receipt of the grant should be used to reduce revenue requirement. Witness Kollen testified that the Company should defer the amount of the grant and the associated depreciation and use the grant money, when received, to reduce the account by the amount of the grant.

We find that the Smart Grid Investment Grant will allow FPL to accelerate investment in smart grid technology. The investment is in incremental projects and not projects that are being recovered through rate base. Since FPL proposes to use the grant like a CIAC contribution, it will not receive any return now, or in the future, on any money received from the grant.

Customers will receive the benefits of having smart meters and a smarter infrastructure, affording them more information on their usage. As we discussed above, implementation of smart grid technology will have significant cost savings to FPL customers. In recognition of the cost savings that will be realized by FPL, we direct FPL to bring us a program to help customers use AMI to reduce energy consumption. Accordingly, we make no adjustments to the 2010 test year for this issue. We note that we addressed the affects of any accumulated tax benefit and any adjustment for bonus depreciation previously in this order.

Income Tax Expense

FPL originally proposed an income tax expense of $243,338,000 for the 2010 projected test year. However, due to a number of subsequent adjustments, FPL proposed an updated 2010 jurisdictional projected income tax expense of $248,680,000. FPL asserted that after accounting for the adjustments in Exhibits 358, 481, 511, and 514, the projected income tax expense for 2010 is appropriate. Each of the intervening parties suggested adjustments based on their recommendations in other issues.

The income tax expense is a result of other adjustments we made in this Order. Reductions to expenses we made increase the income tax expense based on the statutory income tax rate of 38.575 percent. Based on our decisions above, the requested total income tax expense of $243,338,000 shall be increased by $223,207,072 resulting in an adjusted total income tax expense of $466,545,072, and is shown on Schedule 3 attached to this Order.

Projected Net Operating Income

A determination of the appropriate net operating income for the projected test year is a culmination of our other decisions in this Order. Based on our decisions in this Order, the appropriate net operating income is $1,070,179,348 for the 2010 projected test year, and is shown on Schedule 3 to this Order.

## REVENUE REQUIREMENTS

Revenue expansion factors

FPL stated that the appropriate projected 2010 revenue expansion factor was 1.63411 (1.63342 per original filing). According to FPL, the elements and rates were shown on MFR C-44, and then adjusted by Exhibit 358. OPC proposed that the appropriate net operating income multiplier for the 2010 test year was 1.630911.

We agree with FPL's bad debt rate adjustments in Exhibit 358. These adjustments increase the bad debt rate from 0.260 percent to 0.302 percent for 2010. We find that the Company's calculations are correct and that the appropriate revenue expansion factors and the appropriate net operating income multipliers are 61.195 percent and 1.63411, respectively, for the 2010 projected test year. The appropriate elements and rates are shown on Schedules 4 attached to this Order.

Annual operating revenue increase

Our decision on the annual operating revenue increase is a culmination of our decisions in this Order. Based on our decisions, the appropriate annual operating revenue increase is 75,470,948 for the 2010 projected test year and is shown in Schedule 5, attached to this Order.

## COST OF SERVICE AND RATE DESIGN

Revenue Calculations

Consistent with our decision to revise FPL's forecast of billing determinants, we have recalculated the revenue at current rates for 2010.

Minimum Distribution Cost Methodology

The issue of the classification of distribution costs was raised by SFHHA witness Baron. Distribution costs are composed of both demand and customer related costs. Distribution demand related costs are allocated to classes based on the class's non-coincident peak demand (NCP) and customer related costs are allocated on the basis of number of customers. How distribution costs are classified between demand and energy can impact how costs are allocated and how much distribution cost is recovered from each class.

Witness Baron noted that FPL has followed our historical practice of classifying all costs in Account 364, Poles, Towers and Fixtures, as demand related and allocated to rate schedules on the basis of rate class NCP demand. Witness Baron argued that this proposed classification results in too little of the distribution facilities costs, such as poles and transformers, being allocated to the residential and small commercial classes and leads to commercial and industrial customers paying too much for facilities that do not benefit them.

Witness Baron proposed to classify more of the distribution costs as customer-related, by establishing a Minimum Distribution System (MDS) construct. He noted that the MDS approach is particularly justified in the current environment because of the number of vacant residential dwellings that have little or no demand and therefore are not allocated any distribution costs using a non-coincident peak demand (NCP) allocator. The primary reason for adopting the MDS classification approach is that it recognizes, to some extent, there is a minimum cost to interconnect a customer to the system and that accordingly, it is appropriate to allocate costs associated with primary and secondary lines and transformers on a customer basis as opposed to a demand basis.

FPL witness Ender stated in his rebuttal testimony that the MDS system presumes a type of electric system and a method of planning that does not reflect how FPL designs its distribution system. He asserted that the zero or minimum load requirements of customers is purely fictitious because no utility builds to serve zero load. Witness Ender argued that the MDS approach shifts all benefits obtained from economies of scale to large customers, even though there are similar economies of scale in serving residential load. For example, he explained, the diversity of load inherent in residential use allows the addition of new customers without the need for new poles or transformers. No such diversity is applicable to commercial customers who require a single pole and transformer. Witness Ender also contended that the MDS methodology double counts the kW load for smaller customers because residential and small commercial load would first be assigned the assumed minimum distribution costs, and would then be assigned additional costs based on their non-coincident Peak (NCP) demand, with no adjustment for the costs already assigned under the MDS. FPL also argued in its Brief that use of the MDS methodology would drastically increase the amount of distribution plant costs allocated to residential and very small commercial customers.

We have consistently rejected the MDS methodology on numerous occasions in the past. The most recent discussion on MDS took place in the 2001 Gulf Power Company rate proceeding. In that docket, we found that:

> [Gulf Witness] Mr. O'Sheasy describes MDS as identifying the costs of the facilities needed to simply hook-up a customer to the power system. Yet, distribution lines must be connected to subtransmission and transmission lines and ultimately to the busbar at the power plant in order to be able to deliver a single kWh. To artificially separate distribution accounts on the basis that these facilities are necessary to make service available ignores the way the electric system works. MDS is internally inconsistent in that it separates out distribution facilities for different treatment than transmission lines. As cited in the order in Gulf's last rate case:
>
>> There is a fundamental flaw in this proposal in that only part of the distribution system is classified as customer-related. None of the subtransmission and transmission system would be classified as customer-related. Hence, customers served at primary voltage through dedicated substations, and customers served at higher voltages would not pay for any of this network path.
>>
>> We believe this minimum distribution system approach should be rejected because it is inequitable and inconsistent to apply the concept to only those customers served at secondary voltage or at primary voltage through common substations when the network path must be there to serve each and every customer.
>>
>> In our opinion distribution facilities that function as service drops or dedicated tap lines should be directly assigned the classes whose members the facilities serve. No distribution costs other than service drops and meters should be classified as customer related.[73]

[73] Order No. PSC-02-0787-FOF-EI, issued June 10, 2002, in Docket No. 010949-EI, In re: Request for Rate Increase by Gulf Power Company, p. 64

In FPL's 1981 rate case we found:

> The Company and the Commission Staff have proposed the use of a theoretical minimum distribution system as part of the customer charge. We believe the appropriate customer charge should be based only upon the cost of the meter, service drop, meter reading and basic customer service costs.[74]

We affirmed that position in FPL's 1982 rate case and again in Tampa Electric's 1982 rate case. The FPL order states:

> FIPUG contended that the concept of the minimum distribution system should be recognized in a cost of service study. However, in recent rate cases, we have not approved use of the minimum distribution system in classifying costs and no evidence was presented in this case to persuade us to depart from this policy.[75]

The 1982 Tampa Electric Company order states:

> In designing rates we have selected the Staff Requested Cost of Service Study (Exhibit 22-D) using the 12 CP and weighted one thirteenth average demand allocation methodology. The major philosophical differences between the Staff Requested Study and the Company's 12 CP and average cost of service study are that the Staff Requested study does not recognize the concept of the minimum distribution system, allocates the uncollectible expense to all customer classes on the basis of revenues and classifies conservation costs as energy rather than customer related. The Staff's treatment of all three of these items is correct.[76]

We again addressed the MDS methodology in Florida Power Corporation's (PEF) 1982 rate case:

> FIPUG contended that the Commission should select a cost of service study for use in designing rates that recognized the concept of the minimum distribution system. In the last four electric utility rate cases, we have determined that only the meter and service drop portion of the distribution system are properly classified as customer related. The evidence presented by FIPUG has not persuaded us to change our minds. For this reason, we selected a Staff Requested cost of service study which does not recognize the minimum distribution system concept for use in this proceeding.[77]

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[74] Order No. 10306, issued September 23, 1981, in Docket No. 810002-EU, <u>In re: Petition of Florida Power & Light Company for authority to increase its rates and Charges, p. 43.</u>

[75] Order No. 11437, issued December 22, 1982, in Docket No. 820097-EU, <u>In re: Petition of Florida Power and Light Company to increase its rates and charges, p. 43.</u>

[76] Order No. 11307, issued November 10, 1982, in Docket No. 820007, <u>In re: Petition of Tampa Electric Company for an increase in rates and charges,</u> p. 36.

[77] Order No. 11628, issued February 17, 1983, in Docket No. 820100-EU, <u>In re: Petition of Florida Power Corporation to increase its rates and charges,</u> p.35-6.

In Tampa Electric Company's 1980 rate case, we noted that our staff and the company had proposed a theoretical minimum distribution cost as part of the customer cost. We found:

> While we agree that sound regulatory practice should provide for a customer charge to defray otherwise fixed costs, as proposed by the Company and the staff, we do not agree that a theoretical cost of a minimum distribution system is appropriate. . . . The installation of the distribution system is made in anticipation of a projected level of actual use. The system does not contain a basic theoretical minimum distribution system. Reliance on such a mechanism is speculative at best. Instead, we believe the appropriate customer charge should be based upon the cost of the meter, service drop, meter reading and basic customer services costs (not including uncollectibles).[78]

In a Florida Power Corporation (now PEF) case in 1980, we stated:

> The company has proposed increases in the level of the customer charges in all rate classifications. As in previous cases (Orders 9599 and 9628), we feel that the distribution costs which should be included in the customer charges consist of those related to distribution from the pole to the customer's structure.[79]

SFHHA also pointed out that the MDS methodology requires that assumptions be made, for each FERC account, on the minimum size of a particular component that would be required to serve customers without respect to the ultimate level of demand. Witness Baron provided no objective criteria for determining which costs should be classified as customer related as opposed to demand related. In Order No. PSC-02-0787-FOF-EI we stated:

> We find that the simpler, more straightforward approach of allocating only service drops and meters on a customer basis adequately captures the distribution investment that is solely required to extend service to a new customer. This methodology is clear, generally accepted, and requires no series of hypothetical cost and system design calculations that do not reflect how the actual system is designed. . . .
>
> For the reasons provided above, we find that the treatment of distribution costs shall remain consistent with our past decisions, and accordingly, only Accounts 369 and 370 shall be classified as customer related.[80]

While we have approved an MDS approach for a Rural Electric Cooperative, that order contains specific conditions inherent in the Cooperative's customer base that makes the use of

[78] Order No. 9599, issued October 17, 1980, in Docket No. 800011-EU, In re: Petition of Tampa Electric Company for an increase in its rates and charges, p. 18

[79] Order No. 9864, issued March 11, 1981, in Docket No. 800119-EU, In re: Petition of Florida Power Corporation for authority to increase its rates and charges, p. 31.

[80] Order No. PSC-02-0787-FOF-EI, p. 66

MDS appropriate for that utility.[81] Witness Baron was unable to state conclusively that the conditions precedent to our decision in Docket No. 020357-EC were present in the FPL rate case. Therefore, it is not appropriate to rely upon that order to justify using the MDS methodology for FPL. Witness Baron also relied on five orders from other states to support the use of the MDS. While he maintained that he had personal knowledge of the use of MDS by these five utilities, nothing in the orders provided described the use of MDS or why the respective utility Commissions believed the MDS approach was appropriate. We will not rely on such unverified representations and incomplete information about conditions found in utilities in other states to make a decision for a Florida utility.

We have a long history of limiting the costs that are allocated on a customer basis and recovered through the customer charge. As pointed out by FPL witness Ender, FPL plans and constructs its distribution system based on expected load, not customers served. The number and size of poles and transformers is driven by the size of the load to be served, whether for commercial or residential customers. In addition, the MDS requires value judgments to be made on an account by account basis for several FERC accounts in order to arrive at the distribution costs to be assigned on a customer basis. This introduces an unnecessary element of discretion and judgment into the cost allocation process. Witness Baron has not presented any convincing evidence on either the calculation of MDS costs, or the appropriateness of using the MDS approach, that justifies this change to our longstanding policy.

We do not adopt the proposed minimum distribution system to classify Account 364 costs on a customer basis. Distribution costs shall continue to be allocated to rate classes using the methodology proposed by FPL.

Cost of Service Methodology

The purpose of a cost of service study is to form a cost basis for establishing revenue requirements for each rate class. The cost of service is a matter of judgment, and there is no one correct cost allocation methodology. While the 12 CP and 1/13 methodology has been the dominant methodology in the past, we have also approved different methodologies. Most recently, in the Tampa Electric Company rate case, we approved the 12 CP and 25 percent energy methodology.[82] That method increased the proportion of production demand costs that are allocated on energy from eight percent to 25 percent. Other than the treatment of St. Lucie Unit 2, FPL has not proposed to change its cost of service methodology. FPL witness Ender testified that FPL made a judgment call and believed that the right methodology for this case is the 12 CP and 1/13 methodology because it is consistent with the manner in which FPL plans its generation system. The 12 CP and 1/13 method recognizes that both energy and peak demand influence the type of generation unit that is added. The method also recognizes that FPL must meet the peak demands for every month.

[81] Order No. PSC-02-1169-TRF-EC, issued August 9, 2002, in Docket No. 020357-EC, In re: Petition for Modifications of Electric Rate Schedules by Choctawhatchee Electric Cooperative.
[82] Order No. PCS-09-0283-FOF-EI, issued April 30, 2009, in Docket No. 080317-EI, In re: Petition for rate increase by Tampa Electric Company.

SFHHA Witness Baron testified that a more reasonable cost of service study for FPL is a method based on a summer CP methodology. Under the summer CP methodology, cost of production plant would be allocated among FPL's rate classes according to their contribution to the summer coincident peak. The summer CP methodology is only taking one hour in the summer as the basis for allocating costs. In cross-examination of witness Ender, SFHHA established that the coincident peaks in the months of June, July, August, and September were higher than the coincident peaks in any other months in 2005, 2006, 2007, and 2008. Witness Ender also agreed that the forecasted summer coincident peaks on FPL's system for 2009, 2010, and 2011 will be higher than the coincident peaks in any other months of the year. Witness Ender added, however, that the summer coincident peaks are higher, but only slightly so in some cases.

FIPUG Witness Pollock testified that while FPL is a summer peaking utility and experiences its tightest margins during the summer months, we have adopted the 12 CP and 1/13 in past cases, and it should not be replaced with another method that places greater emphasis on energy usage. Witness Pollock stated that should the Commission decide to replace the 12 CP and 1/13 method, it should adopt the Average and Excess (A&E) method because it recognizes the dual functionality of generating plants. Some plant is required for year-round operation, i.e., average demand, and the remaining plant is required for cycling, i.e., excess demand. Under the A&E method 59 percent of production and transmission plant would be allocated on average demand. The remaining costs, or the excess demand component, would be allocated to rate classes based on the difference between the class maximum demand and their average demand. Witness Ender rejected the A&E method, stating that class maximum demand is rarely coincident with the peak demand on the system, and the use of this non-coincident demand to allocate production and transmission plant is inconsistent with FPL's generation plan.

In his rebuttal testimony, witness Ender testified that the 12 CP and 1/3 methodology accurately reflects FPL's generation plan because it (1) it recognizes that the type of generation unit is influenced by both energy and peak demand; (2) it reflects the influence of the summer reserve margin; and (3) it recognizes that capacity must be available throughout the year to meet FPL's winter reserve margin and the annual loss-of-load probability criteria.

Witness Ender also testified that while the summer reserve margin criterion of 20 percent currently drives FPL's need for new resources, we should not accept SFHHA's proposed use of the summer CP methodology for the following reasons: (1) the summer CP method is inconsistent with FPL's generation planning process; (2) the summer CP allocation does not send a better price signal than the 12 CP and 1/13 methodology; and (3) the summer CP method would allocate no production costs to two rate classes even though all rate classes receive the benefit of FPL's generation capacity. The two classes that would not be allocated any productions costs are the OL-1 (outdoor lighting) and SL-1 (street lighting) rate classes. That is because generally in the summer the peak occurs during the daylight hours and the lights are not on, and therefore those classes make no contribution to production costs. If no costs are allocated to the OL-1 and SL-1 rate classes, those costs would be allocated to the other classes. Witness Ender added that the reason the 12 CP and 1/13 method was approved was because it provided some cost responsibility to all rate classes.

Witness Ender explained that SFHHA's proposed use of the summer CP allocation method would shift costs away from the medium and large commercial rate classes, onto residential and small commercial classes. Witness Ender explained that the use of the summer CP method does not recognize the energy component of the energy usage, and as a result, it would shift costs over to the higher demand customers like residential and general service, which are small commercial customers. Witness Ender also stated that witness Baron represents customers that are in rate classes that would receive a fairly significant reduction in cost allocations as a result of witness Baron's proposed methodology.

We find that the appropriate cost of service methodology for production and transmission plant, including St. Lucie Unit 2, is the 12 CP and 1/13 methodology. Both witness Baron and witness Ender made persuasive arguments regarding the appropriate cost of service methodology. However, based on the review of the evidence, we are of the opinion that the record more strongly supports FPL's continued use of the 12 CP and 1/13 methodology, as it more appropriately reflects FPL's generation plan, and recognizes both demand and energy in allocation costs to all rate classes.

Revenue Requirement Allocations

This section addresses the allocation of any revenue increase to the various rate classes. Rate classes are groups of individual rate schedules with similar billing attributes and rate design relationships, so they are treated for rate design purposes on a combined basis.[83] FPL, FIPUG, and SFHHA disagreed on whether any increase to a particular rate class should be limited to no more than 1.5 times, or 150 percent, the system average. When a rate increase limit is imposed on a rate class, the remaining classes will have to absorb that difference. Gradualism is a concept that is applied to prevent a class from receiving an overly-large rate increase.

FPL set the target revenues by rate class in order to obtain parity among the classes to the greatest extent possible without limiting any rate classes' increase to 1.5 times the system average. A rate class is at parity if it is earning the same as the system retail rate of return. FPL witness Ender testified that FPL's current rates were set over 20 years ago in FPL's last fully litigated rate case, Docket No. 830465-EI, and since that time customer rates have been adjusted several times without regard to parity levels. FPL witness Deaton stated that FPL's proposal provides an opportunity to address inequities between the rate classes at a time when overall bills are projected to decrease for most customers in 2010, with moderate increases in 2011. Bills on average will decrease in 2010 as a result of a reduction in fuel costs and increased efficiencies in FPL's system. Witness Deaton further testified that taking a more gradual approach and not moving to parity to the fullest extent practicable now would result in the continued subsidization of certain rate classes by others. Witness Deaton stated that for a number of years, medium and large commercial and industrial customers have benefited from a subsidy by residential and small commercial customers. Larger commercial/industrial rate classes are below parity and need to be brought up to parity in order to carry their fair share of the cost. Finally, Witness Deaton testified that the larger commercial/industrial customers are heavier energy users. They

[83] For example, time-of-use rate schedules are combined with their non-time-of-use counterparts.

will see larger benefits in the fuel savings, and should therefore pay their fair share of the production costs that produce those benefits.

To support its position, FPL relied on two previous decisions in which we did not limit the increase to 1.5 times the system average. First, FPL stated that in the 1982 Gulf Power Company (Gulf) rate case, we departed from the policy to limit the increase to any one class to no more than 1.5 times the system average.[84] In the Gulf order we stated; "were we to apply that policy in this case, some classes whose present rates of return are above parity, would receive an increase. Thus, the greater equity lies in allocating the increase to those classes with substantially lower rates of return." In 1982, Gulf had six rate classes, and the Residential (RS) and Outdoor Service (OS) rate classes were below parity, while the four commercial rate classes were well above parity. The Commission divided the revenue increase between the RS and OS rate class.

The second order FPL relied on involved a recent Peoples Gas System (PGS) rate case.[85] In that decision, we allowed increases to rate classes greater than 150 percent of the system average. We are of the opinion that the PGS case presented unique circumstances, and different considerations go into setting gas rates. In our view, the PGS case does not provide a reasonable basis to support FPL's position.

Witness Deaton also referenced the 1981 FPL rate case order in her rebuttal testimony. In that order we ruled that no customer class shall receive a revenue increase greater than 1.5 times system average increase.[86] Witness Deaton argued, however, that in that order we indicated that this guideline was designed to mitigate the impact on customers' bills, and not out of some general principle of slowly moving towards parity and allowing cross-subsidization to continue.

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

We agree with Witness Pollock that cost recovery clauses can have a positive or negative impact on bills, and FPL's projection of a decrease in fuel prices for 2010 is not a valid reason to not apply the concept of gradualism. Upon cross examination, Witness Deaton agreed that fuel is volatile. Furthermore, FPL does not know what fuel prices will be in 2011. Witness Deaton testified that FPL does not know, for example, if there might not be some fuel disruption, and a consequent spike in fuel prices that could amount to an increase in the total bill. Conversely,

[84] Order No. 10557, issued February 1, 1982, in Docket No. 810136-EU, In re: Petition for Gulf Power Company for an increase in its rates and charges.
[85] Order No. PSC-09-0411-FOF-GU, issued June 9, 2009, in Docket No. 080318-GU, In re: Petition for rate increase by Peoples Gas System.
[86] Order No. 10306, issued September 23, 1981, in Docket No. 810002-EU, In re: Petition of Florida Power & Light Company for authority to increase its rates and charges.

FPL does not know if there will be further fuel reductions. Furthermore, approximately 70 to 80 percent of FPL's fuel costs reflect natural gas prices, and natural gas prices are volatile. While Witness Deaton testified that fuel prices will not go up as much as they would have, absent efficiency savings that FPL is making on its system, Witness Deaton also stated fuel prices vary from period to period.

SFHHA Witness Baron testified FPL has not implemented any material measure of gradualism or mitigation in assigning increases to the rate schedule. Witness Baron stated that under FPL's proposed increases, some commercial rate schedules will receive increases of 50 percent to 60 percent. Witness Baron rejected FPL's position that prior rate case settlements and other factors have limited our full consideration of cost of service and rate parity. Witness Baron testified that each case rests on its own merits, and FPL agreed to past rates that were a result of a settlement. Witness Baron stated that FPL's position seems to be that the prior settlements produced unjust rates and therefore in this case it is necessary to fix the problem and address those past mistakes.

From our review of our prior decisions, it is clear that we have discretion in whether to apply the 1.5 limit in this case. While it is true that we did not apply this limit in the 1982 Gulf rate case, in more recent electric rate cases we have decided that no class should receive an increase greater than 1.5 times the system average.[87] FPL, FIPUG, and SFHHA raised valid arguments in support of their positions. We are persuaded by FIPUG's and SFHHA's testimony that fuel costs are volatile and could increase in the future, thus raising overall bills again. The timing of FPL's rate case filing could have also happened during a period of increasing fuel costs.

Consistent with our decisions in more recent electric rate cases, we find that in this case no class shall receive an increase greater than 1.5 times the system average percentage increase in total, i.e., with adjustment clauses, and no class should receive a decrease. When calculating the percentage increase, FPL shall use the approved 2010 adjustment clause factors.

Service Charges

Initial Connect

The initial establishment of service charge is collected to cover the cost for the work required to connect a location to FPL's infrastructure. FPL's current rate for the initial connection of service is $14.88, and the proposed rate is $100.00. A cost study was completed to evaluate the cost the company incurs for this service. The cost established was $135.95. FPL Witness Santos stated that a service charge of $100 is a reasonable charge, based on the work required for the initial connect/disconnect activity. In its brief and during cross examination of FPL witness Santos, the AG, raised concerns with this higher charge for initial connect. Upon

[87] Order No. 080317-EI, issued April 30, 2009, in Docket No. 080317-EI, In re: Petition for rate increase by Tampa Electric Company; Order No. PSC-08-0327-FOF-EI, issued May 19, 2008, in Docket No. 070304-EI, In re: Petition for rate increase by Florida Public Utilities Company; Order No. PCS-02-0787-FO-EI, issued June 10, 2002, in Docket No. 010949, In re: Request for rate increase by Gulf Power Company.

consideration we find that it is appropriate at this time to keep the current charge of $14.88 for initial connection of service in place

Field Collection

The field collection charge is added to a customer's bill for electric service when a field visit is made and payment is collected on a delinquent account. If the service is disconnected, or a current receipt of payment is shown at the time of the field visit, no charge would be applied. FPL's current rate for the field collection charge is $5.11 and the proposed rate is $19.00. Upon consideration we find that it is appropriate at this time to keep the current charge of $5.11 in place.

Reconnect for Non-Payment

The reconnection charge covers FPL's cost of reconnection of service after disconnection for nonpayment or violation of a rule or regulation. FPL's current rate for the reconnect for non-payment service charge is $17.66, and the proposed rate is $48.00. The proposed rate was set at cost of service. We find, however, upon consideration, that it is appropriate at this time to keep the current charge of $17.66 in place.

Connection of an Existing Account

The connection of an existing account charge is collected to cover the costs the company incurs to establish a new account at a location already established on FPL's infrastructure. This cost also includes the customer's subsequent disconnect of service. FPL's current rate for Non-payment Reconnect is $14.88 and the proposed rate is $21.00. The proposed rate was set at cost of service. We find, however, upon consideration, that it is appropriate to keep the current charge of $14.88 in place at this time.

Returned Payment

A returned payment charge is collected when a check or draft is not honored by the bank on which it was drawn. Currently FPL charges $23.24 or 5% of the amount of payment, whichever is greater. FPL's proposed charge would comply with Florida Statute 68.065, which specifies a tiered fee structure based on the returned payment amount:

$25 if payment amount is less than or equal to $50;

$30 if payment amount exceeds $50 but is less than or equal to $300;

$40 if payment amount exceeds $300 or 5% of the amount, whichever is greater

FPL stated that it had a 20 percent increase in returned payments from 2007 to 2008. FPL incurs additional costs when a check is returned. Customers who cause the utility to incur additional costs should be responsible for paying those costs. With these new rates, FPL hoped to create a stronger deterrent and help minimize the number of returned items received. We find, however, upon consideration, that it is appropriate to keep the current charge of $23.24 or 5% of the amount of payment, whichever is greater, in effect at this time.

In consideration of current difficult economic conditions, we find it appropriate to leave FPL's service charges unchanged.

Late Payment Charge

FPL asked to establish a minimum late payment charge that it argued would provide the appropriate incentive for customers to improve payment behavior. FPL currently charges 1.5 percent for late payments, but proposed the greater of 1.5 percent or $10. FPL stated that it had seen a steady increase in the number of customers making late payments, which it believed was driven largely by the deteriorating economy. The percent of customers with late payments increased from 21% in 2006 to 24% in 2008. This amounts to an increase of 150,000 customers on average per month. FPL argued that other industries use late payment charges greater than $10 to encourage customers to pay on time. FPL stated that the other Florida utilities that currently charge a fee similar to what FPL proposed are the City of Miramar Utilities, which charges a $15 fee, and the Lee County Electric Cooperative, which charges a $10 fee for residential customers. FPL argued that $5 would not be sufficient to encourage good payment behavior. FPL did state in its brief, however, that if we did not accept its position with respect to the new fee's effect on revenues, FPL would withdraw its late payment charge proposal. Since we did not accept FPL's position with respect to the new fee's effect on revenues, FPL has in effect withdrawn its request. Accordingly, FPL's request to establish a $10.00 late payment fee shall be denied.

Termination Factors

FPL's proposed termination factors are applied to customers taking service on the PL-1 or RL-1 rate schedule who chose monthly payments rather than a lump sum payment, and who then terminate their lighting agreement prior to the expiration of their 10 or 20 year contract period. The RL-1 rate schedule is a closed schedule, and not available to new customers. As stated in the Company's tariff sheet MFR E-14, Sixth Revised Sheet No. 8.722, and Second Revised Sheet No. 8.745, in order to terminate service the customer must provide a 90-day written notification to the company of their intent to cease service. The amount a customer pays to terminate their contract is computed by applying the termination factor to the installed cost of the facilities, based on the year in which the agreement is terminated. The company proposed to remove the 10-year and 20-year payment options from the PL-1 and RL-1 tariff, which is addressed in stipulated Issue 153.

We have reviewed the FPL's calculations and we find that the proposed termination factors are appropriate and we approve them.

Present Value Revenue Requirement

The Present Value Revenue Requirement (PVRR) multiplier is designed to produce an estimate of the cumulative cost of the project over its useful life. Under FPL's PL-1 and RL-1 lighting tariffs, FPL provides FPL-owned facilities, and the customer requesting those facilities is required to pay FPL for the facilities in a lump sum payment. The amount is the Company's total work order cost for the facilities times the PVRR multiplier. FPL provided the calculations and assumptions used to determine the PVRR in response to our staff's discovery requests.

We have reviewed FPL's calculations, and we find that the calculations used to determine the PVRR are appropriate. We approve the charges FPL has proposed.

Relamping Option

FPL currently offers a relamping option for Street Lighting (SL-1) and Outdoor Lighting (OL-1) customers who own their own lights and poles. Relamping only covers changing out light bulbs that need to be replaced. It does not cover any other maintenance or repair. As of March 2009, there were 244 accounts with fixtures covered by the current relamping option. These customers would be grandfathered in under FPL's proposed change.

FPL proposed to remove the relamping option for new customers on the Street Lighting (SL-1) and Outdoor Lighting (OL-1) tariffs. FPL argued that this change would clarify maintenance responsibilities, and eliminate potential customer dissatisfaction. FPL claimed that customers choosing this option often believe that FPL is responsible for all maintenance instead of just relamping. FPL did not provide any details on the number or frequency of customer complaints. The relamping option is the only service option available to customers who own their fixtures. If the relamping option is closed to new customers, customers who own their own units will have to secure another means for relamping their units. FPL has not proposed to change the service options for customers who lease lighting fixtures from the utility.[88]

We deny FPL's proposal to close the relamping option on the Street Lighting (SL-1) and Outdoor Lighting (OL-1) tariffs for new street light installations. Eliminating the relamping option would shift this burden to customers who may not have other readily available options for relamping. If the only issue is customer confusion over the utility's responsibility, that can be remedied by providing customers with a more detailed description of FPL's maintenance responsibilities.

Transformation Rider

Pursuant to FPL's Transformation Rider, if customers install their own transformers, FPL provides a monthly credit per kilowatt (kW) of billing demand to recognize the avoided cost. FPL proposed to revise the monthly credit from \$0.39 to \$0.32 per kW for 2010, and to \$0.33 per kW for 2011. The credit is based on distribution secondary transformer costs as calculated in the cost of service study. The underlying assumptions and supporting calculations FPL used to develop the monthly credits are appropriate.

[88] FPL Retail Tariffs, Sheet Nos. 8.715 and 8.725.

We find that the monthly kW credit to be provided customers who own their own transformers pursuant to the Transformation Rider proposed by FPL is appropriate and we approve it.

Monthly Fixed Carrying Charge Rate

FPL's tariff provides that the Company may, at its option, provide and maintain transformers and other facilities which are required by the customer beyond the point of delivery or which are needed because the customer requires unusual facilities due to the nature of the customer's equipment.

The customer may elect to make either a lump sum payment or pay a monthly maintenance charge. FPL proposed to revise the monthly charge from 28 percent to 27 percent of the agreed installed cost of the transformers and other facilities per year. This annual facility rental charge is calculated based on the following percentage charges: adjusted return on capital, distribution maintenance, general and administrative, customer account and service, depreciation, insurance, and property taxes. These percentages total the annual facility rental charge of 27 percent.

We reviewed the assumptions used to calculate the annual facility rental charge and we them appropriate. We find, therefore, that the proposed monthly fixed charge carrying rate to be applied to the installed cost of customer-requested distribution equipment for which there are no tariffed charges shall be approved.

Monthly Rental Factor

FPL proposed to change the distribution substation facilities monthly rental factor from 1.62 percent to 1.83 percent. The monthly rental factor is applied to the in-place value of customer-rented distribution substations to determine the monthly rental fee for the facilities. This monthly rental factor is calculated based on the following percentage charges: levelized annual distribution substation factor, distribution substation maintenance factor, general and administrative factor, customer account and service factor, insurance, and property taxes. Together the percentages total the annual distribution substation rental charge. The charge is then divided by twelve to get the monthly rental factor of 1.83%.

We have reviewed the assumptions used to calculate the monthly rental factor, we find that they are appropriate, and we approve them.

Termination Factors

The long-term rental agreement for distribution substation facilities provides for a 20-year initial term. If the customer elects to terminate the agreement during the initial term, the customer is responsible for a termination fee. The termination fee is calculated by applying the termination factors to the in-place value of the facilities based on the year in which the agreement is terminated. FPL proposed to revise those termination factors.

FPL explained that the termination fee is calculated by taking the present value of what the customer would have paid on a non-levelized basis up to the point of termination and subtracting the present value of what the customer has already paid up to that date on a levelized basis. Interest is applied to this amount using the weighted average cost of capital. At twenty years, the termination factor goes to zero.

We have reviewed the methodology used to calculate the termination factors and we find that it is appropriate. Therefore, we approve the proposed factors.

High Load Factor Time of Use Rates

The High Load Factor Time of Use (HLFT) rates were approved in the 2005 Settlement Order.[89] The Stipulation approved in that case states that the HLFT rates are designed to achieve a break-even point at a 65 percent load factor.[90] FPL has proposed no changes to the rate structure for this class, other than an increase in revenue requirements. FPL has provided the calculations underlying the HLFT rate design, showing the breakeven point is now targeted at 70 percent. The method used to design the rate is consistent with general ratemaking principles. The customer charge reflects the weighted cost of meters, drops and customer service for the class. The on-peak demand charge recovers the costs of production, transmission and one-half of the distribution costs allocated to the class. The maximum demand charge recovers the remainder of the distribution costs. The off-peak energy charge reflects the energy unit cost from the cost of service study and the on-peak energy charge collects the remainder of the class revenue requirement.

In its brief, FIPUG argued that the proposed HLFT rates would make the HLFT rate more expensive than GSLDT, unless the customer can achieve load factors above 84 percent for HLFT-2, and over 100 percent for HLFT-3, which is impractical. FIPUG recommended that the HLFT rate be designed for customers with load factors above 70 percent. FIPUG witness Pollock maintains that the HLFT rates are a derivative of the GSLDT rates and that it is essential to maintain a consistent relationship between GSLDT and HLFT to prevent customer migration.

FIPUG did not cite the source of the data used to arrive at the numbers presented in its Brief that support its contention that the proposed HLFT factor would result in higher rates for customers than the corresponding GSD rate except at unrealistically high load factors. Neither did FIPUG cite to any calculations to show that the HLFT rates are not designed for customers with load factors of 70 percent or higher, as FPL witness Deaton stated. Therefore, we are unable to verify FIPUG's assertions.

MFR Schedule E-13C presents the proposed billing determinants and rates for each rate class. Using the billing determinants (kwh and kW demand), the actual load factor for all three HLFT classes is approximately 80 percent. Given that the HLFT is an optional rate, and assuming that customers make intelligent choices about which rate is most cost effective for

[89] Order No. PSC-05-0902-S-EI, issued September 14, 2005, in Docket No. 050045-EI, In re: Petition for rate increase by Florida Power & Light Company.
[90] Order No. PSC-05-0902-S-EI, p. 11

them, these numbers support FPL's contention that the rate is appropriately designed for customers with load factors of at least 70 percent.

Witness Pollock is correct that FPL used the demand costs allocated to the GSD, GSLD-1, GSLD-2 and GSLD-3 (collectively GSD) rate classes to derive the demand charges for the HLFT rates. This is appropriate because the capacity needed to serve the HLFT customers is identical to the capacity needed to serve the corresponding GSD classes. Unless the HLFT customer also takes service under a separate tariff, the Commercial Demand Reduction Rider (CDR), that customer is considered a firm customer, just like other GSD customers. The HLFT rates offer lower energy charges to recognize the higher load factor of customers in that class.

Witness Pollock argued that the energy and demand charges should be the unit charge from the Cost of Service Study The HLFT rates more closely mirror the rate design proposed by FIPUG in that the on-peak demand charge is higher, and the energy charges lower, than the corresponding GSD rates. As we state in our discussion of the overall methodology for designing time-of-use rates below, we find that the methodology used by FPL properly matches costs to rates, keeping in mind rate shock and the impact on both high and low load factor customers within a class.

As stated above, FPL witness Deaton stated that the HLFT rate was designed at a 70 percent load factor. This is consistent with the proposal approved in FPL's 2005 rate case. FIPUG presented no documentation or calculations demonstrating that the HLFT rate was not designed as FPL asserted it was. Further, FIPUG presented no support for the numbers shown in its Brief, where it alleged that the proposed design would result in HLFT rates higher than the GSD rates except at unrealistically high load factors. We will address FIPUG's remaining arguments on the design of time-of-use rates in general, including the appropriate method for setting energy and demand charges, in the Rates and Charges section below. Here we find that FPL's methodology used to design the HLFT rate is appropriate.

Commercial Industrial Load Control Rate

FPL's Commercial Industrial Load Control (CILC) program is a demand side management program. Unlike similar programs for PEF and TECO, the revenue requirement used to set the CILC base rates is reduced to recognize the costs avoided by the ability to interrupt CILC load.[91] There is no separate credit. In response to the Public Utility Regulatory Policies Act of 1978 (PURPA), we opened a generic docket on the feasibility of implementing load management techniques by electric utilities. In that docket, we cited the PURPA definition of load management as "any technique (other than a time-of-day or seasonal rate) to reduce the maximum kilowatt demand on the electric utility, including ripple or radio control mechanisms, or other types of interruptible service, energy storage devices and load limiting devices."[92] In that order, we stated that a load management technique shall be cost-effective if the long run cost

[91] Interruptible rates for Progress Energy Florida (Docket No. 090079-EI) and Tampa Electric Company (Docket No. 080317-EI) have a base rate set on fully allocated cost, with a separate credit applied to load subject to interruption.
[92] Order No. 8951-A, issued September 7, 1979, in Docket No. 790594-EI, In re: General Investigation of the feasibility of implementing load management techniques by the electric companies, p. 1

savings to the utility of such reductions are likely to exceed the long run costs to the utility associated with the implementation such techniques.[93]

Commission Order No. 18259 approving the initial trial CILC program approved credits on each monthly bill to reflect a reduction in the utility's coincident peak demand sufficient to avoid construction of a new generating unit.[94] That order goes on to explain that the credit would be based on the cost of the utility's next avoided generation unit.[95]

FPL modified the per-KW credit approach used in the original CILC pilot when it requested approval of a permanent CILC program. The rate was restructured from a flat dollar credit per KW to a design that set charges to reflect the different types of costs incurred to provide service. The base demand charge was divided into three components: maximum demand charge; firm on-peak demand charge; and load control on-peak charge (transmission). The permanent tariff using this rate structure was approved by Order No. 22747.[96] Certain non-rate provisions of the proposed permanent CILC rate schedule were protested and then resolved by Order No. 23709 in that docket.

Maximum demand charge The maximum demand charge consists of distribution costs. Consistent with the method used to design other demand rates, the distribution costs are allocated to the class based on non-coincident KW demand because the distribution system must support the customer's maximum demand whenever it occurs.

On-peak demand charge Consistent with all other rate classes, the on-peak demand charge is derived by dividing the demand costs allocated to the class by the firm coincident on-peak demand. Any individual CILC customer may choose to operate on peak, and FPL must provide capacity to meet that demand. Therefore, it is appropriate for customers using firm capacity on-peak to pay a proportionate share of those demand costs. The on-peak charge consists of costs associated with production and transmission costs, and is assessed only to KW demand which occurs during the on-peak period. This charge can be avoided by operating off-peak.

Load control on-peak charge. The load control on-peak demand charge recovers the allocated cost of transmission divided by the KW load subject to load control. Order 18259 noted that transmission costs are not likely to be reduced by scattered CILC load reductions. As a result, CILC customers pay a transmission charge on the total demand subject to load control.[97] Without this charge, CILC customers who operate only off-peak would pay nothing for the transmission investment necessary to serve them.

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[93] Order 8951-A, p. 2

[94] Order No. 18259, issued October 7, 1987, in Docket No. 861403-EG, In re: Petition of Florida Power and Light Company for Authority to Implement a Trial Commercial/Industrial Load Control Project, p1.

[95] Order No. 18259, p. 1.

[96] Order No. 22747, issued March 28, 1990, in Docket No. 891045, In re: Petition of Florida Power & Light Company for approval of a permanent Commercial/Industrial Load Control program eligible for energy conservation cost recovery.

[97] Order No. 18259, p. 3

All of the components shown on the CILC rate schedule are described in Order No. 22747, and reflect the cost incurred to provide service to CILC customers, based on their usage characteristics. There is no specific credit listed in the tariff; instead the total revenue used to design rates is reduced by the avoided cost, and the resulting rates reflect the cost for the type of service provided. As a result, the CILC customer is only paying for the services he uses.

FPL has continued to calculate the components of the CILC rate according to the method approved in Order 22747. The rates shown on MFR Schedule E-14, page 26 of 37, are consistent with the costs shown in MFR Schedule E-6b, unit costs for each rate schedule using the requested revenue requirements and Cost of Service Methodology. The total cost of providing service to the CILC class is $101,734,000 as shown in MFR Schedule E-1, Attachment 2, page 1. From that total allocated cost, FPL subtracted the avoided cost savings of ($19,670,000), which is collected through the Energy Conservation Cost Recovery Clause from all customers. Base rates were then designed on a revenue requirement of $82,064,000.

It is not clear how FIPUG witness Pollock derives the numbers used in his testimony to allege that there is a subsidy embedded in the CILC rate. However, it appears that the subsidy he alleges is simply the result of the increase in the base rate costs properly assigned to the class, based on its usage characteristics. The $30.6 million difference, which witness Pollock calls an improper subsidy, results from the base rate portion of the bill increasing while the avoided cost offset has not. Witness Pollock appears to assume that the avoided cost savings must increase by the same amount as the base rates, thus maintaining the relationship between the credit amount and the total class revenue requirement. There is no provision in the CILC rate design that requires this symmetry. The savings attributable to the CILC program are based on avoided costs. Witness Deaton noted that avoided costs will be reviewed in the Demand Side Management (DSM) proceedings. If avoided costs, or savings, attributable to the CILC program are increased in another proceeding, that will reduce the revenue requirements used to determine the CILC rates, and rates will correspondingly be reduced.[98] Until the amount of the avoided costs attributable to CILC load changes, however, reducing rates below the approved cost of service is not appropriate.

We find that FPL has properly calculated the CILC base rates, in accordance with our Order No. 22747.

Commercial/Industrial Demand Reduction Rider Credit

The Commercial/Industrial Demand Reduction Rider (CDR) credit is available to commercial or industrial customers eligible to participate in this optional load management program offered by FPL. The CDR program was first proposed by FPL in 1999 as part of its demand-side management plan to meet the numeric conservation goals we set for FPL in Order No. PSC-99-1942-FOF-EG. The proposed program included a monthly credit of $4.75 per kW based upon the difference between firm demand and total demand. We approved the CDR

[98] Specific credits for load management programs will be addressed in the implementation phase of Docket No. 080407-EQ, Commission review of numeric conservation goals (Florida Power& Light).

program on May 8, 2000.[99] We again approved the program, including the CDR credit of $4.75 per kW, in 2004 when FPL submitted the conservation plans it was proposing to meet the goals we set in Docket No. PSC-04-0029-EG.[100] The CDR was subsequently reduced to $4.68 per kW when Gross Receipt Taxes previously embedded in base rates were removed as a result of the 2005 Settlement Order.[101]

FIPUG witness Pollock testified that the CDR credit should be increased from $4.68 to $5.50 per kW to reflect the increased cost of new generation and transmission capacity. The costs for new generation and transmission capacity are reflected in FPL's most recent Ten Year Site Plan. In its brief, FIPUG stated that FPL is projecting significant growth in non-firm load and that this load has been and is projected to be a valuable resource to FPL to serve firm load customers when needed. Witness Pollock explained that he arrived at the $5.50 figure by looking at FPL's avoided cost in their standard offer filing which showed a capacity need in 2021, projected the revenue requirements from that study, and then discounted those requirements back to the period of 2010 to 2012.

We note that FPL is required to submit estimates of the cost-effectiveness of any existing, new, or modified demand-side conservation programs per our Rule 25-17.0021(4)(j), F.A.C., Goals for Electric Utilities. Our Rule 25-17.008(3), F.A.C., prescribes the cost-effectiveness tests that must be performed by referencing the "Florida Public Service Commission Cost Effectiveness Manual For Demand Side Management Programs and Self-Service Wheeling Proposals" This manual requires three tests: (1) RIM test, (2) Participant test, and (3) Total Resource Costs test. None of these tests have been performed as part of this docket. They will be performed for all programs FPL submits to meet the new numeric conservation goals which are being set in Docket No. 080407-EG. FPL is required to submit any existing, new or modified programs it has designed to meet our approved goals. At that time, we will review the cost-effectiveness of the program, including costs and credits to customers such as the CDR credit. The CDR rider will receive a thorough review and evaluation of its cost-effectiveness then.

Customer participation in this demand reduction program is entirely voluntary. FPL is not seeking any changes to the CDR credit in this docket. The appropriate amount for the CDR credit can be addressed at the program implementation phase in the numeric conservation goals docket.[102] We set new numeric goals for FPL on December 2, 2009.[103] FPL is required to file programs designed to meet the goals we approved within 90 days following the final goals order, in accordance with Section 366.82(7), F.S., and Rule 25-17.0021(4), F.A.C.

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[99] Order No. PSC-00-0915-PAA-EG, issued May 8, 2000, in Docket No. 991788-EG, In re: Approval of Demand-Side Management Plan of Florida Power & Light Company.
[100] Order No. PSC-06-0025-FOF-EG, issued January 10, 2006, in Docket No. 040029, In re: Petition for approval of numeric conservation goals by Florida Power & Light Company.
[101] Order No. PSC-05-0902-S-EI, issued September 14, 2005, in Docket No. 050045-EI, In re: Petition for rate increase by Florida Power & Light Company.
[102] Docket No. 080407-EG, In re: Commission review of numeric conservation goals (Florida Power & Light Company).
[103] Order No. PSC-09-0855-FOF-EG, issued on December 30, 2009, in Docket Nos. 080407-EQ – 080413-EG, In re: Commission review of numeric conservation goals.

Time of Use Rate Design

We first addressed time-of-use rates in 1978 when, under the requirements of PURPA, the Commission evaluated the standard relating to Peak Load Pricing. Order No. 9523 stated that the main purpose of peak load pricing is to promote economic efficiency.[104] In Order No. 9661, we ordered all investor-owned electric utilities to offer an optional time-of-use rate to all customers.[105] That order further set forth uniform definitions for on- and off-peak billing periods, establishing the two period rating still used today. It states that average incremental costs during on-peak and off-peak hours are used to allocated average fuel costs between on and off-peak periods and the system annual load factor is used to allocated demand cost components to on-peak and off-peak rating periods.

FPL has calculated demand rates based on demand costs as proposed in the Cost of Service Study. It proposed to use the same demand charge for both the standard rate and the corresponding time-of-use rate, with the time-of-use rate demand rate only applying to demand occurring in the on-peak period. Customers pay no demand charge for demand occurring in off-peak periods. The composite per unit demand cost for the General Service Demand classes is shown at $11.95, as noted by FIPUG witness Pollock. However, FPL then adjusts this number to arrive at different demand charges for each rate class. The proposed demand charges for each class are shown in MFR Schedule E-13C. Based on MFR Schedule E-14, Attachment 2 of 3, page 10 of 37, the unit cost was reduced by $2.00 across the board for all rate classes. FPL then made further adjustments to each class for what appears to be the decreasing proportion of distribution costs allocated the large classes, with the GSLDT-3 receiving the largest adjustment to reflect that this class is transmission level only.

We acknowledge witness Pollock's position that demand charges should reflect demand costs and energy charges should reflect energy costs. However, consideration of rate stability and rate shock are also important considerations in rate design. Increases in the demand charge impact low load factor customers to a greater extent than high load factor customers because they are less able to offset the higher demand costs with lower energy costs and are thus less able to affect their total bill. FPL's demand rates have not changed significantly in over twenty years and increasing demand charges to unit costs in one step might be too drastic and could disproportionately affect low load factor customers. For these reasons we agree with the method used by FPL to set demand rates for the GSD classes.

The purpose of time-of-use rates is to encourage customers to use capacity during off-peak hours. The differential between the on- and off-peak energy charge should establish a meaningful pricing signal. For all but the largest GSD class (GSLDT-3) FPL has reduced the differential between on- and off-peak rates, compared to existing rates. FPL began its calculations of the energy charge with the energy unit cost from the Cost of Service Study.

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[104] Order No. 9385, issued May 20, 1980, in Docket Nos. 790793-EU, In re: Show Cause order to electric utilities concerning peak load pricing for general service customers, and 790859-EU, In re: General investigation into electric rate structures to see whether they tend to promote the conservation of energy.

[105] Order No. 9661, issued November 26, 1980, in Docket Nos. 790793-EU, In re: Show Cause order to electric utilities concerning peak load pricing for general service customers, and 790859-EU, In re: General investigation into electric rate structures to see whether they tend to promote the conservation of energy.

From there, FPL adjusted the unit cost, using the class average on- and off-peak kWh ratios and establishing a break even rate with the otherwise applicable flat rate.

Similar to the design of the demand rates, FPL started with the energy unit cost for the class as described above, adjusting the calculated per kWh costs for both demand and energy. The end result is a reduction in the on-peak to off-peak ratio compared to existing rates. This makes time-of-use rates less advantageous to both customers and FPL. The customer saves less by shifting load to off-peak periods and loses less by operating during peak periods. If less load is shifted, any conservation impacts of reduced on peak demand of a time-of-use rate are diminished.

FPL failed to adequately explain how it arrived at the new rates, and has not provided adequate support for decreasing the differential between on- and off-peak energy rates. In Docket No. 910890-EI, we approved a formula for calculating time-of-use energy rates that sets the off-peak rate at the average system energy component from the cost of service study. In addition, in that order we stated that the on-peak charge will then be the result of a break even calculation with the standard rate, based on the class's (or combined classes') on-peak and off-peak energy consumption.[106] There is no evidence in this docket on what the impact would be to apply the strict formula used in the 910890-EI docket. However, it is reasonable, as a proxy, to maintain the current differential between on- and off-peak ratios to prevent unexpected impacts on existing time-of-use customers who have adapted their usage to this ratio. This results in differentials close to those advocated by FIPUG. Reducing the differential could negate investments in energy efficiency measures designed to move load off peak.

AFFIRM represents a coalition of quick-serve restaurants that have substantially similar electrical usage characteristics. Affirm Witness Klepper stated that AFFIRM members are economically disadvantaged because the pricing alternatives currently available to them do not reflect the economies of scale to FPL that result from the load characteristics of AFFIRM members. AFFIRM witness Klepper stated that AFFIRM members have a limited ability to respond to price signals because of the limited rate options available to them. Witness Klepper also noted that most of AFFIRM's members operate during system peak periods but use disproportionately lesser amounts of energy during FPL's defined on-peak periods and a disproportionately greater amount of energy during FPL's defined off-peak periods, compared to other commercial and industrial customers. FPL's Witness Deaton stated that, contrary to AFFIRM's contention that its customers are limited to the GSD and GSDT rate schedules, FPL offers many options, such as the high load factor time-of-use rate that may be beneficial. Witness Deaton contended that AFFIRM's members may not have adequately explored the options available to them, prior to requesting that FPL design a new rate.

AFFIRM did not propose a specific rate design; nor was there any discussion of the impacts on other customers of offering a new rate designed as AFFIRM would desire. In order to design a new rate FPL would need to identify the types of customers to be targeted, and determine what the specific load and cost characteristics of the proposed new sub-group of

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[106] Order No. PSC 92-1198-FOF-EI, issued October 22, 1992, in Docket No. 910890-EI, In re: Petition for a Rate Increase by Florida Power Corporation.

customers would be. Assuming that existing customers would leave existing classes to take advantage of any new rate, FPL would also have to estimate the impact on existing rate classes (migration). None of that information was presented in this docket. As a result, we cannot design a specific new rate as AFFIRM has requested. Witness Deaton did state that FPL is willing to work with AFFIRM, or any of its customers to explore the benefits of the existing HLFT rates. We direct FPL to work with AFFIRM and its members to explore other options, such as multi-period pricing, which would address at least some of AFFIRM's concerns. This is consistent with the federal legislation cited by AFFIRM it is Brief.

We find that FPL's design of the time-of-use demand charges is appropriate. We direct FPL to design the energy charges to maintain the current ratio between on- and off-peak energy charges, in order to maintain the current incentive to use energy off peak. We also find that there is insufficient evidence in this docket to require FPL to design a new time-of-use rate for commercial customers. We direct FPL to work with AFFIRM, and any other parties who wish to participate, to design a new time-of-use option to address the concerns raised by AFFIRM, and report back to us no later than August 1, 2010, on the progress of such discussions.

Prepayment Option

This matter arose from customer testimony presented at the Ft. Myers service hearing. FPL witness Santos testified that during that hearing several customers were interested in a prepayment plan. The customers wished to pay an estimated yearly amount of their electric bill a year early, and receive a discount from FPL based on FPL's cost of capital. The customers would then in turn borrow money to pay their electric bills at a low cost to them, and thus save money.

Witness Santos testified that FPL has formed a team to evaluate the proposal. Witness Santos explained that FPL is willing to evaluate the proposal and come back to us early next year with the results of its evaluation. Witness Santos stated that FPL has to be certain that none of its other customers are jeopardized by the prepayment plan option, and it needs to establish what the appropriate discount rate is. Further, FPL may have to change its billing system to accommodate the prepayment plan. Witness Santos stated the FPL would report back to us by the second quarter of 2010.

In its brief, OPC stated that FPL should be required to provide a study evaluating the merits of a prepayment option in lieu of monthly billing within a month of the agenda conferences in this case. The concept of a prepayment plan first surfaced at the Ft. Myers service hearing, which took place on June 19, 2009. OPC stated that while FPL has created a team to look at the issue, FPL has not done much else and that this Commission should require more.

Witness Santos also stated that, prior to the Ft. Myers service hearing, a customer had communicated with FPL regarding a pre-payment plan. We agree that FPL has had time to evaluate the proposal, and therefore we direct FPL to provide a study to us evaluating the merits of a prepayment option in lieu of monthly billing no later than March 1, 2010.

We would expect that any prepayment option would be codified as a tariff, similar to the budget billing option. If the initial study results in a proposed tariff, the tariff would be brought before us for approval under normal tariff procedure, and parties could participate in the Agenda Conference at which the tariff would be discussed. If the study does not result in a proposed tariff, the study itself shall be brought before us to discuss what further actions, if any, are appropriate regarding this matter. We would expect that the study would be a collaborative effort involving all interested persons, who will have the opportunity to address the study when we consider it.

Nuclear Uprates

In Order No. PSC-09-0783-FOF-EI, issued on November 19, 2009, we approved FPL's Nuclear Cost Recovery Clause amounts for 2010.[107] All costs that FPL removed from its base rate revenue requirements were allowed in the NCRC for 2010. We approve FPL's proposal to transfer revenue, expenses and investments associated with nuclear uprates from base rates to the NCRC for the 2010 projected test year.

LED Street Lighting

This issue arose from testimony at the Plantation service hearing Lauderhill Mayor Richard Kaplan testified that his city received an energy block grant fund of $595,200 from the federal government to reduce energy consumption. Federal regulations governing use of the funds place a high priority on replacing conventional street lights with LED lights. Under FPL's existing tariff, however, the city would continue to pay the same rate even if it replaced existing lights with LED lights. According to Mayor Kaplan, energy usage can be reduced from 40 percent to 60 percent through the use of LED street lighting. Mayor Kaplan asked that we address the issue because of the difficulty he encountered trying to work with FPL on conservation programs.

FPL indicated that In March 2009, it installed LED street lights at its headquarters as a pilot program. FPL witness Spoor testified that it is his understanding that the energy consumption of the LED lights is less than the traditional light that is offered presently. Witness Spoor stated that LED lights are a newer technology, and that is why FPL is piloting them in the corporate parking lot. He testified that FPL will have to run the pilot for a year to understand everything about the technology. According to witness Spoor, FPL is studying how LED lights will function in high humidity, lightning, and rain.

There seems to be no dispute on this issue other than when FPL should be required to provide us a report on its pilot project. FPL stated in its brief that FPL would file the results of the pilot program by June 1, 2010. OPC stated in its brief that FPL should be required to provide a study by March 1, 2010. Since the City of Lauderhill and possibly other cities have an opportunity to save energy usage with LED lights, we agree that FPL should provide the study in a timely fashion, but we also believe that FPL should be given adequate time to fully analyze the

[107] Order No. PSC-09-0783-FOF-EI, issued on November 19, 2009, in Docket No. 090009-EI, In re: Nuclear cost recovery clause.

performance of the LED lights. Therefore, we will establish the due date for submission of FPL's study of April 1, 2010. We will review the results of the study and determine what further actions, if any, FPL shall take on this matter.

## RATES AND CHARGES

This section of our Order addresses the rates issues we considered at our January 29, 2010, rates Agenda Conference.

Based on the decisions we made at our January 13, 2010, revenue requirements Agenda, FPL filed a compliance cost of service study on January 18, 2010. The compliance cost of service study establishes the revenue requirement for each rate class, and final rates and charges.

As explained earlier, the appropriate method to allocate any revenue increase to the various rate classes, after recognizing any additional revenues realized in other operating revenues, is to track, to the extent practical, each class's revenue deficiency as determined from the approved cost of service study, and move the classes to parity as practicable. No rate class shall receive an increase greater than 1.5 times the system average percentage increase in total, and no class shall receive a decrease. The allocation of the rate increase is shown in Schedule 6. The current and approved rates and charges for all rate classes are shown in Schedule 7, pages 1 through 19.

Several interim steps are necessary to establish the allocation of the rate increase by rate class. First, FPL calculated present class operating revenues and the increase at parity. The increase at parity represents that target revenue requirements deficiency, i.e., the increase necessary to bring revenues from that rate class to the system rate of return. This is a calculation to establish a baseline for allocation of the increase to individual classes. The cost of service indicates that certain rate classes are currently earning above the system rate of return and should therefore be entitled to a revenue reduction. However, consistent with our decision that no class shall receive a decrease, FPL adjusted the increase needed to achieve parity for the other rate classes by this calculated revenue reduction of $58 million. This process establishes the initial revenue increase for each class. This initial increase must then be adjusted to account for the percentage increase limitation we have approved. The average system percentage increase is 0.8 percent. Consistent with our decision that no rate class shall receive an increase greater than 1.5 times the system average percentage increase in total, each class's percentage increase was limited to 1.2 percent (0.8% x 1.5 = 1.2%). The final revenue requirements by rate class are derived through an iterative process which repeatedly reallocates dollars so that all three constraints (movement towards parity, no decreases, and no increase greater than 1.5 percent of system average) are maximized. The percentage increase for all rate classes is shown in column 11 of Schedule 6.

The final step is to translate the class revenue requirement into actual rates. The revenue requirement for each rate class is first reduced by the customer charge revenues. Customer charges are set at the customer unit cost as derived from the cost of service study. The initial demand and energy charges are based on unit costs, and then adjusted to meet target group revenues and revenue neutrality with the time-of-use option.

As mentioned previously, we denied FPL's proposed increase in its service charges, and therefore no additional revenues are achieved from service charges. We did approve a stipulation to approve an increase in the temporary service charges. That increase is reflected in the $222,000 total increase shown in column 5 of Schedule 6, and represents the only increase in service charge revenues.

Residential bill impacts.

Schedule 8 contains a calculation of FPL's 1,000 kilowatt-hours (kWh) monthly residential bill at both present and approved rates. As a result of this rate case, a residential customer who uses 1,000 kWh per month will see a $1.03 increase in the monthly bill. We note that in January 2010, the residential 1,000 kWh bill decreased by $15.29 primarily as a result of lower fuel costs. In addition, customers received a one-time refund on the electric bill in January 2010 as a result of our decision in the fuel docket.[108] The one-time refund for a residential customer using 1,000 kWhs was $44.46.

Schedule 8 also shows bill impacts at various other residential consumption levels. The amount of the increase decreases with increasing consumption levels. FPL's residential rates typically have been inverted rates with a one cent differential. That rate design has been in place since the 1970s. Inverted rates are set at a level to produce the same revenues as under a flat rate design while maintaining the one cent differential. In May 2007, FPL's base rates increased as a result of the Generation Base Rate Adjustment (GBRA) associated with the commercial operation of Turkey Point Unit 5. Pursuant to the 2005 Settlement Order, the GBRA was to be implemented by adjusting base rates by an equal percentage. Turkey Point Unit 5 resulted in a 3.271 percent GBRA factor. Applying the GBRA factor to FPL's residential energy charges resulted in the second tier energy charge to be more than one cent higher than the first tier energy charge. As shown on page 1 of Schedule 7, FPL has proposed to revert back to the one cent inversion, consistent with our original approved design. To achieve the residential target revenues, the resulting second tier energy charge is lower than the current energy charge, reducing the impact on large residential users.

The revised rates shall be effective for meter readings taken on or after March 1, 2010.

Customer Charges

Customer charges are flat fees assessed each month, regardless of the amount of energy (kilowatt hours) used. Utilities typically design and levy customer charges to recover specific accounts associated with meter reading, metering equipment, customer service, and bill processing. Customer charges differ by rate class, depending on the class of customer and the types of equipment used to provide service.

[108] Order No. PSC-09-0795-FOF-EI, issued December 2, 2009, in Docket No. 090001-EI, In re: Fuel and purchased power cost recovery clause with generating performance incentive factor.

The appropriate customer charges are shown in Schedule 7. We grant our staff the authority to administratively approve the tariffs filed to implement the rates, charges, and credits presented in Schedule 7.

Demand and Energy Charges

In this section of the Order we address the appropriate methodology to design the demand and energy charges, as well as the appropriate final demand and energy charges. Since the demand and energy charges are set in combination to produce the class revenue requirements, we will discuss the methodology for both charges here.

FIPUG took issue with the way in which FPL calculated the demand and energy charges. Specifically, witness Pollock asserted that all demand related costs should be recovered through the demand charge and only energy related costs should be recovered through the energy charge. He asserted that FPL has underpriced the demand charge and overpriced the energy charge for both standard and time-of-use rates.

FPL Witness Deaton stated that following a strict unit rate for demand charges as proposed by Witness Pollock would distort the relationships between the general service demand classes, and make it difficult to achieve target revenue while maintaining time-of-use design goals and principals. Witness Deaton further stated that FPL made limited adjustments to the general service demand rates to maintain the appropriate relationships between rate schedules within the general service demand classes. Adjustments were also made to the energy charges for the purposes of meeting target revenue levels by rate class.

We agree with witness Pollock that demand charges should reflect demand costs and energy charges should reflect energy costs to the greatest extent possible. We must also consider rate stability and rate shock, however, in our decisions regarding rate design. Increases in the demand charge affect low load factor customers to a greater extent than high load factor customers, because they are less able to offset the higher demand costs with lower energy costs, and are thus less able to affect their total bill. FPL's demand rates have not changed significantly in over twenty years. Increasing demand charges to recover the full demand allocated costs could disproportionately affect low load factor customers.

We find that FPL's method of limited adjustments to the demand and energy unit cost to maintain the appropriate relationship between rate schedules is reasonable. We approve the demand charges shown in Schedule 7. We approve the energy charges also shown in Schedule 7. The energy charges were set at a level that, in combination with the remaining rate components, will result in the recovery of the total revenues allocated to each rate class.

Lighting Rate Charges

We approve the appropriate lighting rate charges shown in Schedule 7.

Standby and Supplemental Services (SST-1) Rate Schedule

We approve the charges under the SST-1 rate schedule as shown in Schedule 7. The charges are calculated consistent with our Order No. 17159, issued February 6, 1987, in Docket No. 850673-EU, In re: Generic Investigation of Standby Rates for Electric Utilities.

Interruptible Standby and Supplemental Services (ISST-1) Rate Schedule

We approve the charges under the ISST-1 rate schedule as shown in Schedule 7. The rates are calculated consistent with Commission Order No. 17159, issued February 6, 1987, in Docket No. 850673-EU, In re: Generic Investigation of Standby Rates for Electric Utilities.

Based on the foregoing, it is

ORDERED by the Florida Public Service Commission that Florida Power & Light Company's Petition for Rate Increase is hereby granted in part and denied in part as set forth more specifically in this Order. It is further

ORDERED that each of the findings and directives made in the body of this Order are hereby approved in every respect. It is further

ORDERED that all matters contained in the appendix, attachments, and schedules appended hereto are incorporated herein by reference. It is further

ORDERED that the revised rates and charges shall become effective for meter readings made on or after March 1, 2010. It is further

ORDERED that Florida Power & Light Company shall file, within 90 days after the date of the Final Order in this docket, a description of all entries or adjustments to its annual report, earnings surveillance reports, and books and records that will be required as a result of the findings made in this docket. It is further

ORDERED that upon expiration of the period for appeal these dockets shall be closed.

By ORDER of the Florida Public Service Commission this 17th day of March, 2010.

ANN COLE
Commission Clerk

( S E A L )

LCB

CONCURRENCE AND DISSENT BY: CHAIRMAN ARGENZIANO

CONCURRENCE BY: COMMISSIONER SKOP

DISSENTS BY: COMMISSIONER EDGAR
COMMISSIONER KLEMENT

CHAIRMAN ARGENZIANO, concurring in part and dissenting in part:

I concur with the decisions of the majority with respect to Generation Base Rate Adjustment (GBRA), Corrective Reserve Measures, and Return on Equity (ROE), and dissent with respect to the Equity Ratio and the Appropriate Equity Ratio for Ratemaking Purposes.

I. Generation Base Rate Adjustment (GBRA)

Use of a Generation Base Rate Adjustment (GBRA) mechanism in this case would be gross error, because (1) the mechanism has been crudely transplanted to an inappropriate context; (2) use of GBRA removes important factors from the regulatory calculus that can lower recovery amounts in the future; and (3) it would trigger a sea-change in the Commission's procedure in rate cases without any guarantee of administrative cost advantage. Future Commissions should approach requests for GBRA or GBRA-like mechanisms with skepticism.

FPL has attempted to apply GBRA to an inappropriate context in an effort to create a power-plant cost recovery clause in disguise. Originally, GBRA was an element of a settlement agreement. The settlement agreement provided that FPL's retail base rates and base rate structure would be frozen for four years; no petition for any new surcharges to recover costs traditionally recovered in base rates would be permitted; there would be a revenue sharing plan between FPL and its customers; and other components. The GBRA mechanism was a modification of the freeze on base rates, and was created to allow FPL to recover cost plus profit for plants for which the Commission had approved a need determination and which would be placed in service during the period covered by the settlement agreement. GBRA should not be expanded beyond its original context.

GBRA would set recovery amounts for new plants at the peak of a utility's revenue requirement.[109] After setting the rate of recovery at the accounting high-tide line, GBRA removes important factors from the regulatory calculus that can lower the necessary recovery level on a forward basis. For instance, under GBRA ratepayers would no longer receive a corresponding benefit from FPL's declining costs from depreciation, effects of plant retirements, increased sales, and productivity improvements.[110] These same reasons were recognized when the Commission rejected TECO's proposal for a GBRA-like mechanism in a case earlier this year.[111] In that case the Commission noted that it would be inappropriate to consider "the cost of constructing new transmission facilities in isolation, without considering potential increases in revenues from additional sales or decreases in rate base due to retirements or depreciation that may offset the impact of construction costs."[112] The same reasoning applies today.

Adopting GBRA would constitute a sea-change in the Commission's approach without lowering administrative costs. While avoiding administrative costs is a valid goal, FPL failed to demonstrate that the cost of conducting a rate proceeding would outweigh potential reductions resulting from declines in rate base.[113] Moreover, certain benefits that the current procedure provides to *all* interested parties—examining a utility's entire cost of service to determine whether reductions in rate base may offset capital additions,[114] the level of detail provided, and the time available to make a decision on an important issue[115]—are unavailing under GBRA. Adopting GBRA would also change the relationship between interest groups: as witness Kollen noted, "[GBRA] provides the Company an almost unfettered ability to automatically impose base rate increases to recover selective increases in certain costs without consideration of

[109] TR 3115.

[110] EXH 485; TR 4268-4269.

[111] Order No. PSC-09-0283-FOF-EI, issued April 30, 2009, in Docket No. 080317-EI, In re: Petition for rate increase by Tampa Electric Co.

[112] Id. at 127.

[113] TR 1266.

[114] TR 3731.

[115] The time period required for a traditional rate case proceeding differs from that required for need determination proceedings that the GBRA mechanism would utilize. Rate cases generally take at least eight months to complete and include five months devoted to discovery, in accordance with section 366.06, Florida Statutes (2009). Need determination proceedings, by contrast, must be completed within 135 days from the date a petition is filed. § 403.519(4), Fla. Stat. (2009).

increases in revenues and reductions in other costs."[116] In other words, current procedure sets the table with dishes equally before all interest groups, but GBRA would offer certain dishes exclusively to a utility company.

I suggest that future commissions approach requests for GBRA or GBRA-like mechanisms with skepticism. FPL already collects about 61% of its total costs through various "pass-through" mechanisms and cost-recovery clauses.[117] Fuel costs, environmental costs, conservation costs, and certain preconstruction costs for nuclear units are dealt with outside the base rate mechanism. The Commission authorized fuel cost recovery charges because the volatility in prices made the costs ill-suited for inclusion in base rates; for other costs, the legislature directed the Commission to permit recovery through special clauses. While there are often benefits to breaking decisions down into more manageable bites, at some point this can degenerate into piecemeal policy where regulators are buried in a series of discordant facts with no way to assess the system as a whole and allow all interested parties the chance to discuss the larger picture. Rate cases, for all their trouble, do provide an opportunity for assessment giving a clearer and more complete picture than a series of preordered recoveries.

II. Corrective Reserve Measures

FPL has over-collected depreciation expense by roughly $1.2 billion dollars. After applying a portion of that reserve surplus to offset unrecovered costs associated with capital recovery schedules, the Commission was left with $894 million dollars in depreciation reserve. The Commission, by unanimous vote, has correctly weighed the relevant factors,[118] and decided to amortize the entire $894 million dollar surplus over four years, in keeping with Commission policy regarding amortization as quickly as possible consistent with utility impact.

III. Return on Equity (ROE)

Federal Power Commission v. Hope Natural Gas Company, 320 U.S. 591 (1944) and Bluefield Water Works & Improvement Company v. Public Service Commission of West Virginia, 262 U.S. 679 (1923) set forth the standards for determining the rate of return for regulated enterprises. The authorized return for a public utility should be (1) commensurate with returns on investment in other companies of comparable risk, (2) sufficient to maintain the financial integrity of the company, and (3) sufficient to maintain its ability to attract capital under reasonable terms. Id. The Commission was presented with conflicting evidence regarding the

[116] TR 3732.

[117] TR 2421.

[118] There are three factors the Commission considers when deciding how to correct a depreciation reserve imbalance: (1) the size of the intergenerational inequity (the greater the inequity the more compelling the need to address the imbalance over a shorter period); (2) the state of the ratepayers and the impact the proposed remedy would have on them (current state of the economy, ability to absorb costs, etcetera); and (3) the state of the company and the impact the proposed remedy would have on them (will the company earn a fair return, would a rapid amortization adversely affect the company's financial integrity to a *significant* degree—one that would justify a departure from the Commission's precedent of rectifying reserve imbalances as quickly as possible).

proper rate of return for FPL. It is the Commission's prerogative to evaluate the evidence and accord whatever weight to the conflicting opinions it deems appropriate. United Tel. Co. of Fla. v. Mayo, 345 So. 2d 648, 654 (Fla. 1977); Shevin v. Yarborough, 274 So. 2d 505, 508-509 (Fla. 1973).

FPL's request for 12.5% ROE was exceedingly high when compared to returns on investment for other business undertakings with corresponding risks and uncertainties. I came to this conclusion because FPL is not a risky venture, because witness Woolridge's testimony was extremely creditable and more convincing than that of competing experts, and because FPL's "heightened risk" arguments were unconvincing. The evidence demonstrated that FPL's specific risk characteristics merit a lower point within the acceptable ranges of return on equity.

FPL is a monopoly earning a guaranteed profit by providing an essential service in an economic environment made virtually risk-free by legislative action. In fact, FPL already collects about 61% of its total costs through various "pass-through" mechanisms and cost-recovery clauses.[119] It runs essentially no risk for (i) costs related to storm events, per section 366.8260, Florida Statutes (2009); (ii) renewable energy undertakings, per section 366.91, Florida Statutes (2009); (iii) nuclear costs, per section 366.93, Florida Statutes (2009); (iv) recoveries for environmental compliance costs, per section 366.8295, Florida Statutes (2009); (v) conservation costs, per section 366.82, Florida Statutes (2009); (vi) fuel and capacity costs, per Commission orders.

Moreover, the reduction in risk from Florida's constructive regulatory environment is necessarily an element to consider when setting the return on equity for Florida firms. I would like to see this risk component reduced to a calculable formula, in order to more accurately adjust the returns of Florida firms when compared to returns on investment earned by comparable firms. I believe that the essentially risk free rate of treasury bills would serve as an appropriate comparator for the risk associated with the 60% of its costs which Florida utilities are guaranteed.[120]

The average authorized ROE by regulatory commissions across the country is 10.51%.[121] No state regulatory commission authorized an ROE of 12.5% from January 2009 to August 2009.[122] FPL filed for a 12.5% ROE and failed to make its case.

Dr. Avera was FPL's primary witness on the matter of ROE. Dr. Avera's non-utility proxy group was not helpful, in that setting the ROE is a utility-specific, factual determination. Bluefield Water Works & Improvement Co. v. Pub. Serv. Comm'n of West Virginia, 262 U.S.

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[119] TR 2421.

[120] See also Order No. PSC-09-0283-FOF-EI, issued April 30, 2009, in Docket No. 080317-EI, In re: Petition for rate increase by Tampa Electric Co. (Commissioner Argenziano, dissenting) (concluding that it is difficult to see what risk exists for the utility in the conduct of its operations).

[121] EXH 462.

[122] Id.

679, 692 (1923); United Tel. Co. v. Mayo, 345 So. 2d 648 (Fla. 1977). As witnesses Woolridge and Baudino stated, there are multiple reasons why a non-utility proxy group is an inappropriate comparison for FPL.[123]

Indeed, witness Avera could only justify FPL's requested 12.5% ROE under the discounted cash flow method through heavy reliance upon a non-utility proxy group. The average indicated returns of the non-utility proxy group—composed of companies like Walmart and Walgreens, none of which are vertically integrated, regulated monopoly businesses[124]—came in at 12.9-13.4%.[125] In contrast, witness Avera's utility proxy group had a range of 10.6-11.5%.[126]

More to the point, competing witnesses offered more persuasive testimony than witness Avera, and there were significant flaws in witness Avera's methodology for his utility proxy group. Of the experts testifying on the matter of ROE, I was most convinced by witness Woolridge. His demeanor was more natural and his replies on cross-examination more responsive and credible than those of witness Avera, and his explanations demonstrated a thoroughness and attention to detail. For example, witness Woolridge examined data and used three criteria to establish a proxy group similar to FPL for his discounted cash flow analysis. One criterion required that a company receive a minimum of 70% of its total revenues from electric utility operations.[127] This criterion is significant because it screens out disparate firms—either in product or service provided, or in the dimensions of unregulated portions of the business. Witness Baudino had a similar requirement for his proxy group: the companies must have generated at least 50% of their revenues from regulated electric operations. By comparison a number of firms within witness Avera's utility proxy group included companies with electric revenues as little as 10%, 4%, and 22% of total revenues.[128]

There were other flaws in witness Avera's methodology. For one, witness Avera ignored dividend growth rates, resulting in inflated ROE calculations. No satisfactory explanation was provided for this oversight. (Witness Avera was not inclined to this mistake, however, when testifying in other jurisdictions.)[129] Second, witness Avera relied exclusively on growth rates projected by Wall Street analysts and Value Line.[130] Such estimates are inflated and biased.[131]

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[123] TR 2623, 3254. Witness Baudino concluded that "using higher required returns from a group of unregulated companies is obviously unjustified, inflates FPL's required ROE, and should be rejected by the Commission." TR 2624.

[124] Witness Avera's non-utility group was composed of the 66 non-utility companies listed in Exhibit 138.

[125] TR 4424; EXH 138.

[126] EXH 136.

[127] TR 3201.

[128] TR 3253; EXH 220.

[129] TR 4512.

[130] TR 3255-56.

[131] TR 3255-59, 4510, 4512; EXH 493.

Third, witness Avera improperly included an adjustment for flotation costs.[132] This adjustment was not linked to any actual costs incurred.[133] Witness Baudino demonstrated that flotation costs are already included in current stock prices and that adding an adjustment amounts to a double recovery.[134]

A 10% ROE is sufficient to maintain the financial integrity of the company and its ability to attract capital under reasonable terms. Witness Lawton demonstrated that FPL will continue to demonstrate strong financial integrity consistent with a single-A rating.[135] In addition, FPL's high equity ratio allows it to continue to access the capital markets on favorable terms. The use of a more reasonable amount of debt leverage is indicated because currently FPL's equity ratio is too high and places an undeserved burden on ratepayers.

Besides the fact that FPL is not a risky venture and the testimony on balance supported 10% as the appropriate ROE for FPL, FPL's arguments for its "riskiness" were unconvincing. I address these arguments here so future Commissions need not:

a. FPL argues that it should receive a bump in its ROE because of "exemplary management." This is nonsense. FPL's management has a statutory duty to provide reliable service to customers. This duty does not change with the ROE approved by the Commission. Any insinuation otherwise—for instance, that FPL's management will not work as diligently and will oversee lower service quality without an added bump in ROE—is crass and an unfortunate reflection on management.

b. FPL's argument that it is entitled to a higher ROE because of its high reliance on nuclear generation is faulty. Accepting FPL's argument would allow a utility to deliberately take on energy production mechanisms that are perceived as risky in order to increase its ROE. Introducing this type of regulatory reward would inappropriately skew the decisions of utility companies. The status quo, where utilities rely upon a variety of methods of production and balance the overall risks of production in a portfolio of different methods, is preferable.[136] And the risk factor of reliance on nuclear generation is systemic to the industry and not unique to FPL, so investors' expectations regarding this factor have already been captured in the cost of equity models.[137]

c. FPL appears to take two positions with regard to Florida's growth. When the Commission has to make a need determination for new plants, Florida is booming and thousands

[132] TR 2622.

[133] TR 2630.

[134] TR 2360-31.

[135] EXH 254; TR 2300-01.

[136] Moreover, the logical extension of FPL's argument cuts against the position held by the company on other matters because it would give outside entities greater influence over a utility's portfolio standards. Cf. Fla. SB 1154, § 1 (2009) (attempting to set clean energy portfolio standards).

[137] TR 4752-86, 5474-82.

are demanding electricity. When the Commission has to set ROE, FPL faces increased risk because of a slowdown in customer growth, with a customer count now down to levels last seen in July 2007. The Florida population is not so flexible. Predicting energy demand in Florida may be slightly more difficult than in other areas because of a more itinerant population, but it is not the significant risk factor that FPL paints it to be.

d. FPL argues that Florida's geographical location and exposure to adverse weather events are firm-specific risk factors that require FPL's ROE be set higher than other comparable utilities. The guaranteed recovery of prudently incurred storm costs per section 366.8260, Florida Statutes, eliminates any such risk. FPL provided excellent returns during the 2004 and 2005 storm seasons, when there were seven hurricanes and approximately $1.8 billion dollars in costs to restore electric transmission and distribution. This demonstrates the vacuity of FPL's argument. Also, as noted by witness Avera, to the extent that cost recovery clauses are prevalent across the industry, this risk factor has already been included in the cost of equity estimates for utility proxy groups.[138]

IV. Equity Ratio and the Appropriate Equity Ratio for Ratemaking Purposes

I dissent from the decision of the majority on this issue. The Commission should not utilize the 59.6% equity ratio suggested by FPL for ratemaking purposes because it excessively and unreasonably burdens ratepayers; differs in kind from the appropriate capital structure of utilities in FPL's peer group; and allows FPL to subsidize the activities of FPL Groups' unregulated affiliates on the backs of Florida's ratepayers. The Commission should have used either the 53.5% ratio recommended by witness Baudino, or the 54.4% ratio suggested by witness Woolridge, when setting FPL's equity ratio for ratemaking purposes.

Equity costs more than debt. A higher proportion of equity in a utility's capital structure results in higher rates. Using more debt increases risk but also reduces the utility's costs and thus the amounts charged to ratepayers. FPL's equity ratio is excessive and unreasonable, and results in rates that are unnecessarily high.[139] A 59.6% equity ratio is not needed to support FPL's credit rating.[140] If a utility uses excessive equity financing, a regulatory authority may impute a more reasonable capital structure for ratemaking purposes. See In re Northern States Power Co., 416 N.W.2d 719, 724-727 (Minn. 1987) (reasoning that the petitioning utility had the burden of proving the proposed rate is fair and reasonable, and, as a component of the rate base, that the capital structure debt-equity allocation is fair and just; concluding that when, in the Commission's judgment, a petitioning utility has failed to establish the reasonableness of costs which it claims justifies a proposed rate increase, the Commission may impute a hypothetical

[138] TR 4437-38, 4760-61.

[139] TR 2610. Cf. In re Northern States Power Co., 416 N.W.2d 719, 724-727 (Minn. 1987) (quoting with approval the Minnesota Public Utility Commission's decision stating: "The excessive equity ratio proposed by [the utility] for ratemaking purposes places an unreasonable burden on . . . ratepayers through an unnecessarily high cost of capital. The Commission agrees . . . that if . . . management chooses to maintain a higher than needed cost of equity ratio, then the shareholders, not [the utility's] customers, should pay the increased cost of capital.").

[140] TR 2611-12.

capital structure that will afford an ultimate determination of a reasonable and just rate); see also Citizens Utilities Co. v. Idaho Pub. Utilities Comm'n, 112 Idaho 1061, 739 P.2d 360 (1987) (affirming the Commission's decision adopting a hypothetical capital structure for ratemaking purposes, and noting that one of the rationales for adopting a hypothetical capital structure is to counter the effect of an "equity-thick utility" so that a Commission can achieve a proper balance between the interests of the utility investor and the utility ratepayer); Carnegie Natural Gas Co. v. Pa. Pub. Util. Comm'n, 61 Pa. Commw. 436, 433 A.2d 938 (1981) (stating that "[w]here a utility's actual capital structure is too heavily weighted on either the debt or equity side, the commission, which is responsible for determining a capital structure which allocates the cost of debt and equity in their proper proportions, must make adjustments to the utility's capital structure").[141] The Commission should do so here.

FPL's 59.6% equity ratio differs in kind from the appropriate capital structure of utilities. Two separate experts evaluating different peer groups that they independently compiled for comparability to FPL agreed on this.[142] The average equity ratio for witness Woolridge's peer group was roughly 42%.[143] The average equity ratio for witness Baudino's peer group was 47.6%.[144] FPL proposes a 59.6% equity ratio. This difference is a hole plugged with 100 million dollars a year from the pockets of ratepayers.

FPL's 59.6% equity ratio subsidizes the activities of the unregulated affiliates of FPL Group. FPL Group Capital is highly leveraged yet maintains an "A" credit rating; FPL Group could not do this without FPL's excessively high equity ratio.[145] This is because FPL Group can offset the high risk of one of its entities with the lower risk of another.[146] FPL Group Capital is (1) highly leveraged,[147] and (2) owns FPL Energy, which has high risk operations that detract from FPL Group's credit.[148] FPL is the counterweight. Allowing FPL its excessive equity ratio exposes ratepayers to the risk of subsidizing FPL Group's unregulated activities.[149]

The consequence of the Commission's decision is to allow a utility to retire debt and shore up its capital structure prior to a rate case, anticipating that this alteration—based on

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[141] TR 3208.

[142] And a third expert, witness Pollock, agreed with them. Witness Pollock testified that FPL's equity ratio is much higher than the equity ratios of other electric utilities. TR 2961. In fact, at an equity ratio approaching 60 percent, FPL is one of the least leveraged regulated utilities in the nation. TR 2953-2954. He recommended that FPL's equity ratio be adjusted to put FPL in line with other electric utilities, and suggested a 50.2% equity ratio. TR 2961-2962.

[143] TR 3207.

[144] TR 2615.

[145] TR 2519.

[146] FPL Group's "A" credit rating is based on the consolidated credit profile of the company, including FPL and FPL Group Capital (which owns FPL Energy). TR 2586.

[147] TR 2519.

[148] TR 2586.

[149] TR 2619.

regulatory gamesmanship, not business judgment—will result in a windfall to shareholders, who will collect the difference in the returns between debt and equity. Here the difference amounts to $106 million dollars per year (comparing the 54.4% ratio suggested by witness Woolridge and the 59.6% ratio proposed by FPL). There is a reason not a single other regulatory commission in this country has authorized more than a 55% equity ratio for a utility's capital structure.[150]

COMMISSIONER SKOP, concurring specially with comment on Issue 120:

With respect to Issue 120 (Storm Damage Reserve Accrual), I concur with the majority and write separately to briefly articulate my basis for decision. The Florida Power & Light Company (FPL) storm damage reserve account is a funded reserve account. In simple terms, this means that any storm damage reserve funds collected from FPL ratepayers are actually deposited and held within a restricted storm damage account to offset actual storm damage costs at a future point in time when such costs may arise. In deciding this issue, it is important to recognize that the storm damage reserve accrual is ultimately a discretionary expenditure which increases the FPL revenue requirement on a dollar for dollar basis. In the instant case, suspending the storm damage reserve accrual is justified because the suspension of the storm damage reserve accrual reduces the overall FPL revenue requirement, the existing FPL storm damage reserve balance was approximately $184.8 million dollars[151] at the end of 2009, FPL customers are currently paying a surcharge for past storm costs, and the Commission has proven mechanisms to address the timely recovery of storm damage costs via surcharge or securitization should such action be necessary.[152]

In closing, there are opportunity costs and various tradeoffs involved in any decision. Given the prevailing economic conditions and the discretionary nature of the expense, the majority decision to suspend the storm damage reserve accrual was prudent. As with any discretionary expenditure, should economic conditions improve, I would support reinstating the

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[150] No state regulatory commission authorized more than a 55% equity ratio for a utility's capital structure from January 2009 to August 2009. EXH 462.

[151] The existing FPL storm damage reserve balance of approximately $184.8 million dollars (MFR Schedule B-21) seems to provide an adequate measure of protection for FPL ratepayers based upon statistical analysis. In his direct testimony, witness Harris testified that there was only a 30.5 percent probability of having storm damages greater than $100 million dollars in any given year, and only a 18.0 percent probability of having storm damages greater than $200 million dollars in any given year. (EXH 127)

[152] See Order No. PSC-05-0937-FOF-EI, issued September 21, 2005, in Docket No. 041291-EI, In re: Petition for authority to recover prudently incurred storm restoration costs related to 2004 storm season that exceed storm reserve balance, by Florida Power & Light Company; Order No. PSC-05-0748-FOF-EI, issued July 14, 2005, in Docket No. 041272-EI, In re: Petition for approval of storm cost recovery clause for recovery of extraordinary expenditures related to Hurricanes Charley, Frances, Jeanne, and Ivan, by Progress Energy Florida, Inc.; Order No. PSC-06-0464-FOF-EI, issued May 30, 2006, in Docket No. 060038-EI, In re: Petition for issuance of a storm recovery financing order by Florida Power & Light Company.

FPL storm damage reserve accrual as necessary to achieve an appropriate storm damage reserve balance.

COMMISSIONER EDGAR, dissenting with the following opinion:

I respectfully dissent with the majority decision on Issue 120. FPL proposed to establish an annual accrual to the storm damage reserve. Our staff recommended in favor of an accrual but at a lesser amount. By a 3-2 vote, the majority voted to deny not only a lesser amount, but also went further and denied any annual accrual to a storm damage reserve. I disagree with this decision.

In Order No. PSC-93-0918-FOF-EI, the Commission authorized a self-insurance mechanism for storm damage. As discussed in Order No. PSC-09-0283-FOF-EI, our current overall regulatory framework for the recovery of storm damage costs consists of three major components: an annual storm accrual, a storm reserve adequate to accommodate most, but not all, storm years, and a provision for utilities to seek recovery of costs that go beyond the storm reserve. Section 366.8260, Florida Statutes, permits utilities to recover all reasonable and prudent expenses for storm damage. In dockets addressing the damages resulting from the 2004 and 2005 hurricane seasons, we heard from thousands of residents and businesses about the impact on their lives and their local economy when electricity was unavailable post-severe storm. We also heard testimony opposing imposition of a monthly surcharge at the very time families and businesses were attempting to recover from the costs that they had incurred from storm damage (damage to property, housing, loss of revenue, etc.).

I believe that a small annual accrual to support a healthy and reasonable reserve is an important and beneficial component of our state's storm preparedness.

COMMISSIONER KLEMENT dissents on Storm Damage Reserve and Service Charges, without opinion.

NOTICE OF FURTHER PROCEEDINGS OR JUDICIAL REVIEW

The Florida Public Service Commission is required by Section 120.569(1), Florida Statutes, to notify parties of any administrative hearing or judicial review of Commission orders that is available under Sections 120.57 or 120.68, Florida Statutes, as well as the procedures and time limits that apply. This notice should not be construed to mean all requests for an administrative hearing or judicial review will be granted or result in the relief sought.

Any party adversely affected by the Commission's final action in this matter may request: 1) reconsideration of the decision by filing a motion for reconsideration with the Office of Commission Clerk, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850, within fifteen (15) days of the issuance of this order in the form prescribed by Rule 25-22.060, Florida Administrative Code; or 2) judicial review by the Florida Supreme Court in the case of an electric, gas or telephone utility or the First District Court of Appeal in the case of a water and/or wastewater utility by filing a notice of appeal with the Office of Commission Clerk, and filing a copy of the notice of appeal and the filing fee with the appropriate court. This filing must be completed within thirty (30) days after the issuance of this order, pursuant to Rule 9.110, Florida Rules of Appellate Procedure. The notice of appeal must be in the form specified in Rule 9.900(a), Florida Rules of Appellate Procedure.

SCHEDULE 1

FLORIDA POWER & LIGHT COMPANY
DOCKET NO. 080677-EI
13-MONTH AVERAGE RATE BASE
DECEMBER 2010 TEST YEAR

| Issue No. | | Plant in Service | Accumulated Depreciation | Net Plant in Service | CWIP | Plant Held for Future Use | Nuclear Fuel - No AFUDC (Net) | Net Plant | Working Capital | Total Rate Base |
|---|---|---|---|---|---|---|---|---|---|---|
| | Adjusted per Company | 28,288,080,000 | (12,590,521,000) | 15,697,559,000 | 707,530,000 | 74,502,000 | 374,733,000 | 16,854,324,000 | 209,262,000 | 17,063,586,000 |
| | Commission Adjustments: | | | | | | | | | |
| 14 | WCEC 3 - No GBRA | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 15 | Transmission Investments and Costs | (386,896,000) | 144,299,000 | (242,597,000) | (18,623,000) | (4,200,000) | 0 | (265,420,000) | 3,700,000 | (261,720,000) |
| 16 | Jurisdictional Separation | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 42 | Fossil Dismantlement Accrual | 0 | (1,320,284) | (1,320,284) | 0 | 0 | 0 | (1,320,284) | 0 | (1,320,284) |
| 46 | Cost Recovery Clause Over-Recovery | 0 | 0 | 0 | 0 | 0 | 0 | 0 | (101,971,000) | (101,971,000) |
| 47 | Advanced Metering Infrastructure | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 50 | Plant in Service Level | (785,187,189) | 460,387,189 | (324,800,000) | 0 | 0 | 0 | (324,800,000) | 0 | (324,800,000) |
| 51 | Accumulated Depreciation | 0 | 469,416,500 | 469,416,500 | 0 | 0 | 0 | 469,416,500 | 0 | 469,416,500 |
| 52 | Florida EnergySecure Line | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 53-S | ECRC Capital Items | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 55 | Construction Work in Progress | 0 | 0 | 0 | (1,264,000) | 0 | 0 | (1,264,000) | 0 | (1,264,000) |
| 56 | Property Held for Future Use | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 57-S | Fuel Inventories | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 58 | Nuclear End of Life and Last Core | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 59 | Nuclear Fuel in Rate Base | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 60 | Nuclear Fuel Level | 0 | 0 | 0 | 0 | 0 | (3,771,000) | (3,771,000) | 0 | (3,771,000) |
| 61 | Glades Power Park Amortization | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 62 | Working Capital Level | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 4,078,000 | 4,078,000 |
| 63 | Total Rate Base | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 83 | SJRPP Transfer to CCRC | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 94 | Aviation Costs | (53,268,205) | 27,853,907 | (25,414,298) | 0 | 0 | 0 | (25,414,298) | 0 | (25,414,298) |
| 108 | Department of Energy Settlement | (25,866,000) | 252,000 | (25,614,000) | (828,000) | 0 | 0 | (26,442,000) | 0 | (26,442,000) |
| 120 | Storm Damage Reserve | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 122 | Rate Case Expense | 0 | 0 | 0 | 0 | 0 | 0 | 0 | (2,948,000) | (2,948,000) |
| 173 | Nuclear Uprates | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| --- | Total Commission Adjustments | (1,251,217,394) | 1,100,888,312 | (150,329,082) | (20,715,000) | (4,200,000) | (3,771,000) | (179,015,082) | (97,141,000) | (276,156,082) |
| 63 | Commission Adjusted Rate Base | 27,036,862,606 | (11,489,632,688) | 15,547,229,918 | 686,815,000 | 70,302,000 | 370,962,000 | 16,675,308,918 | 112,121,000 | 16,787,429,918 |

SCHEDULE 2

FLORIDA POWER & LIGHT COMPANY
DOCKET NO. 080677-EI
13-MONTH AVERAGE CAPITAL STRUCTURE
DECEMBER 2010 TEST YEAR

| Company As Filed | ($) Amount | Ratio | Cost Rate | Weighted Cost |
|---|---|---|---|---|
| Common Equity | 8,178,980,000 | 47.93% | 12.50% | 5.99% |
| Long-term Debt | 5,377,787,000 | 31.52% | 5.55% | 1.75% |
| Short-term Debt | 161,857,000 | 0.95% | 2.96% | 0.03% |
| Preferred Stock | 0 | 0.00% | 0.00% | 0.00% |
| Customer Deposits | 564,652,000 | 3.31% | 5.98% | 0.20% |
| Deferred Income Taxes | 2,723,327,000 | 15.96% | 0.00% | 0.00% |
| Tax Credits - Weighted Cost | 56,983,000 | 0.33% | 9.74% | 0.03% |
| Total | 17,063,586,000 | 100.00% | | 8.00% |
| | | | | |
| Equity Ratio | 59.62% | | | |

| Commission Adjusted | ($) Amount | ($) Specific Adjustments | ($) Adjusted Total | Ratio | ($) Pro Rata Adjustments | ($) Staff Adjusted | Ratio | Cost Rate | Weighted Cost |
|---|---|---|---|---|---|---|---|---|---|
| Common Equity | 8,178,980,000 | (305,580,000) | 7,873,400,000 | 47.00% | 16,567,199 | 7,889,967,199 | 47.00% | 10.00% | 4.70% |
| Long-term Debt | 5,377,787,000 | (89,953,000) | 5,287,834,000 | 31.57% | 11,126,654 | 5,298,960,654 | 31.57% | 5.49% | 1.73% |
| Short-term Debt | 161,857,000 | (6,071,000) | 155,786,000 | 0.93% | 327,805 | 156,113,805 | 0.93% | 2.11% | 0.02% |
| Preferred Stock | 0 | 0 | 0 | 0.00% | 0 | 0 | 0.00% | 0.00% | 0.00% |
| Customer Deposits | 564,652,000 | (21,084,000) | 543,568,000 | 3.24% | 1,143,775 | 544,711,775 | 3.24% | 5.98% | 0.19% |
| Deferred Income Taxes | 2,723,327,000 | 162,847,000 | 2,886,174,000 | 17.23% | 6,073,084 | 2,892,247,084 | 17.23% | 0.00% | 0.00% |
| Tax Credits - Weighted Cost | 56,983,000 | (51,565,000) | 5,418,000 | 0.03% | 11,401 | 5,429,401 | 0.03% | 8.19% | 0.00% |
| Total | 17,063,586,000 | (311,406,000) | 16,752,180,000 | 100.00% | 35,249,918 | 16,787,429,918 | 100.00% | | 6.65% |
| | | | | | | | | | |
| Equity Ratio | 59.62% | | | | | 59.12% | | | |

| Interest Synchronization | ($) Adjustment Amount | Cost Rate | ($) Effect on Interest Exp. | Tax Rate | ($) Effect on Income Tax |
|---|---|---|---|---|---|
| Dollar Amount Change | | | | | |
| Long-term Debt | (78,826,346) | 5.49% | (4,327,566) | 38.575% | 1,669,359 |
| Short-term Debt | (5,743,195) | 2.11% | (121,181) | 38.575% | 46,746 |
| Customer Deposits | (19,940,225) | 5.98% | (1,192,425) | 38.575% | 459,978 |
| Tax Credits - Weighted Cost | (51,553,599) | 8.19% | (4,221,210) | 38.575% | 1,628,332 |
| | | | | | 2,176,083 |
| Cost Rate Change | | | | | |
| Long-term Debt | 5,377,787,000 | -0.06% | (3,226,672) | 38.575% | 1,244,689 |
| Short-term Debt | 161,857,000 | -0.85% | (1,375,785) | 38.575% | 530,709 |
| Tax Credits - Weighted Cost | 56,983,000 | -1.55% | (884,375) | 38.575% | 341,148 |
| | | | | | 2,116,545 |
| TOTAL | | | | | 4,292,628 |

FLORIDA POWER & LIGHT COMPANY
DOCKET NO. 080677-EI
NET OPERATING INCOME
DECEMBER 2010 TEST YEAR

SCHEDULE 3

| Issue No. | Adjusted per Company | Operating Revenues | O&M - Fuel & Purchased Power | O&M Other | Depreciation and Amortization | Taxes Other Than Income | Total Income Taxes and ITCs | (Gain)/Loss on Disposal of Plant | Total Operating Expenses | Net Operating Income |
|---|---|---|---|---|---|---|---|---|---|---|
| | Adjusted per Company | 4,114,727,000 | 27,505,000 | 1,694,367,000 | 1,074,265,000 | 350,370,000 | 243,338,000 | (1,002,000) | 3,388,844,000 | 725,883,000 |
| | Commission Adjustments: | | | | | | | | | |
| 3 | 2010 Customer, kWh & kW Forecast | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 7 | 2011 Customer, kWh & kW Forecast | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 14 | WCEC 3 - No GBRA | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 15 | Transmission Investments and Costs | (33,639,000) | 0 | (10,462,000) | (10,335,000) | (4,918,000) | (3,056,683) | 0 | (28,771,683) | (4,867,317) |
| 16 | Jurisdictional Separation | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 58 | Nuclear End of Life and Last Core | 0 | 0 | (6,137,000) | 0 | 0 | 2,367,348 | 0 | (3,769,652) | 3,769,652 |
| 61 | Glades Power Park Amortization | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 82 | Customer Growth and Inflation Factors | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 83 | SJRPP Transfer to CCRC | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 84 | FAC Revenues & Expenses | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 85 | ECCR Revenues & Expenses | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 86 | CCRC Revenues & Expenses | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 87 | ECRC Revenues & Expenses | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 88 | C/I Demand Reduction Rider | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 89 | Late Payment Revenues | 18,390,146 | 0 | 0 | 0 | 13,241 | 7,088,891 | 0 | 7,102,132 | 11,288,014 |
| 90 | Revenue Forecast | 36,969,000 | 0 | 0 | 0 | 26,618 | 14,250,524 | 0 | 14,277,142 | 22,691,858 |
| 91 | Total Operating Revenues | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 92 | Charitable Contibutions | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 93 | Historical Museum | 0 | 0 | (45,470) | 0 | 0 | 17,540 | 0 | (27,930) | 27,930 |
| 94 | Aviation Costs | 0 | 0 | (1,633,916) | (2,092,009) | 0 | 1,437,276 | 0 | (2,288,649) | 2,288,649 |
| 95 | Advanced Metering Infrastructure | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 96 | Bad Debt Expense | 0 | 0 | 3,805,000 | 0 | 0 | (1,467,779) | 0 | 2,337,221 | (2,337,221) |
| 97 | FAC Bad Debt Expense | 0 | 0 | 16,893,000 | 0 | 0 | (6,516,475) | 0 | 10,376,525 | (10,376,525) |
| 98-S | Advertising Expenses | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 99-S | Lobbying Expenses | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 100 | Unfilled Positions and Overtime | 0 | 0 | (15,392,467) | 0 | (882,729) | 6,278,157 | 0 | (9,997,039) | 9,997,039 |
| 101 | Productivity Improvements | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 102 | Nuclear Production Staffing | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 103 | Salaries and Employee Benefits | 0 | 0 | (49,510,136) | 0 | 0 | 19,098,535 | 0 | (30,411,601) | 30,411,601 |
| 106 | Pension Expense | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 107 | Environmental Insurance Refund | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 108 | Department of Energy Settlement | 0 | 0 | (6,084,000) | (747,000) | (109,000) | 2,677,105 | 0 | (4,262,895) | 4,262,895 |
| 109 | Affiliated Companies Transactions | 0 | 0 | (4,555,224) | 0 | (510,000) | 1,953,910 | 0 | (3,111,314) | 3,111,314 |
| 116A | Gain on Sale | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 119 | FPL-NED Assets | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 120 | Storm Damage Accrual | 0 | 0 | (148,666,500) | 0 | 0 | 57,348,102 | 0 | (91,318,398) | 91,318,398 |
| 121 | Fossil Dismantlement Accrual | 0 | 0 | 0 | 2,640,568 | 0 | (1,018,599) | 0 | 1,621,969 | (1,621,969) |
| 122 | Rate Case Expense | 0 | 0 | (217,250) | 0 | 0 | 83,804 | 0 | (133,446) | 133,446 |
| 123-S | Atrium | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 124 | ECCR Payroll in Base Rates | 0 | 0 | 1,582,000 | 0 | 0 | (610,257) | 0 | 971,744 | (971,744) |
| 125 | CCRC Payroll in Base Rates | 0 | 0 | 427,000 | 0 | 0 | (164,715) | 0 | 262,285 | (262,285) |
| 126 | Hedging Costs in FAC | 0 | 0 | 650,000 | 0 | 0 | (250,738) | 0 | 399,263 | (399,263) |
| 127-S | Orange Grove Operations | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 128 | Level of O&M Expenses | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 129 | Customer Information System | 0 | 0 | 0 | (435,000) | 0 | 167,801 | 0 | (267,199) | 267,199 |
| 130 | Capital Expenditures Reduction | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 131 | Depreciation Expense | 0 | 0 | 0 | (310,060,000) | 0 | 119,605,645 | 0 | (190,454,355) | 190,454,355 |
| 132 | Taxes Other Than Income | 0 | 0 | 0 | 0 | 972,000 | (374,949) | 0 | 597,051 | (597,051) |
| 133 | American Recovery & Reinvestment Ac | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 134 | Income Tax Expense | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 173 | Nuclear Uprates | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Interest Synchronization | 0 | 0 | 0 | 0 | 0 | 4,292,628 | 0 | 4,292,628 | (4,292,628) |
| | Total Commission Adjustments | 21,720,146 | 0 | (219,346,963) | (321,028,441) | (5,407,870) | 223,207,072 | 0 | (322,576,202) | 344,296,348 |
| 135 | Commission Adjusted NOI | 4,136,447,146 | 27,505,000 | 1,475,020,037 | 753,236,559 | 344,962,130 | 466,545,072 | (1,002,000) | 3,066,267,798 | 1,070,179,348 |

SCHEDULE 4

FLORIDA POWER & LIGHT COMPANY
DOCKET NO. 080677-EI
DECEMBER 2010 PROJECTED TEST YEAR
NET OPERATING INCOME MULTIPLIER

| Line No. | | (%) As Filed | (%) Commission Adjusted |
|---|---|---|---|
| 1 | Revenue Requirement | 100.000 | 100.000 |
| 2 | Gross Receipts Tax | 0.000 | 0.000 |
| 3 | Regulatory Assessment Fee | (0.072) | (0.072) |
| 4 | Bad Debt Rate | (0.260) | (0.302) |
| 5 | Net Before Income Taxes | 99.668 | 99.626 |
| 6 | Income Taxes (Line 5 x 38.575%) | 38.447 | 38.431 |
| 7 | Revenue Expansion Factor | 61.221 | 61.195 |
| 8 | Net Operating Income Multiplier (100%/Line 7) | 1.63342 | 1.63411 |

SCHEDULE 5

FLORIDA POWER & LIGHT COMPANY
DOCKET NO. 080677-EI
DECEMBER 2010 PROJECTED TEST YEAR
OPERATING REVENUE INCREASE CALCULATION

| Line No. | | As Filed | Commission Adjusted |
|---|---|---|---|
| 1. | Rate Base | $ 17,063,586,000 | $16,787,429,918 |
| 2. | Overall Rate of Return | 8.00% | 6.65% |
| 3. | Required Net Operating Income (1)x(2) | 1,364,748,000 | 1,116,364,090 |
| 4. | Achieved Net Operating Income | 725,883,000 | 1,070,179,348 |
| 5. | Net Operating Income Deficiency (3)-(4) | 638,865,000 | 46,184,742 |
| 6. | Net Operating Income Multiplier | 1.63342 | 1.63411 |
| 7. | Operating Revenue Increase (5)x(6) | $1,043,535,000 | $75,470,948 |

SCHEDULE 6

FLORIDA POWER & LIGHT COMPANY
DOCKET NO. 080677-EI
ALLOCATION OF THE RATE INCREASE BY RATE CLASSES
(in $000)

| Line No. | (1) Rate Class | (2) Present ROR | (3) Present Index | (4) Present Class Operating Revenue | (5) Increase from Service Charges | (6) Increase from Sale of Electricity | (7) Increase from Unbilled | (8) Total Increase | (9) Approved ROR | (10) Approved Index | | (11) % Increase With Adjustment Clauses | (12) % Increase Without Adjustment Clauses |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | CILC-1D | 4.68% | 73% | 73,071 | 0 | 2,448 | -12 | 2,436 | 5.10% | 77% | | 1.2% | 3.3% |
| 2 | CILC-1G | 7.11% | 112% | 6,031 | 0 | 83 | -1 | 82 | 7.33% | 110% | | 0.6% | 1.4% |
| 3 | CILC-1T | 4.82% | 76% | 25,572 | 0 | 1,071 | -4 | 1,067 | 5.40% | 81% | | 1.2% | 4.2% |
| 4 | CS1 | 5.82% | 91% | 5,149 | 0 | 90 | -1 | 89 | 6.04% | 91% | | 0.6% | 1.7% |
| 5 | CS2 | 5.76% | 90% | 1,950 | 0 | 10 | 0 | 10 | 5.83% | 88% | | 0.2% | 0.5% |
| 6 | GS1 | 8.59% | 135% | 306,675 | 20 | 3,270 | -65 | 3,226 | 8.79% | 132% | | 0.5% | 1.1% |
| 7 | GSCU-1 | 10.38% | 163% | 1,569 | 0 | 19 | 0 | 19 | 10.66% | 160% | | 0.5% | 1.2% |
| 8 | GSD1 | 6.08% | 95% | 767,469 | 4 | 22,900 | -172 | 22,732 | 6.49% | 98% | | 1.2% | 3.0% |
| 9 | GSLD1 | 4.35% | 68% | 146,931 | 0 | 3,544 | -32 | 3,512 | 4.63% | 70% | | 0.9% | 2.4% |
| 10 | GSLD2 | 4.73% | 74% | 21,730 | 0 | 110 | -4 | 106 | 4.80% | 72% | | 0.2% | 0.5% |
| 11 | GSLD3 | 6.02% | 95% | 4,612 | 0 | 198 | -1 | 197 | 6.67% | 100% | | 1.2% | 4.3% |
| 12 | HLFT1 | 5.30% | 83% | 35,996 | 0 | 224 | -7 | 216 | 5.38% | 81% | | 0.2% | 0.6% |
| 13 | HLFT2 | 3.27% | 51% | 119,909 | 0 | 4,559 | -26 | 4,533 | 3.68% | 55% | | 1.2% | 3.8% |
| 14 | HLFT3 | 3.32% | 52% | 24,433 | 0 | 675 | -5 | 670 | 3.62% | 54% | | 0.8% | 2.7% |
| 15 | MET | 5.64% | 89% | 2,906 | 0 | 86 | -1 | 86 | 6.04% | 91% | | 1.2% | 2.9% |
| 16 | OL-1 | 19.42% | 305% | 12,057 | 0 | 68 | -3 | 66 | 19.66% | 296% | | 0.4% | 0.5% |
| 17 | OS-2 | 3.59% | 56% | 912 | 0 | 21 | 0 | 21 | 3.83% | 58% | | 1.2% | 2.3% |
| 18 | RS1 | 6.65% | 104% | 2,469,818 | 197 | 35,147 | -522 | 34,822 | 6.88% | 103% | | 0.7% | 1.4% |
| 19 | SDTR-1 | 5.78% | 91% | 15,912 | 0 | 495 | -4 | 492 | 6.20% | 93% | | 1.2% | 3.1% |
| 20 | SDTR-2 | 4.06% | 64% | 16,143 | 0 | 499 | -4 | 496 | 4.41% | 66% | | 1.1% | 3.1% |
| 21 | SDTR-3 | 3.08% | 48% | 1,754 | 0 | 26 | 0 | 26 | 3.23% | 49% | | 0.5% | 1.5% |
| 22 | SL-1 | 10.36% | 163% | 70,632 | 0 | 459 | -15 | 444 | 10.50% | 158% | | 0.4% | 0.6% |
| 23 | SL-2 | 11.98% | 188% | 1,147 | 0 | 16 | 0 | 16 | 12.29% | 185% | | 0.5% | 1.4% |
| 24 | SST-DST | 4.79% | 75% | 265 | 0 | 8 | 0 | 8 | 5.14% | 77% | | 1.2% | 3.0% |
| 25 | SST-TST | 19.08% | 300% | 3,807 | 0 | 105 | -1 | 104 | 19.90% | 299% | | 1.0% | 2.7% |
| 26 | | | | | | | | | | | | | |
| 27 | | | | | | | | | | | | | |
| 28 | Total | 6.37% | 100% | 4,136,447 | 222 | 76,131 | -882 | 75,471 | 6.65% | 100% | | 0.8% | 1.8% |
| 29 | | | | | | | | | | | 1.5x | 1.2% | |
| 30 | | | | | | | | | | | Max | 1.2% | |
| 31 | | | | | | | | | | | | | |
| 32 | **Notes:** | | | | | | | | | | | | |
| 33 | Certain general service demand level classes do not receive the maximum increase in order to maintain relationships between the related rate classes | | | | | | | | | | | | |
| 34 | No rate increase should exceed 1.5x the system average percentage increase in total, i.e. with adjustment clauses, and no class should receive a decrease | | | | | | | | | | | | |
| 35 | TOTALS MAY NOT ADD DUE TO ROUNDING | | | | | | | | | | | | |

SCHEDULE 7
Page 1 of 19

| (1) CURRENT RATE SCHEDULE | (2) TYPE OF CHARGE | (3) CURRENT RATE | (4) RATE SCHEDULE | (5) COMMISSION APPROVED RATE |
|---|---|---|---|---|
| RS-1 | Residential Service | | | |
| | Customer Charge/Minimum | $5.69 | | $5.90 |
| | Base Energy Charge (¢ per kWh) | | | |
| | First 1,000 kWh | 3.631 | | 3.711 |
| | All additional kWh | 4.733 | | 4.711 |
| RST-1 | Residential Service -Time of Use | | | |
| | Customer Charge/Minimum | $9.04 | | $16.04 |
| | with $160.45 Lump-sum metering payment made prior to January 1, 2010 | $5.69 | | |
| | with $608.40 Lump-sum metering payment effective January 1, 2010 | | | $5.90 |
| | Base Energy Charge (¢ per kWh) | | | |
| | On-Peak | 7.618 | | 7.734 |
| | Off-Peak | 2.338 | | 2.454 |
| GS-1 | General Service - Non Demand (0-20 kW) | | | |
| | Customer Charge/Minimum | | | |
| | Metered | $9.08 | | $6.89 |
| | Unmetered | $6.04 | | $0.89 |
| | Base Energy Charge (¢ per kWh) | 4.189 | | 4.427 |
| GST-1 | General Service - Non Demand - Time of Use (0-20 kW) | | | |
| | Customer Charge/Minimum | $12.42 | | $13.53 |
| | with $160.45 Lump-sum metering payment made prior to January 1, 2010 | $9.08 | | |
| | with $398.40 Lump-sum metering payment effective January 1, 2010 | | | $6.89 |
| | Base Energy Charge (¢ per kWh) | | | |
| | On-Peak | 8.189 | | 8.453 |
| | Off-Peak | 2.361 | | 2.625 |

| (1) CURRENT RATE SCHEDULE | (2) TYPE OF CHARGE | (3) CURRENT RATE | (4) RATE SCHEDULE | (5) COMMISSION APPROVED RATE |
|---|---|---|---|---|
| GSD-1 | General Service Demand (21-499 kW) | | | |
| | Customer Charge | $35.31 | | $16.44 |
| | Demand Charge ($/kW) | $5.44 | | $6.50 |
| | Base Energy Charge (¢ per kWh) | 1.485 | | 1.382 |
| GSDT-1 | General Service Demand - Time of Use (21-499 kW) | | | |
| | Customer Charge | $41.87 | | $22.77 |
| | with $390.51 Lump-sum metering payment made prior to January 1, 2010 | $35.31 | | |
| | with $379.80 Lump-sum metering payment effective January 1, 2010 | | | $16.44 |
| | Demand Charge - On-Peak ($/kW) | $5.44 | | $6.50 |
| | Base Energy Charge (¢ per kWh) | | | |
| | On-Peak | 3.466 | | 3.102 |
| | Off-Peak | 0.953 | | 0.635 |
| GSLD-1 | General Service Large Demand (500-1999 kW) | | | |
| | Customer Charge | $41.37 | | $50.13 |
| | Demand Charge ($/kW) | $6.30 | | $7.60 |
| | Base Energy Charge (¢ per kWh) | 1.175 | | 0.903 |
| GSLDT-1 | General Service Large Demand - Time of Use (500-1999 kW) | | | |
| | Customer Charge | $41.37 | | $50.13 |
| | Demand Charge - On-Peak ($/kW) | $6.30 | | $7.60 |
| | Base Energy Charge (¢ per kWh) | | | |
| | On-Peak | 2.328 | | 2.028 |
| | Off-Peak | 0.707 | | 0.407 |

SCHEDULE 7
Page 3 of 19

| (1) CURRENT RATE SCHEDULE | (2) TYPE OF CHARGE | (3) CURRENT RATE | (4) RATE SCHEDULE | (5) COMMISSION APPROVED RATE |
|---|---|---|---|---|
| CS-1 | Curtailable Service (500-1999 kW) | | | |
| | Customer Charge | $111.00 | | $50.13 |
| | Demand Charge ($/kW) | $6.30 | | $7.60 |
| | Base Energy Charge (¢ per kWh) | 1.176 | | 0.903 |
| | Monthly Credit ($ per kW) | ($1.72) | | ($1.72) |
| | Charges for Non-Compliance of Curtailment Demand | | | |
| | Rebilling for last 12 months (per kW) | $1.72 | | $1.72 |
| | Penalty Charge-current month (per kW) | $3.70 | | $3.70 |
| | Early Termination Penalty charge (per kW) | $1.09 | | $1.09 |
| CST-1 | Curtailable Service -Time of Use (500-1999 kW) | | | |
| | Customer Charge | $111.00 | | $50.13 |
| | Demand Charge - On-Peak ($/kW) | $6.30 | | $7.60 |
| | Base Energy Charge (¢ per kWh) | | | |
| | On-Peak | 2.329 | | 2.028 |
| | Off-Peak | 0.707 | | 0.407 |
| | Monthly Credit (per kW) | ($1.72) | | ($1.72) |
| | Charges for Non-Compliance of Curtailment Demand | | | |
| | Rebilling for last 12 months (per kW) | $1.72 | | $1.72 |
| | Penalty Charge-current month (per kW) | $3.70 | | $3.70 |
| | Early Termination Penalty charge (per kW) | $1.09 | | $1.09 |
| GSLD-2 | General Service Large Demand (2000 kW +) | | | |
| | Customer Charge | $171.54 | | $179.19 |
| | Demand Charge ($/kW) | $6.30 | | $7.60 |
| | Base Energy Charge (¢ per kWh) | 1.172 | | 0.845 |

SCHEDULE 7
Page 4 of 19

| (1) CURRENT RATE SCHEDULE | (2) TYPE OF CHARGE | (3) CURRENT RATE | (4) RATE SCHEDULE | (5) COMMISSION APPROVED RATE |
|---|---|---|---|---|
| GSLDT-2 | General Service Large Demand - Time of Use (2000 kW +) | | | |
| | Customer Charge | $171.54 | | $179.19 |
| | Demand Charge - On-Peak ($/kW) | $6.30 | | $7.60 |
| | Base Energy Charge (¢ per kWh) | | | |
| | On-Peak | 2.445 | | 1.496 |
| | Off-Peak | 0.661 | | 0.604 |
| CS-2 | Curtailable Service (2000 kW +) | | | |
| | Customer Charge | $171.54 | | $179.19 |
| | Demand Charge ($/kW) | $6.30 | | $7.60 |
| | Base Energy Charge (¢ per kWh) | 1.172 | | 0.845 |
| | Monthly Credit (per kW) | ($1.72) | | ($1.72) |
| | Charges for Non-Compliance of Curtailment Demand | | | |
| | Rebilling for last 12 months (per kW) | $1.72 | | $1.72 |
| | Penalty Charge-current month (per kW) | $3.70 | | $3.70 |
| | Early Termination Penalty charge (per kW) | $1.09 | | $1.09 |
| CST-2 | Curtailable Service -Time of Use (2000 kW +) | | | |
| | Customer Charge | $171.54 | | $179.19 |
| | Demand Charge - On-Peak ($/kW) | $6.30 | | $7.60 |
| | Base Energy Charge (¢ per kWh) | | | |
| | On-Peak | 2.449 | | 1.496 |
| | Off-Peak | 0.661 | | 0.604 |
| | Monthly Credit (per kW) | ($1.72) | | ($1.72) |
| | Charges for Non-Compliance of Curtailment Demand | | | |
| | Rebilling for last 12 months (per kW) | $1.72 | | $1.72 |
| | Penalty Charge-current month (per kW) | $3.70 | | $3.70 |
| | Early Termination Penalty charge (per kW) | $1.09 | | $1.09 |

| (1) CURRENT RATE SCHEDULE | (2) TYPE OF CHARGE | (3) CURRENT RATE | (4) RATE SCHEDULE | (5) COMMISSION APPROVED RATE |
|---|---|---|---|---|
| GSLD-3 | General Service Large Demand (2000 kW +) | | | |
| | Customer Charge | $403.63 | | $1,441.88 |
| | Demand Charge ($/kW) | $6.30 | | $6.32 |
| | Base Energy Charge (¢ per kWh) | 0.609 | | 0.624 |
| GSLDT-3 | General Service Large Demand - Time of Use (2000 kW +) | | | |
| | Customer Charge | $403.63 | | $1,441.88 |
| | Demand Charge - On-Peak ($/kW) | $6.30 | | $6.32 |
| | Base Energy Charge (¢ per kWh) | | | |
| | On-Peak | 0.678 | | 0.723 |
| | Off-Peak | 0.543 | | 0.588 |
| CS-3 | Curtailable Service (2000 kW +) | | | |
| | Customer Charge | $403.63 | | $1,441.88 |
| | Demand Charge ($/kW) | $6.30 | | $6.32 |
| | Base Energy Charge (¢ per kWh) | 0.609 | | 0.624 |
| | Monthly Credit (per kW) | ($1.72) | | ($1.72) |
| | Charges for Non-Compliance of Curtailment Demand | | | |
| | Rebilling for last 12 months (per kW) | $1.72 | | $1.72 |
| | Penalty Charge-current month (per kW) | $3.70 | | $3.70 |
| | Early Termination Penalty charge (per kW) | $1.09 | | $1.09 |

| (1) CURRENT RATE SCHEDULE | (2) TYPE OF CHARGE | (3) CURRENT RATE | (4) RATE SCHEDULE | (5) COMMISSION APPROVED RATE |
|---|---|---|---|---|
| CST-3 | Curtailable Service -Time of Use (2000 kW +) | | | |
| | Customer Charge | $403.63 | | $1,441.88 |
| | Demand Charge - On-Peak ($/kW) | $6.30 | | $6.32 |
| | Base Energy Charge (¢ per kWh) | | | |
| | On-Peak | 0.678 | | 0.723 |
| | Off-Peak | 0.543 | | 0.588 |
| | Monthly Credit (per kW) | ($1.72) | | ($1.72) |
| | Charges for Non-Compliance of Curtailment Demand | | | |
| | Rebilling for last 12 months (per kW) | $1.72 | | $1.72 |
| | Penalty Charge-current month (per kW) | $3.70 | | $3.70 |
| | Early Termination Penalty charge (per kW) | $1.09 | | $1.09 |
| OS-2 | Sports Field Service [Schedule closed to new customers] | | | |
| | Customer Charge | $9.08 | | $97.28 |
| | Base Energy Charge (¢ per kWh) | 6.233 | | 4.874 |
| MET | Metropolitan Transit Service | | | |
| | Customer Charge | $216.95 | | $373.94 |
| | Base Demand Charge ($/kW) | $10.54 | | $9.28 |
| | Base Energy Charge (¢ per kWh) | 0.477 | | 0.826 |

| (1) CURRENT RATE SCHEDULE | (2) TYPE OF CHARGE | (3) CURRENT RATE | (4) RATE SCHEDULE | (5) COMMISSION APPROVED RATE |
|---|---|---|---|---|
| CILC-1 | Commercial/Industrial Load Control Program [Schedule closed to new customers] | | | |
| | Customer Charge | | | |
| | (G) 200-499kW | $605.45 | | $122.00 |
| | (D) above 500kW | $605.45 | | $175.00 |
| | (T) transmission | $3,229.09 | | $1,866.00 |
| | Base Demand Charge ($/kW) | | | |
| | per kW of Max Demand All kW: | | | |
| | (G) 200-499kW | $2.39 | | $3.20 |
| | (D) above 500kW | $2.46 | | $3.17 |
| | (T) transmission | None | | None |
| | per kW of Load Control On-Peak: | | | |
| | (G) 200-499kW | $1.13 | | $1.32 |
| | per kW of Load Control On-Peak: | | | |
| | (D) above 500kW | $1.17 | | $1.35 |
| | (T) transmission | $1.16 | | $1.29 |
| | Per kW of Firm On-Peak Demand | | | |
| | (G) 200-499kW | $4.84 | | $6.92 |
| | (D) above 500kW | $5.91 | | $7.12 |
| | (T) transmission | $6.30 | | $6.79 |
| | Base Energy Charge (¢ per kWh) | | | |
| | On-Peak | | | |
| | (G) 200-499kW | 1.046 | | 1.160 |
| | (D) above 500kW | 0.727 | | 0.631 |
| | (T) transmission | 0.536 | | 0.585 |
| | Off-Peak | | | |
| | (G) 200-499kW | 1.046 | | 1.160 |
| | (D) above 500kW | 0.727 | | 0.631 |
| | (T) transmission | 0.536 | | 0.585 |
| | Excess "Firm Demand" | | | |
| | ¤ Up to prior 60 months of service | Difference between Firm and Load-Control On-Peak Demand Charge | | Difference between Firm and Load-Control On-Peak Demand Charge |
| | ¤ Penalty Charge per kW for each month of rebilling | $0.99 | | $0.99 |

SCHEDULE 7
Page 8 of 19

| (1) CURRENT RATE SCHEDULE | (2) TYPE OF CHARGE | (3) CURRENT RATE | (4) RATE SCHEDULE | (5) COMMISSION APPROVED RATE |
|---|---|---|---|---|
| CDR | Commercial/Industrial Demand Reduction Rider | | | |
| | Monthly Rate | | | |
| | Customer Charge | Otherwise Applicable Rate | | Otherwise Applicable Rate |
| | Demand Charge | Otherwise Applicable Rate | | Otherwise Applicable Rate |
| | Energy Charge | Otherwise Applicable Rate | | Otherwise Applicable Rate |
| | Monthly Administrative Adder | | | |
| | GSD-1 | $570.14 | | $570.14 |
| | GSDT-1 | $563.58 | | $563.58 |
| | GSLD-1, GSLDT-1 | $564.07 | | $564.07 |
| | GSLD-2, GSLDT-2 | $433.91 | | $433.91 |
| | GSLD-3, GSLDT-3 | $2,825.46 | | $2,825.46 |
| | HLFT | Applicable General Service Level Rate | | Applicable General Service Level Rate |
| | SDTR | Applicable General Service Level Rate | | Applicable General Service Level Rate |
| | Utility Controlled Demand Credit $/kW | -$4.68 | | -$4.68 |
| | Excess "Firm Demand" | $4.68 | | $4.68 |
| | ¤ Up to prior 60 months of service | | | |
| | ¤ Penalty Charge per kW for each month of rebilling | $0.99 | | $0.99 |
| SL-1 | Street Lighting | | | |
| | Charges for FPL-Owned Units | | | |
| | Fixture | | | |
| | Sodium Vapor 5,800 lu 70 watts | $3.91 | | $3.91 |
| | Sodium Vapor 9,500 lu 100 watts | $3.98 | | $3.98 |
| | Sodium Vapor 16,000 lu 150 watts | $4.11 | | $4.11 |
| | Sodium Vapor 22,000 lu 200 watts | $6.22 | | $6.22 |
| | Sodium Vapor 50,000 lu 400 watts | $6.29 | | $6.29 |
| | * Sodium Vapor 12,800 lu 150 watts | $4.27 | | $4.27 |
| | * Sodium Vapor 27,500 lu 250 watts | $6.61 | | $6.61 |
| | * Sodium Vapor 140,000 lu 1,000 watts | $9.95 | | $9.95 |
| | * Mercury Vapor 6,000 lu 140 watts | $3.09 | | $3.09 |
| | * Mercury Vapor 8,600 lu 175 watts | $3.13 | | $3.13 |
| | * Mercury Vapor 11,500 lu 250 watts | $5.23 | | $5.23 |
| | * Mercury Vapor 21,500 lu 400 watts | $5.21 | | $5.21 |
| | * Mercury Vapor 39,500 lu 700 watts | $7.37 | | $7.37 |
| | * Mercury Vapor 60,000 lu 1,000 watts | $7.54 | | $7.54 |

SCHEDULE 7
Page 9 of 19

| (1) CURRENT RATE SCHEDULE | | (2) TYPE OF CHARGE | (3) CURRENT RATE | (4) RATE SCHEDULE | (5) COMMISSION APPROVED RATE |
|---|---|---|---|---|---|
| SL-1 | | Street Lighting (continued)) | | | |
| | | Maintenance | | | |
| | | Sodium Vapor 5,800 lu 70 watts | $1.50 | | $1.17 |
| | | Sodium Vapor 9,500 lu 100 watts | $1.51 | | $1.18 |
| | | Sodium Vapor 16,000 lu 150 watts | $1.54 | | $1.20 |
| | | Sodium Vapor 22,000 lu 200 watts | $1.98 | | $1.55 |
| | | Sodium Vapor 50,000 lu 400 watts | $1.95 | | $1.53 |
| | * | Sodium Vapor 12,800 lu 150 watts | $1.72 | | $1.35 |
| | * | Sodium Vapor 27,500 lu 250 watts | $2.09 | | $1.63 |
| | * | Sodium Vapor 140,000 lu 1,000 watts | $3.83 | | $3.00 |
| | * | Mercury Vapor 6,000 lu 140 watts | $1.36 | | $1.06 |
| | * | Mercury Vapor 8,600 lu 175 watts | $1.36 | | $1.06 |
| | * | Mercury Vapor 11,500 lu 250 watts | $1.96 | | $1.53 |
| | * | Mercury Vapor 21,500 lu 400 watts | $1.92 | | $1.50 |
| | * | Mercury Vapor 39,500 lu 700 watts | $3.26 | | $2.55 |
| | * | Mercury Vapor 60,000 lu 1,000 watts | $3.18 | | $2.49 |
| | | Energy Non-Fuel | | | |
| | | Sodium Vapor 5,800 lu 70 watts | $0.65 | | $0.79 |
| | | Sodium Vapor 9,500 lu 100 watts | $0.92 | | $1.11 |
| | | Sodium Vapor 16,000 lu 150 watts | $1.34 | | $1.63 |
| | | Sodium Vapor 22,000 lu 200 watts | $1.97 | | $2.39 |
| | | Sodium Vapor 50,000 lu 400 watts | $3.75 | | $4.57 |
| | * | Sodium Vapor 12,800 lu 150 watts | $1.34 | | $1.63 |
| | * | Sodium Vapor 27,500 lu 250 watts | $2.59 | | $3.15 |
| | * | Sodium Vapor 140,000 lu 1,000 watts | $9.19 | | $11.17 |
| | * | Mercury Vapor 6,000 lu 140 watts | $1.39 | | $1.69 |
| | * | Mercury Vapor 8,600 lu 175 watts | $1.72 | | $2.09 |
| | * | Mercury Vapor 11,500 lu 250 watts | $2.32 | | $2.83 |
| | * | Mercury Vapor 21,500 lu 400 watts | $3.58 | | $4.35 |
| | * | Mercury Vapor 39,500 lu 700 watts | $6.08 | | $7.39 |
| | * | Mercury Vapor 60,000 lu 1,000 watts | $8.60 | | $10.46 |
| | | Total Charge-Fixtures, Maintenance & Energy | | | |
| | * | Incandescent 1,000 lu 103 watts | $7.61 | | $7.78 |
| | * | Incandescent 2,500 lu 202 watts | $7.87 | | $8.21 |
| | * | Incandescent 4,000 lu 327 watts | $9.22 | | $9.78 |
| | * | Incandescent 6,000 lu 448 watts | $10.27 | | $11.03 |
| | * | Incandescent 10,000 lu 690 watts | $12.37 | | $13.55 |

SCHEDULE 7
Page 10 of 19

| (1) CURRENT RATE SCHEDULE | | (2) TYPE OF CHARGE | (3) CURRENT RATE | (4) RATE SCHEDULE | (5) COMMISSION APPROVED RATE |
|---|---|---|---|---|---|
| SL-1 | | Street Lighting (continued)) | | | |
| | | Charge for Customer-Owned Units | | | |
| | | Relamping and Energy | | | |
| | | Sodium Vapor 5,800 lu 70 watts | $1.41 | | $1.38 |
| | | Sodium Vapor 9,500 lu 100 watts | $1.69 | | $1.72 |
| | | Sodium Vapor 16,000 lu 150 watts | $2.11 | | $2.23 |
| | | Sodium Vapor 22,000 lu 200 watts | $2.74 | | $3.16 |
| | | Sodium Vapor 50,000 lu 400 watts | $4.54 | | $5.35 |
| | * | Sodium Vapor 12,800 lu 150 watts | $2.37 | | $2.37 |
| | * | Sodium Vapor 27,500 lu 250 watts | $3.40 | | $3.96 |
| | * | Sodium Vapor 140,000 lu 1,000 watts | $11.00 | | $12.98 |
| | * | Mercury Vapor 6,000 lu 140 watts | $2.15 | | $2.28 |
| | * | Mercury Vapor 8,600 lu 175 watts | $2.49 | | $2.69 |
| | * | Mercury Vapor 11,500 lu 250 watts | $3.15 | | $3.47 |
| | * | Mercury Vapor 21,500 lu 400 watts | $4.37 | | $4.97 |
| | * | Mercury Vapor 39,500 lu 700 watts | $7.80 | | $7.43 |
| | * | Mercury Vapor 60,000 lu 1,000 watts | $9.69 | | $11.31 |
| | * | Incandescent 1,000 lu 103 watts | $2.70 | | $2.87 |
| | * | Incandescent 2,500 lu 202 watts | $3.49 | | $3.83 |
| | * | Incandescent 4,000 lu 327 watts | $4.54 | | $5.10 |
| | * | Incandescent 6,000 lu 448 watts | $5.48 | | $6.24 |
| | * | Incandescent 10,000 lu 690 watts | $7.54 | | $8.72 |
| | * | Fluorescent 19,800 lu 300 watts | $3.73 | | $4.32 |
| | * | Fluorescent 39,600 lu 700 watts | $7.20 | | $8.47 |
| | | Energy Only | | | |
| | | Sodium Vapor 5,800 lu 70 watts | $0.65 | | $0.79 |
| | | Sodium Vapor 9,500 lu 100 watts | $0.92 | | $1.11 |
| | | Sodium Vapor 16,000 lu 150 watts | $1.34 | | $1.63 |
| | | Sodium Vapor 22,000 lu 200 watts | $1.97 | | $2.39 |
| | | Sodium Vapor 50,000 lu 400 watts | $3.75 | | $4.57 |
| | * | Sodium Vapor 12,800 lu 150 watts | $1.34 | | $1.63 |
| | * | Sodium Vapor 27,500 lu 250 watts | $2.59 | | $3.15 |
| | * | Sodium Vapor 140,000 lu 1,000 watts | $9.19 | | $11.17 |
| | * | Mercury Vapor 6,000 lu 140 watts | $1.39 | | $1.69 |
| | * | Mercury Vapor 8,600 lu 175 watts | $1.72 | | $2.09 |
| | * | Mercury Vapor 11,500 lu 250 watts | $2.32 | | $2.83 |
| | * | Mercury Vapor 21,500 lu 400 watts | $3.58 | | $4.35 |
| | * | Mercury Vapor 39,500 lu 700 watts | $6.08 | | $7.39 |
| | * | Mercury Vapor 60,000 lu 1,000 watts | $8.60 | | $10.46 |
| | * | Incandescent 1,000 lu 103 watts | $0.80 | | $0.98 |
| | * | Incandescent 2,500 lu 202 watts | $1.59 | | $1.93 |

SCHEDULE 7
Page 11 of 19

| (1) CURRENT RATE SCHEDULE | (2) TYPE OF CHARGE | | (3) CURRENT RATE | (4) RATE SCHEDULE | (5) COMMISSION APPROVED RATE | |
|---|---|---|---|---|---|---|
| SL-1 | Street Lighting (continued)) | | | | | |
| | * Incandescent 4,000 lu 327 watts | | $2.59 | | $3.15 | |
| | * Incandescent 6,000 lu 448 watts | | $3.53 | | $4.29 | |
| | * Incandescent 10,000 lu 690 watts | | $5.45 | | $6.63 | |
| | * Fluorescent 19,800 lu 300 watts | | $2.72 | | $3.32 | |
| | * Fluorescent 39,600 lu 700 watts | | $5.91 | | $7.19 | |
| | Non-Fuel Energy (¢ per kWh) | | 2.235 | | 2.718 | |
| | Other Charges | | | | | |
| | Wood Pole | | $2.80 | | $2.80 | |
| | Concrete Pole | | $3.85 | | $3.85 | |
| | Fiberglass Pole | | $4.55 | | $4.55 | |
| | Underground conductors not under paving (¢ per foot) | | 2.10 | | 2.10 | |
| | Underground conductors under paving (¢ per foot) | | 5.14 | | 5.14 | |
| | Willful Damage | | | | | |
| | Cost for Shield upon second occurrence | | $120.00 | | $280.00 | |
| PL-1 | Premium Lighting | | | | | |
| | Present Value Revenue Requirement Multiplier | | 1.1605 | | 1.4094 | |
| | Monthly Rate | | | | | |
| | Facilities ( Percentage of total work order cost) | | | | | |
| | 10 Year Payment Option | | 1.380% | | 1.565% | * |
| | 20 Year Payment Option | | 0.969% | | 1.038% | * |
| | Maintenance | | FPL's estimated cost of maintaining facilities | | FPL's estimated cost of maintaining facilities | |
| | Termination Factors | | | | | |
| | 10 Year Payment Option | | | | | |
| | | 1 | 1.1605 | | 1.4094 | * |
| | | 2 | 0.9949 | | 1.2216 | * |
| | | 3 | 0.9184 | | 1.1198 | * |
| | | 4 | 0.8349 | | 1.0108 | * |
| | | 5 | 0.7440 | | 0.8941 | * |
| | | 6 | 0.6450 | | 0.7692 | * |

| (1) CURRENT RATE SCHEDULE | (2) TYPE OF CHARGE | | (3) CURRENT RATE | (4) RATE SCHEDULE | (5) COMMISSION APPROVED RATE | |
|---|---|---|---|---|---|---|
| PL-1 | Premium Lighting (continued) | | | | | |
| | | 7 | 0.5371 | | 0.6355 | * |
| | | 8 | 0.4196 | | 0.4924 | * |
| | | 9 | 0.2915 | | 0.3393 | * |
| | | 10 | 0.1520 | | 0.1754 | * |
| | >10 | | 0.0000 | | 0.0000 | * |
| | 20 Year Payment Option | | | | | |
| | | 1 | 1.1605 | | 1.4094 | * |
| | | 2 | 1.0443 | | 1.2848 | * |
| | | 3 | 1.0215 | | 1.2505 | * |
| | | 4 | 0.9966 | | 1.2139 | * |
| | | 5 | 0.9695 | | 1.1746 | * |
| | | 6 | 0.9400 | | 1.1326 | * |
| | | 7 | 0.9079 | | 1.0876 | * |
| | | 8 | 0.8729 | | 1.0395 | * |
| | | 9 | 0.8347 | | 0.9880 | * |
| | | 10 | 0.7931 | | 0.9328 | * |
| | | 11 | 0.7478 | | 0.8738 | * |
| | | 12 | 0.6985 | | 0.8107 | * |
| | | 13 | 0.6447 | | 0.7431 | * |
| | | 14 | 0.5862 | | 0.6707 | * |
| | | 15 | 0.5224 | | 0.5933 | * |
| | | 16 | 0.4528 | | 0.5104 | * |
| | | 17 | 0.3771 | | 0.4217 | * |
| | | 18 | 0.2946 | | 0.3268 | * |
| | | 19 | 0.2047 | | 0.2252 | * |
| | | 20 | 0.1067 | | 0.1164 | * |
| | | >20 | 0.0000 | | 0.0000 | * |
| | Non-Fuel Energy (¢ per kWh) | | 2.235 | | 2.718 | |
| | Willful Damage<br>All occurrences after initial repair | | Cost for repair or replacement | | Cost for repair or replacement | |
| * 10 and 20 year payment options closed to new facilities | | | | | | |
| RL-1 | Recreational Lighting [Schedule closed to new customers] | | | | | |
| | Non-Fuel Energy (¢ per kWh) | | Otherwise applicable General Service Rate | | Otherwise applicable General Service Rate | |
| | Maintenance | | FPL's estimated cost of maintaining facilities | | FPL's estimated cost of maintaining facilities | |

SCHEDULE 7
Page 13 of 19

| (1) CURRENT RATE SCHEDULE | (2) TYPE OF CHARGE | (3) CURRENT RATE | (4) RATE SCHEDULE | (5) COMMISSION APPROVED RATE |
|---|---|---|---|---|
| OL-1 | Outdoor Lighting | | | |
| | Charges for FPL-Owned Units | | | |
| | Fixture | | | |
| | Sodium Vapor 5,800 lu 70 watts | $4.48 | | $4.49 |
| | Sodium Vapor 9,500 lu 100 watts | $4.59 | | $4.59 |
| | Sodium Vapor 16,000 lu 150 watts | $4.75 | | $4.75 |
| | Sodium Vapor 22,000 lu 200 watts | $6.91 | | $6.91 |
| | Sodium Vapor 50,000 lu 400 watts | $7.35 | | $7.35 |
| | * Sodium Vapor 12,000 lu 150 watts | $5.08 | | $5.10 |
| | * Mercury Vapor 6,000 lu 140 watts | $3.45 | | $3.45 |
| | * Mercury Vapor 8,600 lu 175 watts | $3.47 | | $3.47 |
| | * Mercury Vapor 21,500 lu 400 watts | $5.68 | | $5.68 |
| | Maintenance | | | |
| | Sodium Vapor 5,800 lu 70 watts | $1.50 | | $1.03 |
| | Sodium Vapor 9,500 lu 100 watts | $1.51 | | $1.03 |
| | Sodium Vapor 16,000 lu 150 watts | $1.54 | | $1.05 |
| | Sodium Vapor 22,000 lu 200 watts | $1.98 | | $1.36 |
| | Sodium Vapor 50,000 lu 400 watts | $1.95 | | $1.34 |
| | * Sodium Vapor 12,000 lu 150 watts | $1.72 | | $1.20 |
| | * Mercury Vapor 6,000 lu 140 watts | $1.36 | | $0.93 |
| | * Mercury Vapor 8,600 lu 175 watts | $1.36 | | $0.93 |
| | * Mercury Vapor 21,500 lu 400 watts | $1.92 | | $1.31 |
| | Energy Non-Fuel | | | |
| | Sodium Vapor 5,800 lu 70 watts | $0.65 | | $0.85 |
| | Sodium Vapor 9,500 lu 100 watts | $0.92 | | $1.20 |
| | Sodium Vapor 16,000 lu 150 watts | $1.34 | | $1.76 |
| | Sodium Vapor 22,000 lu 200 watts | $1.97 | | $2.58 |
| | Sodium Vapor 50,000 lu 400 watts | $3.76 | | $4.92 |
| | * Sodium Vapor 12,000 lu 150 watts | $1.34 | | $1.76 |
| | * Mercury Vapor 6,000 lu 140 watts | $1.39 | | $1.82 |
| | * Mercury Vapor 8,600 lu 175 watts | $1.72 | | $2.26 |
| | * Mercury Vapor 21,500 lu 400 watts | $3.58 | | $4.69 |

| (1) CURRENT RATE SCHEDULE | (2) TYPE OF CHARGE | (3) CURRENT RATE | (4) RATE SCHEDULE | (5) COMMISSION APPROVED RATE |
|---|---|---|---|---|
| OL-1 | Outdoor Lighting (continued) | | | |
| | Charges for Customer Owned Units | | | |
| | Total Charge-Relamping & Energy | | | |
| | Sodium Vapor 5,800 lu 70 watts | $1.41 | | $0.97 |
| | Sodium Vapor 9,500 lu 100 watts | $1.70 | | $1.16 |
| | Sodium Vapor 16,000 lu 150 watts | $2.11 | | $1.44 |
| | Sodium Vapor 22,000 lu 200 watts | $2.73 | | $1.88 |
| | Sodium Vapor 50,000 lu 400 watts | $4.54 | | $3.12 |
| | * Sodium Vapor 12,000 lu 150 watts | $2.37 | | $1.65 |
| | * Mercury Vapor 6,000 lu 140 watts | $2.15 | | $1.47 |
| | * Mercury Vapor 8,600 lu 175 watts | $2.49 | | $1.70 |
| | * Mercury Vapor 21,500 lu 400 watts | $4.37 | | $2.98 |
| | Energy Only | | | |
| | Sodium Vapor 5,800 lu 70 watts | $0.65 | | $0.85 |
| | Sodium Vapor 9,500 lu 100 watts | $0.92 | | $1.20 |
| | Sodium Vapor 16,000 lu 150 watts | $1.34 | | $1.76 |
| | Sodium Vapor 22,000 lu 200 watts | $1.97 | | $2.58 |
| | Sodium Vapor 50,000 lu 400 watts | $3.76 | | $4.92 |
| | * Sodium Vapor 12,000 lu 150 watts | $1.34 | | $1.76 |
| | * Mercury Vapor 6,000 lu 140 watts | $1.39 | | $1.82 |
| | * Mercury Vapor 8,600 lu 175 watts | $1.72 | | $2.26 |
| | * Mercury Vapor 21,500 lu 400 watts | $3.58 | | $4.69 |
| | Non-Fuel Energy (¢ per kWh) | 2.238 | | 2.931 |
| | Other Charges | | | |
| | Wood Pole | $3.51 | | $3.51 |
| | Concrete Pole | $4.72 | | $4.72 |
| | Fiberglass Pole | $5.55 | | $5.55 |
| | Underground conductors excluding Trenching per foot | $0.017 | | $0.017 |
| | Down-guy, Anchor and Protector | $2.04 | | $2.04 |
| SL-2 | Traffic Signal Service | | | |
| | Base Energy Charge (¢ per kWh) | 3.648 | | 3.700 |
| | Minimum Charge at each point | $2.88 | | $2.88 |

| (1) CURRENT RATE SCHEDULE | (2) TYPE OF CHARGE | (3) CURRENT RATE | (4) RATE SCHEDULE | (5) COMMISSION APPROVED RATE |
|---|---|---|---|---|
| SST-1 | Standby and Supplemental Service | | | |
| | Customer Charge | | | |
| | SST-1(D1) | $136.23 | | $75.13 |
| | SST-1(D2) | $136.23 | | $75.13 |
| | SST-1(D3) | $196.78 | | $204.19 |
| | SST-1(T) | $428.86 | | $1,451.71 |
| | Distribution Demand $/kW Contract Standby Demand | | | |
| | SST-1(D1) | $2.16 | | $2.61 |
| | SST-1(D2) | $2.53 | | $4.31 |
| | SST-1(D3) | $2.22 | | $2.38 |
| | SST-1(T) | N/A | | N/A |
| | Reservation Demand $/kW | | | |
| | SST-1(D1) | $0.80 | | $0.86 |
| | SST-1(D2) | $0.79 | | $0.86 |
| | SST-1(D3) | $0.79 | | $0.86 |
| | SST-1(T) | $0.77 | | $1.03 |
| | Daily Demand (On-Peak) $/kW | | | |
| | SST-1(D1) | $0.37 | | $0.41 |
| | SST-1(D2) | $0.36 | | $0.41 |
| | SST-1(D3) | $0.36 | | $0.41 |
| | SST-1(T) | $0.36 | | $0.29 |
| | Supplemental Service | | | |
| | Demand | Otherwise Applicable Rate | | Otherwise Applicable Rate |
| | Energy | Otherwise Applicable Rate | | Otherwise Applicable Rate |
| | Non-Fuel Energy - On-Peak (¢ per kWh) | | | |
| | SST-1(D1) | 0.754 | | 0.612 |
| | SST-1(D2) | 0.774 | | 0.612 |
| | SST-1(D3) | 0.765 | | 0.612 |
| | SST-1(T) | 0.692 | | 0.627 |
| | Non-Fuel Energy - Off-Peak (¢ per kWh) | | | |
| | SST-1(D1) | 0.754 | | 0.612 |
| | SST-1(D2) | 0.774 | | 0.612 |
| | SST-1(D3) | 0.765 | | 0.612 |
| | SST-1(T) | 0.692 | | 0.627 |

SCHEDULE 7
Page 16 of 19

| (1) CURRENT RATE SCHEDULE | (2) TYPE OF CHARGE | (3) CURRENT RATE | (4) RATE SCHEDULE | (5) COMMISSION APPROVED RATE |
|---|---|---|---|---|
| ISST-1 | Interruptible Standby and Supplemental Service | | | |
| | Customer Charge | | | |
| | Distribution | $630.68 | | $200.00 |
| | Transmission | $3,254.33 | | $1,891.00 |
| | Distribution Demand | | | |
| | Distribution | $2.46 | | $2.59 |
| | Transmission | N/A | | N/A |
| | Reservation Demand-Interruptible | | | |
| | Distribution | $0.17 | | $0.18 |
| | Transmission | $0.15 | | $0.16 |
| | Reservation Demand-Firm | | | |
| | Distribution | $0.79 | | $0.83 |
| | Transmission | $0.77 | | $0.81 |
| | Supplemental Service | | | |
| | Demand | Otherwise Applicable Rate | | Otherwise Applicable Rate |
| | Energy | Otherwise Applicable Rate | | Otherwise Applicable Rate |
| | Daily Demand (On-Peak) Firm Standby | | | |
| | Distribution | $0.36 | | $0.38 |
| | Transmission | $0.36 | | $0.38 |
| | Daily Demand (On-Peak) Interruptible Standby | | | |
| | Distribution | $0.07 | | $0.07 |
| | Transmission | $0.07 | | $0.07 |
| | Non-Fuel Energy - On-Peak (¢ per kWh) | | | |
| | Distribution | 0.762 | | 0.631 |
| | Transmission | 0.536 | | 0.585 |
| | Non-Fuel Energy - Off-Peak (¢ per kWh) | | | |
| | Distribution | 0.762 | | 0.631 |
| | Transmission | 0.536 | | 0.585 |
| | Excess "Firm Standby Demand" | | | |
| | ¤ Up to prior 60 months of service | Difference between reservation charge for firm and interruptible standby demand times excess demand | | Difference between reservation charge for firm and interruptible standby demand times excess demand |
| | ¤ Penalty Charge per kW for each month of rebilling | $0.99 | | $0.99 |

| (1) CURRENT RATE SCHEDULE | (2) TYPE OF CHARGE | (3) CURRENT RATE | (4) RATE SCHEDULE | (5) COMMISSION APPROVED RATE |
|---|---|---|---|---|
| WIES-1 | Wireless Internet Electric Service | | | |
| | Non-Fuel Energy (¢ per kWh) | 19.326 | | 38.877 |
| | Minimum ten internet device delivery points with monthly energy usage not less than 20kWh or more than 50kWh per device. | | | |
| TR | Transformation Rider | | | |
| | Transformer Credit (per kW of Billing Demand) | ($0.39) | | ($0.24) |
| GSCU-1 | General Service constant Usage | | | |
| | Customer Charge: | $10.08 | | $6.00 |
| | Non-Fuel Energy Charges: | | | |
| | Base Energy Charge* | 2.613 | | 3.430 |
| | * The fuel and non-fuel energy charges will be assessed on the Constant Usage kWh | | | |
| HLFT-1 | High Load Factor - Time of Use | | | |
| | Customer Charge: | | | |
| | 21 - 499 kW: | $41.87 | | $22.77 |
| | 500 - 1,999 kW | $41.37 | | $50.13 |
| | 2,000 kW or greater | $171.54 | | $179.19 |
| | Demand Charges: | | | |
| | On-peak Demand Charge: | | | |
| | 21 - 499 kW: | $7.50 | | $7.83 |
| | 500 - 1,999 kW | $7.49 | | $7.83 |
| | 2,000 kW or greater | $7.49 | | $7.83 |
| | Maximum Demand Charge: | | | |
| | 21 - 499 kW: | $1.60 | | $1.81 |
| | 500 - 1,999 kW | $1.65 | | $1.81 |
| | 2,000 kW or greater | $1.62 | | $1.81 |
| | Non-Fuel Energy Charges: (¢ per kWh) | | | |
| | On-Peak Period | | | |
| | 21 - 499 kW: | 1.697 | | 1.179 |
| | 500 - 1,999 kW | 0.533 | | 0.527 |
| | 2,000 kW or greater | 0.533 | | 0.497 |

| (1) CURRENT RATE SCHEDULE | (2) TYPE OF CHARGE | (3) CURRENT RATE | (4) RATE SCHEDULE | (5) COMMISSION APPROVED RATE |
|---|---|---|---|---|
| | Off-Peak Period | | | |
| | 21 - 499 kW: | 0.533 | | 0.635 |
| | 500 - 1,999 kW | 0.533 | | 0.527 |
| | 2,000 kW or greater | 0.533 | | 0.497 |
| SDTR | Seasonal Demand – Time of Use Rider | | | |
| | Option A | | | |
| | Customer Charge: | | | |
| | 21 - 499 kW: | $35.31 | | $22.77 |
| | 500 - 1,999 kW | $41.37 | | $50.13 |
| | 2,000 kW or greater | $171.54 | | $179.19 |
| | Demand Charges: | | | |
| | Seasonal On-peak Demand: | | | |
| | 21 - 499 kW: | $6.08 | | $7.70 |
| | 500 - 1,999 kW | $6.70 | | $8.55 |
| | 2,000 kW or greater | $6.70 | | $9.00 |
| | Non-seasonal Demand Max Demand: | | | |
| | 21 - 499 kW: | $5.12 | | $5.58 |
| | 500 - 1,999 kW | $6.09 | | $7.26 |
| | 2,000 kW or greater | $6.09 | | $7.22 |
| | Energy Charges (¢ per kWh): | | | |
| | Seasonal On-peak Energy: | | | |
| | 21 - 499 kW: | 4.287 | | 5.608 |
| | 500 - 1,999 kW | 3.281 | | 3.614 |
| | 2,000 kW or greater | 3.273 | | 2.949 |
| | Seasonal Off-peak Energy: | | | |
| | 21 - 499 kW: | 1.133 | | 0.952 |
| | 500 - 1,999 kW | 0.896 | | 0.622 |
| | 2,000 kW or greater | 0.893 | | 0.582 |
| | Non-seasonal Energy | | | |
| | 21 - 499 kW: | 1.485 | | 1.382 |
| | 500 - 1,999 kW | 1.175 | | 0.903 |
| | 2,000 kW or greater | 1.172 | | 0.845 |

SCHEDULE 7
Page 19 of 19

| (1) CURRENT RATE SCHEDULE | (2) TYPE OF CHARGE | (3) CURRENT RATE | (4) RATE SCHEDULE | (5) COMMISSION APPROVED RATE |
|---|---|---|---|---|
| SDTR | Seasonal Demand – Time of Use Rider (continued) | | | |
| | Option B | | | |
| | Customer Charge: | | | |
| | 21 - 499 kW: | $41.87 | | $22.77 |
| | 500 - 1,999 kW | $41.37 | | $50.13 |
| | 2,000 kW or greater | $171.54 | | $179.19 |
| | Demand Charges: | | | |
| | Seasonal On-peak Demand: | | | |
| | 21 - 499 kW: | $6.08 | | $7.70 |
| | 500 - 1,999 kW | $6.70 | | $8.55 |
| | 2,000 kW or greater | $6.70 | | $9.00 |
| | Non-seasonal On-peak Demand: | | | |
| | 21 - 499 kW: | $5.12 | | $5.58 |
| | 500 - 1,999 kW | $6.09 | | $7.26 |
| | 2,000 kW or greater | $6.09 | | $7.22 |
| | Energy Charges (¢ per kWh): | | | |
| | Seasonal On-peak Energy: | | | |
| | 21 - 499 kW: | 4.287 | | 5.608 |
| | 500 - 1,999 kW | 3.281 | | 3.614 |
| | 2,000 kW or greater | 3.273 | | 2.949 |
| | Seasonal Off-peak Energy: | | | |
| | 21 - 499 kW: | 1.133 | | 0.952 |
| | 500 - 1,999 kW | 0.896 | | 0.622 |
| | 2,000 kW or greater | 0.893 | | 0.582 |
| | Non-seasonal On-peak Energy: | | | |
| | 21 - 499 kW: | 3.466 | | 3.107 |
| | 500 - 1,999 kW | 2.328 | | 1.865 |
| | 2,000 kW or greater | 2.445 | | 1.718 |
| | Non-seasonal Off-peak Energy: | | | |
| | 21 - 499 kW: | 0.953 | | 0.952 |
| | 500 - 1,999 kW | 0.707 | | 0.622 |
| | 2,000 kW or greater | 0.661 | | 0.582 |

SCHEDULE 8

**FLORIDA POWER & LIGHT COMPANY**
**Docket No. 080677-EI**
**Monthly 1,000 Kilowatt-Hour Residential Electric Bill**

| | Current | Effective March 1, 2010 | Increase/ (Decrease) |
|---|---|---|---|
| Customer Charge | $5.69 | $5.90 | $0.21 |
| Energy Charge | $36.31 | $37.11 | $0.80 |
| Fuel and Purchased Power | $38.57 | $38.57 | $0.00 |
| Energy Conservation Cost Recovery | $1.88 | $1.88 | $0.00 |
| Environmental Cost Recovery | $1.79 | $1.79 | $0.00 |
| Capacity Cost Recovery | $6.21 | $6.21 | $0.00 |
| Storm Cost Recovery Surcharge | $2.59 | $2.59 | $0.00 |
| Gross Receipts Taxes | $2.39 | $2.41 | $0.02 |
| Total Monthly Bill | **$95.43** | **$96.46** | **$1.03** |

**Florida Power & Light Company**
**Total Residential Bill Comparisons by kWh Usage**

| Usage | Current | Effective March 1, 2010 | Difference From Current $ | % |
|---|---|---|---|---|
| 1,000 kWh | $95.43 | $96.46 | $1.03 | 1.1% |
| 1,250 kWh | $123.21 | $124.19 | $0.98 | 0.8% |
| 1,500 kWh | $151.01 | $151.93 | $0.92 | 0.6% |
| 2,000 kWh | $206.57 | $207.38 | $0.81 | 0.4% |
| 2,500 kWh | $262.15 | $262.85 | $0.70 | 0.3% |
| 3,000 kWh | $317.72 | $318.31 | $0.59 | 0.2% |

Appendix A

STIPULATIONS

At the prehearing, the parties reached stipulations on several issues. At the commencement of the hearing, we voted on, and approved, those stipulations. The stipulations previously approved by us are listed below. The stipulations fall within one of two categories, as listed below. "Category 1" stipulations reflect the agreement of FPL, our staff, and all of the intervenors in this docket. "Category 2" stipulations reflect the agreement of FPL and our staff where no other party has taken a position on the issue. Issues 123 and 127 are also classified as Category 2 stipulations, although some, but not all, intervenors agreed with FPL and our staff.

**CATEGORY 1 STIPULATIONS:**

**ISSUE 54:** Should FPL be permitted to record in rate base the incremental difference between Allowance for Funds Used During Construction (AFUDC) permitted by Section 366.93, F.S. for nuclear construction and FPL's most currently approved AFUDC for recovery when the nuclear plants enter commercial operation?

**PARTIES**: The parties agree that this issue will be decided in a different docket.

**CATEGORY 2 STIPULATIONS:**

***The following issues have been agreed to by some parties. All other parties took no position.***

**ISSUE 123:** Should an adjustment continue to be made to Administrative and General Expenses to eliminate "Atrium Expenses" per Order No. 10306, Docket No. 810002-EU?
A. For the 2010 projected test year?
B. If applicable, for the 2011 subsequent projected test year?

**POSITION**: No. the atrium has been retired and the adjustment is no longer necessary.

**ISSUE 127:** Should the Commission adjustment in FPL's 1985 base rate case, Docket No. 830465-EI, for imputed revenues associated with orange groves be reversed?
A. For the 2010 projected test year?
B. If applicable, for the 2011 subsequent projected test year?

**PARTIES**: Yes. The adjustment is no longer necessary as FPL leases the property and has included the lease revenue in operating revenues.

***For the following issues, staff agrees with the FPL's position, and all other parties took no position. Accordingly, there are no factual issues in dispute.***

**ISSUE 53:** Has FPL removed any Environmental Cost Recovery Clause (ECRC) capital cost recovery items from the ECRC and placed them into rate base?
A. For the 2010 projected test year?
B. If applicable, for the 2011 subsequent projected test year?

**POSITION:** No. FPL has not removed any ECRC capital cost recovery items from the ECRC and placed them in base rates.

**ISSUE 57:** Should any adjustments be made to FPL's fuel inventories?

**POSITION:** No. Subject to the adjustments listed on FPL witness Ousdahl's Exhibit KO-16, the 2010 and 2011 projections of FPL's fuel inventories are appropriate.

**ISSUE 98:** Should an adjustment be made to advertising expenses?
A. For the 2010 projected test year?
B. If applicable, for the 2011 subsequent projected test year?

**POSITION:** No. An adjustment is not necessary as advertising expenses included in 2010 and 2011 are utility related and informational, educational or related to consumer safety

**ISSUE 99:** Has FPL made the appropriate adjustments to remove lobbying expenses?
A. For the 2010 projected test year?
B. If applicable, for the 2011 subsequent projected test year?

**POSITION:** FPL has reflected the amounts applicable to lobbying expenses below the line for the projected test year 2010 and for the subsequent test year 2011. Therefore, no adjustment to remove lobbying expenses from net operating income is required.

**ISSUE 143:** Has FPL properly adjusted revenues to account for unbilled revenues?

**POSITION:** Yes. The appropriate adjustment to account for the increase in unbilled revenue is that shown in MFR E-12.

**ISSUE 146:** Are FPL's proposed Temporary Service Charges appropriate? (4.030)

**POSITION:** Yes. The appropriate Temporary/Construction Service Charges, as shown in MFR E-14, Attachment 1, are: (1) for Overhead: $255; and (2) for Underground: $142.

**ISSUE 147:** Is FPL's proposed increase in the charges to obtain a Building Efficiency Rating System (BERS) rating appropriate? (4.041)

**POSITION**: Yes. FPL has properly calculated the proposed charges for providing BERS audits pursuant to Florida Administrative Code Rule 25-17.003 (4) (a ).

**ISSUE 149**: Are FPL's proposed charges under the Street Lighting Vandalism Option notification appropriate? (8.717)

**POSITION**: Yes. The appropriate charge, as shown in MFR-E-14, Attachments 1 and 3, is $279.98.

**ISSUE 151**: Is FPL's proposal to close the Wireless Internet Rate (WIES) schedule to new customers appropriate?

**POSITION**: Yes. As outlined in the current WIES tariff FPL is authorized to petition the Commission to close the WIES rate schedule if the kWh under the rate schedule have not reached 360,000 kWh by June 2004. For the twelve month period ending June 2009, kWh sales under the WIES have only reached 20,640 kWh.

**ISSUE 153:** Should FPL's proposal to remove the 10 year and 20 year payment options from the PL-1 and RL-1 tariff be approved? (8.720 and 8.743)

**POSITION**: Yes. Removing this option will avoid collection issues that often occur when the original customer requesting the payment option (e.g., a developer) transfers payment responsibility to another party (e.g., a homeowner's association).

**ISSUE 158**: Is FPL's proposed minimum charge for non-metered service under the GS rate appropriate?

**POSITION**: Yes, the proposed minimum charge for non-metered service under the GS rate appropriately reflects the difference between the GS customer charge and the metering costs for serving GS-1 customers.

**ISSUE 176**: Should FPL be required to file, within 90 days after the date of the final order in this docket, a description of all entries or adjustments to its annual report, rate of return reports, and books and records which will be required as a result of the Commission's findings in this rate case?

**POSITION**: Yes.