BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In Re: Petition for a rate increase by Florida Power Corporation.	DOCKET NO. 910890-EI ORDER NO. PSC-92-1197-FOF-EI ISSUED: 10/22/92

The following Commissioners participated in the disposition of this matter:

THOMAS M. BEARD, Chairman
SUSAN F. CLARK
J. TERRY DEASON
BETTY EASLEY
LUIS J. LAUREDO

Pursuant to duly given notice, the Florida Public Service Commission held public hearings in this docket on May 5, 1992, in Tallahassee, Florida; on May 13, 1992, in Ocoee, Florida; on May 14, 1992, in Clearwater, Florida; on May 14, 1992, in St. Petersburg, Florida; and July 9 through July 24, 1992, in Tallahassee, Florida. Having considered the record herein, the Commission now enters its final order.

APPEARANCES:

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ORDER GRANTING CERTAIN INCREASES

BY THE COMMISSION:

On January 31, 1992, Florida Power Corporation (FPC) filed a petition requesting a rate increase, with supporting testimony and minimum filing requirements (MFRs). In its petition the company requested a total permanent rate increase of $145,853,000 based on projected test years of 1992 and 1993. This request was later reduced to $131,948,000 as a result of several audit findings and FPC's decision not to request an increase due to the purchase of the Sebring Utilities distribution system. FPC also requested a $9,990,000 reward for excellent performance, and that the proposed increase be implemented in several steps. The requested rate increase was based on a 13.60% return on common equity.

FPC filed supplemental MFRs after its initial MFRs were determined to be deficient by the Director of the Division of Electric and Gas of the Florida Public Service Commission. On April 14, 1992, we issued Order No. PSC-92-0208-FOF-EI, suspending the rate schedules filed by FPC, and authorizing FPC to increase its rates on an interim basis to generate additional annual revenues of $31,208,000. On June 19, 1992, a prehearing conference was conducted in this docket. Hearings were held on FPC's petition for a permanent rate increase July 9 through 10, July 13 through 17, July 20 and July 22 through 24, 1992.

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I. SUMMARY OF DECISION

We authorize an increase to Florida Power Corporation in gross annual revenues of $57,986,000 beginning November, 1992; an additional $9,660,000 increase beginning April, 1993; and a final increase of $18,111,000 beginning November, 1993, for a total increase of $85,757,000. Rate changes shall become effective with the company's first billing cycle of each month for which permanent new rates have been approved.

We have set the rate of return on common equity capital at 12%.

We deny Florida Power Corporation's request for a $9,990,000 regard for excellent performance.

II. TEST PERIOD

A. 1992 And 1993 Test Years

The purpose of the test year is to represent the financial operations of a company during the period in which the new rates will be in effect. Based on the filing date of FPC's request for a rate increase the first year that the new rates will be in effect is approximately from November 1, 1992 to October 31, 1993. Therefore, we should be evaluating the financial operations of FPC for the twelve months from November 1, 1992 to October 31, 1993.

There are primarily two options for evaluating FPC's expected financial operations. The first option is to use a historical test year and make proforma adjustments to it. The second is to use a projected test year. Both of these options have strengths and weaknesses.

The historical test year has the advantage of using actual data for much of rate base, NOI and capital structure; however, the proforma adjustments usually do not represent all the changes which 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 forecast. Many companies are not able to forecast accurately enough to use the forecast for setting rates.

FPC requested the use of two fully projected test years, calendar years 1992 and 1993. It selected the period in which new rates will become effective. The parties agree that, with adjustments, the 1992 test year is appropriate. At issue is the use of the 1993 forecast year. FPC believes that its forecast of financial operations for the years that new rates will be in effect is complete and accurate and provides a valid basis on which to set rates prospectively. The use of dual test periods is authorized by Section 366.076(2), Florida Statutes, and Rule 25-6.0425, Florida Administrative Code, and is consistent with Commission practice. See Order No. 13537, issued July 24, 1984 in Docket No. 830465-EI (FPL rate case). OPC and Occidental believe that the forecast is inaccurate and unreliable and that the authorization of dual test periods would set a dangerous precedent. In its brief, FPC pointed out that the precedent for dual test years was set eight years ago and has not produced the dire consequences predicted by the intervenor witnesses. In addition, we monitor utility earnings through surveillance reports and could require FPC to file MFRs should it exceed its allowed return.

The parties and the staff have conducted extensive discovery on FPC's forecast. We believe that FPC's forecast, as adjusted herein, is accurate enough to use as a basis for setting rates.

B. <u>Forecast</u>

We reviewed the company's original forecasts of customers and KWH by revenue class and system KW for 1992 and 1993 (Exhibit 147), the revised forecast (Exhibit 148), and the relationship of the original to the revised documents. We also reviewed Public Counsel's filing on the forecast. We have voted for using a revised forecast which reduces the 1992 forecast KWH by 3.59 percent and the 1993 forecast KWH by 2.25 percent.

The May 1992 forecast variance (Exhibit 37) showed actual year-to-date KWH sales to be 5.8% below the original KWH forecast.

Nothing we heard at the hearing persuaded us that the originally filed forecast is the better one to use. Instead, we believe that economic conditions warrant our reliance on the revised forecast. (Tr. 1843-1844, 1859-1860) In addition, reliance on the actual and more recent data that is available is generally better than a projection. (Tr. 1835, 1843) We have confidence in the integrity of the company's methodology in preparing the forecast and the record demonstrates the company's forecast process is inherently unbiased. (Tr. 1829, 1833, 1841)

The Commission has the discretion to use the original forecast, the revised forecast, forecasts by other parties, or some numbers in-between so long as the determination is based on the record. Gulf Power v. Florida Public Service Commission, 453 So.2d 799 (Fla. 1984).

C. Forecasted Inflation Rates

FPC originally forecast, inflation of 3.7% for 1992 and 3.8% for 1993, as measured by one Consumer Price Index. These forecasts were taken from the DRI Forecast for the US Economy of May 1991 (LF Exhibit 190). This compares to the June 1992 inflation forecast from DRI of 3.3% for 1992 and 3.5% for 1993 (LF Exhibit 190). In the hearing, whose witness, Mr. Kollen, recommended an inflation forecast of 3.1% for 1992, and 3.3% for 1993. (Tr. 2759)

The inflation forecast is used for rate making purposes to determine the appropriate amount of test year expenses. While we recognize that inflationary expectations have declined by one half of one percent for both 1992 and 1993 since FPC prepared their forecast in May 1991, we believe that FPC's inflation forecasts are appropriate for rate making purposes.

III. ACCOUNTING TREATMENT

A. FAS 87

Statement of Financial Accounting Standard No. (FAS) 87, titled Employer's Accounting for Pensions, which has been in effect since 1987, provides a method to record pension expense on an accrual basis. Although FPC has been using FAS No. 87, it has been making a regulatory adjustment under FAS No. 71, titled Accounting for the Effects of Certain Types of Regulation, to net the expense to zero. However, for the purposes of this proceeding, FPC filed its pension expense based upon a calculation in accordance with FAS No. 87. The company argued that accrual accounting more closely matches the cost of the benefit with the period in which the service is provided. Accordingly, the company stated its desire to move from cash accounting to accrual accounting. The intervenors argued that FAS No. 87 should not be used to determine the appropriate level of FPC's pension expense.

The purpose of FAS No. 87 is to accrue pension expense over the time employees earn benefits. While FPC will not make a cash contribution until 1993, the benefits earned by today's employees should be paid by today's ratepayers. Therefore, we shall use FAS No. 87 for ratemaking purposes. We approve FPC's request to set its pension expense at a level equal to the expense calculated for accounting purposes under the provisions of FAS No. 87.

B. <u>FAS 106</u>

The basic concept underlying FAS No. 106, titled Employers' Accounting for Postretirement Benefits Other Than Pensions, is the concept of accrual verses cash basis accounting to record other postretirement benefits (OPEB). FPC has requested that we begin using the accrual method for ratemaking purposes. Because accrual accounting matches the cost of employees' services to the period in which the employees provide the services, we agree. If we were to continue the pay-as-you-go method, future customers would pay for costs related to past years. Ultimately, the costs of retirement benefits under FAS No. 106 will not vary from costs under pay-as-you-go accounting, but the timing of the recognition of these costs will be different. The accrual accounting prescribed by FAS No. 106 appropriately recognizes the cost of retirement benefits. In fact, we have previously approved the concept of using FAS No. 106 for ratemaking purposes by Order No. PSC-92-0708-FOF-TL, issued July 24, 1992, in Docket No. 910980-TL, the recent rate case for United Telephone Company of Florida. In that order, we noted that we can still make adjustments to the cost of retirement benefits within the framework of FAS No. 106.

OPC, FIPUG, and Occidental testified that FAS No. 106 is unsuitable for ratemaking purposes. OPC argued that FPC could restructure its benefits plan, which would lower its FAS No. 106 cost after the rate case. However, FPC has already updated its FAS No. 106 cost to a lower amount based on its most recent collective bargaining agreement. In addition, FPC is constrained from making substantial changes from year to year due to a binding union contract, possible employee relations problems that could result from such changes, and labor market competitiveness. To the extent FPC continues cost containment measures, those measures will be reflected in FAS No. 106 costs and this effect can be monitored by our staff with the existing surveillance methodology.

OPC and FIPUG testified that the calculation of FAS No. 106 cost is unreliable and speculative. They argued that the FAS No. 106 amount is sensitive to changes in the assumptions used in its calculation, particularly the health care cost trend rate, and that the calculations reflect neither cost containment measures FPC may adopt in the future nor the possibility of government intervention in the health care area. FPC testified that the assumptions represent the best estimate of a particular future event and that the assumptions and measurements used in reporting FAS No. 106 costs are reviewed by independent auditors. FAS No. 106 contains a self-correcting methodology that encompasses changes in assumptions, experience being different from what the company assumed, and benefits plan amendments. Although changes in the FAS No. 106 costs would be accounted for with this methodology, they could not be recognized until the company's next rate case. However, such changes would affect earnings and this effect would be monitored with our present surveillance methodology. The uncertainty surrounding FAS No. 106 costs is no different from the uncertainty involved with the cost of equity, depreciation expense, nuclear decommissioning expense, fossil fuel dismantlement, or any other costs based upon estimates that we consider for ratemaking purposes.

OPC argued that if we approve FAS No. 106, we should establish a mechanism to annually refund to ratepayers any overrecovery of OPEB costs. FPC recommended that we adopt a dollar tracking procedure to account for any differences that may develop between the FAS No. 106 expense included in rates and subsequent changes to the amount of FAS No. 106 expense. However, we believe that requiring surveillance reports and requiring companies to file MFRs every four years will adequately monitor the effects of changes in FAS No. 106 costs.

OPC and FIPUG testified that using FAS No. 106 for ratemaking purposes can create an intergenerational inequity since the amortization of the transition obligation is a part of FAS No. 106 expense. The transition obligation is, essentially, the unrecognized amount of the postretirement benefit obligation as of the date a company initially applies FAS No. 106. The transition obligation represents the present value of benefits to be paid in the future and the amortization of the transition obligation allocates the present value of those future benefits to a 20 year period in the future. Under pay-as-you-go accounting, there will always be a mismatch between in time an employee earns postretirement benefits and the time the company recognizes the cost of those benefits. Even with the amortization of the transition obligation, FAS No. 106 is closer to achieving intergenerational equity than the pay-as-you-go method.

Occidental testified that accounting requirements should not drive the ratemaking process and that utility accounting follows the rate actions of a regulator. While generally accepted accounting principles need not be used for ratemaking purposes, in this instance accrual accounting provides more relevant and useful information than cash basis accounting. To the extent that regulatory accounting and generally accepted accounting principles are the same, the accounting and auditing functions could be simplified. Following generally accepted accounting principles can be appropriate for ratemaking purposes.

FIPUG and Occidental testified that FAS No. 71 can be used to defer the difference between FAS No. 106 costs and pay-as-you-go costs. FPC testified that the Securities and Exchange Commission has taken the position that continued pay-as-you-go accounting is unacceptable. FPC argued that generally accepted accounting principles are the basis for determining cost of service and that continuing the pay-as-you-go method represents a significant departure from cost-based regulation. This, in turn, raises questions about the applicability of FAS No. 71.30

OPC argued that the transition obligation should remain on a pay-as-you-go basis, stating that it would be unwise for the Commission to change its policy "midstream." However, the calculation of the FAS No. 106 expense includes the amortization of the transition obligation. As stated above, FAS No. 106 is appropriate for ratemaking purposes.

Finally, OPC argued that interest expense on OPEB costs that have already been recognized should be excluded from the FAS No. 106 expense calculation. OPC stated that if the company funded its OPEB plan, the plan assets would earn profits that would offset interest. However, funding of OPEBs could be more costly due to the lack of a comprehensive funding method, and interest cost is inherent with the present value concepts behind FAS No. 106. OPC also argued that the discount rate should be the Commission's allowed return on equity. For reasons that will be discussed later, we disagree.

We approve FPC's request to move from a cash basis to an accrual basis when accounting for post-retirement benefits other than pensions for ratemaking purposes. The allowed OPEB expense should be calculated according to FAS No. 106 beginning in November of 1992.

IV. RATE BASE

To establish FPC's overall revenue requirements, we must determine its rate base. The rate base represents that investment on which the company is entitled to earn a reasonable return. A utility's rate base is comprised of various components, including 1) plant-in-service, 2) depreciation reserve, 3) construction work in progress (CWIP) (where appropriate), 4) property held for future use, 5) net nuclear fuel, and 6) working capital.

FPC requested a rate base of $3,006,775,000 ($3,318,818,000 system) for the 1992 current test year and $3,211,239,000 ($3,592,614,000 system) for the 1993 projected test year. Evidence developed during the course of the proceedings has led us to reduce that amount to $2,950,832,000 for 1992 and $3,179,393,000 for 1993. We therefore approve the rate base summarized in the following tables.

1992 Rate Base
Jurisdictional
(000's)

	FPC	Adjustments	Commission Approved
Pl.-in-Serv.	4,245,287	(21,904)	4,223,383
Acc. Deprec.	(1,483,255)	11,509	(1,471,746)
Net P.I.S.	2,762,032	(10,395)	2,751,637
CWIP	124,340	(32,288)	92,052
PHFU	9,559	(7,185)	2,374
Nuc. Fuel	58,351	(15)	58,336
Net Plant	2,954,282	(49,883)	2,904,399
Work. Cap.	52,493	(6,060)	46,433
Total	$3,006,775	$(55,943)	$2,950,832

1993 Rate Base
Jurisdictional
(000's)

	FPC	Adjustments	Commission Approved
Pl.-in-Serv.	4,617,090	(23,584)	4,593,506
Acc. Deprec.	(1,628,030)	18,483	(1,609,547)
Net P.I.S.	2,989,060	(5,101)	2,983,959
CWIP	110,667	(27,746)	82,921
PHFU	9,436	(7,073)	2,363
Nuc. Fuel	50,487	(17)	50,470
Net Plant	3,159,650	(39,937)	3,119,713
Work. Cap.	51,589	8,091	59,680
Total	$3,211,239	$(31,846)	$3,179,393

A. Plant-In-Service

The amount of plant-in-service proposed by FPC was $4,245,287,000 ($4,715,371,000 system) for the 1992 current test year and $4,617,090,000 ($5,175,330,000 system) for the 1993 projected test year. We have made certain adjustments, described below, which reduce plant-in-service to $4,223,383,000 for 1992 and $4,593,506,000 for 1993.

1. Aircraft

a. FPC's ownership of aircraft

FPC owns three aircraft which are also used by FPC's affiliates. None of FPC's investment in this flight equipment is allocated to any of its affiliates, nor is any related depreciation expense recovered from any of its affiliates. However, FPC does allocate to its affiliate other major costs of operating the aircraft such as fuel, salaries, and hangar fees. The affiliates' initial charge for use of the aircraft is generally based on 70% of commercial coach fare. Any remaining expenses not recovered from this initial charge are allocated based on usage.

Because FPC's affiliates' use of the aircraft is substantial, FPC and its affiliates should share the investment for the flight equipment as well as share the related depreciation. Accordingly, the investment and depreciation figures filed by FPC shall be reduced by 50%. The adjusted figures are as follows:

1992	System	Factor	Jurisdictional
Flight equipment	3,465,000	.941986	3,263,981
Accumulated Depreciation	(288,000)	.938045	(270,157)
Depreciation expense	237,000	.938045	222,317

1993	System	Factor	Jurisdictional
Flight equipment	3,465,000	.942785	3,266,750
Accumulated Depreciation	(525,000)	.938942	(492,945)
Depreciation expense	238,000	.938942	223,468

b. Rescinded purchase of airplane

In December 1990, FPC purchased a Piper Cheyenne from Florida Progress. In August 1991, the purchase was rescinded and plant-in-service and accumulated depreciation were adjusted, as though the purchase never occurred. Consequently, the Piper Cheyenne and related accumulated depreciation were on FPC's books during a portion of the interim test period and were included in the MFRs.

The company made pro forma adjustments to remove the airplane's effect on rate base, reducing plant-in-service $833,000 and reducing accumulated depreciation $68,000. However, these pro forma adjustments were calculated incorrectly because they treated the Piper Cheyenne as if it had been on the books for thirteen months, instead of nine months. Plant-in-service shall be increased $265,000 ($278,000 system) and accumulated depreciation shall be increased $38,000 ($40,000 system) in the 1991 interim test period to adjust for these overstatements. Because the 1992 and 1993 pro forma adjustments correctly remove the effects of the rescinded aircraft purchase, no adjustments are necessary for these test years.

2. Crystal River 3

FPC purchased Sebring Utilities Commission's 3.5 megawatt share of Crystal River 3. When compared to FPC's avoided cost, the purchase results in a savings of $893,000 over the remaining life of Crystal River 3; therefore, we find the purchase to be cost-effective. Accordingly, the acquisition and inclusion of $2,310,000 ($2,500,000 system) for Sebring's ownership share of Crystal River 3 is an appropriate addition to rate base for the 1992 current test year.

3. Lake Tarpon Substation

FPC expanded the Lake Tarpon substation to protect existing equipment that was operating at or near its existing emergency rating. An outage of the existing transformer would jeopardize reliable service. The substation upgrade was needed despite the fact that it will serve as the terminal point for the Lake Tarpon-Kathleen 500kv line. Because the substation expansion will maintain system reliability, the installation of the terminal point for the Lake Tarpon-Kathleen 500kv transmission line is a cost-effective addition. Accordingly, $10,838,960 ($14,381,000 system) was appropriately included in the 1992 current test year for capital additions at the Lake Tarpon Substation.

4. Sebring Utilities' Distribution System

The parties stipulated that the Sebring acquisition would not be included in this rate proceeding. Accordingly, for the 1992 and 1993 test years, the following reductions were made to remove the Sebring electric distribution system acquisition from rate base and net operating income:

	1992		1993	
	System	Juris.*	System	Juris.*
Plant In Service	15,924,000	18,640,000	17,150,000	20,317,000
Less:Acc.Dep.	5,787,000	6,910,000	6,783,000	8,011,000
CWIP	0	91,000	0	76,000
Working Capital	2,863,000	2,436,000	2,863,000	2,719,000
PHFU	0	9,000	0	11,000
Nuclear Fuel-Net	0	15,000	0	17,000
Regulatory Prac.	0	25,000	0	24,000
Total	$13,000,000	$14,306,000	$13,230,000	$15,153,000
Op. Revenues	6,927,000	6,927,000	7,158,000	7,158,000
Other Op. Revs.	640,000	540,000	736,000	613,000
Total Op.Revs.	$7,567,000	$7,467,000	$7,894,000	$7,771,000
O&M	6,723,000	6,011,000	6,964,000	6,203,000
Deprec. & Amort.	677,000	800,000	705,000	848,000
Taxes Other	21,000	253,000	229,000	275,000
Rev. Taxes	4,000	4,000	4,000	4,000
Income Tx.-Fed.	(286,000)	(132,000)	(266,000)	(120,000)
Income Tx.-St.	(47,000)	(22,000)	(41,000)	(20,000)
Deferred Tax	146,000	122,000	131,000	104,000
ITC-Net	0	(7,000)	0	(8,000)
Regulatory Prac.	0	1,000	0	1,000
Total Op. Exp.	$7,438,000	$7,030,000	$7,726,000	$7,287,000

*The jurisdictional amounts include the difference due to the change in the allocation factor. This additional amount represents the impact on the jurisdictional amounts resulting from the removal of Sebring sales from the system.

B. Accumulated Depreciation

Florida Power requested $1,483,255,000 ($1,673,510,000 system) for the 1992 current test year and $1,628,030,000 ($1,837,549,000 system) for the 1993 projected test year for accumulated depreciation. FPC used zero net salvage in forecasting the depreciation reserve for the 1992 and 1993 test years, which is unrealistic. The currently prescribed net salvage value is a more viable method. Using our currently prescribed net salvage value with numbers submitted by FPC, we find that the depreciation reserve shall be reduced $5,596,000 ($6,321,000, system) for 1992 and $10,581,000 ($11,958,000, system) for 1993. With the net result of the adjustments discussed below, we find the appropriate amount of accumulated depreciation to be $1,471,746,000 for 1992 and $1,609,547,000 for 1993.

1. <u>Nuclear Decommissioning Expense</u>

We approve the stipulation by the parties that the adjustments made to accumulated depreciation based on the company's nuclear decommissioning study shall be reversed in accordance with our decision in Docket No. 910081-EI regarding FPC's nuclear decommissioning study. Accumulated depreciation shall be reduced $2,221,000 ($2,052,000, system) for 1992 and $6,662,000 ($6,139,000, system) for 1993. This adjustment is included in the line item adjustment removing the entire nuclear decommissioning reserve from rate base, and has a zero effect. However it is necessary to reduce depreciation expense by $4,103,000 in 1992 and by $4,092,000 in 1993.

2. <u>Fossil Fuel Dismantlement Reserve</u>

FPC requested an adjustment to the 1992 and 1993 accumulated depreciation to reflect the effect of implementation of a levelized fossil fuel dismantlement expense. We find that FPC's requested adjustment is not appropriate. FPC's 1992 adjustment shall be increased by $991,687 ($1,193,460 system), and its 1993 adjustment shall be increased by $933,872 ($1,194,960 system). As discussed below, we shall increase the dismantlement expense which shall also serve as a rate base reduction. An increase in the dismantlement expense reduces rate base because of the corresponding increase in the depreciation reserve. Because we increase FPC's yearly fossil fuel dismantlement accrual below, we must adjust the associated reserve.

3. <u>Reserve Transfer Reversal</u>

Our decision in Docket No. 920096-EI, Order No. PSC-92-0680-FOF-EI, dated July 21, 1992, denied FPC's petition to reverse the transfer of reserves. Therefore, all figures associated with this adjustment should be reversed. The accumulated depreciation should be increased by $6,877,000 for 1992 and $6,468,000 for 1993. construction work in progress should be increased by $507,00 for 1992 and $492,000 for 1993. Working capital should be decreased by $582,000 for 1992 and decreased by $2,503,000 for 1993.

When we net these adjustments, rate base is reduced by $6,952,000 in 1992, and $8,479,000 in 1993. In addition, O&M expense is increased by $1,157,000 and depreciation expense is decreased by $3,850,000 for a net decrease of $2,693,000 to net operating income in 1992. For 1993, O&M expense is increased by $1,132,000 and depreciation expense is decreased by $2,987,000 for a net decrease of $1,855,000 to NOI.

C. <u>Construction Work In Progress</u>

The company has requested the amounts $124,340,000 ($139,203,000 system) for the 1992 current test year and $110,667,000 ($123,348,000 system) for the 1993 projected test year for construction work in progress (CWIP) to be included in rate base. However, we find that adjustments should be made to the balances for 1991, 1992, and 1993.

For the 1991 interim test year, CWIP should be reduced by $2,314,122 ($2,452,067 system) for construction projects which were included in Account 107.20, CWIP Not Eligible for allowance for funds used during construction (AFUDC), but which accrued AFUDC. CWIP should be increased by $1,069,179 ($1,131,851 system) for construction work orders which did not accrue AFUDC and were not included in CWIP. This results in a net decrease of $1,244,943.

OPC testified that one project in the 1992 test year was classified as Rate Base CWIP even though it accrued AFUDC. We agree; therefore, 1992 CWIP should be reduced by $1,254,066 ($1,405,000 system).

OPC also testified that actual CWIP for the months of December 1991 through March 1992 was approximately 25% lower than the balances projected by the company. FPC stated that OPC omitted from actual CWIP that portion of CWIP that is considered completed but not classified to electric plant in service. Because Account 106 is for projects that are classified in service, these amounts are plant in service and not CWIP. Because FPC overprojected the beginning months of the two year forecasts, which should be the easiest to accurately project, and it also forecasted by historical trend, it is appropriate to apply these early variances to the future projections. Therefore, the CWIP allowed in rate base should be reduced by 25% for both the 1992 and 1993 test years.

CWIP for 1992 shall be reduced by $1,254,066 ($1,405,000 system) for an AFUDC eligible project that was included in rate base. Also, the 1992 and 1993 test year jurisdictional CWIP allowed in rate base shall be reduced by a 25% overprojection factor, which is $30,684,000 for 1992 and $27,640,000 for 1993. The appropriate amount of CWIP for the 1992 test year is $92,052,000 and for the 1993 test year is $82,921,000.

D. Property Held For Future Use

In the past, Commission rate case decisions have reflected the importance of retaining certain properties held for future use in view of Florida's projected growth rate, the burden on the utilities to meet this growth rate, and the expense that might be incurred if the properties were sold and had to be replaced in the future at a greater cost. In this instance, except for the inclusion of Avon Park Unit 2, the parties agree that the level of Property Held for Future Use is appropriate.

Florida Power requested $9,559,000 ($11,145,000 system) for the 1992 current test year and $9,436,000 ($11,145,000 system) for the 1993 projected test year for property Held for Future Use. Because we have removed Avon Park Unit 2 from property held from future use, the appropriate jurisdictional level of property held for future use is $2,374,000 for 1992 and $2,363,000 for 1993.

1. Avon Park Unit 2

In FPC's 1984 rate case, the Commission ordered seventeen of FPC's units to be placed in extended cold shutdown, and that they be excluded from rate base, but allowed to accrue a carrying charge equivalent to the AFUDC rate until such time as they were returned to commercial service. For the 1992 test year, FPC projects that the only unit of the original seventeen still in extended cold shutdown will be Avon Park Unit 2. The company included this unit in Property Held for Future Use.

FPC has entered into a contract with Eco Peat to lease Avon Park Unit 2 for 32 years beginning in 1994 if Eco Peat meets its performance and construction dates. At present, Eco Peat appears to be on target to meet its schedule. Eco Peat plans to convert Unit 2 to a 40 megawatt electric generating facility fired by peat or other permitted fuels. The lease revenues from Unit 2 range from $500,000 to $1,200,000 per year plus bonus payments, if the tenant exceeds certain profitability thresholds. The net book value of the unit is about $1,028,000 in system figures.

Occidental recommended that Unit 2 be excluded from rate base. Occidental argued that the unit is not presently used and useful and may never be used and useful for retail ratepayers. While it is true that the unit is not used and useful at the present time, to exclude it from rate base entirely would deny the company the opportunity to recover its investment.

OPC argued that the unit should be included in rate base and revenues be recorded above the line. We disagree. Because there is a possibility that the lease may not become operational in 1994, ratepayers would have to pay a return on a unit that was not in service and from which no lease revenue would be recognized.

We considered the option of placing Unit 2 in plant in service and imputing revenues for 1993. However, there is a chance that the lease may not become operational, and it is difficult to calculate revenues that will be imputed since we do not have an executed lease setting specific lease payments. Instead, we shall exclude the unit from rate base, but allow it to accrue a carrying charge at the AFUDC rate until such time as the unit is returned to commercial service, or the lease becomes operational. When the lease becomes effective, the unit shall be recorded in plant-in-service and lease revenues shall be recorded above the line.

For the 1992 and 1993 test years, the following reductions shall be made to remove Avon Park Unit 2 from plant held for future use:

	(000)			
	1992		1993	
	Juris.	System	Juris.	System
PHFU	$7,176	$8,178	$7,062	$8,178
Acc.Dep/Amort.	(6,276)	(6,797)	(6,259)	(6,797)
Fossil Dsmtlmt.	(326)	(353)	(541)	(588)
Working Capital	473	508	472	508
	$1,047	$1,536	$ 734	$1,301

E. Working Capital

FPC requested $52,493,000 ($65,536,000 system) for the 1992 current test year and $51,589,000 ($67,405,000 system) for the 1993 projected test year for working capital. However, the appropriate jurisdictional amounts for 1992 and 1993 are $46,433,000 and $59,680,000. This is a calculation based on the resolution of all other working capital issues.

1. Methodology

Occidental argued that we should direct FPC to calculate working capital based upon a lead/lag methodology in its next base rate filing in lieu of its current methodology. We disagree. It would be inappropriate to single out FPC from the other regulated utilities in Florida to make a change that would be better handled in a generic proceeding.

2. Property Insurance Reserve

FPC currently maintains a funded Property Insurance Reserve to cover losses inflicted by major storms. FPC's base rates were last adjusted in Docket No. 870220-EI. Since that time, the company has been accruing $1,104,000 annually in its reserve. In this case, in accordance with Rule 25-6.0143, Florida Administrative Code, the company has requested an increase to the scope of its current storm damage reserve to include not only tropical storms and hurricanes, but other destructive acts of nature as well. We find that it would be appropriate for FPC to expand the scope of its reserve to cover other destructive acts of nature.

In addition, the company requested a cap of $5 million for its reserve, which is the amount of its Property Insurance deductibles. The company reduced its requested accrual to $314,000 annually to attain this cap. However, if FPC exceeds the $5 million cap before its next rate case, it shall continue to accrue its reserve. Because of the catastrophic damage caused by Hurricane Andrew, which took place after the proceeding in this case, we shall review the adequacy of the reserve in FPC's next rate case.

Also, FPC shall establish an unfunded reserve effective January 1, 1993. This unfunded reserve shall be established in accordance with the provisions of Rule 25-6.0143, Florida Administrative Code. Because an unfunded reserve will reduce rate base, an unfunded reserve will ultimately result in lower revenue requirements. The funded reserve must be discontinued December 31, 1992.

All future charges shall be made against the funded reserve until it is extinguished. Also, all investments should be liquidated upon maturity, or sooner, if economically feasible, with the net proceeds recorded in the general cash account. In addition to enabling the company to go to an unfunded reserve as soon as practical, this should give FPC the necessary flexibility to manage its portfolio. FPC shall record any gains associated with the sale of investments in a deferred account until its next rate case, during which the disposition of these gains will be determined.

FPC shall accrue $100,000 annually in the unfunded reserve. This annual accrual will result in a December 31, 1993, balance of $100,000, or $50,000 on average in the Unfunded Property Insurance Reserve. Accordingly, working capital shall be reduced $46,465 ($50,000 system). FPC's requested Property Insurance Reserve of $3,732,000 ($4,010,000 system) for the 1992 current test year is appropriate.

3. Contract Retainage

Although the company made an error in the 1991 interim test year by removing the wrong amount from working capital for contract retainage, the amount removed in 1992 and 1993 is correct. Therefore, no adjustments shall be made to the 1992 and 1993 working capital allowance for contract retainage.

4. Fuel and Conservation Expenses

It has long been our policy to include net fuel and conservation overrecoveries in working capital. This reduces working capital and consequently rate base. However, FPC excluded from working capital the net overrecovery of fuel and conservation expenses in its 1992 test year and the net under recovery in the 1993 test year.

FPC receives interest on underrecoveries and pays interest on overrecoveries through the Fuel and Conservation Clause Adjustment. This acts as an incentive for the company to make its projections as accurately as possible. If overrecoveries were excluded from working capital, rate base would be increased and ratepayers would have to provide the interest to pay themselves.

FPC disagrees with our practice of including overrecoveries in working capital, because in a projected test year, the company matches the current month fuel/conservation revenues with the appropriate expenses through the corporate model. FPC testified that any overrecovery is eliminated by year end by understating the monthly revenues to be collected during the year. The company argued that customer accounts receivable are not overstated by the accumulated net overrecovery of fuel/conservation expenses, but are really understated because the monthly fuel/conservation revenues have been modeled to be less than the applicable expense in order to eliminate the accumulated net overrecovery.

At no time did the company argue that the overrecovery did not exist, nor did the company dispute the amount of the overrecovery. Both the accounts receivable and the overrecovery are 13-month average amounts. Even though these accounts were adjusted throughout the year, and an overrecovery no longer existed at year's end, there would still be a 13-month average amount that should be included in rate base. To exclude the overrecovery from working capital would mean that ratepayers would be paying FPC a return on the amount of the overrecovery for years after the refund to customers had, in fact, taken place. In addition, the amount paid to the company by ratepayers would exceed many times the one-time refund with interest the company is required to pay.

Based on the above, the net fuel/conservation overrecovery shall be included in rate base and working capital shall be reduced by $8,434,000 ($4,651,000 system) for the 1992 test year. No adjustment is necessary for 1993 because the company properly excluded its projected net underrecovery of $2,328,000 ($6,244,000 system) from working capital.

5. <u>Accrued Utility Revenues</u>

Accrued utility revenue is unrecorded revenue applicable to unread meters. Since meters are read on a cycle basis, at the end of any given accounting period, there are certain meters which have not been read for as many as 30 days. The KWHs recorded on these unread meters represent service actually rendered to customers. Unbilled revenues are booked by utilities in order to preserve the matching principle - matching revenues with expenses for services rendered. Our practice has been to include accrued utility revenues in working capital.

Occidental argued that accrued utility revenue should be excluded from working capital because it is an asset created by accounting that has no associated carrying cost. The intervenor stated that there is no carrying cost because unlike accounts receivable, which have already been billed, these have not been billed. In addition, the amount at issue is the ongoing balance from the initial recognition of accrued utility revenues, not year-to-year changes in that balance. We have repeatedly considered and rejected repeatedly this position in the past.

The company included accrued utility revenues in working capital. FPC records unbilled revenue as other operating revenues and as such reduces the gross cost to be recovered from the customer. Accrued utility revenues, which are offset to the unbilled revenue, compensate for the timing difference between revenue recognition and cash receipt to the company. Therefore, to remove accrued utility revenues from rate base without removing unbilled revenues from net operating income would result in a severe mismatch between the income statement and balance sheet.

Accrued utility revenue is a proper component of working capital. Accordingly, no adjustments shall be made, and accrued utility revenues shall be included in working capital.

6. FAS No. 106 Net Assets

Occidental argued that when FPC accounted for the implementation of FAS No. 106, the result was a net increase to working capital of $22.8 million. FPC testified that implementation of FAS No. 106 would cause a net reduction to working capital.

We find that the implementation of FAS No. 106 results in an increase in the liability side of the working capital calculation which causes a reduction to working capital. FPC updated its FAS No. 106 costs due to a new collective bargaining agreement and a new discount rate, and we have adjusted the discount rate, as discussed below. The effect of these changes is the reduction of FAS No. 106 costs, the reduction of liability associated with FAS No. 106, and the increase of working capital. To reflect these changes, we reduced the FAS No. 106 liability by $3,168,207 ($3,388,095 system) for 1992 and by $10,565,031 ($11,288,633 system) for 1993. Because the implementation of FAS No. 106 results in a net liability that reduces working capital for 1992 and 1993, no adjustments should be made to working capital for 1992 and 1993 to exclude FAS No. 106 net assets.

7. Vacation Pay Accrual Asset

Occidental argued that the vacation pay accrual asset should be a liability rather than an asset that should be excluded from working capital. FPC stated that the vacation pay accrual asset represents the amount of vacation earned but not taken that is estimated to be capitalized. The company charges O&M and the vacation pay accrual asset, and credits the accrued vacation pay liability for vacation pay when earned. The vacation pay accrual asset compensates for the timing difference between vacation earned and vacation taken for payroll that will be charged to construction. No adjustments shall be made to working capital for 1992 and 1993 to exclude the vacation pay accrual asset.

8. Interest on Tax Deficiency

FPC has proved that its ratepayers will benefit in 1992 and 1993 from its tax administration policies, which give rise to this interest expense. The 1992 and 1993 working capital allowances properly include the deferred debit and accrued tax liability related to the interest expense on tax deficiencies, which shall be included in the 1992 and 1993 test year O&M expenses as discussed below in greater detail. The 1992 and 1993 working capital allowances shall not be adjusted to exclude interest on tax deficiencies, as this would result in a mismatch between the income statement and the balance sheet.

9. Light Oil Inventory

We reduced the 1992 test year light oil inventory by $574,522 ($637,120 system). No adjustment is made to the fuel inventory for the 1993 test year.

The Commission's guidelines used to justify Florida Power's fuel inventory levels were approved in Order No. 12645. These guidelines allow for a 30-day level of light oil inventory at peaker units when measured at a high rate of burn and for a 45-day level of inventory at steam units when measured at the average rate of burn.

According to FPC's witness, D.D. Williams, FPC's 1992 fuel inventory target level for light oil inventory is 383,000 barrels (Exhibit No. 149). FPC's methodology for calculating its light oil inventory for 1992 has included a full year of fuel inventory for the DeBary Peakers, which will go in service in November, 1992. (Tr. 1889)

We determined that the fuel inventory for the DeBary plant should be adjusted to reflect only those two months that the plant is scheduled to be in service.

FPC is entitled to recover the full amount of their requested fuel inventory for 1993 (Exhibit 150). In 1993, the DeBary plant will be in service for the entire year.

10. Prepaid Interest

The parties stipulated that an adjustment should be made to the working capital allowance to exclude prepaid interest for the 1991 interim test year, the 1992 current test year, and the 1993 projected test year.

Working capital shall be reduced as follows to exclude prepaid interest:

	Jurisdictional	System
1991 Interim Test Year	$ 186,000	$ 196,000
1992 Current Test Year	229,000	246,000
1993 Projected Test Year	330,000	355,000

In addition, for the 1991 interim test year, temporary cash investments shall be reduced $2,559,000 ($2,692,000) system.

V. COST OF CAPITAL

A. Cost Of Common Equity Capital

To arrive at a fair overall rate of return, it is necessary that we utilize our judgement to establish an allowable rate of return on common equity capital.

Three witnesses presented testimony concerning the fair rate of return on common equity for FPC. Witness Carl H. Seligson, testifying on behalf of FPC, recommends an ROE of 14.15%. (Tr. 162) Witness Mark A. Cicchetti, testifying on behalf of the OPC, recommends an ROE of 10.80%. (Tr. 306) Witness Richard A. Baudino, testifying on behalf of Occidental, recommends an ROE of 10.65%. (Tr. 466)

Witness Carl H. Seligson, testifying on behalf of FPC, relied on a risk premium approach based on the logic of the Capital Asset Pricing Model (CAPM) in arriving at his estimate of a fair ROE for FPC. (Tr. 159, 258-259) The risk premium approach attempts to estimate the ROE by recognizing the higher return investors require on equity securities than on debt securities. (Tr. 160)

Witness Mark a. Cicchetti, testifying on behalf of the OPC, utilized two methodologies in arriving at his estimate of a fair ROE for FPC. He first performed a Discounted Cas Flow (DCF) analysis on an index of high quality electric utility companies. Also performed a risk premium analysis on the same index of companies. (Tr. 296)

Witness Richard A. Baudino, testifying on behalf of Occidental, utilized two methodologies in arriving at his estimate of a fair ROE for FPC. He first performed a DCF analysis on a group of comparable electric companies and on FPC's parent, Florida Progress Corporation. He also performed a "Revised" risk premium analysis based on the analysis done by witness Seligson. (Tr. 442)

Based upon the evidence in the record and a detailed review of the cost of equity capital methodologies presented, we have determined that the cost of common equity capital for FPC is 12% with a range of plus or minus 100 basis points (for ratemaking purposes). We believe that a return of 12% would continue to provide the company with comfortable coverage ratios that, along with its strong qualitative factors, maintain the company's present credit rating. In addition, this ROE is reasonable given the current market conditions and the relatively low risk associated with this high quality, well managed electric utility.

B. Weighted Average Cost Of Capital

Based upon the proper components, amounts, and cost rates associated with the capital structures for the test years ending December 31, 1992 and December 31, 1993, we find that the weighted average cost of capital is 8.39% and 8.37%, respectively.

The company per book amounts were taken directly from FPC's MFR filing. [Exhibit 5, Sch. D-1, p. 1, 1992 and 1993] Specific adjustments were made to the Investment Tax Credit and Deferred Tax balances. After all specific adjustments were made, a pro rata adjustment was made across all other sources of capital to reconcile the capital structure with the rate base.

We agreed with and used the respective cost rates provided by FPC with the exception of the cost rates for common equity, long-term debt, and short-term debt. We used the ROE of 12.0% instead of the ROE recommended by the company of 13.6%, the ROE recommended by OPC of 10.8%, or the ROE recommended by Occidental of 10.65%.

We also adjusted the cost rates the company projected for the issuance of long-term and short-term debt during the 1992 and 1993 test years. The company projected that it would issue $150 million of first mortgage bonds at 9.70%, $100 million of medium term notes at 9.00%, and $50 million of pollution control revenue bonds at

8.00% during 1992. The company also projected that it would issue $100 million of first mortgage bonds at 9.7% in 1993. [Exhibit 5, Schedule D-10a, 1992 and 1993]

Company witness Bongers testified that in the KPMG Peat Marwick audit of FPC, the audit staff came to the conclusion that the interest rate assumptions made by the company concerning its long-term debt were too high relative to the level of interest rates currently prevailing. He stated that KPMG Peat Marwick believed a rate of 8.5% was more reasonable than the 9.7% projected by the company. (Tr. 2208) Company witness Seligson testified that FPC could issue first mortgage bonds at 8.25% or more based on the U.S. long-term bond trading at a yield of 7.40%. (Tr. 138-139) Although he stated that he did not believe the 8.25% rate was wrong, he did state that since the time of his prefiled direct testimony the spread between the rate FPC could probably issue first mortgage bonds and the yield on long-term treasury bonds had narrowed to 70 to 75 basis points. (Tr. 166-167) Based on witness Bongers testimony, we used the rate of 8.5% instead of 9.7% for the first mortgage bonds the company projects to issue in 1992 and 1993.

Company witness Seligson testified that FPC could issue medium-term notes at a rate of 7.25% or less. He also noted that Southern California Edison (SCE), a AA-rated electric utility that OPC witness Cicchetti used in his index of comparable-risk companies and that FPC cited in its legal brief as comparable to FPC as discussed in Issue No. 29, recently issued medium term notes at a rate of 6.22%. We used the rate of 7.25% which is conservatively between the 9.0% used by the company in its MFR filing and the 6.22% recently incurred by SCE for the medium term notes the company projects to issue in 1992.

Company witness Greene testified that in 1991 FPC refinanced its 10.0% and 10.25% pollution control revenue bonds at a rate of 7.2%. (Tr. 635) He also testified that more recently the company established the interest rate on its annual tender pollution control bonds at 6.625%. (Tr. 760) Company witness Bongers testified that this new rate would result in further refinancing of tender pollution control bonds in early 1992. (Tr. 2190-2191) We used the rate of 7.2% which is conservatively between the 8.0% used by the company in its MFR filing and the 6.625% that has recently been established for its annual tender pollution control bonds for the pollution control revenue bonds the company projects to issue in 1992.

Although the company did not issue the bonds and notes as projected in its MFR filing, witness Greene did testify that the company still planned to issue this debt during its projected 1992 and 1993 test years. (Tr. 758-760) In addition, the embedded cost of fixed rate long-term debt the company used to calculate its recommended overall cost of capital reflects the cost rates for these debt issues. The adjustments we made had the effect of reducing the company's embedded cost of fixed rate long-term debt in 1992 and 1993 from 8.53% to 8.24% and from 8.63% to 8.26%, respectively.

Also reflected in the company's overall cost of capital calculation is an assumption of short-term borrowing at rates of 7.4% in 1992 and 7.5% in 1993. Occidental witness Baudino testified that these rates are excessive and do not correspond with current market rates for commercial paper and short-term loans from banks. He stated that based on the Federal Discount Rate of 3.5%, commercial paper rates are at most only 4.0%. He also stated that it would be prudent for FPC to use the most cost effective short-term financing available, i.e., commercial paper. (Tr. 484-485) Since the time of his prefiled testimony, the Federal Reserve lowered the Discount Rate again. (Tr. 171) Although the cost of commercial paper dropped with the decline in the Discount Rate, we used the rate of 4.0% instead of 7.4% or 7.5% for the short-term debt the company projects to issue in 1992 and 1993.

Schedules 2 and 9 show the components, amounts, cost rates, and weighted average cost of capital associated with the respective test year capital structures.

C. Investment Tax Credits

Florida Power's requested balances of accumulated deferred investment tax credits in the amount of $106,584,000 for the 1992 current test year and $102,088,000 for the 1993 projected test year are not appropriate. We find that ITCs should be $106,121,000 for the 1992 test year and $101,666,000 for the 1993 projected test year.

The parties to this docket stipulated to exclude the company's projected acquisition of the Sebring Transmission and Distribution System (Sebring T & D) from consideration in this proceeding. Consequently, we find that the company's Sebring T & D pro forma adjustments to the 1992 and 1993 Rate Base and NOI should be reversed. On MFR Schedule D-1, the company made specific adjustments totalling $463,000 for 1992 and $422,000 for 1993. These adjustments increased its per books ITCs and were identified as adjustments for the Sebring acquisition. Thus, reversing these adjustments to exclude Sebring requires adjustments of $463,000 for 1992 and $422,000 for 1993, reducing the ITC balance as filed. The result of these adjustments decreases 1992 ITCs from $106,584,000 as filed to $106,121,000 and decreases 1993 ITCs from $102,088,000 as filed to $101,666,000.

D. Accumulated Deferred Taxes

Florida Power's requested balances of accumulated deferred taxes in the amount of $388,551,000 for the 1992 current test year and $391,231,000 for the 1993 projected test year are not appropriate. Accumulated Deferred Taxes should be $388,370,000 for the 1992 current test year and $395,325,000 for 1993 projected test year.

Our adjustments to the 1992 current test year and the 1993 projected test year result from three factors: the reversal of the company's pro forma adjustments for the Sebring Transmission and Distribution (Sebring T & D) acquisition; the effect of adjustments to rate base; and the effect of adjustments to operating expenses.

E. FAS 109 Accounting For Income Tax

We do not believe the effect of implementing FAS No. 109, Accounting for Income Tax, in early 1993 should be reflected in setting current rates.

Our current review of the regulatory implications of implementing FAS No. 109 has not been concluded. We believe that its implementation should be revenue neutral; whether or not this is borne out by our review, its effect shall be excluded from consideration in this proceeding.

FPC's calculation of current and deferred income taxes was based on the company's operating and construction forecasts and the statutory tax rates in effect for both the federal and state jurisdictions. The method of calculating deferred income taxes followed the guidelines established in Accounting Principles Bulletin, Opinion No. 11, 'Accounting for Income Taxes.' (Tr. 2252)

FAS No. 109 changes the method of accounting for income taxes. It was issued in February 1992, which is subsequent to the date Florida Power's MFRs were filed. Implementation of FAS No. 109 is mandatory for financial reporting for years beginning after

December 15, 1992. Consequently, the company will be required to implement the accounting during the 1993 projected test year.

The most significant difference between APB 11 and FAS No. 109 is the shift from an income statement to a balance sheet approach which involves the definition and evaluation of accumulated deferred tax balances. Under APB No. 11, the deferred taxes are recorded at the statutory tax rates in effect when recorded and reverse at that same rate even if the tax rate changes. Under FAS No. 109, the accumulated deferred tax balances would be reevaluated if the tax rate changes. For example, if the deferred taxes are recorded at 48% and the statutory tax rate changes to 34%, the accumulated deferred tax balance would be written down to reflect the 14% decrease. FAS No. 109, takes a liability approach. Under FAS No. 109 deferred taxes will still exist, but will be valued at the rate at which they expected to be paid back.

In a nonregulated environment, companies that have fluctuation under GAAP would credit an income account or retained earnings for the difference between the statutory rate previously used and the new rate. However, in a regulated environment, the differences should be reflected through the use of regulatory asset or regulatory liability accounts. This treatment results in an equitable treatment of tax rate changes. The ratepayers will benefit and the stockholders will not realize a "windfall" from a decrease in tax rates which results in a write down of deferred tax balances.

Witness Scardino testified that the adoption of FAS No. 109 will be revenue neutral and have no effect on the ratemaking process if the regulatory assets and liabilities resulting from the implementation of the standard are treated in the same manner as accumulated deferred income taxes in the capital structure. (Tr. 2558) This was not contested by any party at the hearing. Mr. Scardino agreed that implementation of FAS No. 109 in this proceeding may be premature, in view of the Commission's currently ongoing review of the matter. (Tr. 2561)

Our current review of FAS No. 109 has not been concluded. We believe that its implementation should be revenue neutral. We therefore find that its effect should be excluded from consideration in this proceeding.

VI. NET OPERATING INCOME

Having established the company's rate base and fair rate of return, the next step in the revenue requirements determination is to ascertain the net operating income (NOI) applicable to the test periods. The formula for determining NOI is Operating Revenues less Operating Expenses equals NOI.

VII. OPERATING REVENUES

The company has proposed operating revenues of $958,462,000 ($1,047,013,000 system) for the 1992 current test year and $997,294,000 ($1,096,519 system) for the 1993 projected test year. Evidence developed during these proceedings has led us to decrease this amount. As discussed earlier, the company agreed that 1992 Operating Revenues should be reduced by $7,467,000 ($7,567,000 system) and 1993 Operating Revenues by $7,771,000 ($7,894,000 system), associated with the removal of the Sebring Distribution System. In addition, these revenues have been further reduced by $24,280,000 for 1992 and $15,515,000 for 1993 to be consistent with our decision concerning FPC's forecasts of customers and kWh by revenue class. These adjustments result in total operating revenues of $926,715,000 for 1992 and $974,008,000 for 1993.

VIII. OPERATING AND MAINTENANCE EXPENSE

Florida Power requested $409,492,000 ($445,335,000 system) for the 1992 current test year and $435,083,000 ($479,570,000 system) for the 1993 projected test year for Operating and Maintenance Expense. Evidence developed during these proceedings has led us to decrease this amount to $389,322,000 for 1992 and $415,222,000 for 1993.

A. Rescinded Purchase Of Airplane

As discussed above, FPC purchased a Piper Cheyenne from Florida Progress that was later rescinded. The utility's books were adjusted as though the purchase had never occurred. From the net operating income standpoint, the 1991 aircraft depreciation was charged to a clearing account, which was cleared monthly to various expenses and construction work in progress (CWIP). In August 1991, the company reversed the $84,554 of depreciation taken on the airplane. This reversal, which was also booked to the clearing account, removed the CWIP and NOI effect from the interim test period.

The company made a pro forma adjustment to remove $65,000 from interim O&M expenses. However, as noted above, the book adjustment made by the company in August 1991 had already removed the effect of depreciation, which was ultimately charged to the company's expense and CWIP accounts. Consequently, the adjustment filed by FPC is inappropriate and results in an understatement of O&M expenses. Accordingly, we shall adjust the 1991 Interim Test Year to reverse Florida Power's O&M pro forma adjustment by increasing O&M Expense for 1991 by $65,000 ($65,000 system). The pro forma adjustments made to both the 1992 and 1993 test years correctly removed the effects of the rescinded aircraft purchase. Accordingly, no adjustments are needed for these test years.

B. <u>Advertising Expense</u>

FPC projected total advertising expense of $3,075,000 ($3,090,000 system) for 1992 and $3,321,000 ($3,338,000 system) for 1993. The company made adjustments in each year to remove the balances of Accounts 913 and 930, leaving only the balances of Account 909, Informational and Instructional Advertising Expenses. FPC agreed that the "Real People" advertisements in Account 909 should be removed, which totaled $10,317 in 1991.

The company's Christmas 1990 Spot and the PBS-WEDU ads do not provide specific information for customers; they are merely image enhancing. Therefore, the cost of these two ads, totalling $95,579, shall be removed from Account 909.30. Other advertisements discussed during the course of the hearing may also be image-enhancing; however, they were insignificant in amount. Our analysis indicates that the 1991 advertising expense shall be reduced by $95,579.

OPC argued that there should be an adjustment to the 1992 test year to remove the costs of advertisements which promote the company and the use of electricity. OPC also argued that there should be an adjustment related to FPC's strategic plan. We find that OPC did not provide sufficient evidence to make these adjustments.

Because we do not have a detailed list of FPC's projected ads for 1992 and 1993, a method is needed to calculate the appropriate deductions for these two years. A comparison of the company's actual to budgeted expenses indicates that the advertising account was significantly under budget in 1987, 1989, 1990, and 1991; 1992 shows the largest budget increase since 1987. Because the company has consistently overbudgeted the advertising account, an adjustment greater than the inflation rate is necessary. We followed OPC's method of calculating adjustments to Account 909.30, and find that the total amount listed for FPC's ads for 1991 shall be reduced by $387,000 for 1992 and $414,000 for 1993.

The company's $13,879 in 1991 expenses related to nuclear advertising shall be allowed in this instance.

We have made adjustments decreasing the level of advertising expense $420,000 for 1992 and $450,000 for 1993. Accordingly, the appropriate amount of advertising expense for 1992 is $2,655,000 and for 1993 is $2,871,000.

C. Lobbying Expenses

FPC recorded all lobbying expenses below-the-line, even those expenses associated with the company's Tallahassee and Washington offices.

The company made an adjustment to transfer $114,000 above-the -line in 1992 and $120,000 in 1993 for Jim Stanfield, FPC's Tallahassee based employee. This adjustment was made pursuant to Staff Advisory Bulletin No. 36, which states that all lobbying expenses shall be recorded below-the-line, including liaison related expenses. However, when preparing a rate case, the company may make an adjustment to transfer these expenses above-the-line; the company must then justify any amounts charged to jurisdictional expenses. Because rent expenses, utilities, and secretarial expenses were excluded, we find that the company adequately justified the liaison expenses related to Mr. Stanfield. FPC's adjustment, which includes only a portion of the liaison's related expenses, is reasonable and consistent with the last Gulf Power rate case. Accordingly, we shall make no adjustments to the lobbying expenses filed by FPC.

D. Industry Association Dues

FPC budgeted Industry Association Dues of $6,751,000 ($7,142,000 system) for the 1991 interim test year, $7,044,000 ($7,373,000 system) for the 1992 current test year, and $7,406,000 ($7,765,000 system) for the 1993 projected test year. The company removed $25,000 from the 1991 test year, $21,000 from the 1992 test year, and $25,000 from the 1993 test year system amounts by a pro forma adjustment to cost of service. Evidence developed during these proceedings has led us to make the following adjustments.

FPC acknowledges that one third of the EEI administrative dues attributed to lobbying expenses for the 1991 test year should be removed, which would result in a system decrease of $135,000 for the interim period. Concerning the 1992 test year, OPC argued that the NARUC Audit Report of EEI Expenditures using 1988 data should be used to determine the overall percentage by which EEI expenditures should be disallowed.

Based on the recommendation of the NARUC Staff Subcommittee on Accounts, and to remain consistent with our previous decisions, all of the EEI Media Communications Fund dues shall be disallowed. This results in a $180,000 reduction to the 1992 test year and a $189,576 reduction to the 1993 test year. One third of the EEI administrative dues was already removed by the company for the 1992 and 1993 test years.

Because FPC has not actively participated in the U.S. World Energy organization, the dues for this organization shall be disallowed for the 1992 and 1993 years. Accordingly, $1000 shall be disallowed from the 1992 test year and $1053 shall be disallowed from the 1993 test year.

Prior to 1987, the U.S. Council for Energy Awareness was called the Atomic Industrial Forum. Because the dues for this organization have been disallowed by us in the past due to this organization's pro-nuclear lobbying, we shall not allow the dues here. Accordingly, the 1992 test year shall be decreased by $342,000, and the 1993 test year shall be decreased by $360,000.

In the past, we have disallowed dues for membership in the American Nuclear Energy Council and the EEI Utility Nuclear Waste and Transportation Program, both lobbying organizations. However, because of the importance of the nuclear waste issue, and the lobbying activity of these two organizations toward achieving a nuclear waste repository, we shall make an exception here. The membership dues associated with these organizations shall be allowed in this instance.

In addition, we shall allow the inclusion of membership dues for the Earth Energy Association and the Electric Transportation Coalition, both lobbying organizations. The Earth Energy Association promotes the use of geothermal systems. The Electric Transportation Coalition lobbies to improve air quality and to contribute to environmental benefits of the nation. Because FPC's customers receive conservation benefits from FPC's membership in these organizations, these membership dues are justified.

Based on the above adjustments, we shall disallow $726,936 ($769,000 system) for the 1991 interim test year, $499,674 ($523,000 system) for the 1992 test year, and $525,544 ($551,000 system) for the 1993 test year. The resulting totals of $6,000,764 ($6,348,000 system) for the 1991 interim test year, $6,524,427 ($6,829,000 system) for the 1992 test year, and $6,856,868 ($7,189,000 system) for the 1993 test year shall be allowed.

E. <u>Growth In Salaries And Wages</u>

Florida Power requested the O&M expense level for Salaries and Employee Benefits to be $163,960,000 ($176,135,000 system) and $56,408,000 ($60,300,000 system) for the current 1992 test year, and $171,939,000 ($184,948,000 system) and $89,001,000 ($95,058,000 system) for the 1993 projected test year. Based on evidence presented at the hearing, salaries and wages shall be reduced by $745,530 ($797,244 system) in 1992 and by $783,086 ($836,759 system) in 1993. Fringe benefits shall be reduced by $184,796 ($197,614 system) in 1992 and by $288,671 ($308,457 system) in 1993.

FPC budgeted 269 new positions in 1992, whereas it had budgeted only 77 new employees in 1990 and 71 in 1991. By March of 1992, the company had hired only 41 new employees for the year.

OPC argued that the company's 1992 budgeted payroll is excessive, because the budget is based on the number of authorized positions, and not the number of positions that are actually filled. OPC also argued that FPC's projection of 269 new positions for 1992 is excessive. Occidental argued that the company's projected number of employees significantly exceeded its average actual growth rates and should be reduced.

Although FPC budgeted 269 new positions for 1992, no more than 89 are included in this rate case filing. Of those 89, a portion are budgeted to capital projects and are not included in O&M. 59 new employees are projected for 1993. From 1987 to 1991, the company has had an average annual increase of 63 new employees.

The 89 employees included in this rate case filing represent a significant increase over the average. Because 89 positions for 1992 appears to be excessive, we shall adjust this projection to equal the 1987-1991 average by decreasing the 1992 number of new employees to 63. Salaries, wages, and fringe benefits shall also be reduced accordingly.

OPC argued that the company's projected wage increase was too high, and that the budgeted merit increase should be limited to 4%, based on the actual increase granted to the bargaining unit. Occidental testified that assumed growth in salaries and wages should be limited to inflation. FPC argued that OPC's position was mistaken, because exempt and office and technical employee compensation is market based and not tied to the increases negotiated in FPC's bargaining unit agreements.

No record evidence was presented that convinced us that FPC's projected wage increase is not appropriate. However, because we removed 26 employees from FPC's projection of new employees for 1992, salaries and wages shall be reduced by $745,530 ($797,244 system) for 1992 and by $783,086 ($836,759 system) for 1993; and fringe benefits shall be reduced by $184,796 ($197,614 system) for 1992 and by $288,671 ($308,457 system) for 1993.

F. OPEB Expense

FPC requested Other Post Employment Benefits (OPEB) Expense levels in the amount of $24,215,000 ($25,887,000 system) for the 1992 current test year and $26,117,000 ($27,894,000 system) for the 1993 projected test year. These levels should be adjusted to reflect FAS No. 106 accounting, FPC's updates to its FAS No. 106 costs, and a discount rate of 8.25%. After these adjustments, the appropriate levels of OPEB expense are $17,658,368 ($18,883,935 system) for 1992 and $18,804,655 ($20,092,590 system) for 1993.

As discussed above, we have decided to use FAS No. 106 for ratemaking purposes. FPC updated its estimates of the FAS No. 106 costs presented in its MFRs to reflect a new collective bargaining agreement and a change in the discount rate from 8.75% to 7.75%. We shall use this current information in our decision on OPEB expense. Based upon this current information, we reduced the amount of O&M expenses, the amount of CWIP, and the liability associated with FAS No. 106 (which increases working capital) for the 1992 and 1993 test years. These adjustments reflect the removal of the Sebring system.

While we accept the information concerning the new collective bargaining agreement, we believe that the 7.75% discount rate is too low. OPC argued that non-regulated companies have used 9.00% as the discount rate for 1992, and the higher the discount rate, the lower the expense. According to OPC, the discount rate should be our allowed return on equity.

FPC's selection of 8.75% was based on the then existing 8.50% pension discount rate. At the time the company developed its discount rate in September of 1991, a rough range of discount rates was from 7.50% to 9.00%.

FAS No. 106 directs that the discount rate should be based on "high-quality fixed-income investments currently available whose cash flows match the timing and amount of expected benefit payments." Accordingly, the return on equity is disqualified as a suitable discount rate. Because FPC's current discount rate of 7.75% is very close to the current Treasury Bond yield of 7.60%, it reflects a rate of the highest quality. FPC argued that because FPC has an AA bond rating, it must issue new first mortgage bonds at 70-75 basis points above the Treasury Bond yield, or 8.30-8.35%. AA bonds are high-quality fixed-income investments, and an 8.25% discount rate is in line with or slightly lower than current yields on AA rated bonds. We have chosen 8.25% as FPC's appropriate discount rate.

A 1% increase in the discount rate causes an 11% decrease in the FAS No. 106 expense. Accordingly, the discount rate shall be increased by .50%, which results in a 5.50% decrease in the FAS No. 106 expense for 1992 and 1993. This adjustment also decreases the FAS No. 106 amount capitalized as CWIP as well as decreasing the FAS No. 106 liability by 5.50%, as discussed above. The combined adjustment to reduce the expense for both the update and the change in the discount rate for 1992 is $5,196,528 ($5,557,190 system) and for 1993 it is $5,874,536 ($6,276,885 system). The adjustment to reduce CWIP, for both the update and the change in the discount rate is $454,181 ($456,555 system) for 1992 and $478,603 ($481,105 system) for 1993. As we have previously dismissed an adjustment to working capital shall also be made to reduce the FAS 106 liability by $3,168,000 in 1992 and by $10,565,000 in 1993.

G. Pension Expense

Florida Power requested Pension Expense in the amount of $4,270,000 ($4,561,000 system) for the 1992 current test year and $6,257,000 ($6,683,000 system) for the 1993 projected test year. However, we have made adjustments to the company's request as discussed below. Net pension expense shall be reduced by $2,653,000 for the 1992 test period and $2,464,000 for the 1993 test period. Pension liability shall be decreased by $1,672,000 for 1992 and by $4,876,000 for 1993. CWIP shall be reduced by $232,000 for 1992 and by $31,000 for 1993.

Although the intervenors argued that we should make adjustments to pension expense based on cash basis accounting, we have decided to use FAS No. 87 to determine pension expense, as discussed above. Even though FPC filed its pension expense projects pursuant to the provisions of FAS No. 87, we shall make several adjustments to the company's request.

As discussed above, FPC updated its filing to reflect the results of bargaining unit negotiations and a reduction in the discount rate, which resulted in the company's net pension expense request decreasing from $3,386,000 to $2,199,000 for 1992 and from $5,034,000 to $4,337,000 for 1993. While we do not take issue with using the terms of the bargaining unit negotiations, we believe that the new discount rate used by the company is too low.

FPC originally filed a discount rate of 8.5%, and subsequently dropped its estimate to 7.25%. Because only 5 months lapsed between the company's original filing and its update, the drop appears to be excessive. The company testified that a 50 basis point shift in the discount rate would have a $1.2 million dollar impact on Florida Progress, FPC's parent.

FAS No. 87's definition of the discount rate is identical to the definition of the discount rate under FAS No. 106, as discussed above. The relationship between the discount rates used for FAS No. 87 and FAS No. 106 should remain somewhat constant for the timeframe of the test period.

FPC testified that the Pension Benefit Guaranty Corporation (PBGC) publishes a rate that can be used to discount pension liabilities. The PBGC interest rates have dropped from 7.25% in January 1991 to 6.5% in June, 1992, a drop of 75 basis points. However, the company dropped its discount by 125 basis points for the same time frame. The company's drop was too dramatic. Accordingly, the discount rate used for pensions shall be increased from 7.25% to 8.00%. This adjustment will decrease pension expense by $1,573,342 ($1,682,000 system) for 1992 and by $1,574,857 ($1,682,000 system) for 1993.

The professional expense included in pension expense was calculated using 1991 as a base period and was calculated as a percentage of the asset value of the pension fund. In 1991, the professional fees were .71% of the asset value. If a five year average from 1987 through 1991 is used, the percentage is .63%. Because this average is more reflective of typical professional fees, professional fees shall be reduced by $291,812 ($312,199 system) for 1992 and $295,945 ($316,620 system) for 1993 using the five-year average.

These adjustments result in a net reduction to pension expense of $2,653,000 ($2,653,000 system) for 1992 and $2,464,000 ($2,632,000 system) for 1993. The corresponding working capital adjustments are an increase to working capital in 1992 of $1,672,000 ($1,787,000 system) and in 1993 of $4,876,000 ($5,210,000 system). CWIP shall be decreased by $232,000 ($233,000 system) in 1992 and by $31,000 ($31,000 system) in 1993.

H. Pension Expense Amortization

In prior years, FPC's $3.7 million regulatory asset related to pension expense has been deferred. In this proceeding, FPC requested that we include net amortization associated with the pension regulatory asset in the amount of $916,000 for 1992 and $927,000 for 1993. For reasons discussed below, FPC shall not recover amortization expense of this asset.

FPC first recorded pension expense in 1987 for financial statement purposes using FAS No. 87. The company used FAS No. 71 to record as a regulatory liability or asset, the difference between the pension expense allowed rates, and the amount recorded for financial statement purposes. It was not until 1991 that FPC had a positive pension expense under FAS No. 87. For 1992, FPC forecasted a positive pension expense which would result in a net regulatory asset. It is this forecasted asset that FPC wants to amortize over three years.

We believe the regulatory asset and its amortization should be disallowed for ratemaking purposes. First, in order to record an asset or a liability under FAS No. 71, there must be an indication from us that the asset or liability will be recoverable. In this case, there was no such indication. It was inappropriate for FPC to use FAS No. 71 without our prior approval.

Second, we do not believe pension expense should be "tracked." Pension expense will be run through earnings and will fluctuate. Earnings should be reviewed in aggregate with no true-up provision for certain expenses. If a true-up is allowed for one expense, it can easily be argued that all the expenses should be trued-up. Other expenses also change, but the change itself does not justify deferring the expenses. Utilities are given an opportunity to recover their costs, not a guarantee. If costs change, the entire cost to serve must be reevaluated. Individual changes in costs should not be deferred for future recovery in another rate case.

The net amortization associated with the pension regulatory asset resulting from disallowance is $916,000 ($979,000 system) for 1992 and $927,000 ($992,000 system) for 1993. Accordingly, $752,000 ($804,000 system) for 1992 and $2,696,000 ($2,881,000 system) for 1993 shall be removed from rate base. $80,000 ($80,000 system) for 1992 and $12,000 ($12,000 system) for 1993 of CWIP shall also be removed from rate base.

I. Outside Services Expense

Public Counsel argued that all one-time outside professional services should be disallowed. While one-time services may not recur each year, they may be replaced with other new services, thus continuing the annual cycle of expense. However, only a reasonable level of non-recurring expense should be allowed in O&M expenses. Because there is no record basis to support what a reasonable level of one-time services might be, we shall make no adjustment.

Public Counsel further argued that all outside services related to FPC's strategic plan should be disallowed. OPC stated that although FPC's desire to become more environmentally aware is a laudable pursuit, it is unrelated to the provision of electric utility service. In addition, FPC has not performed a cost benefit analysis to determine the overall effect on ratepayers.

In 1992, FPC budgeted $200,000 for land identification, $100,000 for water conservation, $90,000 for solid waste, $100,000 for computer program development, and $150,000 for air quality. These expenses will allow the company to contract with specialized environmental consultants to cope with evolving regulatory requirements and to meet its goal to exercise good environmental stewardship. While not all such expenditures will be allowed, we find these expenses to be reasonable. Accordingly, FPC's request for $640,000 for studies, recommendations, and modeling shall be allowed. The appropriate amount of outside services expense is $12,106,515 ($13,088,960 system) for 1992 and $12,555,047 ($13,586,498 system) for 1993.

J. Medical/Life Accrual

Florida Power maintains an unfunded medical/life reserve for active and retired employees in compliance with Rule 25-6.0143, Florida Administrative Code, and the Uniform System of Accounts as prescribed by us. The amount accrued is based on the pay-as-you-go basis. The company has maintained this reserve since 1984. FPC is self-insured and uses the reserve to pay claims. The medical portion of the reserve is managed by Blue Cross and Blue Shield.

Occidental argued that FPC should amortize the reserve balance over five years as a negative expense. The intervenor proposed no other specific adjustment to the company's expense.

Because we find that FPC should continue to use the reserve concept for its self-insurance program, no specific adjustments shall be made to medical/life expense other than the adjustments to fringe benefits discussed above. Accordingly, FPC's 1992 and 1993 test year accrual for medical/life reserve-active employees and retirees is appropriate.

K. Storm Damage Accrual

FPC requested an accrual of $1,104,000 for 1992 and $314,000 in 1993 in order to attain the $5 million deductible on its property insurance policy. The company requested to cease accruals once the cap is reached. According to the company, the $314,000 expense would continue to be included in rates even though an expense would no longer be incurred.

Occidental testified that the expense accrual is an accounting derived cost due to its discretionary amortization of reserve deficiency. Occidental argued that the $1.636 million reserve deficiency as of December 31, 1991, should be amortized over five years or $327,000 annually. If we were to follow Occidental's suggestion, this would result in a $777,000 reduction to the company's proposed expense for 1992.

Contrary to Occidental's belief, the company does not have significant control over its reserve related expense accruals. Rule 25-6.0143(4)(a), Florida Administrative Code, states that "... [t]he provision level and accrual rate for each account ... shall be evaluated at the time of a rate proceeding and adjusted as necessary. However, a utility may petition the Commission for a change in the provision level and accrual outside a rate proceeding."

The company's requested accrual of $1,104,000 for 1992 is appropriate. This accrual should eliminate any concerns regarding retroactive adjustments to the 1992 funded reserve.

However, FPC's requested accrual for 1993 shall be reduced by \$196,962 (\$214,000 system), to result in an accrual of \$100,000. The \$5 million cap will not be in place. Under this method, the company will continue to incur the expense while the expense is included in the cost of service, and FPC will also attain its \$5 million deductible. The accrual and provision level shall be evaluated in the company's next rate case, or sooner upon petition of the company.

Because we have decided that FPC shall discontinue its funded reserve, O&M expenses shall be credited with the earnings on the funded reserve until the funded reserve is extinguished. This should avoid increasing the funded reserve beyond a reasonable level, and should enable the funded reserve to be extinguished more quickly. Accordingly, O&M expenses shall be reduced \$69,152 (\$75,134 system) for the 1993 pre-tax earnings credited by FPC to the funded reserve.

L. <u>Claims Reserve Accrual</u>

Florida Power maintains an unfunded injuries and damages and Worker's Compensation reserve in accordance with Rule 25-6.0143, Florida Administrative Code, and the Uniform System of Accounts as prescribed by us. The account was established to meet FPC's probable liability for deaths or injuries to employees or others not covered by insurance.

During 1991, FPC expensed \$4.081 million, and projected \$4.208 for 1992 and \$4.568 million for 1993. The company determines the desired balance for the reserve by matching current year charges and accounting accruals and by maintaining an adequate balance to cover unforeseen incidents. The company has projected an increase to the reserve from \$4.009 million for the 1991 interim test year to \$4.340 million for the 1993 projected test year.

The company projected the worker's compensation expense to decrease \$200,00 from 1991 to 1993, and injuries and damage to increase \$487,000 over the same period, for a net increase of \$287,000. FPC calculated an A&G benchmark variance of \$6.864 million for the period 1987 through 1992. Part of the justification for this variance was a decrease of \$3.873 million for injuries and damages expense during this time frame. The company stated that claims have decreased since the mid 1980's because of efforts to educate the public on the hazards of electrical contact with overhead lines. Worker's compensation claims have decreased since the end of 1987 probably because of the implementation of self insured programs and several cost containment procedures.

Occidental testified that the 1992 projected charges are twice as high as FPC's 1991 actual costs, and nearly $.8 million in excess of the 1991 accrual. The intervenor also argued that the company's request does not reflect amortization for the perceived reserve deficiency. Occidental testified that the 1992 requested accrual should be reduced by $1.011 million, and the 1993 projected test year the 1993 accrual should also be reduced by $1.011 million.

Although Occidental proposed a $1.011 million reduction to expense, no corresponding adjustment increasing working capital was proposed. Also, Occidental argued that injuries and damage should be decreased $1.011 million when in fact these expenses increased $150,000 from 1992 to 1993.

We find that the company's requested accrual for the claims reserve is appropriate. Accordingly, no adjustment shall be made to the injuries and damage and worker's compensation expense or reserve.

M. Interest On Tax Deficiencies

Florida Power requested consideration of interest on tax deficiencies in its cost of service. Because the company's last full revenue requirements proceeding was stipulated, we have never explicitly addressed the propriety of interest expense on tax deficiencies as an element of Florida Power's cost of service. Since 1987, the company has recorded the accrual and amortization from interest on tax deficiencies on its books and records as well as on its monthly surveillance report filed with us.

This interest expense arises from the accrual and amortization of interest for actual and potential tax deficiencies. Actual tax deficiencies result at the conclusion of an Internal Revenue Service or Department of Revenue audit and have been either assessed or proposed and agreed to by the company. Potential deficiencies result from carryover items from previous audits and disclosure items. The tax treatment for carryover items extends beyond the tax year in which they arise. These items come about because of the time lapse between when the tax return is filed and when a final agreement is reached on the appropriate tax treatment. Disclosure items relate to income/deduction/capitalization tax positions where the company considers the tax law unclear or where the company has intentionally taken a controversial position. They may or may not be allowed. However, because the company has disclosed its position, it can avoid understatement penalties.

The company has recorded these interest costs as deferred debits and accrued liabilities as they become known and estimated. It has requested regulatory recognition of the amortization of this interest expense over a three-year period as an O&M expense.

OPC argued that interest on tax deficiencies should not be included in O&M expense. Public counsel does not believe that it is appropriate to require ratepayers to pay for an estimated cost that is calculated based on a potential tax deficiency, especially since it is a potential, and not a known deficiency. An interest accrual of this type and magnitude only acts as a signal to the IRS that the company has taken a position on a tax issue that even the company itself considers questionable.

As discussed above, the interest accrual relates to both actual and potential deficiencies: carryovers and disclosures. OPC addresses only the potential deficiencies. Although the potential tax deficiencies may not be known at the time the related interest is accrued, we believe that the company has shown that both the liability and the related interest are highly probable and may be reasonably estimated. In addition, the IRS is already aware of any carryover items from prior audit cycles and it becomes aware of other potential items through the disclosure process. Interest on tax deficiencies gives neither the IRS nor auditors any signals. Tax law often provides little or no guidance with respect to the proper treatment of an item, and there may be varying interpretations. When that is the case, the company has stated that it will interpret the law to protect its customers' interests.

Occidental also argued that interest expense on tax deficiencies should be disallowed. The intervenor stated that the interest expense should not be recovered from ratepayers because it is similar to the costs of any other penalties or fines assessed by government agencies. Occidental further stated that because the utility is prohibited from reducing rate base (or return) by any portion of the allowable credit, the utility reaps the benefit of interest free capital. According to Occidental we would be prohibited from passing this benefit on to the ratepayers because of the danger that FPC may loose all ITC tax benefits.

We reject Occidental's argument that interest on tax deficiencies is similar to the costs of any other penalty or fine assessed by government agencies. The IRS assesses interest expense for the use of money, and for no other reason. Interest on tax assessments, unlike penalties and fines, is fully deductible for tax purposes. Although most, if not all, penalties and fines can be abated for reasonable cause, interest expense cannot. If a tax assessment is made, the taxpayers have had use of the money for some period of time.

Regarding Occidental's argument that the ratepayer never received the interest or return benefit of the disallowed ITC utilization, the intervenor admitted that even though the return benefit may not be passed on to ratepayers, the amortization of the ITCs may be utilized to reduce the cost of service income tax expense. Furthermore, Occidental did not address the savings realized by the ratepayers from the use of zero cost of capital for the increased balance of deferred taxes.

In addressing interest on tax deficiencies, there are two things that we must consider. The first consideration is whether or not the company has demonstrated that its aggressive tax strategy (which results in tax deficiencies and the ensuing interest) has benefitted the ratepayer such that the interest should be considered a cost of service component for 1992 and 1993. If the interest is considered a cost of service component, the second consideration is whether or not the requested three-year amortization period reasonable.

FPC argued that when the company is required to pay interest on a deficiency, it is because the company has withheld cash payments from a taxing authority and has used the cash to displace external capital financing. To the extent that other capital financing has been displaced, the cost of capital displaced presents a savings to the customers of the company.

The company prepared a cost/benefit analysis for the years 1982 through 1985, the latest closed years during which it had been assessed interest on deficiencies. FPC's conservative estimate of the gross benefits received from its aggressive tax preparation for the tax years 1982-1985 was $19,839,000. Its conservative estimate of net benefits was $17,798,000.

We believe that FPC's analysis was reasonable, and that the company has demonstrated that its tax strategies have benefitted the ratepayers through avoided cost-based external financing. This is consistent with our prior treatment of other utilities. Accordingly, we find that FPC's interest on tax deficiencies shall be appropriately included as a component of cost of service.

That brings us to the question of amortization. We have decided to use a three year amortization period because that seems to be the midpoint of amortization periods that we have used for FPC.

Based on the above, we find that FPC's requested interest on tax deficiencies of $2,141,000 ($2,378,000 system) for 1992 and $1,167,000 ($1,308,000 system) for 1993 shall be included in O&M expense.

N. Bad Debt Expense

Florida Power projected $2,521,000 ($2,521,000 system) for 1992 and $2,722,000 ($2,722,000 system) for 1993 for bad debt expense. Because this projection included Sebring Utilities, bad debt expense was reduced $21,000 for 1992 and $22,000 for 1993 because Sebring was stipulated out of the case. This results in bad debt expense of $2,500,000 ($2,500,000 system) for the 1992 current test year and $2,700,000 ($2,700,000 system) for the 1993 projected test year.

The net write-offs as a percentage of sales are 0.14% for 1992 and 1993. Because this percentage equates to a three-year average of net write-offs as a percent of sales, it is consistent with our test that determines the reasonableness of bad debt expense. Accordingly, FPC's request for bad debt expense for 1992 and 1993 is reasonable, and no adjustments are necessary.

O. Rate Case Expense

Florida Power projected rate case expense of $424,200. Because actual expenses were $583,626 as of July 31, 1992, FPC revised its rate case expense projection to $596,726. The revision is $172,526 higher than FPC originally requested and is detailed below:

	Total Forecasted Expenses	Budget MFR C24	Variance
Outside Services	405,860	325,000	80,860
Legal Services	20,488	25,000	(4,512)
Meals and Travel	101,381	52,200	49,181
Paid Overtime	17,628	20,000	(2,372)
Other Expenses			
Duplicating	8,453		8,453
Mats. & Supp.	3,513		3,513

	Total Forecasted Expenses	Budget MFR C24	Variance
Postage & Fedx.	6,224		6,224
Public Notif.	24,849		24,849
Xerox Rental	5,424		5,424
Misc.	2,906	2,000	906
TOTAL	$596,726	$424,200	$172,526

OPC argued that rate case expense should be reduced by fifty percent to recognize excess expense associated with the 1993 test year and because the company's request for a performance reward was unjustified. There appears to be no record basis for Public Counsel's argument. In fact, a fifty percent disallowance is unreasonably high, especially since most of the work was necessary for the 1992 test year as well. Outside services, legal services, and paid overtime could possibly decrease, but meals and travel and "other expenses" would change very little.

The actual expense incurred for the 1987 rate case was $400,254. In our opinion, the rate case expenses for this case appears reasonable. $583,626 of the $596,726 represents actual expenses, with $13,100 in additional expenses forecasted through the end of the case. Although we have declined to allow revised rate case expense in the past, there have been instances where we have allowed a utility to revise its rate case expense, where the revision was based on the most recent information available. Because we have used the most recent information available to decide other issues, we feel it is appropriate to do the same here. Accordingly, $596,726 in rate case expense is appropriate.

At issue is the amortization period over which the expense will be spread. In the last major electric utility rate case, we ordered Gulf Power Company to amortize rate case expense over a 4 year period (Order No. 23573, issued October 3, 1990, in Docket No. 891345-EI). Although we did approve a five year amortization period for Florida Public Utilities - Fernandina Beach Division (Order No. 22224, issued November 27, 1989, in Docket No. 881056-EI).

FPC requested a 2 year amortization period because we approved a 2 year amortization period in FPC's 1984 and 1987 rate cases. FPC also made an assumption in its current Five Year Business Plan that the company would file its next rate case in 1994. However, it has been 8 years since FPC's last rate case where a rate increase was granted, and 5 years since its last rate case. Pursuant to Chapter 366, Florida Statutes, FPC must file Modified

Minimum Filing Requirements (MMFRs) in 1996. Based on these facts and the arguments presented above, we believe the amortization period should be greater than 2 years but less than 5 years. We find that rate case expense shall be amortized over 4 years beginning November 1, 1992. If FPC files for another rate increase in less than 4 years, and there is an unamortized balance left on the books as a result of this proceeding, the recovery can be considered at that time.

The appropriate amount of rate case expense is $596,726, and it shall be amortized over 4 years beginning November 1, 1992. Because the appropriate amount of rate case expense for 1992 and 1993 is $149,182, there shall be a reduction to expenses of $62,918 for each test year.

P. Membership Dues

The company included in operation and maintenance express membership dues in the Chamber of Commerce and the committee of 100. The parties stipulated that expenses should be reduced $71,654 ($75,000 system) and $75,827 ($79,500 system) for 1992 and 1993 respectively to remove these membership dues.

This adjustment is consistent with past Commission practices.

Q. Tree-trimming Expenses

FPC's requested level of tree-trimming expense of $8,855,559 ($8,879,000 system) for 1992 is not appropriate. We find that $7,301,000 ($7,320,000 system) for 1993 is appropriate.

FPC's tree-trimming expenses for the past five years were as follows:

1987	$6,396,000
1988	$5,808,000
1989	$6,902,000
1990	$6,207,000
1991	$6,323,912

According to FPC Witness Scardino, actual 1990 and 1991 tree-trimming expenses were under budget because work was deferred to 1992. Increased expenditures for 1992 were required to "catch-up" with deferred work. Mr. Scardino agreed that the $7.3 million projected for 1993 would be more indicative of ongoing operations in 1992. He also agreed that the amount of $7,320,000 should be the proper level of tree trimming expense for both 1992 and 1993 text years. We find that $7.3 million be the appropriate level of tree trimming expense for both the 1992 and 1993 test years. We make the following adjustment for 1992:

$8,879,000	(FPC's requested 1992 tree trimming expense)
($7,320,000)	(Indicative of ongoing operations for 1992)
$1,559,000	1992 adjustment (system)
X .99736	Jurisdictional Separation Factor
$1,554,884	1992 adjustment (Jurisdictional)

Therefore, expenses for the 1992 current test year shall be reduced by $1,554,884 ($1,559,000 system). This adjustment reduces FPC's tree trimming expenses for 1992 to $7,301,000 ($7,320,000 system) to reflect ongoing operations. We make no adjustment for the 1993 test year.

R. O&M Benchmark

During the course of the proceedings, an issue arose concerning whether the O&M benchmark should be applied to the company as a whole, or to FPC's individual functional units. As discussed below, we find that the O&M benchmark shall be applied to FPC's individual functional units. However, in so doing we are not precluded from examining the O&M expenditures of the company as a whole.

In making this determination, it is important to keep in mind that the benchmark is simply a tool or an indicator. The benchmark is a test, not a reward or penalty mechanism. It is not a floor or a ceiling. Certain expenses may not grow at the benchmark level, while others may exceed the benchmark level. In neither case are we precluded from looking closely at O&M expenditures. The benchmark forces the company to justify any inability it experiences in holding expenses within the rate of inflation and customer growth. It would be an improper use of the benchmark to offset positive variances of one functional group with negative variances of another functional group. The company can not justify being above the benchmark in one area by simply stating that it is below the benchmark in another area.

S. Consumer Price Index Factors

The appropriate Consumer Price Index (CPI) factors to use in determining test year expense is 3.7% for 1992 and 3.8% for 1993.

The company requested these factors in its initial filing, relying on the May 1991 DRI/McGraw-Hill Forecast for the U.S. Economy. During the company's next full requirements rate case, we shall require FPC to true-up the forecasted CPI to the actual data.

During the hearing, an updated June 1992 DRI CPI forecast was introduced. This updated forecast indicated a 3.3% CPI Factor for 1992 and a 3.5% CPI Factor for 1993. OPC argued that we should use the updated CPI forecast to determine test year expenses. Occidental argued that we should use a 3.1% CPI factor for 1992 and a 3.3% factor for 1993. However, if we were to use a lower CPI for O&M expenses in the 1992 and 1993 test years, the benchmark variances for the functional areas would increase. Traditionally, the MFR's filed by the company incorporate a true-up of the CPI and Customer Growth multipliers from those forecasted in the company's last rate case. The initial and supplemental MFR's filed be FPC trued-up the CPI and Customer Growth compound multipliers for the periods 1987-1992 and 1984-1987. These true-ups incorporated the company's last two rate cases. We shall apply these adjustments to the allowed level of O&M to calculate the base year O&M benchmark levels for the current rate case.

T. Nuclear O&M

The Federal Government has continuously required increased expenditures to insure the safety of nuclear facilities. Costs incurred for nuclear power safety vary so much from CPI that we believe the O&M benchmark is not a useful tool to evaluate nuclear O&M expenses. This does not mean that the utilities will be given a "carte blanche" on nuclear related expenditures. We will continue to analyze the prudence of nuclear expenditures, to determine whether those expenditures are justified. We have done so in this case, and we find that variances over the benchmark have been justified by the company.

In order to study the appropriateness of a nuclear operating and maintenance expense benchmark, our staff shall conduct a workshop. This workshop shall focus on the way we should look at nuclear O&M expenses. Our staff shall attempt to develop an appropriate test to analyze nuclear expense.

Florida Power's requested level of Nuclear O&M in the amount of $92,037,897 ($97,819,000 system) for the 1992 current test year and $95,763,861 ($101,779,000 system) for the 1993 projected test is appropriate. We find that FPC has justified its nuclear related expenditures in the following areas:

1. Increased Personnel

We accept the company's justification of $1,373,188 ($1,463,000 system) for 1992 and $1,369,596 ($1,463,000 system) for 1993. We find that FPC has justified $3,010,880 ($3,200,000 system) of expenses associated with Increased Personnel in excess of the 1992 Nuclear O&M benchmark for the 1984 through 1987 time period.

2. B&W Owner's Group

The B&W Owner's Group allows plant owners to share the costs of regulatory programs and modifications, which keeps each utility from having to spend the full amount needed to respond to any such issue on its own. A nonparticipating utility would not be as likely to avoid as many of the NRC compliance costs as participating utilities. This owners group is recognized by the NRC as the focal point for specific regulatory issues generic to the B&W plant design. Because of FPC's membership in the group, the company is expected to avoid expenditures of approximately $1.6 million to $4.1 million. We find that for the 1987 through 1992 time period, Florida Power has justified $408,351 ($434,000 system) of expenses associated with the B&W Owner's Group that are in excess of the 1992 Nuclear O&M benchmark.

3. Motor Valve Testing System

Because the company has justified the variances associated with the motor valve testing system, we shall not make the adjustments recommended by our staff. For the 1987 through 1992 time period, Florida Power has justified $135,490 ($144,000 system) of expenses associated with the Motor Operated Valve Testing System that were in excess of the 1992 Nuclear O&M benchmark.

4. Long Term Maintenance Plan

Because the company has justified the variances associated with the long term maintenance plan, we shall not make the adjustments recommended by our staff. For the 1987 through 1992 time period, Florida Power has justified $2,861,277 ($3,041,000 system) of expenses associated with the Long Term Maintenance Plan which are in excess of the 1992 Nuclear O&M benchmark.

5. Operator Training Simulator

Because the company has justified the variances associated with the operator training simulator, we shall not make the adjustments recommended by our staff. For the 1987 through 1992 time period, Florida Power has justified $478,918 ($509,000 system) of expenses associated with the Operator Training Simulator which are in excess of the 1992 Nuclear O&M benchmark.

6. Wage Differential

We find that for the 1984-87 time period, FPC has justified expenses in excess of the Nuclear O&M Benchmark for wage differential in the amount of $2,397,972 ($2,537,000 system). While we are not disallowing this expense, we are concerned with the comparison used by FPC. This comparison indicated that some FPC employees received annual raises above CPI, which was consistent with selected comparison groups who also received raises exceeding CPI. We believe a more fitting comparison would include an analysis of the employees' entire benefit package, including such items as retirement plans, stock options, health insurance, and vacation time. The analysis should also include a study of the impact the annual wage increase has on employee retention.

Occidental argued that the company failed to justify its wage expenses because FPC presented no evidence showing an increase in productivity or other benefits. FPC argued that it needed wage increases above CPI to maintain parity with industry peers because the wage program attracts and retains qualified personnel.

FPC also introduced a comparison of budgeted merit increases for office and technical employees and exempt employees. The comparison groups were compared to CPI. FPC's average annual merit increase from 1984 through 1990 was between 6% to 8%.

7. Plant Maintenance

FPC justified expenses in excess of the Nuclear O&M Benchmark of $1,660,716 ($1,757,000 system) for plant maintenance for the 1984-87 time period because the scope of FPC's existing and new programs required for plant maintenance has increased.

Occidental testified that FPC has initiated or increased spending for numerous nuclear programs which should decrease, not increase plant maintenance expense. FPC argued that improvements in efficiency have resulted from its Pooled Inventory Management

Program, its Fully Integrated Materials Information System, and its Fire Protection Program. We agree.

8. <u>Projects and Modifications</u>

FPC has justified $4,943,396 ($5,230,000 system) of expenses in excess of the Nuclear O&M Benchmark for Projects and Modifications for the 1984 through 1987 time frame. Because of NRC regulatory requirements, these expenditures have increased faster than the benchmark.

Occidental argued that FPC identified no projects or modifications incurred in 1984 that were not incurred in 1987. The intervenor argued that if some of these expenses were for new or modified systems to improve the performance of Crystal River 3, there should be a net reduction to O&M expense. Any costs associated with the introduction or modification of these systems should be capitalized.

FPC admitted that expenses for this program include nonrecurring items; however, there will always be nonrecurring items and historic data and current forecasts indicate that similar efforts will recur. NRC regulations account for 75% of the costs of this category. The remainder of costs are attributed to the company's increased emphasis on safety.

9. <u>Configuration Management</u>

FPC has justified expenses of $2,146,193 ($2,281,000 system) in excess of the Nuclear Production O&M Benchmark for Configuration Management for the 1987 through 1992 time period. Increased NRC regulatory requirements have caused these expenses to increase faster than the benchmark.

The majority of these costs are for projects to resolve design basis issues and to construct and maintain an online Information System consisting of complex databases which document technical specifications. Occidental argued that this program should result in improved and more efficient maintenance, which should result in long term, if not immediate, reductions in O&M expense.

All capital cost associated with the development of the software have been capitalized; however, maintenance of the information system is on ongoing O&M expense. Although the main justification for the Configuration Management program is safety, the program may also have beneficial effects efficiency and O&M costs.

10. Maintenance Activity Control System

FPC has justified expenses of $288,856 ($307,000 system) in excess of the nuclear production O&M benchmark for its Maintenance Activity Control System for the 1987 through 1992 time period. This program is an enhancement to the control and implementation of the nuclear maintenance program, which has caused these expenditures to increase faster than the benchmark.

The Maintenance Activity Control System is a computerized work process and control system which allows online planning, review, and approval of maintenance activities. The regulatory environment requires detailed documentation and approval of all maintenance activities.

Occidental testified that these expenditures should result in long term, if not immediate, reductions in O&M expense and that the software development and hardware construction should be capitalized, not expensed. However, the only costs attributable to this system are maintenance costs, and not capital costs.

11. Electrical Calculation Program

FPC has justified expenses of $127,962 ($136,000 system) in excess of the nuclear production O&M benchmark for its Electrical Calculation Program for the 1987 through 1992 time period. Increased NRC regulatory requirements have caused these expenditures to increase faster than the benchmark.

The NRC has concluded that the analysis performed on early nuclear plant designs did not always adequately demonstrate compliance with the plant design basis. This program is an ongoing effort to identify areas of potential non-compliance. When deficiencies are identified, the Electrical Calculations program constructs individual modification packages to correct the problem.

12. Planning and Scheduling

FPC has justified expenses of $189,121 ($201,000 system) in excess of the nuclear benchmark for Planning and Scheduling for the 1987 through 1992 time period. These expenses have been justified because this program will provide greater scheduling accuracy and efficient management of outages and daily maintenance.

Occidental testified that the Planning and Scheduling expenditures should result in long term, if not immediate, reductions in O&M expense. FPC argued that planning precision and schedule accuracy are essential to efficient management of outages and daily maintenance. The impact of this program can be seen in the development of midcycle outage and shorter refueling outages at Crystal River 3. This new outage maintenance approach should reduce forced outages between refueling outages.

13. Valve Reliability Program

Because the company has justified the variances associated with the valve reliability program, we shall not make the adjustments recommended by our staff. For the 1987 through 1992 time period, Florida Power has justified $188,180 ($200,000 system) of expenses associated with the valve reliability program that were in excess of the 1992 Nuclear O&M benchmark.

14. Technical Specification Improvement

FPC has justified its expenses of $127,021 ($135,000 system) that are in excess of the nuclear production O&M benchmark for technical specification improvement for the 1987 through 1992 time period. Expenses in this category exceed the benchmark due to FPC's response to industry and NRC concerns.

This program is a multi-utility/NRC effort. Assembled teams from several utilities are working together to refine and upgrade generic technical specifications for nuclear plants. The upgrade will reduce administrative burdens on operators, increasing their flexibility to properly operate the plant. This will result in improved availability and enhanced safety. This cost will continue over the lifetime of the plant due to continuous revisions of operating specifications.

15. Industry Groups

FPC has justified expenses of $125,140 ($133,000 system) in excess of the nuclear production O&M benchmark for Industry Groups for the 1987 through 1992 time period. Membership in these groups allows FPC to take advantage of combined operating experience when addressing regulatory concerns. These efforts are pointed toward achieving consistency and efficient resolutions of generic issues among owners of nuclear plants.

U. Fossil O&M

Florida Power's requested level of Total Fossil O&M in the amount of $88,844,000 ($101,071,000 system) for the 1992 current test year and $100,496,000 ($114,336,000 system) for the 1993 projected test year is not appropriate.

The requested level of Fossil O&M should be $86,322,000-jurisdictional ($98,271,000 system) for the 1992 current test year and $97,936,000-jurisdictional ($111,513,000 system) for the 1993 projected test year.

This is a mathematical calculation which incorporates all recommended adjustments related to FPC's requested level of Fossil O&M expenses as follows:

1. Scheduled Outage Expenses

We make no adjustment to 1987 or 1992 scheduled outage amounts because the increase in O&M expenditures are a result of increased levels of planned maintenance due to plant aging and increased generation from existing plant. We make an adjustment of $2,560,349 ($2,823,126 system) to 1993 scheduled outage amounts to normalize FPC's outage expenses in 1993 and 1994. FPC's requested budgeted outage expenses were lower in 1994 than 1993. The adjustment was calculated by averaging FPC's requested 1993 and 1994 budgeted amounts and subtracting this result from the requested 1993 budgeted amount.

Scheduled Outage expenses for 1992 exceed the benchmark by $7.5 million and represent approximately 45% of the total Fossil Production benchmark variance of $16.9 million. FPC identified expanded scope and increased costs associated with O&M programs addressing the increasing operating hours of the generating units, plant aging, and increased system demand.

FPC cites the reduced Equivalent Forced Outage Rate (EFOR) as the underlying theme and justification for the O&M variance. In 1988, the EFOR rate was 11.24%; due to the increased O&M expenses FPC has lowered the EFOR to 5.32% in 1992. FPC witness Hancock stated that 1992 fuel costs would have increased $23 million if the 1988 EFOR rate was used. However, witness Hancock failed to note FPC's 1987 EFOR of 6.55% was significantly lower than the 11.24% EFOR reported in 1988 which the company relied upon to estimate fuel savings. We note that it took FPC over three years to reduce the EFOR to the 1987 level during which time replacement fuel costs were higher to the customers.

FPC also cites increased generation as a cause of the increased level of O&M expense. In 1987, generation at the oil and gas units had increased by 52% above the 1984 level, and by 70% in 1992. The increased generation has resulted in the need for an increase in the frequency of scheduled maintenance outages. Boiler outages have also increased from 10 performed in 1984 to 17 scheduled for 1992.

2. Environmental Changes

FPC has provided justification for $194,438 ($215,850 system) related to its Ongoing Energy Efficiency Program. The program consists of new regulatory scope, falling under the section Regulatory and Governmental Requirements in the 1992 MFR. Schedule C-57a, page 170, states that FPC will

> Develop, implement, monitor, and up-grade an ongoing program to incorporate energy efficiency into all generating facilities and facility construction methods. It is important for the company to set an example in energy efficiency. Conservation will result in long-term avoidance of costs associated with additional generation and will reduce daily operating costs.

FPC's witness for Fossil O&M, Mr. Hancock, testified that the energy efficiency program would result in future cost avoidance. We believe that any energy efficiency program that results in quantifiable avoided costs is prudent. We do not believe it to be imprudent for a utility to implement programs to comply with governmental requirements. FPC has identified an environmental mandate that calls for an energy efficiency program for its facilities. FPC has justified the expenses in excess of the 1992 Fossil O&M benchmark which have been identified in the MFR's.

Occidental's recommendation to disallow expenses related to the Solid Waste Minimization Program ($62,700), the Water Conservation Program ($139,750), the Crystal River Hazardous Waste ($208,894), and Other Hazardous Waste ($219,763) is not valid. Occidental's reason for recommending disallowance for these programs is that FPC did not quantify any current or future cost savings which would result from them. We believe that the four programs in question are justified by Schedule C-57a because they address new regulatory and environmental requirements. FPC should be allowed to recover expenses in excess of the O&M benchmark due to these four programs:

> The Solid Waste Minimization program is justified because the Florida Solid Waste Act, implemented in 1988 and expanded in 1992, will continue to make it more expensive to dispose of solid waste and less likely that landfill space will be available (Schedule C-57a, p. 170).
>
> The Water Conservation program is justified because federal and state agencies continue to enact restrictions on water use. In addition, the cost of water is becoming increasingly expensive, so this program is a good business decision as well (Schedule C-57a, p. 170).
>
> The Crystal River Hazardous Waste and Other Hazardous Waste programs are justified because increasing federal, state, and local regulations have caused the list of hazardous wastes to continue to grow. Facing the need to dispose of more waste at higher cost, FPC established a centralized hazardous solid waste disposal site at the Crystal River site. Other Hazardous Waste expenses are incurred by the handling and transport of hazardous waste materials from plant sites to the centralized location (Schedule C-57a, pp. 172-4).

3. Increased Painting Costs

For the 1987 through 1992 and the 1992 through 1993 time periods, Florida Power has justified $703,672 ($794,840 system) of expense in excess of the 1992 Fossil Production O&M benchmark and $183,803 ($207,617 system) of expenses in excess of the 1993 Fossil Production O&M benchmark associated with Increased Painting Costs.

In Schedule C-57a of its 1992 MFR (pp. 199-201), FPC provided a table which showed specific detail of the facilities that require painting, the interval between paintings, and the projected cost each time a facility is painted. By estimating an annual cost for painting its facilities, FPC has reasonably levelized future expenses. The majority of the facilities which now have recurring painting costs were not included when the 1987 O&M benchmark was set.

We believe that Occidental's recommendation to disallow painting expenses that exceed the O&M benchmark is not valid. Occidental offered no reason for its position other than a belief that the expenses were not justified. FPC has shown in its MFRs that painting expenses escalated primarily due to the increased scope of facilities that require periodic painting. We believe that this is reasonable, and we believe that FPC has justified its painting expenses. FPC shall be allowed to recover painting expenses which exceed the O&M benchmark.

4. Aging and Maturation Activities

For the 1987 through 1992 and the 1992 through 1993 time periods, Florida Power has justified $1,987,002 ($2,244,439 system) of expenses in excess of 1992 Fossil Production O&M benchmark and $689,419 ($781,300 system) of expenses in excess of the 1993 Fossil Production O&M benchmark associated with Aging and Maturation Activities at Florida Power's coal, oil, and natural gas plants.

This issue received considerable attention at the hearing. FPC Witness Hancock testified that the largest factor influencing outage costs is plant aging. He testified that the average age of FPC's fossil steam plants is 29 years, and that a facility's age affects the amount of maintenance required. Witness Hancock used an automobile as an analogy to a power plant, to describe that an older power plant tends to need more maintenance than a newer one.

In Schedule C-57a of its 1992 MFR, FPC identified several factors related to its coal, oil, and gas plants which resulted in expenses which exceeded the 1992 Fossil O&M benchmark (pp. 192-5). Some of these expenses include the following:

- replacement of boiler controls and plant computer at Crystal River 2 due to aging of existing equipment no longer supported by the manufacturer

- increasing maintenance and repair expenses related to elevators at Crystal River 1 and 2, whose age is nearly 25 years

- replacement and repair of control systems at the oil and gas plants, whose average is nearly 33 years

- increased repair and replacement of mobile equipment, boiler systems, and structures (Bartow and Higgins)

In Schedule C-57a of its 1993 MFR, FPC identified particular maintenance programs for its coal, oil, and gas plants which they believed would result in fewer forced outages (pp. 127-9). These maintenance programs include ones for large motors, air heaters, and fans. FPC stated that this equipment needs very little maintenance during the first several years, but that as the equipment ages, maintenance becomes necessary more frequently (1993 MFR, Schedule C-57a, pp. 127-8). FPC believes that implementing equipment maintenance programs will help reduce the duration and severity of forced outages.

We disagree with Occidental's assertion that FPC did not provide evidence to justify its aging and maturation activities above the benchmark. Occidental argues that "many of the systems cited by FPC are related to capital replacements and should be capitalized, not expensed." We find that the majority of FPC's activities, were prudently incurred. Therefore, we will allow all expenses in excess of the 1992 and 1993 Fossil O&M benchmark attributed to aging and maturation activities.

5. Intercession City Peaking Units

For the 1992 through 1993 time period, Florida Power has justified $970,245 ($1,099,552 system) of expenses associated with the Activation of the New Intercession City Peaking Units in excess of the 1993 Fossil Production O&M benchmark. This issue was stipulated to at the start of the hearing. We approve the stipulation.

6. University of Florida Cogeneration Unit

For the 1992 through 1993 time period, Florida Power has justified $2,406,305 ($2,727,000 system) of expenses associated with the University of Florida Cogeneration Unit in excess of the 1993 Fossil Production O&M benchmark. This issue was stipulated at the start of the hearing. We approve the stipulation.

7. Existing Gas Turbines

For the 1984-87 time period, FPC has justified expenses in excess of fossil O&M Benchmark of $322,431 ($344,000 system) associated with Existing Gas Turbines.

The 1987 Fossil O&M benchmark for expenses was set in the 1984 rate case. At that time, FPC did not budget any expenses to mothball 16 gas turbine units which were subsequently placed into extended cold shutdown (ECS) status (Schedule C-57a Supplemental, p. 20). As such, FPC allocated a large portion of its 1987 Fossil O&M budget for planned mothballing costs for the 16 ECS units. The mothballing costs for the 16 ECS units and the maintenance costs for the four remaining units caused FPC to exceed the 1987 Fossil O&M benchmark by $322,431 ($344,000 system). We believe that these expenses were reasonable.

We disagree with Occidental's argument that FPC's 1987 expense level was overstated because it included nonrecurring mothballing costs. There is no discussion or evidence in the record to support this conclusion. Schedule C-57a (Supplemental) justifies expenses for existing gas turbine maintenance. Therefore, we will allow recovery of these expenses.

8. Predictive Maintenance

For the 1984-87 time period, FPC has justified expenses in excess of fossil O&M Benchmark of $189,335 ($202,000 system) for Predictive Maintenance.

FPC has credited its predictive maintenance program with avoided fuel and maintenance cost savings in 1988, 1989, and 1990 which far outweigh the expense of implementing the program (Schedule C-57a Supplemental, page 21). Expenses related to FPC's predictive maintenance program have been fully justified, and we will allow recovery of program expenses which exceeded the 1987 Fossil O&M benchmark.

9. Engineering Services

For the 1984-87 time period, FPC has justified expenses in excess of fossil O&M Benchmark of $538,948 ($575,000 system) for Engineering Services.

FPC stated in its 1987 MFR that the outage planning program was strengthened to minimize total outage costs, to "reduce overall outage costs through detailed planning, material staging, and daily control of all aspects from labor performance, to parts requisitioning and expediting, to purchasing." (Schedule C-57a Supplemental, p. 21).

Occidental's Witness Kollen testified that FPC didn't identify any offsetting savings in O&M expenses resulting from its outage planning program; thus, the expenses are not justified. (Tr. 2871) FPC made no claim that a reduction in O&M expenses would result from this program. FPC said that improved productivity of its work force allows the size of the work scope to increase for the same amount of O&M dollars (Schedule C-57a Supplemental, p. 21). FPC cited a test of the outage planning program on a turbine outage at Anclote Unit 1 in 1985, which was performed with an eleven percent (11%) improvement in productivity over similar previous outages.

FPC has justified its expenditures in excess of the 1987 Fossil O&M benchmark. We will allow recovery of these expenses related to FPC's outage planning program.

10. Non-Fossil Departments

For the 1984-87 time period, FPC has justified expenses in excess of fossil O&M Benchmark of $373,045 ($398,000 system) for Non-Fossil Departments.

11. Wages Above CPI

For the 1984-87 time period, FPC has justified expenses in excess of fossil O&M Benchmark of $2,066,747 ($2,205,000 system) for Wages above CPI.

12. Budgeted 1991 O&M Expenses Deferred into 1992 Test Year

We make an adjustment of $2,522,346 ($2,800,000 system) to FPC's Fossil O&M expenses in 1992. This adjustment stems from FPC's corporate budget (Exhibit 117), which shows that some maintenance work was deferred from 1991 into 1992 because FPC's management ordered a 4% reduction of expenses in 1991 to protect 1991 earnings. As a result, $2,800,000 (system) in O&M expenses were deferred into the 1992 test year. We will not allow these expenses to be included in the allowed Fossil O&M expenses for purposes of setting permanent rates for 1992.

V. Customer Accounts Expense

Florida Power's requested level of Customer Accounts Expense in the amount of $36,456,000 ($36,569,000 system) for the current 1992 test year and $38,845,000 ($38,845,000 system) for the 1993 projected test year is appropriate.

Florida Power's Customer Accounts Expense for the 1992 and 1993 test years is below the Customer Accounts O&M benchmark. These expenses have been fully justified in the testimony of Mr. Phillips and supporting MFR Schedule C-57c.

W. Customer Services Expense

Florida Power's requested level of Customer Service Expense in the amount of $7,984,000 ($7,984,000 system) for the 1992 current test year and $8,541,000 ($8,541,000 system) for the 1993 projected test year is not appropriate.

The appropriate level of Customer Service Expense is $7,564,000 for 1992 and $8,091,000 for 1993.

The company stated that it is under the benchmark in Customer Service. This is true only if one looks at the overall variance for Transmission, Distribution, Customer Accounts, Customer Service and Sales. FPC is over the benchmark by $4,079,000 in the Customer Service functional area for the 1987-92 period and under the benchmark by $385,000 for the 1984-87 period as reflected in MFR Schedule C-53.

The following is a table of the Customer Services functional group.

Account		Variance from the Benchmark 1992 (000)	1993
907	Customer Serv. & Info.	$477	$1
908	Customer Assistance	2,856	18
909	Infor. & Instutl. Ad.	484	7
910	Misc. Cust. Ser.& Info.	292	2
		$4,079	$28

The greatest variance from the benchmark occurred in Account 908, Customer assistance. FPC witness Phillips explained that this variance, as well as those in Accounts 907 and 910, was due to the reclassification of Customer Field and District Representatives from the Distribution area to the Customer Service area in order to better match the work performed to the appropriate FERC category. The variance in Account 909, Information and Institutional Advertising is due to advertising expenses associated with the company's strategic planning efforts. We have disallowed $420,000 for 1992 and $450,000 for 1993 in Account 909. Those adjustments should be made here for purposes of the benchmark calculation. Based on the above, we have no further adjustments to the Customer Services functional area.

X. Sales Expense

Florida Power's requested level of Sales Expense in the amount of $942,000, ($942,000 system) for the 1992 current test year and $1,007,000 ($1,007,000 system) for the 1993 projected test year is not appropriate.

Actual Sales Expense was significantly under budget in 1987 and 1988, and slightly under budget in 1990 - 1992. The increase to the Demonstration and Sales Expense accounts reflects activity in the areas of economic development and new products and services.

Economic development expenses are projected to increase by 22.8% from 1991 to the 1992 test year. These economic development activities are carried out in connection with the Florida Department of Commerce, the Florida Economic Development Council, the Florida Chamber of Commerce, and local economic development groups, to improve the overall economy of the state.

All economic development expenses were disallowed by this Commission in Order No. 23573, Docket No. 891345-EI:

> It appears that Gulf has assumed some the of responsibilities of local chambers of commerce of development boards. ... In seeking to expand industry or business activity in general, Gulf is actively attempting to increase sales of electricity.

Consistent with Order No. 23573, we disallow all economic development expenses in this docket. Sales Expense shall be reduced by $487,147 ($487,147 system) for 1992 and by $511,504 ($511,504 system) for 1993.

Y. Administrative And General Expense

Florida Power's requested level of Administrative and General Expense in the amount of $103,584,000 ($110,816,000 system) for the current test year and $107,648,000 ($115,093,000 system) for the 1993 projected test year is appropriate.

Other than the specific disallowances we have previously made, no additional adjustments to the A&G function are appropriate.

Z. Post Retirement Benefits Other Than Pensions

For the 1984-87 time period, FPC has justified expenses in excess of the Administrative and General Benchmark of $3,001,000 for Post Retirement Benefits Other than Pensions.

As we have previously discussed, FAS No. 106 will be used for ratemaking purposes. We believe that accrual accounting as prescribed by FAS No. 106 appropriately recognizes the future liability for OPEBs and properly matches the OPEB costs to the period in which the employees earn the benefits. We note that Schedule C-57d Supplemental of the MFRs provides an explanation for OPEB costs above the benchmark. In December, 1985, FPC began accruing the cost of OPEBs for current retirees of the company. The company believed that this accrual was appropriate since the OPEB liability was similar in certain respects to pension liability. Both represented a form of deferred compensation that should be recognized during the employees' active service instead of the post-employment period. For this reason, we believe that the increase above the Administrative and General Benchmark is justified.

AA. Management Incentive Compensation Plan

For the 1984-87 time period, FPC has justified expenses in excess of the Administrative and General Benchmark of $600,000 for Management Incentive Compensation Plan.

Florida Power Corp. filed MFR Schedule C-57D, O&M Benchmark Variance by Function, comparing the 1984 O&M expenses allowed versus the 1987 benchmark. The benchmark variance for the A&G function was $13,153,000. A number of new activities or scope changes between the 1984 case and 1987 justify the variance. One is the Management Incentive Compensation Plan (MICP).

In 1985 FPC developed an incentive compensation plan which is a part of the total compensation plan for its key employees. Witness Scardino in his rebuttal testimony stated that the company "has used incentive compensation to focus the attention and efforts of our key employees on achieving goals that have a direct and significant influence on individual, organizational and corporate performance." "The amount of the total incentive award is influenced by the degree to which the company meets its return on equity expectations." This prevents an award payment if the current year's financial performance is subpar. Achieving individual goals determines how the award is allocated. Many of the goals relate directly to controlling costs, encouraging good customer service and energy efficiency.

The company has placed a portion of the total compensation of specific key employees at risk by requiring the achievement of goals and objectives. Placing part of executives' pay at risk has proven to be a substantial performance motivator.

The company provided the MICP expense for 1987-1991 and projected for 1992 and 1993. The 1992 and 1993 projections were much less than for the previous years. The company budgets on a midpoint value, never on the assumption that there will be a 100% payout.

FPC's incentive plans are similar to plans adopted by other electric utilities in Florida. In the last Gulf Power Company rate case we allowed recovery of the expenses associated with its incentive compensation plan. (Order No. 23573, Docket No. 891345-EI) In the recent Peoples Gas rate case, we accepted that company's plan with an adjustment to recognize that Peoples' projected a 100% payout but in reality the historical payout percentage was less than 100%.

Incentive plans that are tied to the achievement of corporate goals are appropriate and provide an incentive to control costs. FPC has controlled the increase in O&M expense to some extent. We believe that the incentive plans have contributed to this control.

BB. <u>Pension Expense</u>

For the 1987-92 time period, FPC has justified expenses in excess of the Administrative and General Benchmark of $5,794,000 for Pension Expense.

As we have previously discussed, we believe the use of FAS No. 87 is appropriate in ratemaking. FPC's increase over the benchmark is justified since FAS No. 87 requires accrual accounting for pension expense thus recognizing the cost of benefits as the employees earn the benefits.

CC. Post Retirement Benefits Other Than Pension

For the 1987-92 time period, FPC has justified expenses in excess of the Administrative and General Benchmark of $18,287,000 for Post Retirement Benefits Other than Pensions.

The increase over the benchmark is justified since FAS No. 106 requires accrual accounting for OPEBs, thus recognizing the cost of benefits as the employees earn the benefits.

IX. DEPRECIATION EXPENSE

Florida Power's requested Depreciation Expense of $210,428,000 ($231,898,000 system) for the 1992 current test year and $226,109,000 ($251,178,000 system) for the 1993 projected test year is not appropriate.

The appropriate jurisdictional Depreciation Expense is $203,439,000 for 1992 and $219,829,000 for 1993.

A. Crystal River #3 Depreciation Expense

Florida Power's requested adjustment to depreciation expense for 1992 and 1993 associated with Sebring's portion of Crystal River #3 is appropriate.

The company correctly calculated the depreciation expense for Crystal River #3 based on the plant in service and using the depreciation rates we have prescribed. No contradictory evidence was presented in opposition to the company's calculations.

B. Fossil Fuel Dismantlement Expense

Florida Power's adjustment to increase Fossil Fuel Dismantlement Expense in 1992 by $3,919,000 ($4,643,000 system) and to decrease the expense in 1993 by $3,590,000 ($4,390,000 system) is not appropriate.

FPC's fossil fuel dismantlement expense adjustment should be increased by $1,983,000 for 1992 and by $1,868,000 in 1993 from what was filed in the MFRs. The adjustments are to be effective November, 1992.

The methodology for calculating dismantlement accrual was examined in fossil fuel dismantlement Docket 890186-EI, Order No. 24741. This methodology has been used to calculate the appropriate dismantlement accrual in the depreciation studies for FPL in Docket No. 910081-EI and Tampa Electric in Docket No. 910686-EI.

In general, FPC has followed the directive of Order No. 24741, although we have made changes to increase the expense adjustment filed in the MFRs. The first and most important change was use of the most current inflation indices. As stated in Order No. 24741, the "indices should come from the most current DRI Review of the U.S. Economy that is available." When the company filed its MFRs, the Summer 1991 edition was the most current. In February, the Winter 1991-92 edition was released. We have updated the indices accordingly.

Once the indices are used to compute the future cost of dismantlement, the dollars must be discounted back to a current accrual. FPC discounted the dollars with CPI because it "more closely matches the expected change in our customer's purchasing power." We believe the cost to the customer should relate to the increase in the cost of dismantling the plant. The increase in the annual accrual should be designed to capture the rising cost of labor and material to dismantle a plant. Therefore, the DRI inflation rates used to escalate the expenses in the cost study are also used to discount the future costs.

We have also adjusted the retirement date. The company forecasts a mid-year retirement with "dismantling to begin in the same year the retirement was recorded". We prefer a year-end retirement method recognizes that the plant will retire at some time before the end of a specific year with the dismantlement process beginning in the following year.

We accept FPC's use of the Metal and Metal Products Index for inflating the salvage value of the plants. Order No. 24741 directs the use of the Intermediate Materials, Supplies and Components Index for inflating salvage value but further states "we are willing to accept evidence from a utility that adjustments may be necessary to the escalation rates." Witness Scardino, at his deposition, explained that salvage is driven by scrap value which is best represented by the metals index. The record further reflects that "price movements for metals and metal products and scrap metal are highly correlated."

C. Contingency Factor

We do not believe FPC's practice of increasing fossil plant dismantlement expense by a contingency factor of 25% is appropriate. A 20% contingency factor should be adequate to address FPC's concerns.

The company believes the uncertainties and difficulties that may arise when a plant is dismantled call for a 25% contingency factor to be included in the dismantlement cost study. Witness Carlson representing FIPUG and Witness Kollen representing Occidental assert there is no need for the 25% contingency because the dismantlement cost study is periodically updated. Witness Kollen also testifies that the estimate itself is inherently uncertain and adding a contingency adds to the uncertainty.

The validity of the 25% contingency factor can be determined if it is segmented into its two components, the 15% scope omission and error contingency and the 10% pricing contingency. The scope contingency is determined "considering the conceptual nature of the estimate and the difficulty in obtaining quantity records on such old units." The pricing contingency provides "confidence that the estimate will not overrun due to pricing error."

The scope omission and error contingency is designed to accommodate surprises or unexpected costs during the actual dismantlement. These would include weather conditions that may slow down the dismantlement process, labor strikes, or unexpected environmental concerns. Company witnesses Hancock and Scardino acknowledged that although this contingency is needed, it could change in the future as the industry gains experience from actually dismantling some plants. Witness Scardino testified

> As we complete these dismantlements, we will have a much better feel for what we anticipated the cost to be and what the actual turns out to be. And I think as we gain more experience, we'll be able to better focus in on the contingency factor.

We agree that a contingency factor for unexpected costs should continue to be factored into the cost study. The amount should be reevaluated every four years in the dismantlement studies filed with the Commission.

The pricing contingency was discussed by Witness Hancock. He testified

> ...The pricing of what the marketplace requires that we spend to get the job done, with various specialty contractors and engineers, and whatever the case may be, it has an uncertainty of that, that we attach 10% to.

Difficulties in this type of pricing decrease as dismantlement dates approach. Changes in the cost of "specialty contractors and engineers" needed to dismantle the plants should be captured in the periodic updates of the inflation indices. We believe that pricing will become more clear in the few years preceding dismantlement. This contingency should be further analyzed in the company's next depreciation/dismantlement study.

We do not believe a contingency will cause a disincentive for the company to control costs. Although dollars have been booked to the reserve through the years prior to dismantlement, those dollars have actually already been spent. In Docket No. 890186, we decided that an unfunded reserve is appropriate. This means the company could use those revenues for any utility purposes and have the opportunity to earn FPC's internal rate of return on those dollars. At the plant dismantlement date, the dollars used to dismantle the plant are dollars taken from other company uses. The company will have to fund the dismantlement of the plants while continuing to finance its regular operations. Witness Kollen testified that if there were less dollars than the company anticipated spending, the company would be behaviorally oriented towards trying to bring the cost of dismantling in at a lower level. Since it is an unfunded reserve, there will be no cash dollars at the time of dismantlement.

We believe that a 25% contingency may overcompensate the dismantlement revenue. We find that a 20% contingency is appropriate and is amply supported by the record herein.

D. Future Value Of Land

FPC should not consider the future value of the land on which the plants to be dismantled are located in calculating the appropriate fossil fuel dismantlement expense.

Witness Carlson representing FIPUG addressed the question of whether the value of land should be offset with the cost of dismantlement. Witness Carlson supported factoring the land value into the dismantlement cost study to reduce the accrual "just as the positive salvage value of other salable items is factored into the study." She testified that if land is not factored into the study, there is an intergenerational inequity when the land is sold after dismantlement because the future ratepayers receive the benefit of the gain while past ratepayers paid for the cost of dismantlement.

FPC argued that selling the land is an entirely different transaction that should not be considered as part of dismantling a plant. Witness Scardino summarized the company's position in the following statement

> The facility depreciates over time, wears out, is consumed. The land still has value. The land still has functional purpose for the utility. And so we are just not, in the general sense, in the business of selling off our raw property, whether it has use as a replacement for the facility that was there or some new application. Land is a resource that is difficult to come by for us and so we maintain what we have.

If land value is considered as an offset to dismantlement costs, and FPC does not sell the land at the end of dismantlement, FPC will not have accrued enough expense to pay for the cost of dismantlement. Future ratepayers will have to pay this unrecovered cost after the plant is no longer serving the public. Intergenerational inequities will still exist. The misconception in Witness Carlson's testimony is that the company will sell the land when the plant is dismantled.

The treatment of land is a separate issue from fossil fuel dismantlement. Under the current Commission practice, as long as the land is retained by the company, it will remain in rate base at its original cost and continually earn a return from each generation of ratepayers. An intergenerational inequity will occur only when and if the land is finally sold.

Using historical based accounting, intergenerational inequities concerning the sale of land cannot be resolved. If the sale-date of the land could be determined, one alternative would be to forecast the future value of the land. The future value could then be recovered equitably over the remaining life of the plant site. This would solve some of the inequity concerns raised at the hearing. Witness Scardino testified however that forecasting land value is beyond the scope of reasonableness. We agree.

As long as land is considered a part of rate base at its historical cost, there will be an intergenerational inequity when the land is finally sold. This phenomenon exists without regard to fossil fuel dismantlement. Netting the value of land against the cost of dismantling the current site may cause a reserve deficiency because more plants may be built at the same location. We favor keeping the value of land and the cost of plant dismantlement separate.

X. TAXES OTHER THAN INCOME TAX

Florida Power's requested level of Taxes Other Than Income Taxes in the amount of $63,617,000 ($69,969,000 system) for the 1992 current test year and $72,911,000 ($80,785,000 system) for the 1993 projected test year is not appropriate. Taxes Other Than Income Taxes should be reduced by $1,047,000 for 1992 and by $1,151,000 for 1993.

The company's position in the prehearing order was that an adjustment is required for the change in the rate of the Regulatory Assessment Fee. At the time of the filing, the rate was 0.125%. Since that time, the rate was changed to 0.083% for the period of January 1992 and beyond. (Docket No. 911130-EI, Order No. 25585, dated January 8, 1992.) The company's prehearing position was that the Regulatory Assessment Fees should be revised along with the revenue expansion factor. The revenue expansion factor reflects the new rate of 0.083%. The effect of these adjustments is a decrease to Taxes other than Income of $745,000 in 1992 and $845,000 in 1993.

We also agree with the company that, as a result of the company's adjustment for the Sebring Acquisition, Taxes Other Than Income Taxes should also be reduced.

Based upon these adjustments, as well as others previously discussed herein, we reduce taxes other than income by $1,047,000 for 1992 and by $1,151,000 for 1993.

XI. INCOME TAX EXPENSE

Florida Power's requested Income Tax expenses in the amount of $58,597,000 ($63,234,000 system) for the 1992 current test year and $49,316,000 ($51,587,000 system) for the 1993 projected test year is not appropriate.

Based on adjustments previously made, Jurisdictional Income Tax expense is $60,174,000 for the 1992 current test year and $54,711,000 for the 1993 projected test year.

An adjustment, increasing working capital by $2,606,000 in 1992 and by $1,440,000 in 1993, is made to income taxes payable for the effect of revenue and expense adjustments on income tax expense.

A. Consolidating Tax Adjustments

We believe that Consolidating Tax Adjustments (CTAs) are inappropriate in the ratemaking process. Consequently, no CTA adjustments shall be made for the 1992 current test year and for the 1993 projected test year.

"The term 'consolidated tax adjustment' (CTA) refers to the controversial ratemaking procedure whereby utility regulators pass through to ratepayers tax benefits attributable to the losses of non-regulated corporate affiliates. A CTA can be made either by (1) adjusting the ratemaking tax expense (and, ultimately, cost of service) of the utility for a portion of the tax benefits arising from the loss affiliates; or (2) treating as no-cost capital or, alternatively, excluding from rate base, an amount representing the utility's share of the federal income tax benefits attributable to the filing of a consolidated tax return."
(Tr. 2267)

The Commission has a long-standing policy of not considering CTAs in the cost of service of Florida utilities:

> A basic premise of regulation is that utility operations should not subsidize other operations nor should they be subsidized by other operations. This is true whether the operations are those of an affiliate joining in the filing of a consolidated federal tax return or the utility. Regulators remove the assets, capital, revenue and expenses associated with these activities from rate base, cost of service and capital structure. Most of these adjustments would have a tax effect. However, the tax effect is coincidental to the adjustment. That is, the adjustment to taxes is not made in an effort to alter the tax expense. It is a result of allowing the tax effect of the regulatory changes to follow the related revenue or expense item. (Tr. 2269)

The record adequately supports continuing our current policy of excluding CTAs from cost of service consideration.

Accordingly, no CTA adjustments shall be made for the 1992 current test year and for the 1993 projected test year.

XII. TOTAL NET OPERATING INCOME

The net operating income is determined by subtracting total operating expenses from operating revenues. The appropriate net operating income for FPC is $211,495,000 and $212,756,000 for 1992 and 1993, respectively.

XIII. REVENUE EXPANSION FACTOR

The purpose of the revenue expansion factor (NOI multiplier) is to gross up or expand the company's net operating income deficiency to compensate for income taxes and revenue taxes that the company will incur as the result of any revenue increase. We find that the appropriate expansion factor for 1992 and 1993 is 1.607157, which excludes the gross receipts tax component and includes the current regulatory assessment fee rate of 0.0830.

The company originally included a regulatory assessment fee of 0.125% in its revenue expansion factor, the assessment fee rate in effect at the time this case was filed. After the case was filed the rate was changed to 0.083%. We believe it appropriate to recognize the Regulatory Assessment Fee rate currently in effect in calculating FPC's revenue expansion factor.

The company also proposed to exclude the gross receipts tax as a component of the expansion factor and recover it through base rates. We find it appropriate instead to approve recovery of the gross receipts tax as a separate line item on customers' bills, as we have done in other cases.

XIV. REVENUE REQUIREMENTS

The revenue requirements of a utility are derived by establishing its rate base, net operating income (NOI) and fair rate of return. A test year of operations, traditionally based upon one year of operations, is used to derive these factors. Multiplying the rate base by the fair rate of return provides the net operating income the utility is permitted to earn. Comparing the permitted net operating income with the test year net operating income determines the net operating income deficiency or excess. The total test year revenue deficiency or excess is determined by adjusting the deficiency or excess by the revenue expansion factor.

Multiplying the rate base value of $2,950,832,000 for 1992 by the fair overall rate of return of 8.39% yields an NOI requirement for 1992 of $247,575,000 for 1992. The adjusted net operating income for the 1992 test year amounted to $211,495,000 and resulted in an NOI Deficiency of $36,080,000.

Multiplying the rate base value of $3,179,393,000 for 1993, by the fair overall rate of return of 8.37% yields an NOI requirement for 1993 of $266,115,000. The adjusted net operating income for the 1993 test year amounted to $212,756,000 and resulted in an NOI Deficiency of $53,359,000.

We find that the total appropriate revenue for the 1992 current test year and for the 1993 projected test year is $85,757,000.

XV. INTERIM INCREASE

Florida Power Corporation was granted an interim increase of $31,208,000 by Order No. PSC-92-0208-FOF-EI dated April 14, 1992 and effective April 23, 1992. The interim increase was based on a November 30, 1991 test year and a 12.60% return on equity, the floor of the company's last authorized return on equity.

Interim rates were in effect from April through October of 1992, and we are therefore using calendar year 1992 revenue requirements to determine the appropriate amount of interim rate relief. Any significant items that fall outside of the period that interim rates are in effect need to be adjusted. The Debary Unit, FAS No. 106, and increased dismantlement costs are all assumed to be effective in November, 1992, coincident with the rate increase. Accordingly, they should be adjusted for interim purposes.

The company has proposed to refund $907,000 of the interim increase using the interim test year and adjusted for certain audit disclosures contained in staff's audit report covering the interim test year. The company's proposal, however, was based on 1991 information and does not reflect the newly authorized rate of return, as the interim statute requires.

After the above three adjustments we find that Florida Power Corporation's interim revenue requirements are calculated to be $37.3 million. Since the interim increase was $31.2 million, a refund is not appropriate.

We considered the effective dates for implementation of FAS No. 106 concerning Other Post Employment Benefits and of increased dismantlement costs along with our consideration of the appropriateness of interim rates. Since we have decided that the interim rates ordered in this case were not excessive, the effective dates of FAS No. 106 and increased dismantlement costs will be established as November 1, 1992, after the period interim rates were in effect, and coincident with the effective date of the new permanent rates.

Calculation of Interim Revenue Requirements (000)

1992 Rate Base	$2,950,832	
FAS No. 106	5,981	
Fossil Fuel dismantlement	2,459	
DeBary	(48,104)	
Rate Base for Interim purposes		$2,911,168
Cost of Capital		8.39%
Required NOI		244,247
1992 NOI	$211,495	
FAS No. 106	5,235	
Fossil Fuel dismantlement	3,061	
DeBary	1,646	
Interest Reconciliation	(428)	
NOI for Interim purposes		$221,009
NOI deficiency for Interim purposes		23,238
Expansion Factor		1.607157
Interim Revenue Requirements		$37,347
Interim Increase		$31,208

XVI. COST OF SERVICE AND RATE DESIGN

We have ascertained the company's revenue requirement and the amount of revenue increase necessary to fulfill that requirement. We now consider rate design: the rate of return currently earned by each rate class; and how each class's responsibility will be spread between the customer, energy, and demand charges. At the Prehearing Conference, stipulations were proposed on two rate design issues: (1) lowering the minimum KW demand for the Curtailable Rate Schedule to 25 KW and eliminating the minimum KW demand for the Interruptible Rates Schedules (Issue 183): and (2) consolidation of the Outdoor Lighting Schedule and the Street Lighting Schedule into a single Lighting Schedule (LS) (Issue 184). We find both proposals appropriate and approve these proposed stipulations. The balance of issues on Cost of Service and Rate Design were addressed in a separate stipulation.

The parties who took positions on the cost of service and rate design issues in the case entered into a comprehensive stipulation of those issues, dated July 22, 1992. We have carefully reviewed the comprehensive stipulation, we approve it, and we adopt it as our decision on all cost of service and rate design issues in the case. A copy of the Cost of Service and Rate Design Stipulation is attached to this order as Attachment 2. A copy of a spread sheet of approved rates is attached to this order as Attachment 3.

XVII. OTHER ISSUES

A. Performance Reward

We have carefully reviewed Florida Power Corporation's $9,990,000 request for a performance reward for superior management. We are unanimous in our praise of Florida Power Corporation as a well-run, successful utility. We do not believe, however, on the basis of the record in this proceeding, that it is appropriate at this time to approve a general performance reward of the type requested here. Florida Power Corporation's request is therefore denied. We must reassert that we are pleased with the way Florida Power Corporation conducts its business, and we encourage the company to continue on its successful path. We want it clearly understood that our decision to deny the requested reward here in no way precludes us from approving a reward for superior management, or, for that matter, a penalty for inferior management, at another time.

B. Management Audit

One of the issues in this docket was whether we should direct FPC to undergo a management audit focused upon the achievement of operating efficiencies and cost reductions.

We do not believe it is appropriate to require one utility to undergo a management audit without requiring all similarly situated utilities to also undergo a management audit. If we decided to require each utility with O&M expense growth in excess of a specified level to undergo a management audit, adoption of a rule would be a reasonable way to proceed. We will, however, forward pertinent information to the Bureau of Regulatory Review in the Division of Research for its consideration in scheduling the next PSC management audit of FPC.

C. Transactions With Affiliated Companies

One of the issues raised at the prehearing was whether adjustments should be made for the rate base effects of transactions with affiliated companies.

This issue was not addressed in the testimony of any intervenor witness nor in the cross-examination of any Florida Power witness. Accordingly, there is no basis for any such adjustment.

The related issue of whether adjustments should be made for the capital structure effects of transactions with affiliated companies was also not addressed the hearing. There is no record basis for any adjustment.

Finally, the issue of whether adjustments should be made for the net operating income effects of transactions with affiliated companies was not addressed adequately at the hearing. There is insufficient record basis for any adjustment.

D. Revenue And Sales Decoupling

FPC has agreed to file a decoupling proposal with this Commission within 60 days after the issuance of the Order in this docket. We will conduct a more thorough evaluation at that time to determine whether revenue and sales decoupling should be implemented by FPC.

FPC will not be required to implement a decoupling mechanism at this time. FPC has agreed on the record at the Prehearing Conference and at the hearing to file a proposal for the decoupling of revenues and sales within 60 days of the issuance of the Order in this docket. This will provide an opportunity for a more thorough evaluation of the concept of decoupling, with focus on a specific plan. At that time a more thorough study will be conducted, to determine whether the decoupling of revenues and sales should be implemented by FPC.

E. Demand Side Management Incentive

FPC has agreed to file an incentives proposal with the Commission within 60 days of the issuance of the Order in this docket. A more thorough evaluation will be conducted at that time to determine whether a special demand side management incentive (DSM) program for FPC should be implemented.

XVIII. PROPOSED FINDINGS OF FACT

LEAF has submitted proposed findings of facts regarding the decoupling and conservation incentives issues. As previously discussed, FPC has agreed to submit decoupling and conservation incentive proposal for our consideration within 60 days. These issues will be evaluated in another docket which will be opened based on the specific decoupling and incentive plans filed. The proposed findings of facts submitted by LEAF are unnecessary for us to reach the decisions we have made in this order. These matters will be carefully studied in a new docket. We are not rejecting them on their merit, but only because they are unnecessary in deciding the matters at issue here.

An "agency head is not required to make explicit rulings on subordinate, cumulate, immaterial or unnecessary proposed facts." Such proposed facts may be rejected by a "simple statement that they are immaterial or irrelevant." Forrester v. Career Service Commission, 361 So.2d 220, 221 (Fla. 1st DCA 1978); Iturralde v. Department of Professional Regulation, 484 So.2d 1315 (Fla. 1st DCA 1986); Health Care Management, Inc. v. Department of Health & Rehabilitative Services, 479 So.2d 193 (Fla. 1st DCA 1985).

1. The current regulatory connection between FPC's sales and revenues creates strong economic disincentives to FPC's provision of reliable energy services at the lowest cost.

This proposed finding is immaterial, unnecessary or irrelevant.

2. A level playing field for demand and supply-side resource options is necessary to support FPC's provision of reliable energy services at least cost. The current regulatory connection between FPC's sales and revenues operates as a disincentive to demand-side resource options and thus provides

an unbalanced playing field for demand and supply-side resource options.

This proposed finding is immaterial, unnecessary or irrelevant.

3. FPC needs to be more aggressive in the area of energy reducing programs.

This proposed finding is immaterial, unnecessary or irrelevant.

4. The current regulatory connection between FPC's sales and revenues creates strong economic disincentives to FPC's implementation of energy efficiency programs that reduce energy usage.

This proposed finding is immaterial, unnecessary or irrelevant.

5. Decoupling FPC's sales and revenues would improve FPC's achievements in energy reducing programs.

This proposed finding is immaterial, unnecessary or irrelevant.

6. Decoupling FPC's sales and revenues would minimize load forecast gaming.

This proposed finding is immaterial, unnecessary or irrelevant.

7. Decoupling FPC's sales and revenues would help stabilize utility earnings.

This proposed finding is immaterial, unnecessary or irrelevant.

8. Decoupling FPC's sales and revenues would reduce the risk of innovative rate designs.

This proposed finding is immaterial, unnecessary or irrelevant.

9. Decoupling does not remove all significant financial and institutional barriers to that quantity of DSM that would be part of FPC's least cost plan to provide reliable electric service.

This proposed finding is immaterial, unnecessary or irrelevant.

10. DSM incentives are required to remove the significant financial and institutional barriers that remain after decoupling FPC's revenues and sales.

This proposed finding is immaterial, unnecessary or irrelevant.

11. DSM incentives are required to make successful implementation of a least cost plan FPC's most profitable course of action.

This proposed finding is immaterial, unnecessary or irrelevant.

12. DSM Incentives would improve FPC's performance in energy efficiency programs, particularly energy reducing programs.

This proposed finding is immaterial, unnecessary or irrelevant.

13. Economically reasonable levels of energy conservation and load management will not be implemented without utility intervention, i.e., through utility investment in DSM measures that allow provision energy services at least cost.

This proposed finding is immaterial, unnecessary or irrelevant.

14. Decoupling FPC's sales and revenues and adopting DSM Incentives for FPC would minimize environmental damage and reduce the financial costs and risks posed by supply side resource options.

This proposed finding is immaterial, unnecessary or irrelevant.

15. Decoupling and DSM incentives are required to make successful implementation of a least cost plan FPC's most profitable course of action.

This proposed finding is immaterial, unnecessary or irrelevant.

16. Decoupling and incentives together are necessary to get the very best utility performance in the area of DSM acquisition over the long run.

This proposed finding is immaterial, unnecessary or irrelevant.

17. There are a variety of tools, including rate design, that may be used to minimize any adverse financial impacts on low income consumers from demand and supply-side programs.

This proposed finding is immaterial, unnecessary or irrelevant.

18. DSM programs can help FPC's low- or fixed-income consumers to get a higher quality of life out of the dollars they can budget for energy.

This proposed finding is immaterial, unnecessary or irrelevant.

19. Decoupling methods should meet the following standards:

a. remove the lost sales disincentive to conservation, and so avoid the "conflicting incentives" problem with respect to marketing both energy sales and energy conservation.

b. be as practical and administratively convenient as is reasonably feasible.

c. not have unacceptable side effects. In particular, decoupling-related shifts in risk are limited.

This proposed finding is immaterial, unnecessary or irrelevant.

20. Only the RPC and ERAM methods remove the "lost sales" disincentive to energy efficiency programs.

This proposed finding is immaterial, unnecessary or irrelevant.

21. The RPC method as described in Appendix A, attached hereto and hereby incorporated herein, is very simple and creates very little, if any additional administrative burden.

This proposed finding is immaterial, unnecessary or irrelevant.

22. An RPC method in which various customer classes are not aggregated is unnecessarily complex and not likely to be worth the effort.

This proposed finding is immaterial, unnecessary or irrelevant.

23. ERAM, as implemented in California, is a very elaborate system and involves additional regulatory procedures, "little mini-yearly rate cases," where a complicated set of adjustments are made.

This proposed finding is immaterial, unnecessary or irrelevant.

24. The linkage between revenues and customers is at least as soundly based in both theory and statistics as the current regulatory linkage between revenues and sales.

This proposed finding is immaterial, unnecessary or irrelevant.

25. RPC best avoids unacceptable side effects and limits decoupling-related shifts in risk.

This proposed finding is immaterial, unnecessary or irrelevant.

26. DSM incentives for FPC should:

a. limit FPC's economic rewards from DSM investments to no more than 15% of the net financial benefits (above established target levels) that said investments create for FPC's customers; and

b. be designed to make FPC's least-cost resource plan its most profitable plan, provide appropriate impacts on stockholder and customers, and be simple, understandable and easy to administer (as more fully described in Appendix B, attached hereto and incorporated herein by this reference.)

This proposed finding is immaterial, unnecessary or irrelevant.

27. FPC's resource planning process rejects any DSM program that does not pass the rate impact measure ("RIM") test -- without even considering whether revenue requirements would be less if that program was included in the company's DSM portfolio.

This proposed finding is immaterial, unnecessary or irrelevant.

28. DSM programs rejected by FPC for failure to pass the RIM test are not submitted for the Commission's consideration or approval.

This proposed finding is immaterial, unnecessary or irrelevant.

29. A single demand-side management measure, even if the measure were free and even if the measure saved significant amounts of electricity, could still fail the rate impact test because a certain amount of fixed costs would be spread over a smaller number of kilowatt hours.

This proposed finding is immaterial, unnecessary or irrelevant.

30. Any DSM programs that pass the TRC test will be less expensive than new generating resources (even if said programs failed the RIM test).

This proposed finding is immaterial, unnecessary or irrelevant.

31. Since any DSM program that fails the RIM test is excluded from FPC's DSM portfolio, DSM programs that would save significant amounts of electricity at little or no cost would be rejected by FPC without even being submitted for consideration by the Commission.

This proposed finding is immaterial, unnecessary or irrelevant.

32. Supply-side resources are selected primarily on the basis of least cost, that is, to minimize the present value of revenue requirements, and are not eliminated because they have a rate impact on nonparticipating customers.

This proposed finding is immaterial, unnecessary or irrelevant.

XIX. CONCLUSIONS OF LAW

1) Florida Power Corporation is a public utility within the meaning of Section 366.02, Florida Statutes, and is subject to the jurisdiction of the Commission.

2) The Commission has the legal authority to approve and use historical or projected test periods for ratemaking purposes. Calendar years 1992 and 1993 are appropriate base test periods.

3) The adjustments to rate base made herein are reasonable and proper. The value of the company's 1992 rate base for ratemaking purposes is $2,950,832,000. The company's 1993 rate base for ratemaking purposes is $3,179,393,000.

4) The adjustments made to the calculation of net operating income are proper and appropriate. For ratemaking purposes, Florida Power Corporation's net operating income for 1992 is $211,495,000. Its net operating income for 1993 is $212,756,000.

5) The fair rate of return on the equity capital of Florida Power Corporation is 12%.

6) Florida Power Corporation should be authorized to increase its rates and charges by $57,986,000 in annual gross revenues beginning November, 1992. In should be authorized to increase its rates and charges by $9,660,000 beginning April, 1993. It should be authorized to increase its rates and charges by $18,111,000 beginning November, 1993. The total of the increase authorized for Florida Power Corporation shall be $85,757,000.

7) The rate schedules prescribed and approved herein are fair, just and reasonable within the meaning of Chapter 366, Florida Statutes.

8) The new rate schedules shall become effective with the company's first billing cycle of each month for which permanent new rates have been approved.

Accordingly, it is

ORDERED by the Florida Public Service Commission that the findings of fact and conclusions of law set forth herein are approved. It is further

ORDERED that the stipulated issues and positions identified in the Prehearing Order in this docket (Order No. PSC-92-0606-PHO-EI; Issued July 7, 1992) are hereby approved. It is further

ORDERED that the petition of Florida Power Corporation for authority to increase its rates and charges is granted to the extent delineated herein. It is further

ORDERED that Florida Power Corporation is hereby authorized to submit revised rate schedules consistent herewith designed to generate $57,986,000 in additional gross revenues annual beginning November, 1992. It is further

ORDERED that Florida Power Corporation is hereby authorized to submit revised rate schedules consistent herewith designed to generate $9,660,000 in additional gross revenues annually beginning April, 1993. It is further

ORDERED that Florida Power Corporation is hereby authorized to submit revised rate schedules consistent herewith designed to generate $18,111,000 in additional gross revenues annually beginning November, 1993. It is further

ORDERED that the rate changes authorized herein shall become effective with the company's first billing cycle of each month for which permanent new rates have been approved. It is further

ORDERED that Florida Power Corporation shall include in each customer's bill in the first billing of which the increase is effective, a bill stuffer explaining the nature of the increase, average level of the increase, a summary of tariff charges, and the reasons therefore. The bill stuffers shall be submitted to the Division of Electric and Gas of the Florida Public Service Commission for approval before implementation. It is further

ORDERED that this docket be closed should no petition for reconsideration or notice of appeal be timely filed.

DISSENTING VOTES

Chairman Beard dissented as follows:

1.) From the Commission's vote concerning level of sales expense.

Commissioner Clark dissented as follows:

1.) From the Commission's vote concerning FPC's Motor Operated Valve Testing System.

2.) From the Commission's vote concerning FPC's nuclear long term maintenance plan.

3.) From the Commission's vote concerning FPC's nuclear operator training simulator.

4.) From the Commission's vote concerning FPC's nuclear valve reliability program.

Commissioner Deason dissented as follows:

1.) From the Commission's vote concerning FPC's forecasts of customers and KWH by Revenue Class and System KW.

2.) From the Commission's vote concerning FPC's forecast of inflation rates.

3.) From the Commission's vote concerning the appropriate consumer price index (CPI) factor.

Commissioner Easley dissented as follows:

1.) From the Commission's vote concerning FPC's forecasts of customers and KWH by Revenue Class and System KW.

Commissioner Lauredo dissented as follows:

1.) From the Commission's vote concerning advertising expenses.

2.) From the Commission's vote concerning level of sales expense.

By ORDER of the Florida Public Service Commission, this 22nd day of OCTOBER, 1992.

STEVE TRIBBLE, Director
Division of Records and Reporting

(S E A L)

MAP/MAH/MCB:bmi

NOTICE OF FURTHER PROCEEDINGS OR JUDICIAL REVIEW

The Florida Public Service Commission is required by Section 120.59(4), 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 Director, Division of Records and Reporting 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 or sewer utility by filing a notice of appeal with the Director, Division of Records and Reporting 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 Civil Procedure. The notice of appeal must be in the form specified in Rule 9.900 (a), Florida Rules of Appellate Procedure.

ATTACHMENT 1
SCHEDULES 1-12
ORDER NO. PSC-92-1197-FOF-EI
DOCKET NO. 910890-EI
PAGE 91

Company : Florida Power Corporation
Docket No. : 910890-EI
Test Year : December 31, 1992

SCHEDULE 1
22-Sep-92

LN NO	COMPARATIVE RATE BASE (000)	COMPANY POSITION	COMMISSION
1	RATE BASE PER FILING:		
2			
3	Plant in Service	$4,245,287	
4	Depreciation Reserve	(1,483,255)	
5			
6	Net Plant in Service	$2,762,032	
7	Construction Work in Progress	124,340	
8	Property Held for Future Use	9,559	
9	Nuclear Fuel (Net)	58,351	
10	Allowance for Working Capital	52,493	
11			
12			
13	Total rate base	$3,006,775	3,006,775
14			
15			
16	ADJUSTMENTS TO COMPANY FILING:		
17			
18	ISSUE:		
19	4. Plant in Service	0	0
20	5. Aircraft	0	(2,994)
21	12. CWIP	0	(31,938)
22	14. Avon Park Unit 2	0	(1,047)
23	19. FAC & ECCR Overrecoveries	0	(8,434)
24	21. FAS 106 Assets	2,761	3,168
25	23. Interest on Tax Deficiencies	0	0
26	24. Light Oil Inventory	0	(575)
27	25. Accumulated Depreciation	0	5,596
28	27. Fossil Fuel Dismantlement	0	(992)
29	46. OPEB Level	(2,287)	(454)
30	47. Pensions	(454)	1,440
31	48. Unamortized Pension Asset	0	(832)
32	102. Accrued Income Taxes Payable	0	2,606
33	S166. Sebring Distribution System	(14,306)	(14,306)
34	S178. Prepaid Interest	0	(229)
35	S193. Reserve Transfer Reversal	(6,952)	(6,952)
36			
37			
38	Total Adjustment	($21,238)	($55,943)
39			
40			
41	ADJUSTED RATE BASE:	$2,985,537	$2,950,832
42			

Company : Florida Power Corporation
Docket No. : 910890-EI
Test Year : December 31, 1992

SCHEDULE 2
22-Sep-92

COMPARATIVE CAPITAL	AMOUNT (000)	RATIO	COST RATE	WEIGHTED COST
COMPANY				
Long Term Debt	$1,033,252	34.36%	8.32%	2.86%
Short Term Debt	83,541	2.78%	7.40%	0.21%
Preferred Stock	188,185	6.26%	7.28%	0.46%
Customer Deposits	70,454	2.34%	8.17%	0.19%
Common Equity	1,136,208	37.79%	13.60%	5.14%
Deferred ITC - Weighted Cost	105,488	3.51%	10.78%	0.38%
Accumulated Deferred Income Taxes	389,647	12.96%		
Total Capital	$3,006,775	100.00%		9.24%
COMMISSION				
Long Term Debt	$1,010,503	34.24%	8.06%	2.76%
Short Term Debt	81,702	2.77%	4.00%	0.11%
Preferred Stock	184,042	6.24%	7.28%	0.45%
Customer Deposits	68,902	2.34%	8.17%	0.19%
Common Equity	1,111,192	37.66%	12.00%	4.52%
Deferred ITC - Weighted Cost	105,030	3.56%	9.90%	0.35%
Accumulated Deferred Income Taxes	389,461	13.20%		
Total Capital	$2,950,832	100.00%		8.39%

Company : Florida Power Corporation
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SCHEDULE 3
22-Sep-92
Page 1 of 4

LN NO	COMPARATIVE NET OPERATING INCOME (000) OPERATING REVENUE	COMPANY POSITION	COMMISSION
1	OPERATING REVENUE PER FILING:		
2			
3	Revenue From Sales of Electricity	$915,054	
4	Other Operating Revenue	43,408	
5		------------	
6			
7	Total Operating Revenue	$958,462	$958,462
8		============	============
9			
10	ADJUSTMENTS TO COMPANY FILING:		
11			
12	ISSUE:		
13	2. Revenue Forecast	0	(24,280)
14	35. Load Forecast	$0	$0
15	S167. Sebring Distribution System	(7,467)	(7,467)
16		------------	------------
17			
18	Total Adjustments	($7,467)	($31,747)
19		------------	------------
20			
21	ADJUSTED OPERATING REVENUE	$950,995	$926,715
22		============	============

Company : Florida Power Corporation
Docket No. : 910890-EI
Test Year : December 31, 1992

SCHEDULE 3
22-Sep-92

LN NO	COMPARATIVE NET OPERATING INCOME (000) OPERATING EXPENSE	COMPANY POSITION	COMMISSION
23	OPERATING EXPENSES PER FILING:		
25	Operation & Maintenance	$409,492	
26	Depreciation & Amortization	210,428	
29	Total Operating Expense	$619,920	$619,920
32	ADJUSTMENTS TO COMPANY FILING:		
34	ISSUE:		
35	4. Plant in Service	$0	$0
36	5. Aircraft	0	(222)
37	35. Load Forecast	0	0
38	38. Advertising Expense	(11)	(420)
39	40. Industry Association Dues	0	(500)
40	43. Salaries & Wages	0	(931)
41	46. OPEB Level	(4,381)	(5,197)
42	47. Pensions	(1,683)	(2,653)
43	48. Unamortized Pension Asset	0	(916)
44	49. Outside Services	0	0
45	53. Interest on Tax Deficiencies	0	0
46	55. Rate Case Expense	0	(63)
47	59. Nuclear O&M	0	0
48	60. Nuclear O&M - Increased Personnel	0	0
49	62. Nuclear O&M - Valve Testing System	0	0
50	63. Nuclear O&M - Long Term Maintenance	0	0
51	64. Nuclear Operator Training Simulator	0	0
52	72. Nuclear - Valve Reliabilty Program	0	0
53	75. Fossil O&M	0	(2,523)
54	77. Fossil O&M - Environmental Changes	0	0
55	87 Tree Trimming Expense	(1,554)	(1,555)
56	88. Customer Accounts	0	0
57	90. Sales Expense	0	(487)
58	93. Management Incentive Plan	0	0
59	98. Fossil Fuel Dismantlement	0	1,983
60	101. Regulatory Assessment Fee	0	0
61	S167. Sebring Distribution System	(6,810)	(6,810)
62	S181. Membership Dues	0	(72)
63	S194. Reserve Transfer Reversals	(3,850)	(2,693)
64	R195. Nuclear Decommissioning Accrual	(2,943)	(4,100)
67	Total Adjustment	($21,232)	($27,159)
70	ADJUSTED OPERATING EXPENSES	$598,688	$592,761

Company : Florida Power Corporation
Docket No. : 910890-EI
Test Year : December 31, 1992

SCHEDULE 3
22-Sep-92

COMPARATIVE NET OPERATING INCOME (000) OPERATING TAXES / SUMMARY	COMPANY POSITION	COMMISSION
OTHER OPERATING TAXES PER FILING	$63,617	$63,617
ADJUSTMENTS TO COMPANY FILING:		
ISSUE:		
Tax Effect of Revenue Adjustments	$0	($20)
43. Salaries & Wages	0	(57)
101. Regulatory Assessment Fee	0	(745)
S167. Sebring Distribution System	(257)	(225)
Total Adjustments	($257)	($1,047)
ADJUSTED OTHER OPERATING TAXES	$63,360	$62,570
INCOME TAXES PER FILING:		
Current Income Taxes	$89,061	
Deferred Income Taxes	(23,230)	
Investment Tax Credit	(7,234)	
Total Income Tax	$58,597	$58,597
ADJUSTMENTS TO COMPANY FILING:		
ISSUE:		
Tax Effect of Other Adjustments	$5,375	($7,024)
Interest Expense Reconciliation	0	2,973
46. OPEB Level	0	1,956
47. Pensions	0	998
48. Unamortized Pension Asset	0	345
S167. Sebring Distribution System	0	39
S194. Reserve Transfer Reversals	0	747
R195. Nuclear Decommissioning Accrual	0	1,543
Total Adjustments	$5,375	$1,577
ADJUSTED INCOME TAXES	$63,972	$60,174
OTHER ITEMS PER FILING:		
(Gain)/Loss on Sale	($84)	
Regulatory Practices Reconcilation	(199)	
Total	($283)	($283)
ADJUSTMENTS TO COMPANY FILING:		
ISSUE:		
S167. Sebring Distribution System	($2)	($2)
ADJUSTED OTHER ITEMS	($285)	($285)

Company : Florida Power Corporation
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Test Year : December 31, 1992

SCHEDULE 3
22-Sep-92

LN NO	COMPARATIVE NET OPERATING INCOME (000) OPERATING TAXES / SUMMARY	COMPANY POSITION	COMMISSION
132	NET OPERATING INCOME:		
133	Operating Revenue	$950,995	$926,715
134	Operating Expenses	(598,688)	(592,761)
135	Taxes Other than Income	(63,360)	(62,570)
136	Income Taxes	(63,972)	(60,174)
137	Other Items	285	285
138			
139			
140	Net operating income	$225,260	$211,495
141			

FLORIDA POWER CORPORATION
DOCKET NO. 910890-EI
O & M BENCHMARK VARIANCE BY FUNCTION
1992

SCHEDULE 4
Page 1 of 4
12-Oct-92

	Fossil Production (000)	Nuclear Production (000)	Other Power Supply (000)	Trans-mission (000)	Distribution (000)	Customer Accounts (000)	Customer Service (000)	Sales (000)	Admin. & General (000)	Other Adjustments (000)	Total (000)
1987 FPSC Allowed O&M-System	$67,696	$70,854	$1,540	$13,262	$45,173	$26,996	$2,662	$879	$72,105	$2,277	$303,444
1987-1992 Compound Multiplier	1.2425	1.2425	1.4389	1.4389	1.4389	1.4389	1.4389	1.4389	1.4389	0	
1992 O&M Benchmark - System	84,112	88,036	2,216	19,083	64,999	38,845	3,830	1,265	103,752	2,277	408,415
1992 Adj. O&M - System	101,071	97,819	1,692	13,981	60,917	36,269	7,909	917	110,616	9,101 *	440,292
Benchmark Variance	16,959	9,783	(524)	(5,102)	(4,082)	(2,576)	4,079	(348)	6,864	6,824	31,877
Staff Adjustments-System	(2,800)	0	0	0	(8,282)	0	(420)	(487)	(10,033)	0	(22,022)
Adjustments to all Functions										209	209
Adjusted Variance-System	14,159	9,783	(524)	(5,102)	(12,364)	(2,576)	3,659	(835)	(3,169)	7,033	10,064
1992 O&M Benchmark - System	84,112	88,036	2,216	19,083	64,999	38,845	3,830	1,265	103,752	2,277	408,415
Juris. Separation Factors	0.8853	0.9409	0.8145	0.7537	0.9918	0.9969	1.0000	0.9992	0.9346	0.9003	
1992 Benchmark - Juris.	74,464	82,833	1,805	14,383	64,466	38,725	3,830	1,264	96,967	2,050	0
1992 Adj. O&M - Juris.	88,844	91,854	1,438	10,540	60,410	36,157	7,909	917	103,397	8,029 **	409,495
Juris. Benchmark Variance	14,379	9,018	(367)	(3,843)	(4,055)	(2,569)	4,079	(347)	6,426	5,979	28,700
Staff Adjustments-Juris.	(2,523)	0	0	0	(7,565)	0	(420)	(487)	(9,401)	0	(20,396)
Adj. to all Functions-Juris.										226	226
Adjusted Variance-Juris.	$11,856	$9,018	($367)	($3,843)	($11,620)	($2,569)	$3,659	($834)	($2,975)	$6,205	$8,531

		*System	**Jurisd.
Includes:	Interest on Tax Deficiency	$2,378	$2,141
	Sebring Acquisition	6,723	5,888
		$9,101	$8,029

FLORIDA POWER CORPORATION
DOCKET NO. 910890-EI
1992 O & M BENCHMARK VARIANCE BY FUNCTION (JURISDICTIONAL)

		Fossil Production (000)	Nuclear Production (000)	Other Power Supply (000)	Trans-mission (000)	Distribution (000)	Customer Accounts (000)	Customer Service (000)	Sales (000)	Admin. & General (000)	Total (000)
38	ADVERTISING EXPENSE							(420)			(420)
40	INDUSTRY ASSOC. DUES									(500)	(500)
43	SALARIES & WAGES										(931)*
46	FAS 106 ACCRUAL									(5,197)	(5,197)
47	PENSION EXPENSE									(2,653)	(2,653)
48	PENSION ASSET AMORT.									(916)	(916)
55	RATE CASE EXPENSE									(63)	(63)
60	INCREASED PERSONNEL		0								0
62	VALVE TESTING SYS.		0								0
63	LONG TERM MAINT. PLAN		0								0
64	OPERATOR TRAIN. SIMULATOR		0								0
72	VALVE RELIABILITY PROG.		0								0
75	1991 DEFERRED O&M	(2,523)									(2,523)
77	ENVIRONMENTAL CHANGES	0									0
87	TREE TRIMMING EXP.					(1,555)					(1,555)
90	SALES EXPENSE								(487)		(487)
S167	SEBRING DISTR. SYS.					(6,010)					(6,010)
S181	MEMBERSHIP DUES									(72)	(72)
S194	REVERSAL OF RES. TRANSFERS										1,157 *
	TOTAL JURISDICTIONAL	(2,523)	0	0	0	(7,565)	0	(420)	(487)	(9,401)	(20,170)

*THESE ADJUSTMENTS RELATE TO ALL FUNCTIONS

FLORIDA POWER CORPORATION
DOCKET NO. 910890-EI
1992 O & M BENCHMARK VARIANCE BY FUNCTION (SYSTEM)

SCHEDULE 4
Page 3 of 4
12-Oct-92

		Fossil Production (000)	Nuclear Production (000)	Other Power Supply (000)	Trans-mission (000)	Distribution (000)	Customer Accounts (000)	Customer Service (000)	Sales (000)	Admin. & General (000)	Total (000)
38	ADVERTISING EXPENSE							(420)			(420)
40	INDUSTRY ASSOC. DUES									(523)	(523)
43	SALARIES & WAGES										(994)*
46	FAS 106 ACCRUAL									(5,557)	(5,557)
47	PENSION EXPENSE									(2,836)	(2,836)
48	PENSION ASSET AMORT.									(979)	(979)
55	RATE CASE EXPENSE									(63)	(63)
60	INCREASED PERSONNEL		0								0
62	VALVE TESTING SYS.		0								0
63	LONG TERM MAINT. PLAN		0								0
64	OPERATOR TRAIN. SIMULATOR		0								0
72	VALVE RELIABILITY PROG.		0								0
75	1991 DEFERRED O&M	(2,800)									(2,800)
77	ENVIRONMENTAL CHANGES	0									0
87	TREE TRIMMING EXP.					(1,559)					(1,559)
90	SALES EXPENSE								(487)		(487)
S167	SEBRING DISTR. SYS.					(6,723)					(6,723)
S181	MEMBERSHIP DUES									(75)	(75)
S194	REVERSAL OF RES. TRANSFERS										1,203 *
	TOTAL SYSTEM	(2,800)	0	0	0	(8,282)	0	(420)	(487)	(10,033)	(21,813)

*THESE ADJUSTMENTS RELATE TO ALL FUNCTIONS

FLORIDA POWER COMPANY
DOCKET NO. 910890-EI

O & M COMPOUND MULTIPLIERS

	Total Customers			Average CPI-U (1982-1984=100)			
Year	Amount	%Increase	Compound Multiplier	Amount	& Increase	Compound Multiplier	Inflation and Growth Compound Multiplier
1987	1,023,222		1.0000	113.6		1.0000	1.0000
1988	1,060,971	3.69%	1.0369	118.3	4.10%	1.0410	1.0794
1989	1,101,817	3.85%	1.0768	124.0	4.80%	1.0910	1.1748
1990	1,135,499	3.06%	1.1098	130.7	5.40%	1.1499	1.2762
1991	1,159,538	2.12%	1.1333	136.2	4.20%	1.1982	1.3579
1992	1,184,915	2.19%	1.1581	141.2	3.70%	1.2425	1.4389
1993	1,217,404	2.74%	1.1898	146.6	3.80%	1.2897	1.5345
1993 USING 1992 AS BASE YR.	1,217,404	2.74%	1.0274	146.6	3.80%	1.0380	1.0664

Schedule 5

22-Sep-92

Company : Florida Power Corporation
Docket No. : 910890-EI
Test Year : December 31, 1992

LN NO	COMPARATIVE REVENUE REQUIREMENTS (000)	COMPANY POSITION	COMMISSION
1	Adjusted Intrastate Rate Base	$3,006,775	$2,950,832
3	Required Rate of Return	9.24%	8.39%
7	Required Net Operating Income	$277,826	$247,575
9–10	Adjusted Achieved Test Year Intrastate Net Operating Income	216,611	211,495
14	Intrastate NOI Deficiency (Excess)	$61,215	$36,080
16	Revenue Expansion Factor	1.607828	1.607157
20	Revenue Increase (Decrease) - Test Year	$98,427	$57,986
21	Performance Reward	9,669	0
24	Total Revenue Increase	$108,096	$57,986

Company : Florida Power Corporation
Docket No. : 910890-EI
Test Year : December 31, 1992 & 1993

Revenue Expansion Factor

SCHEDULE 6
12-Oct-92

LN NO	REVENUE EXPANSION FACTOR	COMPANY POSITION	COMMISSION
1	Revenue Requirement	100.000000	100.000000
2			
3			
4	Uncollectible Rate	0.154500	0.154500
5			
6	Gross Reciepts Tax	0.000000	0.000000
7			
8	Regulatory Assessment Fee	0.125000	0.083300
9			
10			
11	Net Before Income Taxes	99.720500	99.762200
12			
13	State Income Tax	0.055000	0.055000
14	Rate		
15			
16	Amount	5.484628	5.486921
17			
18			
19	Net Before Federal Income Taxes	94.235872	94.275279
20			
21	Federal Income Tax		
22	Rate	0.340000	0.340000
23			
24			
25	Amount	32.040196	32.053595
26			
27			
28	Net Operating Income	62.195676	62.221684
29			
30			
31			
32	Net Operating Income Multiplier	1.607828	1.607157
33			

Schedule 7

Company : Florida Power Corporation
Docket No. : 910890-EI
Test Year : December 31, 1993

22-Sep-92

LN NO	COMPARATIVE RATE BASE (000)	COMPANY POSITION	COMMISSION
1	RATE BASE PER FILING:		
2			
3	Plant in Service	$4,617,090	
4	Depreciation Reserve	(1,628,030)	
5		------------	
6	Net Plant in Service	$2,989,060	
7	Construction Work in Progress	110,667	
8	Property Held for Future Use	9,436	
9	Nuclear Fuel (Net)	50,487	
10	Allowance for Working Capital	51,589	
11		------------	
12			
13	Total rate base	$3,211,239	3,211,239
14		============	============
15			
16	ADJUSTMENTS TO COMPANY FILING:		
17			
18	ISSUE:		
19	4. Plant in Service	0	0
20	5. Aircraft	0	(2,774)
21	12. CWIP	0	(27,640)
22	14. Avon Park Unit 2	0	(734)
	17. Property Insurance Reserve	0	(46)
23	19. FAC & ECCR Overrecoveries	0	0
24	21. FAS 106 Assets	9,308	10,565
25	23. Interest on Tax Deficiencies	0	0
26	24. Light Oil Inventory	0	0
27	25. Accumulated Depreciation	0	10,581
28	27. Fossil Fuel Dismantlement	0	(934)
29	46. OPEB Level	1,025	(479)
30	47. Pensions	593	4,845
31	48. Unamortized Pension Asset	0	(2,708)
32	102. Accrued Income Taxes Payable	0	1,440
33	S166. Sebring Distribution System	(15,153)	(15,153)
34	S178. Prepaid Interest	0	(330)
35	S193. Reserve Transfer Reversal	(8,214)	(8,479)
36		------------	------------
37			
38	Total Adjustment	($12,441)	($31,846)
39		------------	------------
40			
41	ADJUSTED RATE BASE:	$3,198,798	$3,179,393
42		============	============

Schedule 8

Company : Florida Power Corporation
Docket No. : 910890-EI
Test Year : December 31, 1993

22-Sep-92

LN NO	COMPARATIVE CAPITAL	AMOUNT (000)	RATIO	COST RATE	WEIGHTED COST
1	COMPANY				
2					
3	Long Term Debt	$1,102,212	34.32%	8.42%	2.89%
4	Short Term Debt	147,347	4.59%	7.50%	0.34%
5	Preferred Stock	182,022	5.67%	7.18%	0.41%
6	Customer Deposits	74,561	2.32%	8.17%	0.19%
7	Common Equity	1,211,778	37.74%	13.60%	5.13%
8	Deferred ITC - Weighted Cost	101,273	3.15%	10.85%	0.34%
9	Accumulated Deferred Income Taxes	392,046	12.21%		
10		------------	--------		--------
11					
12	Total Capital	$3,211,239	100.00%		9.30%
13		============	========		========
14					
15					
16	COMMISSION				
17					
18	Long Term Debt	$1,087,808	34.21%	8.08%	2.77%
19	Short Term Debt	145,421	4.57%	4.00%	0.18%
20	Preferred Stock	179,643	5.65%	7.18%	0.41%
21	Customer Deposits	73,587	2.31%	8.17%	0.19%
22	Common Equity	1,195,942	37.62%	12.00%	4.51%
23	Deferred ITC - Weighted Cost	100,854	3.17%	9.92%	0.31%
24	Accumulated Deferred Income Taxes	396,137	12.46%		
25		------------	--------		--------
26					
27	Total Capital	$3,179,393	100.00%		8.37%
28		============	========		========
29					

Schedule 9
Page 1 of 4

22-Sep-92

Company : Florida Power Corporation
Docket No. : 910890-EI
Test Year : December 31, 1993

LN NO	COMPARATIVE NET OPERATING INCOME (000) OPERATING REVENUE	COMPANY POSITION	COMMISSION
1	OPERATING REVENUE PER FILING:		
2			
3	Revenue From Sales of Electricity	$951,042	
4	Other Operating Revenue	46,252	
5			
6			
7	Total Operating Revenue	$997,294	$997,294
8			
9			
10	ADJUSTMENTS TO COMPANY FILING:		
11			
12	ISSUE:		
13	2. Revenue Forecast	0	(15,515)
14	35. Load Forecast	$0	$0
15	S167. Sebring Distribution System	(7,771)	(7,771)
16			
17			
18	Total Adjustments	($7,771)	($23,286)
19			
20			
21	ADJUSTED OPERATING REVENUE	$989,523	$974,008
22			

22-Sep-92

Company : Florida Power Corporation
Docket No. : 910890-EI
Test Year : December 31, 1993

LN NO	COMPARATIVE NET OPERATING INCOME (000) OPERATING EXPENSE	COMPANY POSITION	COMMISSION
23	OPERATING EXPENSES PER FILING:		
24			
25	Operation & Maintenance	$435,083	
26	Depreciation & Amortization	226,109	
27		------------	
28			
29	Total Operating Expense	$661,192	$661,192
30		============	============
31			
32	ADJUSTMENTS TO COMPANY FILING:		
33			
34	ISSUE:		
35	4. Plant in Service	$0	$0
36	5. Aircraft	0	(223)
37	35. Load Forecast	0	0
38	38. Advertising Expense	(11)	(450)
39	40. Industry Association Dues	0	(526)
40	43. Salaries & Wages	0	(1,072)
41	46. OPEB Level	(4,995)	(5,875)
42	47. Pensions	(1,498)	(2,464)
43	48. Unamortized Pension Asset	0	(927)
44	49. Outside Services	0	0
45	51. Storm Damage Accrual	0	(266)
46	53. Interest on Tax Deficiencies	0	0
47	55. Rate Case Expense	0	(63)
48	59. Nuclear O&M	0	0
49	60. Nuclear O&M - Increased Personnel	0	0
50	62. Nuclear O&M - Valve Testing System	0	0
51	63. Nuclear O&M - Long Term Maintenance	0	0
52	64. Nuclear Operator Training Simulator	0	0
53	72. Nuclear - Valve Reliabilty Program	0	0
54	75. Fossil O&M	0	(2,560)
55	77. Fossil O&M - Environmental Changes	0	0
56	87. Tree Trimming Expense	0	0
57	88. Customer Accounts	0	0
58	90. Sales Expense	0	(512)
59	93. Management Incentive Plan	0	0
60	98. Fossil Fuel Dismantlement	0	1,868
61	101. Regulatory Assessment Fee	0	0
62	S167. Sebring Distribution System	(7,051)	(7,051)
63	S181. Membership Dues	0	(75)
64	S194. Reserve Transfer Reversals	(1,855)	(1,855)
65	R195. Nuclear Decommissioning Accrual	(4,090)	(4,090)
66		------------	------------
67			
68	Total Adjustment	($19,500)	($26,141)
69		------------	------------
70			
71	ADJUSTED OPERATING EXPENSES	$641,692	$635,051
		============	============

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Company : Florida Power Corporation
Docket.No. : 910890-EI
Test Year : December 31, 1993

COMPARATIVE NET OPERATING INCOME (000) OPERATING TAXES / SUMMARY	COMPANY POSITION	COMMISSION
OTHER OPERATING TAXES PER FILING	$72,911	$72,911
ADJUSTMENTS TO COMPANY FILING:		
ISSUE:		
Tax Effect of Revenue Adjustments	$0	($13)
43. Salaries & Wages	0	(60)
101. Regulatory Assessment Fee	0	(845)
S167. Sebring Distribution System	(279)	(233)
Total Adjustments	($279)	($1,151)
ADJUSTED OTHER OPERATING TAXES	$72,632	$71,760
INCOME TAXES PER FILING:		
Current Income Taxes	$84,644	
Deferred Income Taxes	(28,160)	
Investment Tax Credit	(7,168)	
Total Income Tax	$49,316	$49,316
ADJUSTMENTS TO COMPANY FILING:		
ISSUE:		
Tax Effect of Other Adjustments	$4,505	($4,032)
Interest Expense Reconciliation	0	3,880
46. OPEB Level	0	2,211
47. Pensions	0	927
48. Unamortized Pension Asset	0	349
S167. Sebring Distribution System	44	44
S194. Reserve Transfer Reversals	0	477
R195. Nuclear Decommissioning Accrual	0	1,539
Total Adjustments	$4,549	$5,395
ADJUSTED INCOME TAXES	$53,865	$54,711
OTHER ITEMS PER FILING:		
(Gain)/Loss on Sale	($65)	
Regulatory Practices Reconcilation	(204)	
Total	($269)	($269)
ADJUSTMENTS TO COMPANY FILING:		
ISSUE:		
S167. Sebring Distribution System	($1)	($1)
ADJUSTED OTHER ITEMS	($270)	($270)

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22-Sep-92

Company : Florida Power Corporation
Docket No. : 910890-EI
Test Year : December 31, 1993

LN NO	COMPARATIVE NET OPERATING INCOME (000) OPERATING TAXES / SUMMARY	COMPANY POSITION	COMMISSION
132	NET OPERATING INCOME:		
133	Operating Revenue	$989,523	$974,008
134	Operating Expenses	(641,692)	(635,051)
135	Taxes Other than Income	(72,632)	(71,760)
136	Income Taxes	(53,865)	(54,711)
137	Other Items	270	270
138		------------	------------
139			
140	Net operating income	$221,604	$212,756
141		============	============

FLORIDA POWER CORPORATION
DOCKET NO. 910890-EI
O & M BENCHMARK VARIANCE BY FUNCTION
1993

SCHEDULE 10
Page 1 of 4
12-Oct-92

	Fossil Production (000)	Nuclear Production (000)	Other Power Supply (000)	Trans-mission (000)	Distribution (000)	Customer Accounts (000)	Customer Service (000)	Sales (000)	Admin. & General (000)	Other Adjustments (000)	Total (000)
1992 FPSC Allowed O&M-System	$98,271	$97,819	$1,692	$13,981	$52,635	$36,269	$7,489	$430	$100,583	$9,310	$418,479
1992-1993 Compound Multiplier	1.0380	1.0380	1.0664	1.0664	1.0664	1.0664	1.0664	1.0664	1.0664	0	
1993 O&M Benchmark - System	102,005	101,536	1,804	14,909	56,130	38,677	7,986	459	107,262	9,310	440,079
1993 Adj. O&M - System	114,336	101,779	1,934	14,862	64,560	38,528	8,462	981	114,881	8,272 *	468,595
Benchmark Variance	12,331	243	130	(47)	8,430	(149)	476	522	7,619	(1,038)	28,516
Staff Adjustments-System	(2,823)	0	0	0	(6,964)	0	(450)	(512)	(10,884)	0	(21,633)
Adjustments to all Functions										31	31
Adjusted Variance-System	9,508	243	130	(47)	1,466	(149)	26	10	(3,265)	(1,007)	6,914
1993 O&M Benchmark - System	102,005	101,536	1,804	14,909	56,130	38,677	7,986	459	107,262	9,310	440,079
Juris. Separation Factors	0.8824	0.9370	0.8387	0.7493	0.9918	0.9971	1.0000	1.0000	0.9349	0.8696	
1993 Benchmark - Juris.	90,009	95,139	1,513	11,172	55,670	38,565	7,986	459	100,279	8,096	408,888
1993 Adj. O&M - Juris.	100,496	95,326	1,622	11,136	64,028	38,414	8,462	981	107,447	7,170 **	435,082
Juris. Benchmark Variance	10,487	187	109	(36)	8,358	(151)	476	522	7,168	(926)	26,194
Staff Adjustments-Juris.	(2,560)	0	0	0	(6,203)	0	(450)	(512)	(10,196)	0	(19,921)
Adjustments to all Functions										60	60
Adjusted Variance-Juris.	$7,927	$187	$109	($36)	$2,155	($151)	$26	$10	($3,028)	($866)	$6,333

	*System	**Jurisd.
Includes: Interest on Tax Deficiency	$1,308	$1,167
Sebring Acquisition	6,964	6,003
	$8,272	$7,170

FLORIDA POWER CORPORATION
DOCKET NO. 910890-EI
1993 O & M BENCHMARK VARIANCE BY FUNCTION (JURISDICTIONAL)

SCHEDULE 10
Page 2 of 4
12-Oct-92

		Fossil Production (000)	Nuclear Production (000)	Other Power Supply (000)	Trans-mission (000)	Distribution (000)	Customer Accounts (000)	Customer Service (000)	Sales (000)	Admin. & General (000)	Total (000)
38	ADVERTISING EXPENSE							(450)			(450)
40	INDUSTRY ASSOC. DUES									(526)	(526)
43	SALARIES & WAGES										(1,072)*
46	FAS 106 ACCRUAL									(5,875)	(5,875)
47	PENSION EXPENSE									(2,464)	(2,464)
48	PENSION ASSET AMORT.									(927)	(927)
51	STORM DAMAGE									(266)	(266)
55	RATE CASE EXPENSE									(63)	(63)
60	INCREASED PERSONNEL		0								0
62	VALVE TESTING PROG.		0								0
63	LONG TERM MAINT. PLAN		0								0
64	OPERATOR TRAIN. SIMULATOR		0								0
72	VALVE RELIABILITY PROG.		0								0
75	SCHEDULED OUTAGES	(2,560)									(2,560)
90	SALES EXPENSE								(512)		(512)
S167	SEBRING DISTR. SYS.					(6,203)					(6,203)
S181	MEMBERSHIP DUES									(75)	(75)
S194	REVERSAL OF RES. TRANSFERS										1,132 *
	TOTAL JURISDICTIONAL	(2,560)	0	0	0	(6,203)	0	(450)	(512)	(10,196)	(19,861)

*THESE ADJUSTMENTS RELATE TO ALL FUNCTIONS

FLORIDA POWER CORPORATION
DOCKET NO. 910890-EI
1993 O & M BENCHMARK VARIANCE BY FUNCTION (SYSTEM)

SCHEDULE 10
Page 3 of 4
12-Oct-92

		Fossil Production (000)	Nuclear Production (000)	Other Power Supply (000)	Trans-mission (000)	Distribution (000)	Customer Accounts (000)	Customer Service (000)	Sales (000)	Admin. & General (000)	Total (000)
38	ADVERTISING EXPENSE							(450)			(450)
40	INDUSTRY ASSOC. DUES									(551)	(551)
43	SALARIES & WAGES										(1,145)*
46	FAS 106 ACCRUAL									(6,277)	(6,277)
47	PENSION EXPENSE									(2,632)	(2,632)
48	PENSION ASSET AMORT.									(992)	(992)
51	STORM DAMAGE									(289)	(289)
55	RATE CASE EXPENSE									(63)	(63)
60	INCREASED PERSONNEL		0								0
62	VALVE TESTING PROG.		0								0
63	LONG TERM MAINT. PLAN		0								0
64	OPERATOR TRAIN. SIMULATOR		0								0
72	VALVE RELIABILITY PROG.		0								0
75	SCHEDULED OUTAGES	(2,823)									(2,823)
90	SALES EXPENSE								(512)		(512)
S167	SEBRING DISTR. SYS.					(6,964)					(6,964)
S181	MEMBERSHIP DUES									(80)	(80)
S194	REVERSAL OF RES. TRANSFERS										1,176 *
	TOTAL SYSTEM	(2,823)	0	0	0	(6,964)	0	(450)	(512)	(10,884)	(21,602)

*THESE ADJUSTMENTS RELATE TO ALL FUNCTIONS

FLORIDA POWER COMPANY
DOCKET NO. 910890-EI

O & M COMPOUND MULTIPLIERS

Year	Total Customers Amount	%Increase	Compound Multiplier	Average CPI-U (1982-1984=100) Amount	& Increase	Compound Multiplier	Inflation and Growth Compound Multiplier
1987	1,023,222		1.0000	113.6		1.0000	1.0000
1988	1,060,971	3.69%	1.0369	118.3	4.10%	1.0410	1.0794
1989	1,101,817	3.85%	1.0768	124.0	4.80%	1.0910	1.1748
1990	1,135,499	3.06%	1.1098	130.7	5.40%	1.1499	1.2762
1991	1,159,538	2.12%	1.1333	136.2	4.20%	1.1982	1.3579
1992	1,184,915	2.19%	1.1581	141.2	3.70%	1.2425	1.4389
1993	1,217,404	2.74%	1.1898	146.6	3.80%	1.2897	1.5345
1993 USING 1992 AS BASE YR.	1,217,404	2.74%	1.0274	146.6	3.80%	1.0380	1.0664

Florida Power Corporation
Docket No. 910890-EI

Schedule 11
12-Oct-92
11:40 AM

NOVEMBER 1993 REVENUE REQUIREMENT
Jurisdictional Revenue Requirements
Intercession City Peaking Units and University of Florida Project

	Jurisdictional (000)	
	Company	Commission Vote
Rate Base Annualization Adjustment		
Electric Plant in Service	$86,407	$86,407
Accumulated Depreciation	(2,552)	(2,552)
Fuel Inventory	0	0
Working Capital-Income Taxes Payable	(3,862)	(3,862)
TOTAL Rate Base Annualization	$79,993	$79,993
NOI Annualization		
O&M	$3,164	$3,164
Property Taxes	3,107	3,107
Depreciation	3,887	3,887
Income Taxes -		
Direct Current	(5,757)	(5,757)
Direct Deferred	1,148	1,148
Imputed Interest	(1,066)	(975)
Total NOI Annualization	($4,483)	($4,574)
Calculation of Revenue Requirement		
Fully adjusted Cost of Capital	9.30%	8.37%
NOI Requirement	$7,439	$6,695
NOI Deficiency	$11,923	$11,269
NOI Multiplier	1.607157	1.607157
Revenue Requirement	$19,162	$18,111
Calculation of Taxes on Imputed Interest		
Weighted Cost of Debt Capital		
Long Term Debt Fixed Rate	2.72%	2.59%
Long Term Debt Variable Rate	0.17%	0.17%
Short Term Debt	0.34%	0.18%
Customer Deposits	0.19%	0.19%
JDIC	0.12%	0.11%
	3.54%	3.24%
Imputed Interest	$2,832	$2,592
Income Taxes on Imputed Interest at 37.63%	($1,066)	($975)

Schedule 12

22-Sep-92

Company : Florida Power Corporation
Docket No. : 910890-EI
Test Year : December 31, 1993

LN NO	COMPARATIVE REVENUE REQUIREMENTS (000)	COMPANY POSITION	COMMISSION
1	Adjusted Intrastate Rate Base	$3,211,239	$3,179,393
2			
3	Required Rate of Return	9.30%	8.37%
4			
5			
6			
7	Required Net Operating Income	$298,645	$266,115
8			
9	Adjusted Achieved Test Year		
10	Intrastate Net Operating Income	214,144	212,756
11			
12			
13			
14	Intrastate NOI Deficiency (Excess)	$84,501	$53,359
15			
16	Revenue Expansion Factor	1.607828	1.607157
17			
18			
19			
20	Revenue Increase (Decrease) - Test Year	$135,863	$85,757
21	Performance Reward - 1993	9,990	0
22			
23			
24	Total Revenue Increase	$145,853	$85,757
25			
26	Less 1992 Revenue Increase	(98,427)	(57,986)
27	Less Performance Reward - 1992	(9,669)	0
ERR	LESS NOVEMBER 1993 STEP INCREASE	(23,684)	(18,111)
ERR			
ERR	APRIL 1993 STEP INCREASE	$14,073	$9,660
ERR			

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition of Florida Power Corporation for authority to increase its rates and charges.

Docket No. 910890-EI

COST OF SERVICE
AND RATE DESIGN
STIPULATION

Florida Power Corporation (the Company), the Florida Industrial Power Users Group (FIPUG), Occidental Chemical Corporation (Occidental), and the Ad Hoc Committee of Local Governments (collectively, the Parties), by and through their undersigned counsel, hereby stipulate and agree to resolve Issues 120 through 159 contained in the Prehearing Order No. PSC-92-0606-PHO-EI, pertaining to Cost of Service and Rate Design, as follows:

1. The Company's separation of joint system costs between the wholesale and retail jurisdiction for 1992 and 1993 contained in Exhibits 40 and 41 is accepted. **(Issue 120)**

2. The 12 CP and 1/13 Average Demand cost of service methodology as contained in Exhibits 40 and 41 is accepted for determining the class revenue requirements and unit costs used in designing the Company's rates. (Issue 122)

3. The interruptible and curtailable service rate classes will be assigned costs within the Company's cost of service study based on each class's respective use characteristics, without adjustment to coincident demands; the fact that such

customers accept nonfirm service will be recognized in the form of credits to the demand charges developed for these classes. The Parties have negotiated, for purposes of settlement, credits of $6.30 and $3.15 per coincident KW for interruptible and curtailable tariffs, respectively. The negotiated values have been tested by the Commission's conservation cost-effectiveness methodology based on the avoidance of a January 1, 1993 combustion turbine which produces a benefit-to-cost ratio of 1.2 to 1. In addition, the negotiated values are reasonable based on the embedded cost standards preferred by FIPUG and Occidental. The Parties further agree that the stipulation with respect to these credits is for settlement purposes only, shall have no precedential value, and shall be without prejudice to the right and opportunity of Parties to present and argue the rate design considerations and rate levels they deem to be appropriate for non-firm rates in future rate proceedings before this Commission. (Issues 121, 147, 148, 149, 151)

4. The Parties stipulate to the approval of interruptible and curtailable service as demand-side management (DSM) programs with authorized recovery of the credit through the Company's Energy Conservation Cost Recovery (ECCR) clause as a program cost. (Issues 146, 153)

5. The ECCR expenses associated with load management, interruptible and curtailable programs (including the interruptible and curtailable credits for the period of November 1992 through March 1993, which will be included in the ECCR true-up provision, and all other similar future dispatchable DSM programs) will be allocated to rate classes based on the methodology currently employed in

the Capacity Cost Recovery mechanism of the Fuel and Purchased Power Cost Recovery clause, beginning with the six-month period of April through September, 1993. (Issue 153)

6. The credits for interruptible and curtailable service will be distributed based on the interruptible and curtailable customers' billing KW for the standard rate and the customers' on-peak billing KW for the time-of-use rate. Expressed on a billing KW basis, the credits for interruptible and curtailable service are $3.37 and $2.33 per billing KW, respectively. (Issue 152)

7. The interruptible rate will be stated at secondary voltage in order to make this rate consistent with the statement of the Company's other rates. The Demand charge for the interruptible and curtailable service will include the classes unit costs for Transmission Plant and Distribution Plant developed from the cost of service study, plus the absolute amount of the credit per billing KW for interruptible and curtailable service, respectively. (Issues 135, 154)

8. The curtailable class will be treated as a separate rate class with rates designed to produce the revenue requirements of that class identified in the cost of service study. Curtailable service will be limited to those customers who agree to curtail the greater of 25 KW or 25% of their maximum annual billing KW. (Issue 136)

9. The interruptible and curtailable credits will remain fixed at the level established in paragraphs 3 and 6 above until the Company's next rate case. (Issue 150)

10. The Company's proposed "Purchase Power" special provision contained in the interruptible and curtailable rate schedules shall be modified such that the customer will pay the actual purchase power cost in lieu of the otherwise applicable energy charges (including fuel charges), plus 3 mills. In addition, the Company will attempt to develop a procedure which provides the customer with real-time estimates of the cost of such purchases. (Issues 155, 156)

11. The Company commits to designing and proposing at least two additional interruptible rates as DSM programs for Commission approval, based on the criteria that the programs are beneficial to both the general body of ratepayers and the Company. (Issue 124)

12. (a) The Company's proposed general service rate structure, which allows general service customers with annual consumption of 24,000 KWH or greater to opt for the rate schedule (GS-1 or GSD-1) most cost effective for them and which eliminates mandatory demand billing, minimum billing demands, optional transition rates, the municipal transition rate, and the general service large demand rate (GSLD-1), is accepted. In addition, the customer migration identified in Exhibits 38 and 39 and in Attachment 1 and 2 hereto is accepted for

establishing rates and revenues for the general service class. (Issues 123, 125, 126, 127, 144, 145)

(b) The general service demand and energy charges will be set such that the combination of the two charges closely tracks the general service cost curve which produces the revenue requirements established from the cost of service study. (Issue 134)

(c) The general service non-demand rates (GS-1 and GST-1) will provide only a metering voltage adjustment of 1% for distribution primary delivery and 2% for transmission delivery. (Issue 139)

13. The Standby rates (SS-1, SS-2, SS-3) will be developed from the final cost of service study consistent with the methodology contained in the Commission's standby rate Order No. 17159 in Docket No. 850673-EU. (Issues 157, 158)

14. The rate design for all Time-Of-Use (TOU) rates will set the off-peak energy rate at the average system energy component from the cost of service study (approximately 0.580 cents per KWH). The on-peak charge will then be the result of a break even calculation with the standard rate, based on the rate class's or combined rate classes' on-peak and off-peak energy consumption. (The combined classes will be the RS-1 and GS-1 classes and the GSD-1 and GSLD-1 classes; the CS-1 class and IS-1 class will be individual classes.) For Demand TOU rates, a demand charge equivalent to ½ of the unit cost for Distribution Plant will be applicable to the customer's maximum measured demand. The on-

peak demand charge shall include the on-peak unit cost for Transmission Plant and ½ of the on-peak unit cost for Distribution Plant. The on-peak demand charge for interruptible and curtailable TOU rates shall also include the absolute amount of the credit per billing KW for interruptible and curtailable service, respectively. **(Issue 131)**

15. The Parties agree that for purposes of apportioning among rate classes matters for which an individual rate class's share is dependent upon the revenues of the rate class relative to the overall total revenues, the nonfirm rate classes' allocators will be based on the difference between the firm base revenue requirements and the nonfirm credits paid to these rate classes for DSM programs (RSL-1, GSLM-1, CS-1, IS-1). **(Issue 159)**

16. (a) The allocation of the rate increase among the classes will be determined by the cost of service study which incorporates all Commission decisions on issues affecting the Company's revenue requirements. (Issue 128)

(b) The Company's method for calculating the increase in unbilled revenues by rate class identified in MFR Schedule E-15 is appropriate. (Issue 129)

(c) The appropriate service charges are as follows:

Service	1992	1993
Initial Service	$24.50	$30.50
Re-establishment of service with field trip	$14.50	$15.00
Transfer of account	$ 5.50	$ 5.50
Reconnection for nonpayment	$25.50	$27.00
Temporary Service	$71.00	$74.00

(Issue 130)

(d) The customer charges will be designed to produce the customer cost component from the cost of service study. For the general service rates (GS-1 and GSD-1) the customer charges will be stated by voltage delivery. For unmetered general service accounts, the customer charge will be based on average unit cost excluding metering investment (approximately $6.25). For all time of use rates except CST-1 and IST-1, the customer charge will reflect the average additional TOU metering costs (approximately $7.50). For the curtailable service rates (CS-1 and CST-1), the customer charge will be the customer charges contained in the general service rates plus the additional costs for hourly metering (approximately $65). For the interruptible service rates (IS-1 and IST-1), the customer charge will be the customer charges contained in the general service rates plus the additional costs for hourly metering and interruptible equipment (approximately $270). For the Lighting service rate (LS-1) the unmetered customer charge shall be based on lines of billing, with an additional charge for metered accounts to reflect the average cost of metering investment (approximately $2.25). (Issue 132)

(e) The appropriate contribution in aid of construction for time of use customers opting to make a lump sum meter payment is $258 for single-phase service and $393 for three-phase service. (Issue 133)

(f) The delivery voltage credits will be 30 cents per KW of billing demand for distribution primary delivery voltage and 69 cents per KW of billing demand for transmission delivery voltage. (Issue 137)

(g) The metering voltage credits will be 1% for distribution primary delivery and 2% for transmission delivery. (Issue 138)

17. The Company's proposed Lighting rate schedule LS-1 is accepted subject to Commission approved revenue requirements for the lighting class developed from the cost of service study, provided that proposed special provision No. 9 shall be eliminated and proposed special provision No. 7 shall be modified to eliminate the requirement of written notification. The methodology used in Attachment No. 3 of this stipulation will be used to develop final fixture and maintenance charges. The monthly fixed carrying charge for poles of a type not listed in rate schedule LS-1, and for distribution equipment that the Company may optionally provide to a customer under any rate schedule shall be 1.67 percent of the installed cost. (Issues 140, 141, 142, 143)

18. The term "cost of service study" as used herein is intended by the Parties to refer to a compliance cost of service study prepared by the Company which incorporates the Commission's decisions on all issues in this proceeding affecting the Company's revenue requirements or billing determinants. The Parties recognize, however, that due to the timing of the Commission's decisions, such final compliance cost of service study may not be available for such use. In that event, the Parties intend that the cost of service study prepared by the

Company based on Staff's recommendations regarding revenue requirements issues, as adjusted by Staff to reflect the Commission's decisions, will be used.

19. Nothing in this stipulation is intended to preclude the Commission from using the Company's updated sales forecast, identified as Exhibit 148. In the event the Commission determines that the updated sales forecast should be utilized, this stipulation shall be modified as necessary to incorporate the effects of the updated sales forecast on the provisions hereof.

20. Each of the provisions set forth in paragraphs 1 through 19 above have been negotiated as essential, interdependent components to a comprehensive settlement of the cost of service and rate design issues in this proceeding and, therefore, collectively constitute a single stipulation between the Parties. As such, the Parties agree that if this stipulation is not approved by the Commission in its entirety, it shall be null and void and of no binding effect on the Parties. The Parties further agree that this stipulation is for settlement purposes only, shall have no precedential value, and shall be without prejudice to the right and opportunity of the Parties to present and argue the cost of service and rate design considerations and rate levels they deem to be appropriate in future rate proceedings before this Commission.

Dated: July 22, 1992.

FLORIDA POWER CORPORATION

By ____________________

James A. McGee
Office of the General Counsel
Post Office Box 14042
St. Petersburg, FL 33733

FLORIDA INDUSTRIAL POWER USERS GROUP

By ____________________

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OCCIDENTAL CHEMICAL CORPORATION

By ____________________

Zori G. Ferkin
Sutherland, Asbill & Brennan
1275 Pennsylvania Avenue, N.W.
Washington, D.C. 20004-2404

AD HOC COMMITTEE OF LOCAL GOVERNMENTS

By ____________________

Robert R. Morrow
Sutherland, Asbill & Brennan
1275 Pennsylvania Avenue, N.W.
Washington, D.C. 20004-2404

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION
Docket No. 910890-EI

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true copy of the foregoing Stipulation has been furnished to the following individuals by hand or express delivery(*), facsimile (**), or U.S. Mail this 22nd day of July, 1992:

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Attorney

RATE COMPARISON
BASED ON APPROVED REVENUE REQUIREMENTS

1992

	Current Rates	FPC Proposed	Commission Approved
Residential			
Customer charge			
Standard	$5.32	$8.50	$8.50
TOU			
Company owned	$8.36	$16.00	$16.00
Customer owned	$5.32	$8.50	$8.50
KWH Charge (Cents/KWH)			
Standard	3.964	4.138	3.841
TOU			
On-peak	11.118	11.875	10.857
Off-peak	0.597	0.580	0.580
General Service			
Customer Charge			
Standard			
Secondary	$5.32	$11.50	$11.50
Primary		$145.00	$145.00
Transmission		$720.00	$720.00
Unmetered	$2.61	$6.25	$6.25
TOU			
Secondary single phase			
Company owned	$8.36	$19.00	$19.00
Customer owned	$5.32	$11.50	$11.50
Secondary Three phase	$9.83	$25.00	$25.00
Primary (cust. own)	$15.46	$145.00	$145.00
Primary (co. own)	$19.98	$152.50	$152.50
KWH Charge (cents/KWH)			
Standard	3.964	4.138	3.841
TOU			
On-peak	10.707	11.875	10.857
Off-peak	0.597	0.580	0.580
General Service Demand			
Customer Charge			
Standard			
Secondary	$15.46	$11.50	$11.50
Primary	$15.46	$145.00	$145.00
Transmission	$720.00	$720.00	$720.00
TOU			
Secondary single phase			
Company owned	$15.46	$19.00	$19.00
Customer owned	$15.46	$11.50	$11.50
Primary (cust. own)	$15.46	$145.00	$145.00
Primary (co. own)	$19.98	$152.50	$152.50
KWH Charge			
Standard	1.307	1.702	1.606
TOU			
On-peak	1.396	4.396	4.503
Off-peak	0.595	0.580	0.580
KW Demand charge			
Standard	$5.45	$3.50	$3.50
TOU			
On-peak	$5.45	$2.59	$2.59
Maximum demand		$0.91	$0.91

RATE COMPARISON
1992

	Current Rates	FPC Proposed	Commission Approved
GS-2			
Customer Charge			
Metered	$2.61	$6.25	$6.25
Unmetered	$5.32	$11.50	$11.50
KWH Charge (cents/KWH)	3.003	2.150	1.431
Curtailable			
Customer Charge			
Standard			
Secondary	$152.49	$210.00	$210.00
Primary	$152.49	$210.00	$210.00
Transmission	$152.49	$785.00	$785.00
TOU			
Primary (co. own)	$152.49	$210.00	$210.00
Transmission(co.own)	$152.49	$785.00	$785.00
KWH Charge (cents/KWH)			
Standard	1.105	1.031	1.026
TOU			
On-peak	2.068	2.342	2.139
Off-peak	0.587	0.580	0.580
KW Demand charge			
Standard	$5.45	$5.83	$5.83
TOU			
On-peak	$5.45	$5.14	$5.14
Maximum demand	na	$0.93	$0.93
Curtailable credit	$1.91	$2.33	$2.33
Interruptible			
Customer Charge			
Standard			
Primary	$413.91	$415.00	$415.00
Primary/Transmission	$413.91	$415.00	$415.00
Transmission	$413.91	$990.00	$990.00
TOU			
Primary	$413.91	$415.00	$415.00
Primary/Transmission	$413.91	$415.00	$415.00
Transmission	$413.91	$990.00	$990.00
KWH Charge (cents/KWH)			
Standard	0.869	0.733	0.608
TOU			
On-peak	1.497	1.239	1.154
Off-peak	0.584	0.580	0.580
KW Demand charge			
Standard	$1.09	$5.14	$5.14
TOU			
On-peak	$1.09	$4.51	$4.51
Maximum demand		$0.80	$0.80
Credit per stipulation		$3.37	$3.37

RATE COMPARISON
1992

	Current Rates	FPC Proposed	Commission Approved
Standby (SS-1)			
Customer charge			
Standard			
Primary	$174.28	$235.00	$235.00
Transmission	$174.28	$810.00	$810.00
Demand Charge			
Local Transmission/Dist.			
Primary	$1.06	$1.10	$1.10
Transmission (Bulk)	0.0	0.0	0.0
Generation/Transmission			
Primary			
Specified SB Cap	$0.91	$0.80	$0.80
Daily Demand	$0.44	$0.38	$0.38
Transmission			
Specified SB Cap	$0.91	$0.80	$0.80
Daily Demand	$0.44	$0.38	$0.38
Energy			
Standard			
Primary	5.590	7.210	7.210
Transmission	5.590	7.210	7.210
Standby (SS-2)			
Customer charge			
Standard			
Primary	$435.69	$440.00	$440.00
Transmission	$435.69	$1015.00	$1015.00
Demand Charge			
Local Transmission/Dist.			
Primary	$1.03	$1.10	$1.10
Transmission (Bulk)	0.0	0.0	0.0
Generation/Transmission			
Primary			
Specified SB Cap	$0.23	$0.80	$0.80
Daily Demand	$0.11	$0.38	$0.38
Transmission			
Specified SB Cap	$0.23	$0.80	$0.80
Daily Demand	$0.11	$0.38	$0.38
Energy			
Standard			
Primary	5.470	7.210	7.210
Transmission	5.470	7.210	7.210

RATE COMPARISON
1992

	Current Rates	FPC Proposed	Commission Approved
Standby (SS-3)			
Customer charge			
Standard			
Primary	$174.28	$235.00	$235.00
Transmission	$174.28	$810.00	$810.00
Demand Charge			
Local Transmission/Dist.			
Primary	$1.06	$1.10	$1.10
Transmission (Bulk)	0.0	0.0	0.0
Generation/Transmission			
Primary			
Specified SB Cap	$0.72	$0.80	$0.80
Daily Demand	$0.34	$0.38	$0.38
Transmission			
Specified SB Cap	$0.72	$0.80	$0.80
Daily Demand	$0.34	$0.38	$0.38
Energy			
Standard			
Primary	5.590	7.210	7.210
Transmission	5.590	7.210	7.210

RATE COMPARISON
April 1993

	Current Rates	FPC Proposed	Commission Approved
Residential			
Customer charge	$5.32	$8.85	$8.85
Standard			
TOU			
Company owned	$8.36	$16.35	$16.35
Customer owned	$5.32	$8.85	$8.85
KWH Charge (Cents/KWH)			
Standard	3.964	4.154	3.856
TOU			
On-peak	11.118	11.926	10.879
Off-peak	0.597	0.580	0.580
General Service			
Customer Charge			
Standard			
Secondary	$5.32	$11.70	$11.70
Primary		$148.00	$148.00
Transmission		$730.00	$730.00
Unmetered	$2.61	$6.60	$6.60
TOU			
Secondary single phase			
Company owned	$8.36	$19.20	$19.20
Customer owned	$5.32	$11.70	$11.70
Secondary Three phase	$9.83	$25.20	$25.20
Primary (cust. own)	$15.46	$148.00	$148.00
Primary (co. own)	$19.98	$155.50	$155.50
KWH Charge (cents/KWH)			
Standard	3.964	4.154	3.856
TOU			
On-peak	10.707	11.926	10.879
Off-peak	0.597	0.580	0.580
General Service Demand			
Customer Charge			
Standard			
Secondary	$15.46	$11.70	$11.70
Primary	$15.46	$148.00	$148.00
Transmission		$730.00	$730.00
TOU			
Secondary single phase			
Company owned	$15.46	$19.20	$19.20
Customer owned	$15.46	$11.70	$11.70
Primary (cust. own)	$15.46	$148.00	$148.00
Primary (co. own)	$19.98	$155.50	$155.50
KWH Charge (cents/KWH)			
Standard	1.307	1.702	1.612
TOU			
On-peak	1.396	4.396	4.496
Off-peak	0.595	0.580	0.580
KW Demand charge			
Standard	$5.45	$3.54	$3.54
TOU			
On-peak	$5.45	$2.63	$2.63
Maximum demand		$0.91	$0.91

RATE COMPARISON
April 1993

	Current Rates	FPC Proposed	Commission Approved
GS-2			
Customer Charge			
Metered	$2.61	$6.60	$6.60
Unmetered	$5.32	$11.70	$11.70
KWH Charge (cents/KWH)	3.003	2.150	1.450
Curtailable			
Customer Charge			
Standard			
Secondary	$152.49	$213.00	$213.00
Primary	$152.49	$213.00	$213.00
Transmission	$152.49	$795.00	$795.00
TOU			
Primary (co. own)	$152.49	$213.00	$213.00
Transmission(co.own)	$152.49	$795.00	$795.00
KWH Charge (cents/KWH)			
Standard	1.105	1.031	1.057
TOU			
On-peak	2.068	2.342	2.245
Off-peak	0.587	0.580	0.580
KW Demand charge			
Standard	$5.45	$5.87	$5.87
TOU			
On-peak	$5.45	$5.15	$5.15
Maximum demand	na	$0.97	$0.97
Curtailable credit	$1.91	$2.33	$2.33
Interruptible			
Customer Charge			
Standard			
Primary	$413.91	$418.00	$418.00
Primary/Transmission	$413.91	$418.00	$418.00
Transmission	$413.91	$1000.00	$1000.00
TOU			
Primary	$413.91	$418.00	$418.00
Primary/Transmission	$413.91	$418.00	$418.00
Transmission	$413.91	$1000.00	$1000.00
KWH Charge (cents/KWH)			
Standard	0.869	0.733	0.624
TOU			
On-peak	1.497	1.239	1.275
Off-peak	0.584	0.580	0.580
KW Demand charge			
Standard	$1.09	$5.23	$5.23
TOU			
On-peak	$1.09	$4.53	$4.53
Maximum demand		$0.84	$0.84
Credit per stipulation		$3.37	$3.37

RATE COMPARISON
April 1993

	Current Rates	FPC Proposed	Commission Approved
Standby (SS-1)			
Customer charge			
Standard			
Primary	$174.28	$238.00	$238.00
Transmission	$174.28	$820.00	$820.00
Demand Charge			
Local Transmission/Dist.			
Primary	$1.06	$1.18	$1.18
Transmission (Bulk)	0.0	0.0	0.0
Generation/Transmission			
Primary			
Specified SB Cap	$0.91	$0.83	$0.83
Daily Demand	$0.44	$0.40	$0.40
Transmission			
Specified SB Cap	$0.91	$0.83	$0.83
Daily Demand	$0.44	$0.40	$0.40
Energy			
Standard			
Primary	5.590	6.970	6.970
Transmission	5.590	6.970	6.970
Standby (SS-2)			
Customer charge			
Standard			
Primary	$435.69	$443.80	$443.80
Transmission	$435.69	$1025.00	$1028.80
Demand Charge			
Local Transmission/Dist.			
Primary	$1.03	$1.18	$1.18
Transmission (Bulk)	0.0	0.0	0.0
Generation/Transmission			
Primary			
Specified SB Cap	$0.23	$0.83	$0.83
Daily Demand	$0.11	$0.40	$0.40
Transmission			
Specified SB Cap	$0.23	$0.83	$0.83
Daily Demand	$0.11	$0.40	$0.40
Energy			
Standard			
Primary	5.470	6.970	6.970
Transmission	5.470	6.970	6.970

RATE COMPARISON
April 1993

	Current Rates	FPC Proposed	Commission Approved
Standby (SS-3)			
Customer charge			
Standard			
Primary	$174.28	$238.00	$238.80
Transmission	$174.28	$820.00	$820.80
Demand Charge			
Local Transmission/Dist.			
Primary	$1.06	$1.18	$1.18
Transmission (Bulk)	0.0	0.0	0.0
Generation/Transmission			
Primary			
Specified SB Cap	$0.72	$0.83	$0.83
Daily Demand	$0.34	$0.40	$0.40
Transmission			
Specified SB Cap	$0.72	$0.83	$0.83
Daily Demand	$0.34	$0.40	$0.40
Energy			
Standard			
Primary	5.590	6.970	6.970
Transmission	5.590	6.970	6.970

RATE COMPARISON
November 1993

	Current Rates	FPC Proposed	Commission Approved
Residential			
Customer charge	$5.32	$8.85	$8.85
Standard			
TOU			
Company owned	$8.36	$16.35	$16.35
Customer owned	$5.32	$8.85	$8.85
KWH Charge (Cents/KWH)			
Standard	3.964	4.396	3.941
TOU			
On-peak	11.118	12.272	11.134
Off-peak	0.597	0.580	0.580
General Service			
Customer Charge			
Standard			
Secondary	$5.32	$11.70	$11.70
Primary		$148.00	$148.00
Transmission		$730.00	$730.00
Unmetered	$2.61	$6.60	$6.60
TOU			
Secondary single phase			
Company owned	$8.36	$19.20	$19.20
Customer owned	$5.32	$11.70	$11.70
Secondary Three phase	$9.83	$25.20	$25.20
Primary (cust. own)	$15.46	$148.00	$148.00
Primary (co. own)	$19.98	$155.50	$155.50
KWH Charge (cents/KWH)			
Standard	3.964	4.396	3.941
TOU			
On-peak	10.707	12.272	11.134
Off-peak	0.597	0.580	0.580
General Service Demand			
Customer Charge			
Standard			
Secondary	$15.46	$11.70	$11.70
Primary	$15.46	$148.00	$148.00
Transmission		$730.00	$730.00
TOU			
Secondary single phase			
Company owned	$15.46	$19.20	$19.20
Customer owned	$15.46	$11.70	$11.70
Primary (cust. own)	$15.46	$148.00	$148.00
Primary (co. own)	$19.98	$155.50	$155.50
KWH Charge (cents/KWH)			
Standard	1.307	1.702	1.600
TOU			
On-peak	1.396	4.396	4.457
Off-peak	0.595	0.580	0.580
KW Demand charge			
Standard	$5.45	$3.80	$3.80
TOU			
On-peak	$5.45	$2.81	$2.81
Maximum demand		$1.00	$1.00

RATE COMPARISON
November 1993

	Current Rates	FPC Proposed	Commission Approved
GS-2			
Customer Charge			
Metered	$2.61	$6.60	$6.60
Unmetered	$5.32	$11.70	$11.70
KWH Charge (cents/KWH)	3.003	2.206	1.497
Curtailable			
Customer Charge			
Standard			
Secondary	$152.49	$213.00	$213.50
Primary	$152.49	$213.00	$213.00
Transmission	$152.49	$795.00	$795.00
TOU			
Primary (co. own)	$152.49	$213.00	$213.00
Transmission(co.own)	$152.49	$795.00	$795.00
KWH Charge (cents/KWH)			
Standard	1.105	1.031	1.049
TOU			
On-peak	2.068	2.342	2.221
Off-peak	0.587	0.580	0.580
KW Demand charge			
Standard	$5.45	$6.13	$6.13
TOU			
On-peak	$5.45	$5.41	$5.41
Maximum demand	na	$0.97	$0.97
Curtailable credit	$1.91	$2.33	$2.33
Interruptible			
Customer Charge			
Standard			
Primary	$413.91	$418.00	$418.00
Primary/Transmission	$413.91	$418.00	$418.00
Transmission	$413.91	$1000.00	$1000.00
TOU			
Primary	$413.91	$418.00	$418.00
Primary/Transmission	$413.91	$418.00	$418.00
Transmission	$413.91	$1000.00	$1000.00
KWH Charge (cents/KWH)			
Standard	0.869	0.733	0.663
TOU			
On-peak	1.497	1.239	1.445
Off-peak	0.584	0.580	0.580
KW Demand charge			
Standard	$1.09	$5.23	$5.23
TOU			
On-peak	$1.09	$4.53	$4.53
Maximum demand		$0.84	$0.84
Credit per stipulation		$3.37	$3.37

RATE COMPARISON
November 1993

	Current Rates	FPC Proposed	Commission Approved
Standby (SS-1)			
Customer charge			
Standard			
Primary	$174.28	$238.00	$238.00
Transmission	$174.28	$820.00	$820.00
Demand Charge			
Local Transmission/Dist.			
Primary	$1.06	$1.18	$1.18
Transmission (Bulk)	0.0	0.0	0.0
Generation/Transmission			
Primary			
Specified SB Cap	$0.91	$0.83	$0.83
Daily Demand	$0.44	$0.40	$0.40
Transmission			
Specified SB Cap	$0.91	$0.83	$0.83
Daily Demand	$0.44	$0.40	$0.40
Energy			
Standard			
Primary	5.590	6.970	6.970
Transmission	5.590	6.970	6.970
Standby (SS-2)			
Customer charge			
Standard			
Primary	$435.69	$443.80	$443.80
Transmission	$435.69	$1025.00	$1028.80
Demand Charge			
Local Transmission/Dist.			
Primary	$1.03	$1.18	$1.18
Transmission (Bulk)	0.0	0.0	0.0
Generation/Transmission			
Primary			
Specified SB Cap	$0.23	$0.83	$0.83
Daily Demand	$0.11	$0.40	$0.40
Transmission			
Specified SB Cap	$0.23	$0.83	$0.83
Daily Demand	$0.11	$0.40	$0.40
Energy			
Standard			
Primary	5.470	6.970	6.970
Transmission	5.470	6.970	6.970

RATE COMPARISON
November 1993

	Current Rates	FPC Proposed	Commission Approved
Standby (SS-3)			
Customer charge			
Standard			
Primary	$174.28	$238.00	$238.80
Transmission	$174.28	$820.00	$820.80
Demand Charge			
Local Transmission/Dist.			
Primary	$1.06	$1.18	$1.18
Transmission (Bulk)	0.0	0.0	0.0
Generation/Transmission			
Primary			
Specified SB Cap	$0.72	$0.83	$0.83
Daily Demand	$0.34	$0.40	$0.40
Transmission			
Specified SB Cap	$0.72	$0.83	$0.83
Daily Demand	$0.34	$0.40	$0.40
Energy			
Standard			
Primary	5.590	6.970	6.970
Transmission	5.590	6.970	6.970

FLORIDA POWER CORPORATION
RATE SCHEDULE LS-1 LIGHTING SERVICE
1992 FINAL RATES

NON-FUEL ENERGY CHARGE: **$0.01548** PER KWH

CUSTOMER CHARGES
UNMETERED: $1.13 PER LINE OF BILLING
METERED: $3.38 PER LINE OF BILLING

MONTHLY FIXED CARRYING CHARGES
FIXTURES: 1.67% OF INSTALLED COST
POLES AND OTHER DIST. EQUIP.: 1.43% OF INSTALLED COST

BILLING NO.	TYPE OF FACILITY	LUMENS	EST. KWH	FIXTURE CHARGE	MAINT. CHARGE	ENERGY CHARGE	TOTAL CHARGE
INCANDESCENT							
110	ROADWAY	1,000	32	$0.92	$3.29	$0.50	$4.71
115	ROADWAY	2,500	66	$1.45	$3.33	$1.02	$5.80
MERCURY VAPOR							
205	OPEN BOTTOM	4,000	44	$2.29	$0.93	$0.68	$3.90
210	ROADWAY	4,000	44	$2.65	$0.93	$0.68	$4.26
215	POST TOP	4,000	44	$3.12	$0.93	$0.68	$4.73
220	ROADWAY	8,000	71	$3.00	$0.92	$1.10	$5.02
235	ROADWAY	21,000	158	$3.63	$0.95	$2.45	$7.03
240	ROADWAY	62,000	386	$4.76	$1.10	$5.98	$11.84
245	FLOOD	21,000	158	$4.76	$0.95	$2.45	$8.16
250	FLOOD	62,000	386	$5.57	$1.10	$5.98	$12.65
SODIUM VAPOR							
305	OPEN BOTTOM	4,000	21	$1.99	$1.28	$0.33	$3.60
310	ROADWAY	4,000	21	$2.44	$1.28	$0.33	$4.05
315	P.T. COL/CONTP	4,000	21	$3.71	$1.28	$0.33	$5.32
320	ROADWAY	9,500	42	$2.47	$1.28	$0.65	$4.40
325	ROADWAY	16,000	65	$2.57	$1.30	$1.01	$4.88
330	ROADWAY	22,000	87	$2.84	$1.32	$1.35	$5.51
335	ROADWAY	27,500	104	$2.82	$1.32	$1.61	$5.75
340	ROADWAY	50,000	169	$3.42	$1.33	$2.62	$7.37
345	FLOOD	27,500	103	$3.65	$1.32	$1.59	$6.56
350	FLOOD	50,000	170	$3.81	$1.33	$2.63	$7.77
360	DECO ROADWAY RECT.	9,500	47	$8.51	$1.28	$0.73	$10.52
365	DECO ROADWAY RECT.	27,500	108	$8.51	$1.32	$1.67	$11.50
370	DECO ROADWAY RND.	27,500	108	$10.47	$1.32	$1.67	$13.46
375	DECO ROADWAY RND.	50,000	168	$10.48	$1.33	$2.60	$14.41
380	DECO P.T ACORN	9,500	49	$5.97	$1.28	$0.76	$8.01
385	DECO P.T. SALEM	9,500	49	$5.63	$1.28	$0.76	$7.67

FLORIDA POWER CORPORATION
RATE SCHEDULE LS-1 LIGHTING SERVICE
1992 FINAL RATES

POLES

BILLING NO.	DESCRIPTION	MONTHLY CHARGE
425	Wood, 14' Laminated	$1.51
420	Wood, 30/35'	$1.51
480	Wood, 40/45'	$3.37
415	Concrete, Curved	$4.12
450	Concrete, 1/2 Special	$1.51
410	Concrete, 15'	$2.00
405	Concrete, 30/35'	$3.04
485	Concrete, 40/45'	$8.32
435	Aluminum, Type A	$5.70
440	Aluminum, Type B	$6.34
445	Aluminum, Type C	$12.39
455	Steel, Type A	$3.56
460	Steel, Type B	$3.81
465	Steel, Type C	$5.33
430	Fiberglass, 14' Black	$1.51
437	Fiberglass, 16' Black, Fluted, Dual Mount	$18.98
449	Deco Fiberglass, 16' Black, Fluted, AB	$15.00
436	Deco Fiberglass, 16' Black, Fluted	$16.86
438	Deco Fiberglass, 20' Black	$5.06
434	Deco Fiberglass, 20' Black, Deco Base	$10.59
446	Deco Fiberglass, 35' Bronze	$10.00
433	Deco Fiberglass, 35' Bronze	$9.61
432	Deco Fiberglass, 35' Bronze, Anchor Base	$23.69
428	Deco Fiberglass, 35' Bronze, Reinforced	$16.52
447	Deco Fiberglass, 35' Silver, Anchor Base	$18.51
431	Deco Fiberglass, 40' Bronze	$12.93
429	Deco Fiberglass, 40' Bronze, Reinforced	$18.94
448	Deco Fiberglass, 41' Silver, Anchor Base	$15.55

FLORIDA POWER CORPORATION
RATE SCHEDULE LS-1 LIGHTING SERVICE
APRIL AND NOVEMBER 1993 FINAL RATES

NON-FUEL ENERGY CHARGE: **$0.01591** PER KWH

CUSTOMER CHARGES
UNMETERED $1.20 PER LINE OF BILLING
METERED: $3.45 PER LINE OF BILLING

MONTHLY FIXED CARRYING CHARGES
FIXTURES: 1.67% OF INSTALLED COST
POLES AND OTHER DIST. EQUIP.: 1.46% OF INSTALLED COST

BILLING NO.	TYPE OF FACILITY	LUMENS	EST. KWH	FIXTURE CHARGE	MAINT. CHARGE	ENERGY CHARGE	TOTAL CHARGE
INCANDESCENT							
110	ROADWAY	1,000	32	$0.94	$3.29	$0.51	$4.74
115	ROADWAY	2,500	66	$1.48	$3.33	$1.05	$5.86
MERCURY VAPOR							
205	OPEN BOTTOM	4,000	44	$2.34	$0.93	$0.70	$3.97
210	ROADWAY	4,000	44	$2.70	$0.93	$0.70	$4.33
215	POST TOP	4,000	44	$3.18	$0.93	$0.70	$4.81
220	ROADWAY	8,000	71	$3.06	$0.92	$1.13	$5.11
235	ROADWAY	21,000	158	$3.70	$0.95	$2.51	$7.16
240	ROADWAY	62,000	386	$4.85	$1.10	$6.14	$12.09
245	FLOOD	21,000	158	$4.85	$0.95	$2.51	$8.31
250	FLOOD	62,000	386	$5.68	$1.10	$6.14	$12.92
SODIUM VAPOR							
305	OPEN BOTTOM	4,000	21	$2.03	$1.28	$0.33	$3.64
310	ROADWAY	4,000	21	$2.49	$1.28	$0.33	$4.10
315	P.T. COL/CONTP	4,000	21	$3.78	$1.28	$0.33	$5.39
320	ROADWAY	9,500	42	$2.52	$1.28	$0.67	$4.47
325	ROADWAY	16,000	65	$2.62	$1.30	$1.03	$4.95
330	ROADWAY	22,000	87	$2.90	$1.32	$1.38	$5.60
335	ROADWAY	27,500	104	$2.88	$1.32	$1.65	$5.85
340	ROADWAY	50,000	169	$3.49	$1.33	$2.69	$7.51
345	FLOOD	27,500	103	$3.72	$1.32	$1.64	$6.68
350	FLOOD	50,000	170	$3.89	$1.33	$2.70	$7.92
360	DECO ROADWAY RECT.	9,500	47	$8.68	$1.28	$0.75	$10.71
365	DECO ROADWAY RECT.	27,500	108	$8.68	$1.32	$1.72	$11.72
370	DECO ROADWAY RND.	27,500	108	$10.68	$1.32	$1.72	$13.72
375	DECO ROADWAY RND.	50,000	168	$10.69	$1.33	$2.67	$14.69
380	DECO P.T ACORN	9,500	49	$6.09	$1.28	$0.78	$8.15
385	DECO P.T. SALEM	9,500	49	$5.74	$1.28	$0.78	$7.80

FLORIDA POWER CORPORATION
RATE SCHEDULE LS-1 LIGHTING SERVICE
APRIL AND NOVEMBER 1993 FINAL RATES

POLES

BILLING NO.	DESCRIPTION	MONTHLY CHARGE
425	Wood, 14' Laminated	$1.60
420	Wood, 30/35'	$1.60
480	Wood, 40/45'	$3.57
415	Concrete, Curved	$4.37
450	Concrete, 1/2 Special	$1.60
410	Concrete, 15'	$2.12
405	Concrete, 30/35'	$3.22
485	Concrete, 40/45'	$8.82
435	Aluminum, Type A	$6.04
440	Aluminum, Type B	$6.72
445	Aluminum, Type C	$13.13
455	Steel, Type A	$3.77
460	Steel, Type B	$4.04
465	Steel, Type C	$5.65
430	Fiberglass, 14' Black	$1.60
437	Fiberglass, 16' Black, Fluted, Dual Mount	$20.11
449	Deco Fiberglass, 16' Black, Fluted, AB	$15.90
436	Deco Fiberglass, 16' Black, Fluted	$17.87
438	Deco Fiberglass, 20' Black	$5.36
434	Deco Fiberglass, 20' Black, Deco Base	$11.22
446	Deco Fiberglass, 35' Bronze	$10.60
433	Deco Fiberglass, 35' Bronze	$10.18
432	Deco Fiberglass, 35' Bronze, Anchor Base	$25.19
428	Deco Fiberglass, 35' Bronze, Reinforced	$17.51
447	Deco Fiberglass, 35' Silver, Anchor Base	$19.61
431	Deco Fiberglass, 40' Bronze	$13.70
429	Deco Fiberglass, 40' Bronze, Reinforced	$20.07
448	Deco Fiberglass, 41' Silver, Anchor Base	$16.50