BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Request for rate increase by Gulf Power Company.	DOCKET NO. 010949-EI ORDER NO. PSC-02-0787-FOF-EI ISSUED: June 10, 2002

The following Commissioners participated in the disposition of this matter:

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ORDER GRANTING IN PART AND DENYING IN PART GULF POWER COMPANY'S PETITION FOR RATE INCREASE

BY THE COMMISSION:

I. CASE BACKGROUND

On September 10, 2001, Gulf Power Company (Gulf or Company) filed a petition for a permanent rate increase. Gulf requested an increase in its retail rates and charges designed to generate $69,867,000 in additional gross annual revenues which would allow the Company to earn an overall rate of return of 8.64% or a 13.00% return on equity (range of 12.00% to 14.00%). This request was based upon a projected June 2002 through May 2003 test year and a 13-month average jurisdictional rate base of $1,198,502,000. The Company filed new rate schedules reflecting the proposed increases. The most significant basis for the requested increase was the addition of Smith Unit 3, a 574 megawatt gas fired combined cycle generating unit along with the associated operation and maintenance (O&M) expenses. Other significant factors included the addition since the last rate case of 100,000 new customers; 1,400 miles of new distribution lines; and 90 miles of new transmission lines; the replacement and repair of an aging electrical infrastructure; and the increased O&M costs associated with aging generating plants.

Pursuant to Order No. PSC-99-2131-S-EI, issued October 28, 1999, in Docket Nos. 990250-EI and 990947-EI, the Commission approved a stipulation that established a revenue sharing plan. Included in the stipulation was a provision whereby Gulf could not request an increase in base rates before the earlier of the commercial in-service date for Smith Unit 3 or December 31, 2002, the expiration date of the Stipulation. Smith Unit 3 began commercial service on April 22, 2002.

Gulf did not request interim rate relief but specifically asked that all or a portion of the requested increase of $69,867,000 be granted beginning on the commercial in-service date of Smith Unit 3 pending a final decision on this petition.

Pursuant to Section 366.06, Florida Statutes, Order No. PSC-01-2300-PCO-EI, issued November 21, 2001, suspended Gulf's permanent rate schedules pending review.

The Federal Executive Agencies (FEA), Florida Cable Telecommunications Association, Inc. (FCTA) and the Florida Industrial Power Users Group, (FIPUG) were granted intervention status in this docket by Order Nos. PSC-01-1934-PCO-EI, PSC-01-1949-PCO-EI, and PSC-01-1703-PCO-EI respectively. The Office of Public Counsel (OPC) is a party to this docket pursuant to Section 350.0611, Florida Statutes; Order No. PSC-01-2024-PCO-EI, acknowledged OPC's intervention. All parties except FCTA filed post-hearing briefs. The parties reached stipulations on a number of topics and these stipulations are attached in Appendix A to this Order.

Customer service hearings were held in Pensacola and Panama City on January 16, 2002. The final hearing was held February 25-26, 2002.

II. SUMMARY OF DECISION

We found Gulf's rate base to be $1,199,732,000. We found the average cost of capital to be 7.92% and the return on common equity to be 11.75% with a range of 10.75% to 12.75%. For rate setting purposes we granted Gulf an additional .25% return on common equity for providing superior service. We granted Gulf a revenue increase of $53,240,000.

III. TEST PERIOD

Gulf proposed a test period, for rate setting purposes, of 12 months ending May 31, 2003. With certain adjustment to Gulf's financial forecast, we find that this test period is appropriate.

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. The projected period June 1, 2002, through May 31, 2003, represents the test year on which Gulf calculated its revenue deficiency in this case. Gulf used this projected test period because it best represents future operations after Smith Unit 3 begins commercial operation. Smith Unit 3 is the major factor behind Gulf's need for rate relief. Of the $69.9 million request for rate relief, approximately $48 million is associated with Smith Unit 3. The test year used will more accurately reflect the operations of the Company during the first 12 months after the new rates go into effect than a historical test year that does not include this investment.

OPC concedes Gulf's need to cover the costs associated with Smith Unit 3. OPC's position is that we would have received far more reliable data from a historic actual test year, with the projected costs associated with Smith 3 superimposed and a historically based earnings attrition allowance.

OPC witness Schultz testified that the use of budgeted information provides significant difficulty in determining the appropriate level of future plant and cost operations. The budget must be in sufficient detail to determine whether the assumptions and cost budgeted by the Company are reasonable. In OPC's opinion Gulf did not supply sufficient detail necessary to properly examine the assumptions.

Witness Schultz testified that he made a number of adjustments based upon a historical level of spending that he considered sufficient to provide the quality of service. In his opinion, the historical spending should be used when establishing rates, especially when considering the lack of detail in the Company's budget. Mr. Schultz further testified that the budget provided by the Company does not appear to support $201 million in costs.

There are primarily two options for evaluating Gulf's expected financial operations. The first option is to use a historical test year and make pro forma adjustments to the test year. 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 pro forma adjustments usually do not represent all the changes that occur from the end of the historical period to the time new rates are in effect. Therefore, this option generally does not present as complete an analysis of the expected financial operations as a projected test year.

The main advantage of a projected test year is that it includes all information related to rate base, NOI, and capital structure for the time new rates will be in effect. However, the data is projected and its accuracy depends on the Company's ability to forecast. Many companies are not able to forecast accurately enough to use the forecast for setting rates.

The parties and the Commission staff have conducted extensive discovery on Gulf's forecast. As will be addressed later in this Order, certain adjustments will be made to Gulf's forecast to increase its accuracy. With the inclusion of these adjustments, the forecast of Gulf's financial operations for the year ending May 31, 2003, is sufficiently accurate to use as a basis for setting rates.

IV. RATE BASE

A. PLANT IN SERVICE - PRODUCTION

Over the four-year period from January 1, 1997, to December 31, 2000, gross production additions to Gulf's Plant in Service averaged $15,294,572 per year. For the 17-month period from January 1, 2001, to May 31, 2002, Gulf's production budget expenditures total $238,059,000. The vast majority of this total, $188,232,000, is associated with the construction of Smith Unit 3. Expenditures associated with the construction of Smith Unit 3 were subject to a stipulation which was approved at the beginning of the hearing.

For the period from June 1, 2002, to May 31, 2003 (projected test year), production-related items are forecasted to be $13,008,999. Approximately $677,000 of this total is associated with the construction of Smith Unit 3. These Smith Unit 3 expenditures were subject to the same stipulation.

The record evidence provides considerable identification and description of Gulf's specific capital projects associated with budgeted production expenses. Gulf provided detailed cost estimates for these capital projects. We agree with Gulf witness Moore's testimony that these projects are necessary to improve the efficiency and availability of Gulf's generating units. Further, even though budgeted production plant items for the projected test year ($13,008,999) include some dollars associated with Smith Unit 3, the budgeted amount is still less than the four-year average for the 1997-2000 period ($15,294,572).

Prior to hearing, OPC took the position that, "a number of budgeted items for production related items appear to be overstated. OPC is awaiting further information from Gulf to explain the items more fully." OPC witness Schultz's prefiled testimony stated that, "tentatively, I believe the production plant additions were overstated." FIPUG adopted OPC's position prior to hearing. However, at the hearing, Mr. Schultz did not identify any specific adjustments to production plant. OPC took no position on this issue in its post-hearing brief.

In summary, we find that Gulf provided substantial detail on its production-related additions. OPC offered no evidence or argument to refute Gulf's position and did not recommend any adjustments to production plant items. We find that the documentation provided by Gulf is adequate to support the reasonableness of budgeted production plant additions. Therefore, we find that no adjustment shall be made.

B. PLANT IN SERVICE - TRANSMISSION AND DISTRIBUTION

Over the four-year period from January 1, 1997, to December 31, 2000, Gulf's transmission plant additions averaged $5,704,145 per year. During the same four-year historic period, distribution plant additions averaged $31,126,711.

For the 17-month period from January 1, 2001, to May 31, 2002 (prior year), Gulf's transmission plant budget totals $48,530,000, while the distribution plant budget totals $57,113,000.

For the period from June 1, 2002, to May 31, 2003 (projected test year), the transmission plant budget is estimated to be $7,505,000. For the same period, the distribution plant budget is estimated to be $38,305,000.

The evidentiary record provides sufficient detail on specific capital projects associated with transmission expenses budgeted by Gulf. Detailed cost estimates are given for these transmission capital projects. Based on this information we find that these projects are necessary to ensure that the transmission system can keep up with increases in the number of customers served and load growth, and to repair and replace facilities.

The evidentiary record also provides sufficient detail on distribution expenses budgeted by Gulf. Detailed cost estimates were given for distribution capital projects. Budgeted transmission and distribution Plant in Service items for the projected test year are comparable to the four-year average for the 1997-2000 period.

OPC witness Schultz testified that $162,822,000 of budgeted additions for distribution, transmission, and general plant should be disallowed because Gulf did not adequately justify their inclusion in rate base. Mr. Schultz testified:

> The transmission, distribution and general plant additions are not identified by the Company. The Company's failure to provide a description of the $162,822,000 of distribution, transmission and general plant additions is an attempt to shift the burden of proof.

Gulf provided a level of detail on budgeted transmission, distribution, and general plant additions similar to that provided on the production plant additions as discussed in Section A, above. At the hearing, Mr. Schultz did not identify any specific adjustments to the transmission or distribution budget.

In summary, we find that the record supports Gulf's requested transmission and distribution-related additions. OPC and FIPUG did not recommend any adjustments to these items. The documentation provided by Gulf is adequate support and justification for the reasonableness of its budgeted transmission and distribution plant additions. Therefore, we find that no adjustment shall be made.

C. <u>PLANT IN SERVICE - GENERAL PLANT RELATED ADDITIONS</u>

Gulf provided its construction budget for the period January 1, 2001, to May 31, 2003, totaling $413,891,000 in capital expenditures. The amount relating to transmission, distribution, and general plant totals $162,822,000. The general plant budgeted additions total $11,400,000.

Gulf's witnesses Fisher and Saxon testified that $5,300,000 reflect budgeted additions for the January 2001 through May 2002 period, and $6,113,000 relates to the test year budgeted additions. The majority of the additions budgeted for the test year relate to improvements to buildings and land, and purchases of automotive equipment including mechanized line and service trucks, and purchases of telecommunications, computer, and other equipment.

Gulf's witness Saxon asserts that the budgeted general plant additions are well within the range of normal spending compared to the last three years and the period of January 2001 through May 2002. Mr. Saxon notes that the total actual 2001 capital expenditures are 1.85 percent under the 2001 budget. Both witnesses Saxon and Fisher provided documentation regarding the general plant additions showing the specific project description, identification, and dollar amounts for the test year.

OPC witness Schultz testified that Gulf's $162,822,000 budgeted additions for distribution, transmission, and general plant should be disallowed on the basis of inadequate support being provided. Mr. Schultz testified:

> The transmission, distribution and general plant additions are not identified by the Company. The Company's failure to provide a description of the $162,822,000 of distribution, transmission and general plant additions is an attempt to shift the burden of proof.

We find that the evidentiary record contains an identification and description of the specific projects associated with the budgeted general plant additions. Moreover, the evidence indicates that the $6.2 million in test year general plant additions is within the range of additions recorded during the 1998 - 2000 period for this function.

Since OPC takes no exception to Gulf's supporting information for budgeted production plant additions, we compared that documentation with the documentation provided for the transmission, distribution, and general plant additions. Specific items included in the construction budget for general plant additions are detailed in much the same format and contain much of the same information as provided for the production plant additions. For example, the production budget information includes individual project numbers with descriptions and estimated expenditures. Likewise, general plant budgeted information also includes individual project numbers with descriptions and estimated expenditures.

In conclusion, OPC argued that Gulf's budgeted additions for distribution, transmission, and general plant should be disallowed based on Gulf's failure to provide supporting identification or description of the additions. However, Gulf provided a similar level of detail for the production plant additions and OPC did not object to that documentation. The supporting detail identifies and describes specific projects relating to the budgeted general plant additions. OPC provided no other specific disagreement with Gulf's budgeted additions. We find that the documentation provided by Gulf is adequate support and justification for the reasonableness of its budgeted general plant additions, and find that no adjustment is necessary to Plant in Service - General Plant Related Additions.

D. DEFERRAL OF RETURN ON THE THIRD FLOOR OF THE CORPORATE OFFICE

The cost of the third floor of Gulf's corporate office, $3,840,000, was removed from rate base in the Company's last rate case. See Order No. 23573, issued October 3, 1990, in Docket No. 891345-EI. The reason was that Gulf had adequate storage space and maintenance facilities at other locations, and that the ratepayers would not benefit from the use of the third floor of the headquarters building for these purposes. Gulf was, however, allowed to earn a return on this plant investment equal to the allowance for funds used during construction (AFUDC).

Order No. PSC-99-2131-S-EI, approving a Stipulation and Settlement, was issued on October 28, 1999, in Docket No. 990947-EI. This Order addressed, among other things, Gulf's regulatory assets including the accumulated balance of the deferred return on the third floor of the corporate offices. The starting date of the Settlement was October 1, 1999, and expires with the earlier of the day before the commercial in-service date of Smith Unit 3 or

December 31, 2002. The agreement authorizes Gulf to record at its discretion, up to $1 million per year through the expiration date to reduce the accumulated balance of the deferred return.

Gulf amortized $1 million in 2000 and in 2001. The MFR balance of the deferred return at the end of May 2002 is $3,470,595 system, which includes the $1 million in discretionary amortization in the year 2000 but does not reflect the additional amortization in 2001. The 2001 amortization was recorded after the MFRs were filed. Based on Witness Labrato's Exhibit 54, Schedule 1, the adjusted balance at May 2002 reflecting the 2001 amortization is $2,444,958.

Gulf is requesting that the deferred return be allowed in rate base and amortized over three years since 100% of the third floor is now being utilized for record retention, spare office furniture, miscellaneous supplies, and other storage for the print shop, safety and health, and power delivery functions. The amortization period is discussed below in Part VI, Section T. The third floor also contains space for building maintenance. Witness Labrato testified that in 1999 a FPSC auditor toured the third floor and found that over 90% of the space was being utilized. Also, based on Disclosure No. 2 in the staff audit report (Exhibit 47, attached to the testimony of staff witness Bass), the utilization of the space was confirmed by the audit staff.

OPC witness Schultz testified that the third floor was initially used for storage space which was originally intended as additional office space to accommodate Gulf's growth. Gulf's employee complement in 1989 was 1,626 and in the year 2000 was 1,319. OPC stated in its brief that the space was never converted to offices as expected. OPC also expressed concern that current customers would be required to pay deferred earnings on something that is not providing service. Accordingly, working capital should be reduced $2,893,000 and amortization expenses should be reduced $1,157,000.

Gulf Witness Labrato testified that at the time of the last rate case, Gulf had adequate space for storage and maintenance functions at other locations. When the office was built, it was built with the additional floor, and that it was not needed for office space at that time. Also, it was anticipated that it would be utilized in the future, and that because of the deferred return, future recovery would be allowed. In addition, it was not anticipated that the period of time would go this long, which is why the amount is so large.

Mr. Labrato further testified that for surveillance purposes the investment was removed from rate base, the deferral was recorded as a regulatory asset, and the earnings were below-the-line so it did not impact the surveillance earnings. For financial accounting purposes it was accounted for the same way. The investors and the financial community realized the amount was deferred and anticipated future recovery.

We find it appropriate to include the deferral of the return on the third floor in rate base. Although the third floor is not being used as it was originally intended, it is being used. Also, it was intended that recovery of the deferred return would ultimately be allowed. Therefore, $2,138,760, which reflects the additional amortization booked during 2001, and a four year amortization period as discussed in Part IV, Section T, below, shall be included in rate base.

E. INVESTMENT IN THE THIRD FLOOR OF THE CORPORATE OFFICE

Gulf's witness Labrato testified that the third floor of the corporate office is being utilized and that the investment should be allowed in rate base. The projected test year rate base includes the $3.8 million of plant-in-service and $338,000 in accumulated depreciation, which were removed in the last case.

Mr. Labrato testified that the space is less expensive than the rest of the building because the space is unfinished with no walls. He further testified that the investment has allowed for convenient, secure, and humidity-controlled space for items that are used in the corporate office. In addition, he noted that if this space were not available, the Company would be required to build or lease additional space.

OPC states in its brief that it accepts the conclusion of the audit report that the third floor is currently being used for storage space and therefore provides some value to the public. However, two concerns were raised by OPC.

First, the space was not originally intended to be used for storage space, but for office space. Accordingly, the "storage rooms" occupy space in a near waterfront building. The space is more expensive than that normally associated with storage space.

Second, the third floor has not been depreciated in the 12 1/2 years since Order No. 23573 was issued in Docket No. 891345-EI. The depreciable life of the office building is approximately 25 years. Therefore, if the third floor is being depreciated over the remaining life of the building, then the current and future customers would be charged double the depreciation rate for a storage area. OPC is therefore recommending that we allow half the investment in rate base and reduce depreciation by half.

The FPSC staff who conducted the audit toured the third floor of the corporate office and indicated that over 90% of the space is utilized. The third floor is primarily used for storage of records, spare office furniture, miscellaneous supplies for the kitchen, print shop, safety and health, and power delivery. It also contains a workshop for building maintenance. Staff witness Bass concluded in Audit Disclosure No. 2 of Exhibit 47 that the third floor of the corporate office is used and useful for utility operations. OPC accepted staff witness Bass' conclusion.

The third floor investment of $3.8 million will be recorded in Account 390, Structures and Improvement, where the investment in the corporate office is recorded. The third floor investment of $3.8 million will be depreciated over the remaining life of Account 390 and not over the remaining life of the individual unit or building. The remaining life of Account 390 is 30 years, not 25 years. The inclusion of the third floor investment will naturally increase depreciation expense. However, the additional investment will not affect the remaining life nor the depreciation rate for Account 390. This is because the $3.8 million associated with the third floor represents only about 7% of the total account investment. Compositing the age of the third floor (15.5 years) with the 16.2 year age given for Account 390 will result in no change in the average remaining life. While OPC is correct that there will be an inherent reserve deficiency associated with the third floor due to its exclusion from rate base for 12 1/2 years, it has no affect on the 2.2% depreciation rate. Moreover, Account 390 has sufficient existing reserve surplus to correct the deficiency. According to the information provided in Gulf's depreciation study, Account 390 has a perceived reserve surplus which could be used to offset the reserve deficit due to the exclusion of third floor investment from rate base.

We find that the third floor is used and useful, therefore the investment and reserve for the third floor shall be included in rate base and the Company shall begin depreciating this investment using a 2.2% depreciation rate.

F. SECURITY MEASURES

Gulf's MFRs and direct testimony were filed on September 10, 2001, and thus do not account for the impact, on test year rate base, of the increased threat of terrorist attacks since September 11, 2001. Staff requested information pertaining to the impact of the increased terrorist threat on Gulf's costs in Staff's Seventh Set of Interrogatories Nos. 235-238. Gulf filed its response to these interrogatories under a request for confidential classification on February 4, 2002. Order No. PSC-02-0220-CFO-EI, issued February 22, 2002, granted confidential classification to the interrogatory responses. The confidential interrogatory responses were identified as Exhibit 7 at the hearing.

Having reviewed Exhibit 7, we find that the rate base information provided is reasonable and appropriate. Based on Exhibit 7 we find that a $683,000 adjustment ($714,000 system) should be made to increase rate base for the May 2003 projected test year for investments in additional security measures made in response to the increased threat of terrorist attacks since September 11, 2001.

G. ENVIRONMENTAL COST RECOVERY CLAUSE

We find that the capitalized items currently approved for recovery through the Environmental Cost Recovery Clause (ECRC) need not be included in base rates. During this rate proceeding, no benefit to customers has been shown by including such costs in base rates. In fact, the impact on customers is essentially the same whether the costs are recovered through base rates or the ECRC.

Section 366.8255(5), Florida Statutes, provides in part that "recovery of environmental compliance costs under this section does not preclude inclusion of such costs in base rates in a subsequent rate proceeding, if that inclusion is necessary and appropriate.". This section grants us some discretion to decide whether costs approved for recovery through the ECRC should be moved into base rates.

According to Order No. PSC-94-0044-FOF-EI, issued January 12, 1994, in Docket No. 930613-EI, Gulf is allowed to earn its currently authorized ROE for capitalized items recovered through the ECRC. This fixed midpoint ROE policy is reaffirmed by Order No. PSC-99-2513-FOF-EI, issued December 22, 1999, in Docket No. 990007-EI. Because a company has an opportunity to earn a return higher than the midpoint ROE in base rates, including capitalized ECRC items in rate base may reward Gulf for the costs that are outside its control. For the reasons discussed above, we conclude that not including Gulf's currently capitalized ECRC items in rate base is reasonable and appropriate.

H. <u>PLANT IN SERVICE - TOTAL</u>

Gulf's requested level of Plant in Service was $1,966,492,000 ($2,015,013,000 system) for the May 2003 projected test year. Based on the adjustments described below for house power panels (Account 369.3), anti-terrorism security measures, and cable inspection expense, Plant in Service should be increased $125,000 ($156,000 system). The appropriate amount of Plant in Service is $1,966,617,000 ($2,015,169,000 System) for the May 2003 projected test year, as shown in Attachment 1.

Gulf's policy is to retire house power panels by abandoning them in place rather than physically removing them. Gulf indicates that the rate case budget inadvertently understated the retirements of house power panels, which overstated the plant in service for this account.

We find that the cumulative effect of the relevant adjustments is an increase of $125,000 to test year Plant in Service as shown below:

Test Year Plant in Service Adjustments		
Issues	Jurisdictional	System
Security Measures	$683,000	$714,000
Cable Injection	83,000	83,000
House Power Panels	(641,000)	(641,000)
Total Adjustment	$125,000	$156,000

I. ACCUMULATED DEPRECIATION

Gulf requested a level of accumulated depreciation in the amount of $854,099,000 ($876,236,000 system) for the May 2003 projected test year. We find that the test year accumulated depreciation must be decreased $1,716,000 ($1,754,000 System) as shown in the table below. The appropriate amount of accumulated depreciation for the May 2003 projected test year is $852,383,000 ($874,482,000 System), as shown in Attachment 1.

Test Year Accumulated Depreciation Adjustments		
Issues	Jurisdictional	System
Cable Injection	$ (1)	$ (1)
House Power Panels	698	698
Stipulated 25-year life for Smith Unit 3	1,019	1,057
Total Adjustment	$1,716	$1,754

J. FUEL INVENTORY

Gulf requested a total fuel inventory of $42.6 million (13-month average) which is comprised of $29.4 million for fuel stored at its generating plants and $13.1 million for in-transit fuel. We find that this amount is appropriate.

Under Order No. 12645, we apply a 90 day projected burn plus base coal volumes as a "generic policy" for coal inventory if two conditions are present: 1) the utility fails to justify its fuel inventory levels; and 2) the optimum policy cannot be determined from the evidentiary record.

When calibrating the days supply of its fuel inventory, Gulf must balance two competing concerns. First, if Gulf has too little inventory, Gulf may incur additional costs to purchase fuel on the spot market to maintain reliable service. Second, if Gulf has too much inventory, Gulf will incur greater carrying costs associated with its fuel inventory. Gulf establishes its fuel inventory levels to optimize Gulf's total costs associated with its fuel inventory.

In its brief, OPC advocated that Gulf's coal inventory should be set at the sum of the actual 2000 historical amount and Gulf's requested in-transit amount. OPC witness Schultz testified that Gulf's historic costs are representative of what is necessary to provide the quality of electric service that Gulf has provided. According to Mr. Schultz, Gulf did not provide sufficiently detailed information about its costs in the projected test year to provide much assurance about the accuracy of these projected costs.

Gulf requested a coal inventory of 52 days supply (695,289 tons) in this docket compared with the 90 days supply of coal inventory that was authorized in Gulf's last rate case. Despite a 37 percent increase in Gulf's electric generation needs since 1990, the value of Gulf's coal inventory is $10.2 million less than what was authorized in the last rate case. Mr. Schultz advocates that Gulf's coal inventory should be adjusted downward by 218,808 tons. With an average price of $38.463 per ton, the adjustment to Gulf's working capital balance would be a decrease of approximately $8,416,000.

Robert G. Moore, another Gulf witness, testified on rebuttal that year 2000 was extraordinary and atypical for Gulf on a going forward basis. Gulf's coal inventory levels fell sharply during the last three months of 2000 because the demand for coal was high due to early and prolonged winter conditions, and the increased cost of natural gas-fired generation. Also, the winter conditions negatively impacted coal production and delivery schedules. After the winter conditions subsided, Gulf steadily increased its coal inventory back to normal levels.

In summary, witness Moore stated that a smaller coal inventory amount would adversely affect Gulf's ability to provide reliable electric service and could cause higher coal procurement costs on the spot market for Gulf's ratepayers.

We find that the year 2000 was atypical and therefore unrepresentative of Gulf's coal inventory requirements on a going-forward basis. Gulf has justified the amount and value of its fuel inventory levels. Therefore, no adjustment to Gulf's fuel inventories for the projected test year ending May 31, 2003, is necessary.

K. WORKING CAPITAL

Gulf's requested level of Working Capital was $67,194,000 ($69,342,000 system) for the May 2003 projected test year. However, based on our decision on the amortization of the third floor of Gulf's corporate office, working capital must be reduced by $611,000 ($753,403 system), for a total working capital of $66,583,000 ($68,589,000 system).

L. RATE BASE

Gulf's requested rate base in the amount of $1,198,502,000 for the May 2003 projected test year, as shown on the table below. We find that the appropriate rate base for Gulf is $1,199,732,000 as shown on the table below and in Attachment 1.

2003 Jurisdictional Rate Base (000's)		
	Gulf	Approved
Utility Plant-in-Service	$1,966,492	$1,966,617
Accumulated Depreciation	(854,099)	(852,383)
Net Plant-in-Service	1,112393	1,114,234
Construction Work in Progress	15,850	15,850
Property Held for Future Use	3,065	3,065
Net Utility Plant	1,131,308	1,133,149

Working Capital	67,194	66,583
Total Rate Base	$1,198,502	1,199,732

V. COST OF CAPITAL

A. ACCUMULATED DEFERRED TAXES

Per MFR Schedule D-1, Page 2 of 6, the "Company Total per Books" deferred taxes for the test year ending May 31, 2003, was $164,672,000. To the $164,672,000, the Company made adjustments to remove $33,458,000 of deferred taxes specifically identified with unit power sales contracts and to remove $6,757,000 of deferred taxes for the appropriate portion of other rate base adjustments which were made on a pro rata basis over all sources of capital. The result is total system adjusted deferred taxes of $124,457,000. The Company then applied a jurisdictional factor of .9760026 to this amount, resulting in adjusted jurisdictional deferred taxes of $121,471,000.

On January 18, 2002, the Company revised its projected capital structure as Exhibit 2 to Mr. Labrato's deposition. The revised capital structure also reflected jurisdictional deferred taxes of $121,471,000.

OPC did not take issue with the methodology or the amount of deferred taxes in rate base prior to Commission adjustments, but it did state that the actual dollar amount is dependent on our adjustments to rate base.

We agree with OPC. In addition, we find it necessary to make a specific adjustment of $662,000 related to the Smith Unit 3 life, as addressed in the Depreciation Stipulation. The result is adjusted jurisdictional deferred taxes of $122,133,000. Accordingly, we find that the adjusted jurisdictional Accumulated Deferred Taxes is $122,133,000 for the May 31, 2003, projected test year.

B. UNAMORTIZED INVESTMENT TAX CREDITS

Per MFR D-1, Page 2 of 6, the "Company Total per Books" weighted cost investment tax credits for the projected test year ending May 31, 2003, is $22,113,000 and the cost rate is 9.70%. To the $22,113,000, the Company made adjustments to remove $4,201,000 of investment tax credits specifically identified with unit power sales contracts and to remove $920,000 of investment tax credits for the appropriate portion of other rate base adjustments which were made on a pro rata basis over all sources of capital. The result is total system adjusted investment tax credits of $16,992,000. The Company then applied a jurisdictional factor of .9760026 to this amount, resulting in adjusted jurisdictional investment tax credits of $16,584,000 with a cost rate of 9.70%. The cost rate is derived from long-term debt, preferred stock, and common equity.

On January 18, 2002, the Company revised its projected capital structure in Exhibit 2 to Mr. Labrato's deposition. The revised capital structure also reflects jurisdictional investment tax credits of $16,584,000, but alters the cost rate from 9.70% to 9.48%.

OPC's position is that the actual dollar amount is dependent on the adjustments to rate base and the cost rate is dependent upon the allowed return on equity.

We agree with OPC, but do not believe that there are any rate base adjustments that would affect investment tax credits. The result is that no adjustment is necessary and the balance therefore remains at $16,584,000. We recalculated the investment tax credit cost rate based on other adjustments and the return on equity, resulting in a 8.99% weighted average cost rate for the investment tax credits. Accordingly, we find that the adjusted jurisdictional investment tax credits of $16,584,000 with a weighted average cost of 8.99% for the May 31, 2003 projected test year is appropriate.

C. <u>RECONCILING RATE BASE AND CAPITAL STRUCTURE</u>

The Company presented its reconciliation of rate base and capital structure on MFR Schedules D-12a and D-12b. On January 18, 2002, the Company revised its projected capital structure in Exhibit 2 to Mr. Labrato's deposition. The Company made a specific adjustment to remove non-utility investment from equity and made specific adjustments to remove the unit power sales capital structure amounts from the per books capital structure balances. The Company also properly removed dividends declared from its capital structure. The remaining rate base adjustments required to reconcile the rate base and capital structure were made on a pro rata basis over all sources of capital. Finally, the jurisdictional factors were applied to these balances, resulting in the reconciliation of rate base and capital structure.

As stated, the Company removed all other rate base adjustments on a pro rata basis from all sources of capital. It has been our practice to make specific adjustments where possible and to prorate other rate base adjustments over investor sources only. However, Gulf's per books capital structure includes deferred taxes and investment tax credits that are being considered, along with the related assets, in cost recovery clauses. We believe that it is appropriate for the Company, in this case, to make pro rata adjustments for the remaining rate base items over all sources. This will allow the Company to match the related deferred taxes and investment tax credits with the assets being recovered through these clauses. For this reason it is appropriate to recognize the recovery clause treatment so as not to penalize the Company through the double counting of lower cost capital items.

OPC did not take issue with the methodology of reconciliation, but it did state that the actual reconciled amounts will depend on the rate base allowed. We agree with OPC and have also made a pro rata adjustment over all investor's sources of capital. We also agree with the revised capital structure provided in Mr. Labrato's deposition Exhibit 2. Accordingly, we find that with the specific capital structure adjustments and the pro rata adjustment, capital structure and rate base have been reconciled appropriately.

D. RETURN ON EQUITY TO USE FOR ESTABLISHING GULF'S REVENUE REQUIREMENT

For the reasons provided below, we find that the appropriate ROE to use in establishing Gulf's revenue requirement is 11.75%.

Mr. Benore, the Company's primary witness on cost of capital, based his ROE analysis on a group of 8 companies involved in the regulated electric utility business. He employed 9 risk measures to select this comparable risk group. These measures included a

Value Line beta no greater than .60, a Value Line safety rank of at least 2, and a Standard and Poor's (S & P) bond rating of A- or higher. He also eliminated any company involved in a merger. Mr. Benore updated his analysis, which resulted in the exclusion of 1 of the 8 original companies. His recommended ROE remained at 13.0%.

To estimate Gulf's ROE, Mr. Benore relied upon the results of three market-based models: a discounted cash flow (DCF) model, an equity risk premium model, and a capital asset pricing model (CAPM). For his DCF model, Mr. Benore used stock prices for his comparable risk companies from July 16, 2001, to August 14, 2001, and a growth rate of 6% based on earnings growth. He obtained a DCF result of 11.7% without flotation costs and 11.9% with flotation costs.

Mr. Benore calculated a 5.0% equity risk premium using actual, annual returns realized by investors for investments in the common stocks of Moody's Electric Power Companies and in long-term Treasury bonds. The premium was calculated for the period 1932 to 1993. Mr. Benore stopped at 1993 because he believes this year marked the onset of structural changes in the industry from regulated monopoly to competition. He added the 5.0% equity risk premium to the 6.4% yield on long-term Treasury bonds. Mr. Benore's estimate of the risk-free rate was normalized for the impact of the Treasury's planned buyback of long-term debt. The equity risk premium result is 11.4% before flotation costs.

Mr. Benore's CAPM model result is 11.4% before flotation costs. This is based on the average of a standard CAPM and an empirical CAPM, a model which adjusts for underestimation problems associated with low beta stocks. The inputs for the CAPM are a risk-free rate, a beta, and a market equity risk premium. The risk-free rate is the same 6.4% "normalized" Treasury yield discussed above and the average beta for his comparable risk companies is .51. Mr. Benore used both historical and projected market equity risk premiums in his CAPM analysis.

In addition to the three market-based models, Mr. Benore used a comparable earnings analysis. This method is based on the projected returns on book common equity, as reported by Value Line, for the comparable risk companies. The result of the comparable earnings method is 13.3%.

Mr. Benore noted that the proceeds to a company from the sale of common stock are reduced by issuance or flotation costs. Using flotation costs of 3% of proceeds, Mr. Benore recommended that the ROE be increased by 20 basis points.

Throughout his direct and rebuttal testimony, Mr. Benore emphasized that his DCF, risk premium, and CAPM results should be adjusted because the stock prices (market value) of his comparable risk group are above book value per share. He refers to this adjustment as "transformation." Mr. Benore believes that transformation, accomplished through an iterative process, determines the necessary, regulatory book return so that investors have an opportunity to earn their required market return. Using a mathematical example of transformation, Mr. Benore believes that, when the market price of a utility stock exceeds it's book value, the regulatory return based on a DCF model must be increased to maintain the market value of the stock.

For the comparable risk companies, the market price per share currently exceeds book value per share. Thus, Mr. Benore's transformation adjustment is an increase to the results of his models. According to Mr. Benore, the result of the comparable earnings analysis is a book-to-book test and no transformation adjustment is needed.

Mr. Benore updated his DCF, equity risk premium, and CAPM results. The updated DCF result is 12.1%. The equity risk premium result is 11.2% and the updated CAPM result is 11.1%. The comparable earnings test is 13.5%. With the transformation adjustment, the DCF result is 14.2%, the equity risk premium result is 13.3%, and the CAPM result is 13.2%. All these results exclude flotation costs.

Mr. Benore recommends 13.0% as the appropriate ROE for Gulf. He notes that flotation costs should be considered along with Gulf's lower risk compared to the comparable risk companies. Gulf's smaller size relative to the comparable risk companies also should be considered.

For his analysis, OPC witness Rothschild used Mr. Benore's comparable risk companies. Mr. Rothschild used two DCF models and two risk premium/CAPM models. He also applied a DCF model to Southern Company.

Mr. Rothschild's constant growth DCF model used stock prices as of November 30, 2001, and the average of the high and low stock price for the year ended November 30, 2001. He derived the growth rate using the retention growth method whereby the Company's retention rate - the percent of earnings not paid out as dividends - is multiplied by the future expected earned return on book equity. The results of the constant growth DCF model range from 8.86% to 9.64%. Using dividend information from Value Line and his analysis of long term growth trends, Mr. Rothschild's multi-stage DCF model produced results ranging from 9.28% to 10.73%.

For his inflation risk premium method, Mr. Rothschild used historical returns on common stocks, net of inflation, ranging from 6.60% to 7.20%. With his expected inflation of 2.0%, the mid-point cost of equity for a company of average risk is 8.90%. Using a beta of .52 for electric companies, he calculated a risk premium applicable to electric companies of 6.23%. Mr. Rothschild employed a debt risk premium method whereby he measured the equity risk premium over the yields on short-term treasury bills, long-term treasury bonds, and corporate bonds. The results of this method range from 8.94% to 10.62%.

Mr. Rothschild believes that pending recession fears currently cause the DCF to overstate the cost of equity. He notes that his inflation premium method is difficult to interpret due to the "flight to quality" impact on Treasury bond yields. He recommends 10.0% as the appropriate ROE and notes that this is conservatively high given the results of his multistage DCF model.

Mr. Rothschild disagrees with Mr. Benore's transformation adjustment. He notes that the Federal Energy Regulatory Commission (FERC) and the Federal Communications Commission (FCC) have rejected the argument. Specifically, FERC found that, when the cost of capital and interest rates decline, market prices of utility stock rise above book value per share. This occurs because the utility earns a higher ROE than that required by investors. Regulators have traditionally viewed market-to-book ratios above

1.0 as a possible indicator that the Company's return is higher than the return required by investors. The FCC found that setting the revenue requirement at investors' required return might cause the stock price to decline but "the requirement that we balance ratepayer and investor interest does not allow us to insulate investors from a diminution in the value of their stock." Mr. Rothschild believes Mr. Benore's transformation adjustment is circular because it suggests, once excessive earnings have caused the utility's stock price to increase, regulators must keep earnings at that level to prevent a decline in the stock price.

Regarding the specifics of Mr. Benore's models, Mr. Rothschild disagreed with Mr. Benore's risk premium method noting that the arithmetic average for historical returns is upwardly biased and that the geometric average should be used. Mr. Benore's CAPM result also has the problem of using arithmetic instead of geometric averages in calculating the market risk premium, according to Mr. Rothschild. Mr. Rothschild disagreed with Mr. Benore's comparable earnings model because the earned return on book equity is a separate and distinct concept of investors' required return. Regarding flotation costs, Mr. Rothschild notes that flotation costs, as allowed by FERC, are very small and similar to rounding error.

In rebuttal to Mr. Rothschild's testimony, Mr. Benore notes that Mr. Rothschild's results need a transformation adjustment to produce the return that investors require. Mr. Benore found errors and inconsistencies with Mr. Rothschild's models and results.

In particular, Mr. Benore noted that Mr. Rothschild substituted his own judgement in using a ROE of 13.0% in developing the sustainable growth rate for his DCF model. The comparable rate reported by Value Line was 13.5%. Regarding Mr. Rothschild's multi-stage DCF model, Mr. Benore again noted that Mr. Rothschild ignored the use of expected ROEs as reported by Value Line and Zacks in favor of his own judgement.

Regarding Mr Rothschild's inflation risk premium/CAPM results, Mr. Benore noted the results are untenable - ROEs below the current yield on "A" rated utility bonds. He also noted that Mr. Rothschild mixed real and nominal rates in calculating his results. Regarding Mr. Rothschild's debt risk premium/CAPM model, Mr. Benore notes that the arithmetic average of historical risk premiums, instead of the geometric average, is appropriate to reflect investors' expected risk premium. Mr. Benore also noted that certain empirical studies show that the standard CAPM underestimates investors' required returns for low beta stocks like utilities.

Using his recommended corrections, Mr. Benore recalculated the results of Mr. Rothschild's models. These results range from 11.5% to 12.4% for the DCF models and 10.6% to 11.6% for the risk premium/CAPM models. Mr. Benore noted these results are before flotation costs and transformation.

Regarding risk premium methods, Mr. Rothschild and Mr. Benore disagree on the calculation of the historical risk premium, specifically on whether a geometric average or an arithmetic average should be used. We find that prospective risk premium analyses are more appropriate because historical risk premiums rely on earned returns instead of investors' required returns. Historical, earned returns can and do vary significantly from current, required returns. Also, both calculations of historical risk premiums include periods when returns on debt exceeded returns on common stock, i.e., periods of negative risk premiums. In his CAPM, Mr. Benore used both prospective and historical risk premiums.

We reject the transformation adjustment to ROE recommended by Mr. Benore. Given current market conditions in which prices of utility stocks exceed the book value per share, the transformation adjustment is convenient for utility witnesses because it results in an increase beyond the results of ROE models. In the past, when prices of utility stocks were below book value per share, Mr. Benore did not recommend the transformation adjustment. He apparently became aware of the supposed need for the adjustment when utility stock prices exceeded book value.

Though Mr. Benore states that he would make the adjustment if utility stock prices fell below book value, it is not known whether that situation will recur in the foreseeable future. The market price-to-book ratio of the comparable risk companies is approximately 1.38. At the same time, Mr. Benore testified that utility stocks have underperformed the market.

In addition to these shortcomings, both the FCC and the FERC have rejected the transformation adjustment. See FERC Docket RM87-35-000, P. 3348 of the Federal Register/Vol. 53, No. 24, Friday Feb. 5, 1988; FCC Docket 89-624, Order 90-315, P. 15, Sep. 19, 1990. These decisions note that a utility may earn a return higher than that required by investors, causing the stock price to exceed book value. Resetting the allowed return at the investors' required return may cause the stock price to decline but the required return is reasonable and balances the interests of ratepayers and investors. Further, the FCC decision suggested investors may have anticipated and discounted reductions in the utility's ROE so that the reduction would have no effect on the stock price.

Regulators may not be capable of maintaining a certain market price to book value ratio for a utility, even if they wanted to do this. We note that book value of utility stocks, and stocks in general, can be affected by one-time changes in accounting rules. The market price-to-book ratio may be substantially outside the influence of regulators.

Mr. Rothschild disagreed with the growth rates that Mr. Benore used in his DCF model. In particular, Mr. Rothschild notes that the long-term growth rate is based on 5-year earnings per share forecasts by analysts. Mr. Rothschild believes this results in projecting a continued increase in the cost of equity. We note that dividend growth is less volatile than earnings growth.

We agree with Mr. Benore that some of the results of Mr. Rothschild's models are untenable. We also agree that the standard or simple CAPM may underestimate the cost of equity for low beta stocks. Further, we agree with Mr. Benore that Gulf has lower regulatory risk compared to the comparable companies and that Florida's adjustment clauses reduce risk.

Regarding flotation costs, we agree with Mr. Benore that these costs should be included in the ROE. The Hope and Bluefield decisions mandate a return that can attract capital, and flotation costs are a necessary part of attracting capital. See Federal Power Comm'n, et al. v. Hope Natural Gas Co., 320 U.S. 591 (1944); Bluefield Water Works & Improvement Co. v. Public Service Comm'n, 262 U.S. 679 (1923). We find that Mr. Benore's allowance of 20 basis points for flotation cost is reasonable.

Mr. Benore bases part of his recommendation on his opinion that Gulf is a small company, a point with which Mr. Rothschild disagrees. We note that Gulf has an "A+" bond rating by Standard and Poor's. We believe that companies that can issue rated debt should not be considered small, even though Gulf is smaller than the comparable risk companies. We agree with Mr. Benore that Gulf should be treated on a stand-alone basis for purposes of deciding the ROE issue.

We note that determination of the appropriate ROE is ultimately a subjective process. Considering Mr. Benore's updated results without the transformation adjustment, and Mr. Benore's adjustments to Mr. Rothschild's results, we find the appropriate range for Gulf's ROE is 10.8% to 11.8%, and we choose 11.75% as the appropriate ROE for Gulf. We note that Mr. Benore used stock prices from November 27, 2001, to December 27, 2001, in his updated results. We further note that this update resulted in a moderate increase in the cost of common equity. Recognizing this moderate increase along with Gulf's reasonable equity ratio of 47% and it's A+ bond rating, we believe an ROE near the top of the reasonable range is appropriate.

E. <u>REWARDS FOR GULF'S PAST PERFORMANCE AND INCENTIVES FOR GULF'S FUTURE PERFORMANCE</u>

Several issues in this docket addressed whether Gulf should be rewarded for its high quality of service or penalized if its service deteriorated to something less than adequate. Specifically, those issues were: 1) whether we should establish a mechanism that would provide payment or credit to customers if Gulf had frequent outages in the future; and, 2) whether Gulf should be rewarded for its current and past high quality of service in the form of an adder to the mid-point ROE and/or a broader range on equity.

During his live testimony, Mr. Bowden proposed an earnings sharing plan that incorporated some of the same issues identified above. His proposal was very general and we asked Gulf to file a late-filed exhibit filling in the details of the plan and demonstrating that those details were in the evidentiary record. The parties were given an opportunity to respond to the late-filed exhibit, identified as number 25, by filing comments after a two week review period.

OPC and FIPUG claimed that the details contained in the late-filed exhibit were not contained in the evidentiary record. They argued that to allow the late-filed exhibit to be moved into the record would violate their due process rights because they would have had no chance to conduct discovery, file testimony, or conduct cross-examination on the contents of the late-filed exhibit. We agree, and thus the late-filed exhibit shall not be entered into the record.

As a result, we will address the issues of penalties and rewards individually, as they were raised during the course of the proceeding. We note that the earnings sharing plan included components not addressed in this proceeding, and that the idea of a comprehensive plan has merit. We also believe it is beneficial for OPC and other interested parties to participate in shaping such a plan. For these reasons, Gulf shall have until July 26, 2002, to file a petition for approval of an incentive sharing plan.

The issues related to rewards and penalties are discussed below.

1. <u>Performance Based Incentives to Promote High Quality Service in the Future</u>

Staff witness Breman proposed an incentive mechanism to promote reliability of service. The mechanism involves routine reporting of the measurement of Customers Experiencing More than Five Interruptions (CEMI5). His proposed annual minimum performance standard for Gulf is a CEMI5 of 2 percent. The Company would fail this standard if more than 2 percent of its customers experienced more than 5 interruptions a year. Based on the proposed mechanism, Gulf would be required to make an annual refund to its retail customers when CEMI5 exceeds 2 percent in any consecutive 12 month period. This penalty for poor performance is capped at the equivalent of 10 basis points of ROE.

Gulf argued that a penalty mechanism is unnecessary because the Company has demonstrated a record of good performance and a commitment to satisfying its customers. Gulf witness Fisher cited the results of customer surveys and distribution reliability indices to demonstrate its record of good performance in customer satisfaction and distribution reliability. In addition, Mr. Fisher argued that Gulf's commitment comes willingly.

We find that Gulf's arguments are not sufficient to support its position. A company's past performance and stated commitment to customer satisfaction do not obviate the need for a minimum performance standard, and incentives for a company to maintain such a standard in the future. If willing commitment could be an argument against a penalty, it could also be an argument against a reward, which would contradict Gulf's position on its proposed ROE adjustments.

Although Gulf has proven its capability to achieve a CEMI5 of 1 percent in 2001, Gulf appears to believe that it could be penalized by the standard of 2 percent CEMI5. We believe that a performance guarantee would be a more concrete form of commitment.

The idea that a proactive incentive approach is more effective than a reactive intervention approach is unchallenged in the record. The evidence suggests that our intervention in 1997, after several years of declines in distribution reliability, resulted in improved distribution reliability. Although the intervention was a reaction to poor performance by other companies, the collaborative efforts of the utilities and our staff have improved reliability performance statewide, including Gulf's. Similarly, we believe a well designed proactive incentive mechanism will be effective whether a company has demonstrated poor performance or not.

At the hearing, Gulf witness Bowden proposed, in his live testimony, a performance based concept that would provide rewards and sharing of earnings based on performance ratings and availability of earnings. Mr. Breman testified that he is not opposed to rewards for future performance if there is a balanced "carrot and stick" approach with properly defined standards. We find that both penalty and reward provisions should be addressed in a performance based mechanism and such a mechanism should be based on future instead of past or current performance. This is one reason why we invited Gulf to file a petition for approval of an earnings sharing plan.

Gulf's major concern is that Mr. Breman's proposed incentive mechanism offers no opportunity for a reward. Gulf also expressed a number of other concerns about the specifics of Mr. Breman's proposed mechanism. First, Mr. Fisher argued that to use a single indicator of reliability could cause Gulf's focus to shift away from other measures which Gulf deems more effective. Second, Gulf suggested that a number of factors that might affect customer interruptions (CEMI5), such as weather and accidents, are outside the utility's control. Finally, Gulf suggests that the administrative costs for such a program could be substantial and these dollars could be better spent to correct the reliability problem.

First, we find that CEMI5 is too narrow a measure to assess performance adequately. Other meaningful measures of distribution reliability such as average minutes of interruption should also be considered. We believe that combining price and service performance measures to form a composite customer value indicator is a good idea.

Second, we find that factors outside of Gulf's control should be considered. Such factors may act to Gulf's benefit or detriment. Extreme weather conditions such as named storms are currently excluded from distribution reliability performance calculations. However, Gulf frequently points to its low rates as a benefit to its customers and a factor that should be considered in granting rewards. Gulf does not mention that its geographic location contributes to its low rates. We believe that all these factors should be considered when establishing performance based incentives. Third we find that administrative costs should be considered.

In summary, we find that Mr. Breman's proposal may be appropriate as a component of a comprehensive incentive mechanism, but alone it is not adequate. We believe that an incentive plan should include both rewards and penalties. A properly balanced incentive mechanism cannot be established at this time. That is why we offer Gulf the opportunity to file a petition for approval of an incentive plan.

2. Adjustment to Return on Equity to Reflect Gulf's Performance

Gulf contends that it deserves an upward adjustment to its return on equity (ROE) as a reward for its continuing high level of performance in customer satisfaction, customer complaints, transmission and distribution reliability, and generating plant availability. Gulf's position is that increasing the ROE sends a message to the Company and the customers that superior performance is important. Furthermore, such an increase provides an incentive to continue to provide superior service. Gulf notes that staff witness Breman supports the concept of rewarding a utility for providing superior service.

FIPUG opposes an upward adjustment to ROE. FIPUG contends that Gulf operates under the current regulatory bargain and should not be further rewarded.

The testimony of Gulf witnesses Labrato and Fisher demonstrates that Gulf's service is excellent. In addition, testimony of customers at the customer service hearings was very favorable. We find that Gulf's past performance has been superior and we expect that level of performance to continue into the future. In recognition of this, we find that Gulf deserves to have 25 basis points added to the mid-point ROE of 11.75%. Thus, a 12% ROE shall be used for all regulatory purposes, including, for example, implementing the cost recovery clauses and allowances for funds used during construction.

3. Range on ROE

Gulf witness Bowden proposes to expand the range for ROE from the traditional 100 basis points on either side of the ROE mid-point to 150 basis points or more. We note that the record for this issue is more qualitative than quantitative. Mr. Bowden and Gulf witness Labrato provided only general statements supporting a wider range. Two reasons they cited were: 1) an expanded range for Gulf, according to Mr. Bowden, would encourage the high level of service; and, 2) an expanded range would aid Gulf in retaining its credit rating. We find that the record in this case does not contain specific evidence on how the expanded range would enhance the Company's bond rating.

Mr. Bowden provided a third reason for expanding the range. In his summary of his direct testimony, he stated:

> As I mentioned earlier, regulatory commissions are considering incentive-based approaches. I think to recognize our superior performance and the importance of continuing that performance in the future, at the low rates that I mentioned on page 7 of my testimony, I suggest two thoughts for the Commission's consideration: One is to increase the return on equity by some 50 to 100 basis points. The second one is to consider expanding the Commission's range that it uses from two hundred basis points to three hundred basis points.
>
> I believe these suggestions could be included in an incentive sharing plan, a plan that would be based on the performance measures that incent this company to provide highly reliable service at low rates with high levels of customer satisfaction.

We have historically allowed 100 basis points on either side of the ROE mid-point used to set rates. Gulf's current authorized ROE is 11.5% with a range of 10.5% to 12.5%. See Order No. PSC-99-1970-PAA-EI, issued October 8, 1999, in Docket No. 991487-EI. In recent gas rate cases, we set the range at 100 basis points around the ROE mid-point. See Order No. PSC-00-2263-FOF-GU, issued November 28, 2000, in Docket No. 000108-GU; see also Order No. PSC-01-0316-PAA-GU, issued February 5, 2001, in Docket No. 000768-GU.

We find that increasing the range should be the subject of an incentive plan addressed in a future proceeding. We also find that the range shall be set at 100 basis points because no witness has provided specific reasons for quantifying a specific range, either more or less than 100 basis points. Therefore, using 11.75% as the mid-point ROE, the range on ROE shall be 10.75% to 12.75%.

F. WEIGHTED AVERAGE COST OF CAPITAL

The appropriate weighted average cost of capital including the proper components, amounts, and cost rates associated with Gulf's projected test year ending May 31, 2003, is 7.92%. Gulf specifically identified the balances for ITCs, deferred income taxes, and customer deposits.

Based on the stipulations among the parties, the appropriate cost rate of long-term debt is 6.44% and the appropriate cost rate of short-term debt is 4.61%. The cost rate for preferred stock is 4.93%, and the cost rate for customer deposits is 5.98%. The deferred taxes should have a zero-cost rate. The cost rate for ITCs is 8.99%, based on the weighted average cost of investor's capital. For rate setting purposes the cost rate for common equity is 12.00%.

Using the Company's reconciled capital structure, we made the following three adjustments to the Company's jurisdictional capital structure. First, due to the change in depreciation, a specific adjustment of $662,000 to deferred taxes was made. Next, specific adjustments were made to reconcile investor sources with Exhibit 11. Finally, a pro-rata adjustment was made over investor sources to reconcile capital structure to rate base.

Based on the relative amounts of investor capital, ITCs, deferred income taxes, customer deposits, and the respective cost rates, discussed above, the resulting weighted average cost of capital is 7.92%. Attachment 2 shows the components, amounts, cost rates and weighted average cost of capital associated with the May 31, 2003, projected test year capital structure.

VI. NET OPERATING INCOME

A. ZERO BASED BUDGET

Gulf Witness Saxon testified that the financial forecast is the basis for Gulf's projected data for the test year used in this rate case. The financial forecast is comprised of eight individual budgets: Construction, O&M, Interchange, Fuel, Revenue, Customer, Energy, and Peak Demand. Each of these budgets is reviewed and approved by the Company's Leadership Team, consisting of Gulf's executive officers.

The budget process begins with five major functional areas that are broken into 29 individual planning units. These planning units provide input into each of the eight individual budgets mentioned above. Each individual planning unit uses a modified zero based budget which gives the planning unit the ability to build its budget program each year.

Staff witness Bass testified that each planning unit develops its budget by FERC Subaccount. Each planning unit maintains supporting documentation for these developed amounts. If the planning unit is unable to develop budgeted amounts for a given expenditure, then inflation rates or customer growth rates may be used.

Corporate Planning reviews submittals for compliance with the Company guidelines and compiles the data for review by the CFO and leadership team. Any changes are documented and then the approved budget is sent to the planning units. Each planning unit monitors its budget to an actual comparison, using the accounting on-line system referred to as Southern Financial Information Access System (SOFIA). Quarterly reports are required that explain any variance of plus or minus 10 percent when the variance amount is greater than or equal to $25,000. Year-end projections are also received from each planning unit.

OPC stated in its brief that Gulf's budgeting process has resulted in numerous illogical results, such as those for substation maintenance expense, tree trimming expense, and pole line inspection expense. OPC observes that many account balances have been in a constant gradual growth pattern for years only to expand by an unprecedented increase in the projected test year. OPC maintains that any utility has the ability to "load up" the test year for setting rates, but this Commission must decide whether the projected activity will be the new norm. In other words, it is OPC's position that Gulf has the discretion to unilaterally decide to engage in the activity projected for the test year, but that fact alone does not make those activity levels representative of Gulf's ongoing future needs.

We find that Gulf's modified zero based budget shall be accepted. Staff's audit report (Exhibit 47) provided a disclosure on the budget process; no exceptions were taken. In addition, after the adjustments made in related issues are coupled with Gulf's budget, the projected test year budget resulting from the zero based budget methodology appears reasonable and appropriate.

B. OPERATION AND MAINTENANCE EXPENSE

Operation and maintenance (O&M) expense is a fallout calculation based on our decision in the following sections, as shown in Attachment 3. The appropriate level of O&M expense is $180,731,000.

C. SECURITY MEASURES

As discussed in Part IV, Section F, above, Gulf's MFRs and direct testimony were filed on September 10, 2001, and do not contain the impact of the increased threat of terrorist attacks since September 11, 2001 on test year operating expenses. Through discovery, Gulf provided information on these expenses. The discovery responses were granted confidential classification in Order No. PSC-02-0220-CFO-EI, issued February 22, 2002, in this docket.

Gulf Witness McMillan stated in his rebuttal testimony that premiums for the Company's all-risk property insurance policy, which covers both generating plants and general plant, increased by $380,000 (system) as a result of the terrorist events of September 11, 2001, and the deductible increased from $1 million to $10 million. In addition, Gulf elected to self-insure for property losses between $2 million and $10 million at an estimated cost of $243,000 per year (system). The sum of these property insurance expense adjustments is $578,000 ($623,000 system).

We find that the adjustment for depreciation expense related to the rate base security adjustments described in Part IV, Section F is $101,000 ($105,000 system). In addition, we find that the additional security-related operating expenses, not specified above, but approved for confidential treatment, are reasonable and appropriate. Those additional expenses are $166,000 ($173,000 system). The sum of the incremental property insurance expenses, depreciation expense, and other confidential expenses related to the increased terrorist threat for the test year is $845,000 ($901,000 system). Thus, we find that a jurisdictional adjustment (increase) of $845,000 ($901,000 system) should be made to test year operating expenses to reflect the cost of additional security measures implemented in response to the increased threat of terrorist attacks since September 11, 2001.

D. ADVERTISING EXPENSES

Gulf requested recovery of $1,145,000 in advertising expenses in the projected test year. Gulf seeks to recover $595,000 (system & jurisdictional) in advertising for Customer Service and Information Expense. Gulf also seeks to recover $550,000 ($539,000 jurisdictional) for Corporate Communications and Advertising.

Gulf witness Neyman explained that the utility has a two-step advertising expense philosophy. The first step is to develop trust, loyalty, and confidence in the utility. Once the customer believes in the utility, then the second step is to advertise to affect the customers' behaviors.

In its brief, OPC stated that advertising expense for corporate image building has been disallowed in the past because the ratepayers of any regulated utility are customers that are provided services in a monopolistic environment. Consequently, these customers cannot exercise a choice as to whether or not to pay for such advertising expenses.

OPC noted that its witness, Ms. Dismukes, pointed out that the requested advertising expense of $550,000 is purely image-enhancing in nature because the examples of ads do not inform the customers about products or services nor do they assist customers in any way. Ms. Dismukes explained that these ads are the type that have been disallowed.

Under cross-examination, Ms. Neyman agreed that the ads that the utility was requesting recovery for did not promote the utility's products and services but supported the efforts of the utility in an indirect way. She explained that the ads in the historical year ended December 31, 2000, were the same type of advertisements disallowed in the last rate case and would be the same that would be used in the projected test year. Further, Ms. Neyman is asking us to reconsider our past position on this type of advertising.

Ms. Dismukes testified that Order No. 6465, issued January 17, 1975, disallowed advertising expense related to enhancing the Company's image, and goodwill-type advertising. Ms. Dismukes referred to the ads in "Part C" of Exhibit 22 and states that these ads have been disallowed by Order No. 6465.

Contrary to Ms. Neyman's suggestion, Ms. Dismukes noted that not one of the ads in Part C of Exhibit 22 informs the customer about products and services available to assist customers "in making their home and businesses more enjoyable, comfortable and safe and provide for operation which is more energy efficient and, therefore, cost efficient." Ms. Dismukes further asserted that the ads do nothing to educate customers. The ads merely enhance Gulf's image with the customers.

Ms. Dismukes further noted that in Order No. PSC-96-1320-FOF-WS, issued on October 30, 1996, in Docket NO. 950495-WS, the Commission disallowed advertising costs related to image enhancement. Consequently, Ms. Dismukes argued that $550,000 in advertising expenses be disallowed.

Staff Witness Bass testified the utility removed $226,000 for image enhancing ads for the historical year, 2000, but did not remove $550,000 for image enhancing ads in the projected test year.

Mr. Bass identified two problems with Gulf's request to recover the cost of image enhancing ads in base rates. First, it runs afoul of Order No. 6465, issued January 17, 1975, in Docket No. 9046-EU. Docket No. 9046-EU was a general investigation into promotional practices of electric utilities. The order expressly disallows, for rate making purposes, "[a]dvertising which has as its primary objective the enhancement of or preservation of the corporate image of the utility." Recovery of image enhancement expenses was disallowed in Order No. 6465 because:

> Most, if not all, of this advertising is merely designed to improve the image of the utility in the eyes of the public. It has not been proven, in our judgment, that

> such programs reduce operating costs or result in greater operating efficiency nor do we see any tangible benefits to the customers.

The second problem Mr. Bass identified with Gulf's request was that the cost of image enhancing advertising increased dramatically from the historical year, 2000, to the projected test year. Gulf spent $226,000 on image enhancing ads in 2000 but requested $550,000 for the projected test year.

Under cross examination, Mr. Bass identified only one requirement that need be present in an ad in order to recover the full cost of the ad. The requirement was that the ad offer any information on conservation, safety or electric efficiency. Thus, even if the ad was also image enhancing, the full cost of the ad could be recovered if it also included, for example, the GoodCents logo. Mr. Bass also explained that if the ads contained information pertaining to conservation, safety, or customer information, the ad was allowed. Further, Mr. Bass agreed that the customer should not have to pay for image enhancing ads because the customer does not have a choice of electric utilities and to change this policy would break precedent established in Order No. 6465.

Under cross-examination, Ms. Neyman noted that Commission Order No. PSC-96-1320-FOF-WS, issued on October 30, 1996, in Docket NO. 950495-WS, stated:

> However, we recognize that the utility's conservation efforts need to gain support and trust from its customer in order to be successful.

Again, Ms. Neyman explained that these ads are critical to the success of Gulf's conservation programs.

OPC argued, that Mr. Bass disagreed with Ms. Neyman's premise about the need for the recovery of indirect advertising expense. OPC noted that Mr. Bass did testify that Gulf could communicate the substance of its educational messages, without engaging in these image enhancement types of advertising.

Gulf argued that Mr. Bass said that if the Commission should choose to change its policy that he would no longer have a concern with the Company's requested advertising expense being included in base rates. Gulf also argued that times have changed since Order No. 6465 because today's ads are focused on educating the consumer regarding product and services available to ensure the efficient use of energy.

We find that the Orders 6465 and PSC-96-1320-FOF-WS dictate that the cost of advertising that is purely image enhancing should not be recovered through base rates. Order No. PSC-96-1320-FOF-WS states:

> We agree with OPC that advertising expense only for image enhancement purposes should not be borne by the ratepayers.

However, that Order clearly acknowledged that it may be impossible to distinguish between advertising expense for image enhancement and advertising expense for public education and conservation. We allowed recovery of the advertising expense because it was not purely image enhancing. Rather, the advertisements were such that a single purpose for the ads could not be isolated.

We note that under Order 6465, the cost of ads that are both image enhancing and educational can be allowed in rate base. It is only ads that are purely image enhancing that are not allowed in rate base. The Orders are not in conflict.

We find that the ads in Part C of Exhibit 22 are purely image enhancing. Gulf does not refute this. For this reason the cost of the ads shall not be included in base rates, and Gulf shall not be allowed to recover the advertising expense of $539,000 ($550,000 system). The utility shall recover advertising expenses of $595,000, in Account 909, for Customer Service and Information Expense in the test year.

E. <u>ACCRUAL FOR INCENTIVE COMPENSATION</u>

OPC witness Schultz testified that the gross payroll and fringe benefits on Schedule C-33 in the MFRs included all compensation and benefits. Mr. Schultz further stated that the 2000 historical test year costs included an accrual of $10.8 million for bonuses or performance pay, which was an 83% increase over 1999. Mr. Schultz also compared the accrual for the compensation plan with the total gross payroll and fringe benefits and stated that the compensation plan was material to the total gross payroll and fringe benefits. Witness Schultz recommended disallowing the accrual and reducing expenses by $4,917,000.

Gulf witness Bell testified that Gulf's compensation philosophy is centered on the need to attract, retain, and motivate talented employees. In order to achieve these goals, Mr. Bell stated that Gulf offers a compensation plan that consists of base salaries and incentive compensation. Mr. Bell explained that base salaries are targeted at or near the median of a similar group of salaries. The additional incentive pay plan above the base pay allows the employees an opportunity to earn in the top quartile of the industry.

Mr. Bell asserted that in order to keep the employees focused on their performance, the incentive compensation must be re-earned each year. Mr. Bell explained that even though the incentive compensation portion for an individual employee may decline, the utility's total compensation expense will remain relatively constant over time because the base salaries rarely decline in amount. Therefore, the utility offers total pay that is market competitive. Lastly, only through performing well and meeting customer needs do employees have the opportunity to be paid at the top quartile of the industry.

Each year Gulf conducts an analysis of overall compensation using compensation surveys that are developed by independent consulting firms. Current analysis of these approximately 40 surveys shows that the utility's pay for each position is both consistent with its compensation philosophy and the current market.

On rebuttal, Gulf Witnesses Silva and Twery testified that Mr. Schultz's concerns were unfounded because the comparison of incentive compensation to gross payroll and fringe benefits is inappropriate. It is more appropriate to evaluate Gulf's total cash compensation against the market to insure competitiveness. The survey data (approximately 40 surveys) provides total cash compensation for various jobs in the relevant market.

Witnesses Silva and Twery explained that to ensure Gulf's pay policy is competitive, Gulf produces a Market Position report on an annual basis. Organizations are considered to be "at market" if their pay policy falls between +/- 10% of the market. An analysis of Gulf's pay policy to the market was conducted in August of 2001. The report confirmed Gulf's total compensation pay policy was within +/-5% for all job groups, on average, to the actual market pay levels.

Gulf's philosophy is to pay employees at the 75th percentile. To only receive a base salary would mean Gulf employees would be compensated at a lower level than employees at other companies. Therefore, an incentive pay plan is necessary for Gulf salaries to be competitive in the market. Another benefit of the plan is that 25% of an individual employee's salary must be re-earned each year. Therefore, each employee must excel to achieve a higher salary. When the employees excel, we believe that the customers benefit from a higher quality of service.

We believe that OPC's adjustment to remove the increase in costs from 1999 to the 2000 historical test year is not justified. The utility did implement a new incentive compensation plan in 2000. Also, to compare the total incentive "cash" compensation to gross payroll is not a valid comparison. The total compensation plan should be compared to the market value for similar job groups.

We also believe that to analyze each individual's compensation for whether the base salary and incentive compensation, within each job group, is appropriate would be beyond the scope of the data collected from the individual utilities in the industry. Lastly, the utility is within +/- 5% of the market values for their overall compensation policy. As a result, its employees will be paid based on market value and the customers will receive quality service and low rates.

Based on the above, no adjustment shall be made to the accrual for incentive compensation.

F. <u>EMPLOYEE RELOCATION EXPENSE</u>

Gulf's employee relocation plan covers a variety of costs involved in moving an employee and the employee's family. These costs include cost of living allowances, transportation, household goods moving and storage cost, closing costs, and other associated costs. The Company included in projected test year expenses $461,754 for employee relocations. The Company stated that it budgets relocation expenses based on the previous four years actual relocation expenses escalated for inflation.

In Gulf's last rate case, the $324,100 budgeted for relocations was found to be too high and was reduced. See Order No. 23573, issued October 3, 1990, in Docket No. 891345-EI. In that Order we found that a reasonable approach was to use a four year average. Actual amounts were used in calculating the average and the average was not escalated for inflation. This approach was used because relocation expenses show wide variations from year to year and cannot be neatly extrapolated like salaries or plant maintenance expenses. For example, in this case the Company expensed $371,664 in 1997 to relocate nine employees or $43,516 each, compared with $335,664 in 1998 to relocate thirteen employees or only $27,179 each.

Based on Order No. 23573, we find that relocation expenses shall be reduced $15,832 ($16,832 system) based on a four year average of expenses. This adjustment reduces the Company's projected relocation expenses from $461,754 to $445,922.

G. SALARIES AND EMPLOYEE BENEFITS

OPC witness Schultz, testified that the projected test year had an increase of 48 employees and that he agreed with the 29 additional employees needed for Smith Unit 3. Mr. Schultz further stated that the remaining increase of 19 positions in the projected test year were not explained because in 1998 downsizing was the trend. In 1999, eight positions were added and in 2000 only five positions were added. Mr. Schultz emphasized that the utility should not have incorporated a significant increase in employee complement without providing any justification for the increase. Lastly, Mr. Schultz testified that an adjustment should be made to reduce payroll expense by $701,410, fringe benefits should be reduced by $131,177, and payroll tax expense should be reduced by $58,475 in order to remove the 19 positions from the projected test year.

On rebuttal testimony, Gulf witness Saxon testified that the projected test year expenses include additional expense for six cooperative educational students, 11 positions in Power Delivery for which employees are trained in an earned progression program, and two positions in the Company's Leadership Development program. Therefore, Mr. Saxon stated that these 19 positions should not be removed from the projected test year.

We find that the 29 positions are needed for Smith Unit 3. The utility should have positions in which the employees are trained in Power Delivery so that the qualified employees can fill vacant positions and power delivery will be uninterrupted. In addition, a Leadership Program is essential for the development of qualified employees as well as a qualified management team.

Gulf projected a test year complement of 1,367 employees. Mr. Saxon stated in his deposition, Exhibit 21, that the Company did not take into account a hiring lag in projecting the 1,367 employee complement. A hiring lag is the length of time before an employee is hired to fill a vacant position. Mr. Saxon further agreed that it would be appropriate to include a hiring lag adjustment that would reduce the projected payroll expenses. Mr. Saxon filed a late-filed exhibit to his deposition that reflected a hiring lag equivalent to 34 employees, and this hiring lag would reduce projected O&M expenses by $323,635, ($330,628 system) including fringe benefits and a payroll tax adjustment of $19,274 ($19,690 system). We find that the hiring lag adjustment is consistent with a similar adjustment made in the Company's last rate case, Order No. 23573.

Based on the above, projected O&M expenses shall be reduced by $323,635 ($330,628 system) and payroll taxes be reduced by $19,274 ($19,690 system).

H. TRANSACTIONS WITH AFFILIATED COMPANIES

Gulf is a wholly owned subsidiary of Southern Company, which is the parent company of five southeastern utilities and other direct and indirect subsidiaries. The Public Utility Holding Company Act (PUHCA) regulates Southern Company and its subsidiaries. With the exception of Southern LINC, all affiliates provide services and materials to Gulf at cost in accordance with

PUHCA. Southern LINC provides telecommunications services to Gulf at market cost.

Contracts among the southeastern utilities related to jointly owned generating facilities, interconnecting transmission lines, and the exchange of electric power are regulated by the Federal Energy Regulatory Commission (FERC) or the Securities and Exchange Commission (SEC). Southern Company Services (SCS), the system service company, provides at cost specialized services to Southern Company and its subsidiary companies. SCS services include general executive and advisory services, engineering, purchasing, accounting and auditing, finance, marketing and public relations, insurance, rate, employee relations, and, in the case of the operating utilities, power pool operations. All SCS costs are either directly charged or allocated to Southern's affiliates through a work order system.

The SCS allocation methodology is approved and periodically audited by the SEC. All of the allocation methods are derived from system statistics that reflect the size of each company relative to the entire Southern Company. Percentages for these allocation methods are updated annually by Gulf. To derive the allocation factors, Gulf uses historical statistics based on a single year with a one-year lag; therefore, 2001 allocations were based on 1999 statistics.

The allocation factors applied by the Company in its MFRs were based upon 1999 data. OPC witness Dismukes testified that because Gulf's allocation factors do not reflect the high growth of its non-regulated affiliates for the period 1999 to 2003, Gulf's customers will end up subsidizing non-regulated activities. Therefore, Ms. Dismukes modified the allocation factors to include additional allocations to Southern Power Company (SPC), a new subsidiary that the Southern Company expects to grow at a rate of 15% per year. SPC will own, manage, and finance wholesale generating assets in the Southeast.

Ms. Dismukes modified data to reflect what could be expected for SPC in 2003. The fossil allocation factor, which is based upon the KW capacity of the various companies' plants, was modified to recognize the expected generation from SPC in 2003. There were several allocation factors where 2003 information was not readily available. For these factors, Ms. Dismukes adjusted the amounts for SPC by increasing them by a factor of seven based upon the relationship between the 2001 KW capacity of SPC compared to the KW capacity expected for SPC by 2003. For allocation factors where no information for SPC was available (e.g., for allocation factors that use employees as the allocation basis) Ms. Dismukes adjusted the factor for Gulf downward by the average of the change in all other allocation factors where data was available.

In addition, Ms. Dismukes removed the revenue component from two allocation factors that included revenue, expenses, and investment as components. She believes that including revenue in these two factors underallocates costs to new non-regulated companies because new companies in the start-up phase of operations produce little revenue relative to investment expenses. Allocation factors that used customers as the basis were not modified. Ms. Dismukes' factors did not reflect increases for growth in the other non-regulated companies. The above adjustments to the allocation factors resulted in Ms. Dismukes recommending a reduction in costs allocated to Gulf of $1.4 million.

Gulf witness McMillan testified that the amounts used to project O&M related to affiliate transactions were based upon the best information available at the time Gulf prepared the test year data for the original filing in this case. He believes that Ms. Dismukes' modification of the allocation factors using projected or estimated 2003 data for SPC is flawed by numerous errors and inappropriate assumptions.

Mr. McMillan stated that components of allocation factors reviewed and approved by the SEC can not be arbitrarily changed. Another criticism he had of Ms. Dismukes' testimony was that overall increases in total SCS allocated costs were ignored, as were changes in other affiliates' statistics; these allocations may offset the impact of adding SPC into the allocation. For example, while increasing capacity related allocations to include SPC, the increase in capacity related to Gulf's Smith Unit 3 and other Southern generating capacity additions were ignored. It appears that Mr. McMillan's position is that increasing the capacity factor for SPC and the other affiliates would reduce the amount allocated to Gulf while increasing the factor for Gulf would increase the allocation to Gulf.

In addition, Mr. McMillan stated that Ms. Dismukes assumed that all allocated costs were charged to O&M expense, when in fact, her proposed adjustment to O&M included capital and below-the-line charges. Mr. McMillan disagreed with Ms. Dismukes' use of a factor of seven to estimate some of SPC's statistics. He stated that there is no basis for using such a factor because there is no support for a correlation in the relationship between the increase in SPC's KW capacity and the statistics. A larger portion of SCS's costs were allocated to SPC by using this methodology.

Mr. McMillan further noted that the period of time selected by Ms. Dismukes, calendar year 2003, extends beyond the test year which ends in May of 2003, and she incorrectly assumes that SPC should receive allocations for all SCS activities except those based on customers. For example, she failed to exclude activities, such as transmission and distribution related activities, which are not related to generation, and therefore not applicable to SPC.

Mr. McMillan tested the reasonableness of the projected test year allocated amounts by looking at two scenarios. First, he updated the allocation factors to include year 2000 data, the most current historical data available, which reflects the inclusion of SPC. These factors were applied to the 2003 projected test year amounts used in preparing the MFRs. Next, he compared the test year SCS O&M amounts to the recently completed SCS 2002 budget. In both cases, the amount allocated to Gulf was more than the amount included in the projected test year. Therefore, Mr. McMillan concluded that the projected test year O&M expenses related to affiliated transactions are conservative, and are understated.

In the 2003 projected test year, $20,420,000 of SCS costs (capital, expense, and below-the-line charges) were allocated to Gulf. Ms. Dismukes made many assumptions, projections, and estimates in modifying the allocation factors she applied to the 2003 SCS costs.

We find that Mr. McMillan's evaluation of Ms. Dismukes' modifications is correct. In particular, we are influenced by the fact that costs were allocated to SPC for all SCS activities when SPC should not have received allocations for transmission and distribution. SPC owns generation only, therefore costs related to transmission and distribution are not applicable to SPC. This would incorrectly reduce allocations to the other affiliates.

We also find that the components of the SEC approved allocation factors should not be changed. When Gulf desires to change its allocation methodology, approval must be obtained from the SEC. By removing the revenue component, Ms. Dismukes' factors are no longer in compliance with SEC approved methodology.

In addition, we find that in order to calculate the appropriate allocations, statistics for all the affiliates should reflect the same time period in accordance with the matching principle. If factors are updated to reflect 2003 statistics for SPC, then the factors should be updated to reflect 2003 statistics for all the affiliates in order to create a level playing field and to fairly allocate costs. Total SCS costs will also be increased by updating to 2003, amounts and some affiliates will have increases while others will have decreases to their statistics as a result of changes in 2003. It is not appropriate to pick and choose which affiliates' statistics to update.

Further, Ms. Dismukes allocated costs that should have been capitalized or recorded below-the-line. This would incorrectly increase O&M expenses for all affiliates. Finally, we find that the use of a factor of seven to increase SPC amounts and adjusting some factors downward by the average of the change in all other allocation factors is arbitrary. There is no true correlation between these measures and the statistics to which Ms. Dismukes applies them.

Based on the above, we find that the level of allocated costs included in the 2003 test year is reasonable and representative of future costs. No adjustments are necessary.

I. ACCRUAL FOR PROPERTY DAMAGES

Gulf included in projected test year expenses, $3,245,000 ($3,500,000 system) for the accrual to the Accumulated Provision for Property Insurance (reserve). The accrual, which was approved in Order No. PSC-96-1334-FOF-EI, issued November 5, 1996, in Docket No. 951433-EI, increased the reserve balance at the end of the projected test year to $16.5 million, including projected charges to the reserve. In his rebuttal testimony, Gulf witness McMillan testified that the projected charges to the reserve were based on very conservative estimates, for example, no costs were projected for hurricane damages. Mr. McMillan further testified that as a result of the terrorist events of September 11, 2001, property insurance costs increased. Premiums for its insurance policies covering its generating and general plant increased $380,000 or 60% while increasing uninsured deductibles $1 million. Mr. McMillan states that this increase in uninsured deductibles will increase future charges to the reserve.

OPC witness Schultz testified that the Company's authorized annual accrual of $3,500,000 since 1996, and average annual charges against the reserve of $1,536,000 since 1996, have resulted in an increase in the reserve balance to $8,731,000. Based on a continuation of the accrual the reserve balance will be $16,488,000 at May 31, 2003. Mr. Schultz further testified that the annual accrual should be reduced to $1,679,616 resulting in a reduction of $1,680,384 to the projected test year expense. The reduced accrual is based on a five year average of annual charges to the reserve escalated by an inflation multiplier. In his opinion, the adjusted accrual is reasonable and would offset any charges and still maintain the current reserve balance.

Gulf had a balance of approximately $12 million in its reserve as of August 2, 1995. On August 3, 1995, Hurricane Erin caused $11 million in damages which were chargeable against the reserve. Two months later Hurricane Opal caused an additional $9 million in damages, also chargeable against the reserve. The damages from the two storms resulted in a negative balance in the reserve of approximately $9 million.

Based on the financial impact of the two storms, Gulf filed a petition requesting that it be allowed to increase its annual accrual to the reserve from $1.2 million to $3.5 million. In Order No. PSC-96-0023-FOF-EI, issued January 8, 1996, in Docket No. 951433-EI, we recognized that even increasing the accrual to $3.5 million, effective October 1, 1995, with additional charges, the reserve would have a negative balance until late 1997. In that Order we found the situation to be undesirable because the Company was in a self-insurance position. Gulf's request to increase its accrual was temporarily approved and the Company was ordered to file a storm damage study to determine the reasonableness of the proposed $3.5 million accrual.

Upon our receipt and review of the study, we allowed Gulf to continue the annual accrual of $3.5 million. In approving Gulf's request we stated that the primary concern was that the level of the accrual be sufficient to cover annual damages and promote growth in the reserve. We also required the appropriate target level for the reserve to be between $25.1 and $36 million. The balance in the accumulated provision account was $8.7 million as of December 31, 2000, and the balance is projected to be $16.5 million by May 31, 2003. The projected balance is based on $297,000 in charges to the reserve in the year 2000, and $324,000 in each of the years ending May 2002 and 2003.

We find that Gulf shall continue its $3.5 million annual accrual until the ordered target level is reached. The accrual and target levels shall only be changed based on a review of an in depth storm damage study. We find that OPC's proposal is not reasonable because it would not allow Gulf to reach the approved target level especially if Gulf were to sustain hurricane damage as in the past. If this were the case, Gulf could possibly have charges to the reserve which would put it in a negative reserve balance. This is contrary to the above referenced Order which states that it would not be desirable to have a negative balance since the Company is in a self-insurance position.

J. RATE CASE EXPENSE

In Direct Testimony, Gulf witness Labrato requested $1,383,500 in rate case expense to be amortized over four years. Gulf explained that in its last rate case, a four year amortization period was approved. The rate case expense for this case would be $345,875 using a four year amortization period.

OPC witness Schultz testified that an adjustment is needed to the $603,000 in legal expense because in the prior rate case the legal expense was $188,953, and this requested increase would be a 219.13% increase. Mr. Schultz reduced estimated legal fees by $153,223 for a total rate case expense of $1,230,277. Mr. Schultz also used a six year amortization period for annual rate case expense of $205,046, and a recommended test year reduction of $140,829.

Because of the shortened hearing schedule Mr. Labrato was asked to file a late-filed exhibit reflecting the Company's most up to date estimate of rate case expense. Accordingly, Gulf filed late-filed Exhibit 55 showing the Company's revised expense compared to its original estimate. The table below shows the comparison, along with our approved expenses.

Item	Original Filing	Gulf's Revised Rate Case Estimate	Approved Rate Case Expense
Outside Consultants	$ 200,000	$ 240,000	$ 200,000
Legal Services	603,000	$ 550,000	$ 550,000
Meals and Travel	125,000	$ 55,000	$ 55,000
Paid Overtime	40,000	$ 70,000	$ 40,000
Other Expenses	415,500	$ 418,000	$ 418,000
Total	$1,383,500	$1,333,000	$1,263,000

In its brief, OPC argued that late-filed Exhibit 55 raises additional concerns because the "Outside Consultants" estimate increased from $200,000 to $240,000 and "Paid Overtime" also increased $30,000 without any additional justification from the utility. OPC recommends $200,000 for outside consultants, $449,777 for legal services, $55,000 for meals and travel, $40,000 for paid overtime, and $418,000 in Other Expenses for a total of $1,162,777 in rate case expense. With a six year amortization period, the annual amortized rate case expense would be $193,796.

We have broad discretion in deciding what should be allowed in rate case expense. <u>See</u> <u>Meadowbrook Utility Systems v. Florida Public Service Commission</u>, 518 So. 2d 326 (Fla. 1st DCA 1987). We find that the utility has not provided sufficient justification to recover the additional $40,000 for Outside Consultants or the additional $30,000 for overtime costs. A late-filed exhibit was required because the hearing lasted two days instead of five, an undisputed fact. The increases in "Outside Consultants" and "Paid Overtime" are unsupported by the record.

Based on the above, the Company's per filing amount of rate case expense shall be reduced by $120,500. Using a four year amortization period, the annual rate case expense is $315,750 for a test year reduction of $30,125 ($345,875 - $315,750) to O&M expenses.

K. MARKETING EXPENSES FOR ELECTRIC APPLIANCES

Gulf's Water Heating Conversion Program allows customers to replace existing gas-fired water heaters with free, energy-efficient electric water heaters. As a result, the Program increases Gulf's winter peak demand by 0.25 KW per customer and annual energy consumption by 4,367 KWh per customer. Although the program does not reduce peak load or kwh consumption, it is cost effective and reduces the bills of participating and non-participating customers. It also improves Gulf's load factor, thereby increasing the efficiency with which Gulf's plants are used.

We find that this program has a net benefit for the general body of rate payers and that it is appropriate to recover, through base rates, the cost of marketing the program. However, we also find that Gulf has the burden of demonstrating, on an ongoing basis, that the program continues to be cost effective. If the program stops being cost effective, Gulf shall bring this matter back before us.

L. PRODUCTION EXPENSES

For the projected test year period from June, 2002, to May, 2003, Gulf estimates that production O&M expense will be $77,202,000. This level exceeds the test year benchmark by approximately $10,714,000. We note, however, that the baseline for benchmark comparisons was set twelve years ago in 1990, at Gulf's last rate case. Furthermore, Gulf's requested test year production O&M expense is approximately $9.5 million less than the 5-year average projected for the 2002-2006 time period.

Gulf witness Moore identified and justified the reasons for the increase in production O&M. He cited three primary factors for the increase:

- The addition of new generating units - Mr. Moore testified that the addition of Smith Unit 3 and the Pea Ridge cogeneration station, both combined cycle units, result in a benchmark variance of $3,840,000 in the "Production Steam" subcategory.

- The increase in generation from an aging steam generation fleet, coupled with a more proactive maintenance philosophy - Mr. Moore testified that substantially increased costs to maintain and operate Gulf's aging fleet of steam generating units have resulted in improved reliability and reductions in outages. These factors, coupled with a 37% increase in generation, result in a benchmark variance of $5,786,000 in the "Production Other" subcategory.

- The $1,088,000 benchmark variance for the "Production Other Power Supply" subcategory - This variance results from two items: (1) increased costs related to Gulf's share of operating the Southern Company's wholesale energy trading floor; and, (2) increased costs to operate the Power Coordination Center, whose responsibility is to carry out bulk power supply operations including those required by FERC Orders 888, 889, and 2000.

OPC Witness Schultz recommends that production expenses be reduced by $10,251,700. However, he did not identify any specific items to be disallowed. In forming his opinion, Mr. Schultz relied on his prefiled testimony exhibit which appears to show that Gulf's production expenses in the test year are forecasted to exceed 2000 levels. Mr. Moore testified that Mr. Schultz made an erroneous conclusion because his prefiled testimony exhibit does not include all dollars allocated to production expense.

We find that Gulf has provided sufficient identification and justification of its test-year production expenses. Therefore, no adjustments shall be made. OPC did not identify any specific item in Gulf's testimony or exhibits on which it disagreed with Gulf's conclusions.

M. CABLE INSPECTION EXPENSE

The Company budgeted $166,000 in the 2003 projected test year for a cable inspection and injection program. Before 1990, Gulf had over 600 trench miles of underground cable installed. Gulf is instituting a program to inject a silicone fluid into the cable to remove water and fill voids. This process has proven to retard the deterioration of the cable insulation and extend the life of the underground cable. A warranty by the manufacturer of the cable injection process carries an unconditional 20-year guaranty. Through implementation of the program, Gulf believes the likelihood of future outages caused by the premature failure of the older cables can be reduced. The Company has identified 28 miles of cable that will benefit from the injection process and anticipates injecting approximately four and a half miles per year. The project is anticipated to take about six years to complete.

Projects designed to extend the life of capital assets are normally capitalized. The cable injection process has been treated as a maintenance expense by Gulf because there was no installation or removal of a plant or property unit involved. Further, the cable injection did not qualify for a retirement unit code under the Company's capitalization guidelines, and Gulf believed its accounting treatment was consistent with that of other utilities. However, by Order No. PSC-94-1199-FOF-EI, issued September 30, 1994, in Docket No. 931231-EI, we determined that cable injection costs should be capitalized and recovered over the associated guarantee period. Cable injection costs will be recorded with underground cable costs in Account 367 which has a stipulated 20-year average remaining life and resulting 3.0% remaining life rate. Since the guarantee period matches the remaining life of the account, the cable injection costs shall be capitalized and depreciated over the life of the associated cable.

FEA, FIPUG, and OPC are in agreement that the cable injection costs should be capitalized. However, the parties have not proposed specific adjustments to rate base, maintenance expense, or depreciation expense. Although Gulf believes that it has properly classified the costs as an expense, it has no objection to capitalizing these costs.

In its brief, Gulf stated that if the cable injection program is capitalized, O&M expense should be reduced by $166,000 and Plant-in-Service, Accumulated Depreciation, and Depreciation Expense should be increased by $152,000, $2,000, and $4,000,, respectively. It appears that Gulf assumed that the project will go into plant in the first month of the projected test year. Staff can find no record basis for Gulf's adjustments to rate base and depreciation expense. No evidence was presented as to the date the project begins or the months in which the injections will take place. Based on our prior practice when project dates are unknown, adjustments are calculated based on the assumption that the $166,000 project will go into plant evenly over the 2003 test year at one twelfth per month. Therefore, we find cable injection expense shall be removed from O&M expense, capitalized in Account N0. 367, Underground Conductors and Devices, and depreciated over the life of the associated cable. We also find O&M Expense shall be reduced by $166,000 and Plant-in-Service, Accumulated Depreciation, and Depreciation Expense be increased by $83,000, $865, and $2,490, respectively.

N. <u>SUBSTATION MAINTENANCE EXPENSE</u>

Gulf Witness Fisher presented direct testimony stating that test-year substation maintenance expense should be increased over the total for 2000 due to three factors: 1) an additional $555,000 to prevent failures of aging substation equipment; 2) $200,000 increased maintenance expenses for new substation transformer banks, breakers, and capacitor banks installed between 2001 and 2003; and 3) $60,000 additional annual expense to prevent insulator arching due to salt contamination at one distribution substation. These factors account for $815,000 of the total requested test-year increase in substation maintenance expense over the total for the year 2000 of $829,744. The total substation maintenance expense requested by Gulf is $1,647,000. This requested amount exceeds its benchmark level by $266,000.

OPC Witness Schultz presented testimony questioning the need for these proposed increases, noting that Gulf's actual substation maintenance expense in 1999 and 2000 and budgeted substation maintenance expense for 2001 were lower than the benchmark levels for those years, and that Gulf's requested increase was not reflected in its 2001 budgeted expenses.

Mr. Schultz calculated an Indexed Five-Year Average of Gulf's substation maintenance expenses over the years 1996 through 2000. Mr. Schultz inflated each historic year's total annual expenses to make them comparable to test year expenses in terms of customers served and price levels and averaged the inflated expenses over the five years. Mr. Schultz's Indexed Five-Year Average of Gulf's substation maintenance expense is $1,255,684. Mr. Schultz offered this average as the reasonable level of substation maintenance expense, noting that this recommended expense level is $438,838 or 54% more than was actually expended in the year 2000. This recommended expense level represents an adjustment of $391,000.

On rebuttal, Mr. Fisher testified that in the years 1999, 2000, and 2001, substation maintenance expense was lower than normal due to six substation electricians normally assigned to substation maintenance being temporarily assigned to substation plant construction. These six substation electricians returned to their maintenance activities at the beginning of 2002. Mr. Fisher thus contends that Mr. Schultz's Adjusted Five-Year Average is not representative of future periods.

Mr. Fisher detailed the additional $555,000 over actual 2000 expense intended to prevent failures to aging substation equipment as consisting of $422,200 in additional salaries and $132,800 in additional material cost, and he detailed the $200,000 expense increase intended for maintenance of the new substation facilities as $141,000 in additional salaries and $59,000 in additional material cost.

Mr. Fisher explained the need for $60,000 additional annual expense to prevent insulator arching due to salt contamination at one distribution substation. This substation is located near the Escambia River. In periods of low rain, the salt content of the river water increases. This causes salt corrosion to build up on the substation's insulators. The $60,000 is requested to clean the insulators in this substation to prevent arching and outages.

Mr. Schultz compared Gulf's 1999 and 2000 substation maintenance expenses with their respective benchmark levels which exceeded actual expenditures. Those years' actual expenses and benchmark expense levels appear in the following table along with the same data for 1996-1998. The benchmark levels for 1996-1998 are calculated using the $754,000 Commission approved expense level in 1990 and the Inflation and Growth Compound Multipliers for those years.

Actual and Benchmark Expense Levels
Substation Maintenance

Year	Actual Expense	Benchmark Level	Difference
1996	$1,059,337	$1,033,915	$ 25,422
1997	$ 938,694	$1,092,184	(153,490)
1998	$1,488,667	$1,148,478	$ 340,189
1999	$ 861,904	$1,196,666	(334,762)
2000	$ 817,256	$1,263,056	(445,800)

We note that in the three years prior to the reassignment of the six substation electricians, Gulf's substation maintenance expenses exceeded the annual benchmark levels by an average of approximately $70,000 per year. We find that Gulf has accounted for the decreases in 1999 and 2000, and its expenses falling short of their benchmark expense levels in those years.

With Gulf's explanation of its decreases in substation maintenance expense by the transfer of the substation electricians away from substation maintenance for 1999-2001 and their return in 2002, its additional substation maintenance activities planned for the test year, and its pre-1999 annual substation maintenance expenses, we find that Gulf's requested test-year substation maintenance expense is a reasonable estimate of an appropriate level of test year expenses. We find that Gulf demonstrated the need for the expense level it requested for the test year, and no adjustment shall be made to this category.

O. TREE TRIMMING EXPENSE

Gulf witness Fisher presented testimony requesting $4,123,000 for annual tree-trimming expense, $2,488,000 greater than the actual tree-trimming expense for the year 2000. Mr. Fisher stated that as a result of efforts to reduce costs, Gulf is presently relying on spot trimming. He also noted that Gulf started to depend more on spot trimming beginning 5 years after the last rate case, and that as a result, tree related outages have risen. The present level of tree trimming is estimated by the witness to be roughly a "seven year cycle that includes the use of spot trimming." Mr. Fisher stated that the increase in tree-trimming expense is intended to cover a three-year tree-trimming cycle, which would result in reduced outages. Mr. Fisher does not believe that Gulf has achieved a three-year tree-trimming cycle since determining this to be the optimal cycle in 1981.

OPC Witness Schultz questioned the need for the increase of \$2,488,000. Mr. Schultz noted that in the year 2000, Gulf budgeted \$3,010,997 and expended only \$1,634,914 for this activity, and for the year 2001, Gulf budgeted only \$1,639,694. Mr. Schultz further questioned the need for a more proactive position with regard to improving distribution reliability, since Gulf's customers site reliability as one the Company's strengths.

Mr. Schultz calculated an Indexed Five-Year Average of Gulf's tree-trimming expenses over the years 1996 through 2000. He inflated each historic year's total annual expenses to make them comparable to test year expenses in terms of customers served and price levels and averaged the inflated expenses over the five years. Mr. Schultz' Indexed Five-Year Average of Gulf's tree-trimming expense is \$2,743,625. Mr. Schultz offers this average as the reasonable level of tree-trimming expense. This recommended expense level represents an adjustment of \$1,379,000.

Mr. Fisher testified on rebuttal testimony that the number of miles trimmed has declined from 889 miles in 1998 to 241 in 2000. The expenses associated with these numbers of miles trimmed are \$2,656,185 and \$1,634,914, respectively. The numbers of minutes of interruption due to tree related outages increased from 1,557,000 minutes to 5,988,000 minutes over the same period. The planned number of miles trimmed in the test year is 1,710 miles. This is the number of miles of tree-trimming activity for which the \$4,123,000 test year expense request is made.

We find that more tree-trimming activity is needed to counter the increased interruption minutes that have accompanied the reduced numbers of miles trimmed since 1998. We agree that Gulf's level of distribution reliability is presently at a satisfactory level.

Due to the satisfactory performance by Gulf in spite of declining tree-trimming activity, not all of the additional expense requested is necessary. We do not agree with Mr. Schultz that including the 1999 and 2000 expenses in an Indexed Average is appropriate for test-year tree-trimming budgeting purposes, when tree-trimming activity during those years was significantly reduced from previous years' levels and those reductions were accompanied by increased numbers of tree-related interruption minutes.

We find that the level of service that Gulf delivers to its customers in this area should return to, at a minimum, the level delivered in 1998. In that year, Gulf trimmed 889 miles of distribution line with associated expenses of $2,656,185. For purposes of calculating OPC's Adjusted Five-Year Average, Mr. Schultz inflated that level of expense to the test year, accounting for customer growth and price level increases. The inflated number of dollars is $3,193,000. This expense level should be great enough to fund a level of activity comparable to the tree trimming carried out before Gulf switched to the less systematic program of spot trimming.

We find that tree trimming is an expense category wherein the budgeted amount should be closely tied to the benchmark, and the budgeted amount should be spent for the purpose intended in order to avoid significant increases in minutes of interruption. We find that the annual expense of $3,193,000 is sufficient for Gulf to perform a reasonable level of tree trimming and maintain its present level of distribution reliability. This represents a $930,000 (jurisdictional) reduction of the requested test-year expense for Account 593, maintenance of overhead lines.

P. <u>POLE LINE INSPECTION EXPENSE</u>

Gulf Witness Fisher requested $734,000 for Gulf's pole-line inspection program for the test year. This amount is a $734,000 increase over the pole-line expenses for the year 2000. Mr. Fisher described the pole-line inspection program as an effort to treat, repair, or replace 60,000 poles installed prior to 1980.

Mr. Fisher explained that in the early 1980's, Gulf switched to using Chromium Copper Arsenate (CCA) treated wood poles with superior decay resistance. Plans for treating the 60,000 poles, over the next five years are based on Gulf's experience so far in treating 48,000 such poles beginning in 1991.

OPC witness Schultz calculated an Indexed Five-Year Average of Gulf's pole line inspection expenses over the years 1996 through 2000. Mr. Schultz inflated each historic year's total annual expenses to make them comparable to test-year expenses in terms of customers served and price levels he then averaged the inflated expenses over the five years. Mr. Schultz's Indexed Five-Year Average of Gulf's pole line inspection expense is $207,274. Mr. Schultz offered this average as the reasonable level of pole line inspection expense. This recommended expense level represents an adjustment of $527,000.

On rebuttal Mr. Fisher testified that the age of the poles remaining to be treated - now all the poles are over 20 years old - is a factor to be considered in projecting expenses to the test year. Mr. Fisher described the process envisioned for the proposed pole line inspection program. Following its work with the remaining 60,000 line poles, Gulf will need to reinspect the original 48,000 line poles treated in the 1990's.

Mr. Fisher stated that in the future, Gulf will need to inspect the poles installed since 1980, which have superior wood decay properties compared to those installed prior to 1980. He noted that some of those poles are now twenty years old and their exact condition is not known. Mr. Fisher stated that although the numbers of poles to be inspected should be smaller at the end of five years, the number of poles in service to be inspected and maintained will continue to grow, so Gulf will continue to incur expenses for this activity.

Mr. Schultz's claim that the requested $734,000 is excessive is based partly on the difference between the rate of replacement before the test year (48,000 poles in 10 years) and the rate proposed for the test year and beyond (60,000 poles in 5 years). Mr. Schultz also questions Gulf's intentions to engage in this activity to the extent planned due to the absence of any expenses in 1999 or 2000, and no expenses budgeted for 2001.

Mr. Fisher pointed out that Gulf embarked on the pole line inspection program in the early 1990's and that its funding has had to come from existing programs. Mr. Fisher also noted that in the late 1990's, funding for this program and others was reduced due to Gulf's efforts to prepare for the transition to Y2K.

We find that this inspection program enables Gulf to make repairs necessary to avoid more expensive repairs in the future. We also find that Gulf's efforts to inspect, treat, reinforce, or replace the remaining 60,000 poles should be accelerated, as all of these poles are now over 20 years old. For these reasons no adjustment shall be made to pole line inspection expense.

Q. STREET AND OUTDOOR LIGHT MAINTENANCE EXPENSE

Gulf Witness Fisher estimated the test year street and outdoor light maintenance expense based on the growth in the number of street lights and the effects of group relamping in certain areas. Between 1990 and 2000, the number of lights maintained by Gulf increased by 263%. To account for increases in total maintenance expense, the number of dollars allowed in 1990 was escalated by that percentage to $1,328,000. To that amount, Mr. Fisher added $110,000 to account for additional lights and planned group relamping. Thus, the test-year expense proposed by Mr. Fisher is $1,438,000. This amount is proposed for two accounts, Account 585, street lighting and signal system expense, and Account 596, maintenance of street lighting and signal systems.

OPC Witness Schultz testified that applying the growth rate since 1990 for the number of lights is not the appropriate method for projecting future expenses, as maintenance expense per light has declined since 1990. Mr. Schultz calculated the Five-Year Average of Gulf's street and outdoor light maintenance expenses over the years 1996 through 2000. This average was not adjusted for cost of living increases or for customer growth. Mr. Schultz's claim that maintenance expense per light has decreased since 1990 is supported by the fact that while the number of lights doubled during this period, expenses increased by only 63 percent.

Mr. Schultz calculated the annual average expense per light and average of annual averages for 1996 - 2000. The average of the five annual averages is $7.86. Mr. Schultz then multiplied the five-year average by his estimated number of lights in service for the test year, 142,255, to arrive at the estimated total street and outdoor light maintenance expense of $1,118,000, which he recommended as the total expense for this category. Mr. Schultz thus recommends a reduction of $320,000 in street and outdoor light maintenance expense.

On rebuttal Mr. Fisher testified that the cost of group relamping in the test year was $425,600, or $38 per unit for the 11,200 lights expected to be replaced. On direct Mr. Fisher stated that the group relamping program reduces inefficiencies of individually relamping street lights as they fail. However, he was not able to demonstrate how greater efficiency could be achieved by adding the expense of group relamping for a subset of Gulf's lights to the total cost of maintaining all lights.

We find that expense maintenance per light has decreased since 1990. We also find that the component of Gulf's proposed expense consisting of the total expense inflated by growth in the number of lights since 1990 would overstate the appropriate expenses for street and outdoor light maintenance. Therefore, the additional expense proposed by Gulf for group relamping is not justified.

Although we do not believe that the additional expense for group relamping in the test year is justified, we note that Gulf performed some group relamping in 1998 and the expenses for that year are included in Mr. Schultz's five-year average. We agree with Mr. Schultz that the product of the Five-Year-Average of Gulf's street and outdoor light maintenance expense and the estimated number of lights in the test year represents a reasonable level for street and outdoor light maintenance expense ($1,118,000). For these reasons a jurisdictional adjustment (reduction) of $320,000 shall be made to Gulf's test-year street and outdoor light maintenance expense.

R. CUSTOMER ACCOUNTS - POSTAGE EXPENSE

OPC witness Schultz testified that the postage expense was $1,114,054 in 2000 and $1,645,717 in the test year which was an increase of $531,663, or 48%. Mr. Schultz stated that Gulf's filing does not provide any explanation for such an increase and requested detail was not provided. Consequently, Mr. Schultz recommended a $427,975 decrease in postage expense.

On rebuttal, Gulf witness Saxon testified that an error was found in the breakdown of expenses budgeted to Account 903-Postage and Account 903-Operations. The budgeted postage expense should have been reduced by $489,000, and, instead, budgeted in the operations account. If the correct amount were budgeted in the test year, the balance in Account 903-Postage Expense would have been $1,156,635, which compares favorably to the 2000 actual postage expense of $1,114,054. Even with the budgeted increase of $489,000 for Account 903-Operations, the test year amount would still be under the 2000 actual expenses for this account.

We find that no adjustment is necessary after the correction of the $489,000 error in the budgeted postage and operation accounts for the test year was made.

S. <u>CUSTOMER RECORDS EXPENSE</u>

OPC witness Shultz testified that the utility requested customer record expense of $3,102,769 for the projected test year is $743,942 higher than the 2000 actual expense of $2,338,827.

On rebuttal, Gulf witness Saxon testified that a change in the allocation of corporate and district facility operation and maintenance expenses was made in 2001 to more accurately assign the expenses to the various business functions. Mr. Saxon testified that the customer expense accounts would then be $657,754 higher in the projected test year. Mr. Saxon explained that an adjustment is not justified because of the change in the allocation method.

In its brief, OPC accepted Gulf's explanation that a change in the Company's accounting mechanics was the cause for the apparent excess in this account. We also find Gulf's explanation to be acceptable. Therefore, no adjustment shall be made to the Customer Accounts Expense because of the utility's change in its allocation method.

T. AMORTIZATION OF THE DEFERRAL OF THE RETURN ON THE THIRD FLOOR OF THE CORPORATE OFFICE

Gulf is requesting that the deferred return be amortized over three years. Gulf witness Labrato testified that the requested level of amortization is consistent with the revenue sharing plan approved in Order No. PSC-99-2131-S-EI, which permitted amortization of up to $1 million per year.

OPC witness Schultz testified that Gulf based its three year amortization period on the above referenced order, but Gulf did not make the election in the time frame established by the revenue sharing agreement, to defer up to $1 million per year. The witness further testified that the deferral should not be included in rate base and that the requested amortization period was not appropriate. However, if the deferral is allowed in rate base then the deferral should be amortized over the life of the building.

We find that the deferral shall be amortized over four years, the same time period used for amortizing rate case expense. Mr. Schultz was in error when he testified that Gulf did not elect to write-off up to $1 million per year. It is clear that it was the intent of the parties to the revenue sharing agreement to allow the write-off of the deferral over a short period of time by authorizing Gulf to record at its discretion, up to $1 million per year to reduce the deferred return. We find that the four year period is reasonable and would allow a fast write-off of the regulatory asset. In addition, the Company shall be allowed to continue its discretion to write-off up to an additional $1 million per year. Therefore, expenses shall be reduced $535,057 ($544,469 system).

U. DEPRECIATION AND AMORTIZATION EXPENSE

Based on the adjustments made by us above, Depreciation and Amortization expense shall reduced by $2,522,000 ($2,603,000 System) for the May, 2003 projected test year, as shown in the table below. The appropriate jurisdictional depreciation and amortization expense is $75,042,000 for the projected test year, as shown in Attachment 3.

Test Year Accumulated Depreciation Adjustments		
Issues	Jurisdictional	System
House Power Panels	$ (49)	$ (49)
Security Measures	101	105
Cable Injection	2	2
3rd Floor Corp. Office- Amortization of Deferred Return	(535)	(544)
Stipulated 25-year life for Smith Unit 3	(2,041)	(2,117)
Total Adjustment	$(2,522)	$(2,603)

V. TAXES OTHER THAN INCOME TAXES

Per MFR Schedule C-38a, page 1 of 2, the adjusted jurisdictional May 31, 2003, projected Taxes Other Than Income Taxes is $36,969,000. This amount includes taxes primarily related to revenues, property, and payroll. Gulf takes the position that Taxes Other Than Income Taxes should be reduced by $11,110,000 to reflect the unbundling of its gross receipts tax, and by $20,000 to reflect the adjustment to payroll taxes discussed in Part VI, Section G. OPC contends that property taxes should be reduced by $1,251,000 to reflect the tax exemption that Gulf received on Smith Unit 3.

We find that with the unbundling of the gross receipts taxes, it is appropriate to reduce this account by $11,110,000. We also find that it is appropriate to reduce this account for payroll-related taxes discussed in Part VI, Section G. However, the adjustment shall be rounded down to $19,000 rather than up to $20,000 to reflect the jurisdictional adjustment of $19,274 that is recommended in Part VI, Section G.

Regarding property taxes, because only five months of property taxes for Smith Unit 3 were included in the test year, the Company made an annualization adjustment of $1,853,000. Per Gulf witness McMillan, these estimated taxes do not reflect a county tax exemption for the Smith plant. Gulf requested and was granted a tax exemption by the Bay County Board of Commissioners. However, Mr. McMillan testified that the Bay County Property Appraiser has taken the position that the exemption for Smith Unit 3 is unlawful. Further, in a lawsuit testing the legality of the exemption, Gulf received a Summary Judgement in its favor in circuit court. The decision was affirmed by the First District Court of Appeal, which affirmed. See Davis v. Gulf Power Corp. 799 So. 2d 298 (1st DCA 2001). The decision was appealed to the Florida Supreme Court. Per Mr. McMillan, the timing and final outcome related to this lawsuit cannot be determined at this time. However, if the Company prevails in court and the property appraiser is required to honor the tax exemption, the annual property taxes would be reduced by $1,251,000 based upon the 2000 millage rates.

In its brief, the OPC argued that property taxes should be reduced by the $1,251,000 to reflect the exemption that Gulf currently has. Gulf will retain that exemption unless the Bay County Property Appraiser can succeed in overturning the Commission decision on appeal. OPC believes that Gulf should have filed this case on the existing status, rather than on the assumption that it would lose the appeal.

We find that a $1,251,000 reduction to property taxes is appropriate. First Gulf has not actually paid the tax. Second, the decision of the First DCA has legal effect because that court has issued its mandate and review by the Florida Supreme Court is discretionary. See Rule 9.310, Florida Rules of Appellate Procedure; Section 12.5, Florida Appellate Practice, 2001-2002 Edition. Therefore, Gulf has no legal obligation to pay at this time. Finally if the decision of the First DCA is reversed, and Gulf has to pay, Gulf may seek relief at that time. Given the above, the most conservative approach under the current circumstances is to reduce and property taxes by $1,206,00 ($1,251,000 system) for the May 31, 2003 test year.

Based on the above three adjustments, Taxes Other Than Income by shall be reduced by $12,335,000 from $36,969,000 to $24,634,000.

W. INCOME TAX EXPENSE

Per MFR Schedule C-2, page 3 of 3, jurisdictional adjusted income tax expense for the May 31, 2003 projected test year is $15,846,000. None of the parties took issue with this amount. We find that this amount is reasonable, based on the other financial information provided in the Company's MFRs for the test year.

However Gulf, FIPUG, and OPC agree that adjustments are required for: 1) other revenue, expense and rate base adjustments that have been proposed by the Company; and 2) adjustments on related issues. We find that this is appropriate as well. To accomplish this, income tax expense shall be increased by $1,460,000 for the adjustments made to revenues and expenses. In addition, the interest synchronization adjustment shall be increased by $1,282,000 based on adjustments made to rate base. The result, as shown in Attachment 3, is an income tax expense increase of $2,742,000, which increases income tax expense from $15,846,000 to $18,588,000 for the May 31, 2003 projected test year.

X. <u>NET OPERATING INCOME</u>

Gulf requested a Net Operating Income of $61,378,000 ($61, 658,000 system) for the May 2003 projected test year. Based on the adjustments made above, in Part VI of this Order, the Company's Net Operating Income is $62,419,000.

VII. REVENUE REQUIREMENT

A. <u>REQUESTED ANNUAL OPERATING REVENUE</u>

Gulf requested an annual operating revenue increase of $69,867,000 for the May 2003 projected test year. We find that the appropriate annual operating revenue increase for the May 2003 projected test year is $53,240,000, as shown in Attachment 5.

The annual operating revenue is a fallout decision and is affected by adjustments made to rate base and net operating income. A summary of the adjustments and the final approved value for annual operating income are shown in the table below.

Calculation of Revenue Requirements (000's) May 31, 2003 Test Year	
Rate Base Rate of Return	$1,199,732 7.92%
Required NOI Adjusted Achieved NOI	$ 95,019 ($ 62,419)
NOI Deficiency Revenue Expansion Factor	$ 32,600 1.633125
Total Revenue Increase	$ 53,240

VIII. COST OF SERVICE AND RATE DESIGN

A. COST OF SERVICE METHODOLOGY

The appropriate cost of service methodology utilizes the 12 Monthly Coincident Peak and 1/13 Average Demand method for the allocation of production plant, and classifies only the meter and service drop components of the distribution system as customer related. The appropriate study is contained in Hearing Exhibit 20, which is Attachment 4B to Late-filed Deposition Exhibit 2 of Gulf Witness Robert L. McGee.

In its MFR Schedule E-1, Gulf filed two Cost of Service (COS) studies. In Attachment B to Schedule E-1 (non-MDS study), Gulf filed a COS study utilizing a methodology identical to that approved by the Commission in Gulf's last rate case. In Gulf's last approved COS study, only the meter and service drop portions of the distribution system were classified as customer related.

The COS study filed as Attachment A to MFR Schedule E-1 (MDS study) is supported by Gulf for use in this case. In this study, the Minimum Distribution System (MDS) methodology was used, which classifies a significant portion of the distribution system as customer related. We find that the MDS is not the appropriate methodology, for the reasons explained below and in the following section on treatment of distribution costs.

Both of the COS studies filed by Gulf use the 12 Monthly Coincident Peak (MCP) and 1/13 Average Demand (AD) method for the allocation of production plant costs. No party has objected to the use of this method, which was approved for use in Gulf's last rate case. It was also approved in the most recent rate cases of Florida Power Corporation, Florida Power & Light Company, and Tampa Electric Company. (Order No. PSC-93-0165-FOF-EI, issued February 2, 1993, in Docket No. 920324; Order No. PSC-92-1197-FOF-EI, issued October 22, 1992, in Docket No. 910890-EI; Order No. 23573, issued October 3, 1990, in Docket No. 891345-EI; Order No. 13537, issued July 24, 1984, in Docket No. 830465-EI)

Gulf witness McGee provided two revised COS studies in a late-filed exhibit to his deposition in this case. These studies are identical to the MDS and Non-MDS studies filed as Attachments A and B in MFR Schedule E-1, with three minor exceptions.

First, there was a change to the 12 CP demand allocators used for the Street (OS-I) and Outdoor (OS-II) rate classes. The initial filing developed these allocators using historical calendar year 1999 estimates of CP demand responsibility for these classes. The revised COS studies used a five-year (1996-2000) historical average. Use of a five-year average avoids unusual circumstances that might occur when a single year is used. For the same reason, a similar adjustment was made to the 12 CP demand allocators for the Sports Fields (OS-IV) rate class. Finally, there was also an adjustment made to the non-coincident (NCP) peak allocators for the OS-IV rate class to correct for errors made in the original filing.

We approved a stipulation that the proper estimates of 12 CP and NCP demand responsibility by rate class are reflected in the COS studies contained in Mr. McGee's late-filed COS studies. Gulf's rates shall therefore be designed based on the revised non-MDS study contained in Attachment 4B to Late-filed Deposition Exhibit 2 of Mr. McGee, which was identified as Exhibit 20 at hearing.

B. <u>TREATMENT OF DISTRIBUTION COSTS</u>

We find that the appropriate treatment of distribution costs shall remain consistent with past decisions where we required that only Accounts 369 (Services) and 370 (Meters) be classified as customer related.

As explained above, two cost of service studies were under consideration in this case. Both methods are based on the same underlying cost allocation methodology. The significant difference is how Gulf's proposal allocates distribution costs to customer classes.

1. Description of Methodologies

Previously Approved Methodology. The purpose of a cost of service methodology is to perform three activities. First, it functionalizes costs into production, transmission, distribution, customer and administrative/general categories. Second, these functionalized costs are separated into classifications based on the utility service being provided. There are three principal classifications of costs: (1) demand costs that are costs that vary with the KW demand imposed by the customer; (2) energy costs that are costs that vary with the energy or KWH used; and (3) customer costs that are costs that are directly related to the number of customers served. Under the methodology approved in Gulf's last rate case, only investment in two accounts, Account 369 (Service Drops) and 370 (Meters) were considered to be directly related to the number of customers served. The rationale as stated in all IOU rate cases since the 1980's is that only the line from the transformer to the meter and the meter itself are clearly customer related and, therefore should be the only accounts that are allocated on the basis of number of customers. All other distribution facilities are allocated on a demand allocator on the theory that load determines the size of these facilities, not the mere presence of the customer.

Proposed MDS Application. Gulf's proposed cost study classifies certain distribution costs, other than those in Accounts 369 and 370, as "customer" related. Specifically, Gulf's approach divides the distribution facilities from five additional accounts (Accounts 364-368) between demand and customer classification on the idea that a certain amount of poles, transformers, and conductors are necessary to extend service to a customer even if that customer never uses any energy. To arrive at this allocation requires the development of a hypothetical minimum distribution system to determine how much of each account is to be allocated on demand and how much on customers.

The MDS classification methodology uses a Zero Intercept (ZI) method to determine how much of the account should be allocated on a demand basis and how much is allocated on a customer basis by constructing the cost of investment at a zero load. The ZI approach uses a regression analysis to determine the zero capacity unit cost. This analysis plots the current replacement costs of the each type and size of equipment in each account against the various sizes of equipment (transformers, poles, conductors) and interpolates back to a 'zero,' or no-load, size. This provides a theoretical replacement cost for the equipment with no load capability which the MDS then attributes as customer related.

Once the ZI cost is determined, that cost is multiplied by the number of units in inventory to arrive at a theoretical base cost of the distribution facilities designed to carry no load. Then, using the ZI ratio and the replacement costs for all equipment, the ratio of customer costs to demand costs is determined. This ratio is then multiplied times the actual booked costs to determine the actual dollars to be allocated on a customer and demand basis in the cost of service. This zero intercept analysis must be conducted for each piece of equipment in each distribution account which is deemed to have both a customer and demand component.

2. <u>Evaluation of Cost of Service Studies</u>

Gulf relies on four basic tenets to support the use of the MDS methodology. First, Gulf maintains that the National Association of Regulatory Utility Commissioners (NARUC) Cost of Service Manual endorses the methodology. Second, Gulf contends that the complexity of the ZI methodology is necessary to accurately identify customer related costs. Third, Gulf argues that the Commission's reason for rejecting the MDS is that it increases customer related costs for the residential class. Fourth, Gulf maintains that the cost allocation methodology may or may not be used to set rates if the Commission believes the results are unacceptable for any reason.

<u>NARUC Manual.</u> In this filing, Gulf's COS witness Mr. O'Sheasy and other intervenors, rely heavily on a publication by the NARUC entitled, "Electric Utility Cost Allocation Manual" (Manual) to support the use of MDS. In particular, Mr. O'Sheasy cites language from Chapter 6 of this document in which the Manual describes the

MDS methodology. He, along with FEA and FIPUG, appear to place great importance on the fact that this publication includes the MDS. However, the Preface states three objectives of the Manual: (1) it should be simple enough to be used as a primer on the subject of cost allocation yet offer enough substance for experienced witnesses; (2) it must be comprehensive yet fit in one volume; and (3) the writing style should be non-judgmental; not advocating any one particular method, but trying to include all currently used methods with pros and cons. In other words, the Manual was designed to educate, not mandate any particular methodology.

The manual also notes that it discusses only major methodologies and recognizes that no single costing methodology will be superior to any other and the choice of the methodology will depend on the unique circumstances of each utility. Mr. O'Sheasy acknowledged that we are not bound by the manual. Furthermore, Gulf provided no evidence on the circumstances that made it choose the MDS methodology over the method approved in its last rate case.

Hypothetical System - ZI Methodology. As described above, the MDS methodology requires construction of a hypothetical system consisting of equipment that is designed to carry zero load for each account identified as having both a customer and a demand component. Artificial no-load costs are created using replacement costs. Ratios of replacement cost are derived, which must then be translated in booked costs to determine the actual dollars to be allocated. According to Mr. O'Sheasy, that process must be applied to FERC Accounts 363-368. Each account may contain multiple sizes or types of items such as poles, transformers, and conductors. Replacement costs must be determined for each piece of equipment in each account.

This approach assumes that the cost relationships between items in an account remain constant over time. If they do not, it can skew the trend analysis. For example, replacement costs for older smaller equipment may be more expensive than newer products simply because there are fewer sources. In addition, if new technology allows a larger transformer to be sold at a cost comparable or less than a smaller transformer, due to economies of scale, the mathematical result of the zero intercept regression could conceivably show a cost at zero intercept for a no-load situation higher than the use of a larger transformer. Conversely, Mr. O'Sheasy and the NARUC Cost Manual agree that there is common agreement that Accounts 369 and 370 are fully customer related.

The concept of a zero load cost is purely fictitious and has no grounding in the way the utility designs its systems or incurs costs because no utility builds to serve zero load. There is no real equipment that equates to the costs identified by the ZI methodology. We have rejected MDS in the past for this very reason.

> The Company and staff have proposed the use of a theoretical minimum distribution cost as part of the customer cost . . . . While we agree that sound regulatory practice should provide for a customer charge to defray otherwise fixed costs, as proposed by the Company and Staff, we do not agree that a theoretical cost of a minimum distribution system is appropriate . . . . The installation of the distribution system is made in anticipation of a projected level of actual use. The system does not contain a basic theoretical minimum distribution system. Reliance on such a mechanism is speculative at best. Instead, we believe the appropriate customer charge should be based on the cost of the meter, service drop, meter reading and basic customer service costs (not including uncollectibles).

Order 9599, issued October 17, 1980, in Docket No. 800011-EU, p. 18.

<u>Distinction Between COS and Rate Design.</u> Mr. O'Sheasy repeatedly makes a distinction between the cost allocation methodology employed to determine costs, and rate design to set actual charges to customers. However, he also states that the primary purpose of a cost study is to determine if rates need to be changed. Indeed, the primary purpose of a cost of service is to determine the reasonableness of rates. "The cost principle applies not only to the overall level of rates, but to the rates set for individual services, classes of customers and segments of the utility's business."

Mr. O'Sheasy agreed that we can stray from the cost allocation results to mitigate the perceived impact of a particular cost allocation or level. In fact, he noted that Georgia employs the MDS cost methodology but that its customer charges were not set at the full cost of service. We believe, however, that typically the COS study directs how any increase in revenue requirement is allocated across classes for the purpose of setting new rates.

To maintain that cost classification is no more than a theoretical exercise that does not have to affect rates is nonsensical. If a cost study were not used to design rates, there would be no purpose in performing the cost study. Although Mr. O'Sheasy states that it is his belief that this Commission rejected the MDS in previous rate cases because of the impact on residential customers, our prior orders show that it was the theoretical construct with which we disagreed, not the end result.

The NARUC Cost Manual defines customer costs as "...the plant and expenses that are associated with providing the service drop and meter, meter reading, billing and collection and customer information and service." This is precisely the approach we have taken in the past. Only the investment in the service drop and meters were allocated on a customer basis.

Commission Precedent. Mr. O'Sheasy contends that staff opposes the MDS methodology because the Commission has consistently ruled against it. This Commission is not bound by any prior decision in this matter, if it deems that circumstances warrant a change. Similarly, the NARUC manual states that the choice of methodology will depend on the unique circumstances of the case. We find that Gulf has not offered any evidence to show how its circumstances have changed since the last rate case that would justify a change in cost methodology.

Internal Inconsistencies. Mr. O'Sheasy describes MDS as identifying the costs of the facilities needed to simply hook-up a customer to the power system. Yet, distribution lines must be connected to subtransmission and transmission lines and ultimately to the busbar at the power plant in order to be able to deliver a single kWh. To artificially separate distribution accounts on the basis that these facilities are necessary to make service available ignores the way the electric system works. MDS is internally inconsistent in that it separates out distribution facilities for different treatment than transmission lines. As cited in the order in Gulf's last rate case:

> There is a fundamental flaw in this proposal in that only part of the distribution system is classified as customer-related. None of the subtransmission and transmission system would be classified as customer-related. Hence, customers served at primary voltage through dedicated substations, and customer served at higher voltages would not pay for any of this network path.
>
> We believe this minimum distribution system approach should be rejected because it is inequitable and inconsistent to apply the concept to only those customers served at secondary voltage or at primary voltage through common substations when the network path must be there to serve each and every customer.
>
> In our opinion distribution facilities that function as service drops or dedicated tap lines should be directly assigned the classes whose members the facilities serve. No distribution costs other than service drops and meters should be classified as customer related.

Order 23573, issued October 3, 1990, in Docket No. 891345-EI, p. 51. (Emphasis in original)

Impact on Residential Customers. Gulf suggested that there was concern about the shifting of costs to the residential class. This Commission has consistently rejected the use of the Minimum Distribution System for the last twenty years. See Order 9599, issued October 17, 1980, in Docket No. 800011-EU; Order 9864, issued March 11, 1981, in Docket No. 800119-EU; Order 10557, issued February 1, 1982, in Docket No. 810136-EU; Order 11498, issued January 11, 1983, in Docket No. 820150-EU; Order 11628, issued February 17, 1983, in Docket No. 820100-EU; Order 23573, issued October 3, 1990, in Docket No 891345-EI. None of these Orders cite, as a reason for rejecting MDS, the impact on any particular class of customers. The criticisms have all addressed the merits of the methodology, not its eventual impact on rates.

Specifically, as noted above, MDS has been rejected because of inconsistencies in the methodology and because it does not reflect the way a utility incurs costs.

Competitive Pressure. Mr. O'Sheasy also cited as a reason for adopting the MDS in this case the fact that cross-subsidies are bigger issues now than they have ever been. He noted that commercial and industrial customers face greater competitive challenges in their own markets. However, the MDS has been proposed in rate cases for over 20 years. We cannot assign much weight to Mr. O'Sheasy's generalization that competitive pressures are greater now than at any time in the past 20 years. Gulf provided no factual support for the generalization.

Further, we question Mr. O'Sheasy's qualifications to assess competitive trends in unregulated industries. In his background, Mr. O'Sheasy notes that he joined Southern Company in 1980 and has continued in various capacities in a regulated environment until his retirement in 2001. There is no evidence to indicate that he has any special knowledge as a competitive market analyst or an expert of competitive pressures in manufacturing or industrial applications. In fact, FIPUG, a trade association of large industrial customers in the state, presented no evidence that its members faced unusual or significantly changed competitive pressures. Every private enterprise desires to lower the costs of inputs to its production process in order to increase its income. This desire should not, however, drive a cost allocation.

We find that the simpler, more straight forward approach of allocating only service drops and meters on a customer basis adequately captures the distribution investment that is solely required to extend service to a new customer. This methodology is clear, generally accepted, and requires no series of hypothetical cost and system design calculations that do not reflect how the actual system is designed. Despite the Mr. O'Sheasy's claim that the electric industry is very different from 12 1/2 years ago, he presented no evidence to support this statement. When asked what had changed, he again referred to the competitive pressure on commercial and industrial groups and market pressures, and cross subsidies, but did not mention any changes to the electric industry itself which would justify a change in methodology. Changes in competitive markets should not drive the allocation of costs in a regulated electric cost study.

For the reasons provided above, we find that the treatment of distribution costs shall remain consistent with our past decisions, and accordingly, only Accounts 369 and 370 shall be classified as customer related.

C. ALLOCATION OF THE REVENUE INCREASE AMONG THE CUSTOMER CLASSES

The revenue increase shall be allocated to the rate classes in a manner that moves the class rate of return indices as close to parity as practicable based on the approved cost allocation methodology, and subject to the following constraints: 1) no class shall receive an increase greater than 1.5 times the system average percentage increase in total; and, 2) no class shall receive a decrease. The allocation of the increase is shown in Attachment 6.

The allocation of the increase in revenues shown in Attachment 6 moves each rate class closer to parity, and does not impose an increase on any rate class that exceeds 1.5 times the system average increase, including adjustment clause revenues. In addition, no class receives a rate decrease.

No increases are allocated for the Other Outdoor (OS-III), Standby (SBS), Real Time Pricing (RTP), and Large High Load Factor (PX/PXT) rate schedules because they are all significantly above parity. Although the Contract Service Agreement (CSA) customers are significantly below parity, the rates paid by these customers were negotiated pursuant to Gulf's Commercial/Industrial Service Rider, and thus are not subject to change.

D. DEMAND CHARGES

The appropriate demand charges are shown in Attachment 7. The demand charges were set at a level that, in combination with the remaining rate components, will result in the recovery of the total revenues allocated to each rate class.

E. ENERGY CHARGES

The appropriate energy charges are shown in Attachment 7. The energy charges were set at a level that, in combination with the remaining rate components, will result in the recovery of the total revenues allocated to each rate class.

F. CUSTOMER CHARGES

The customer charges are shown below:

RATE CLASS	NON-MDS UNIT COST	CURRENT CHARGES	GULF PROPOSED	APPROVED
RS, RSVP	$ 11.43	$ 8.07	$ 12.00	$ 10.00
GS, OSIV	$ 17.50	$ 10.09	$ 15.00	$ 13.00
GSD	$ 31.88	$ 40.35	$ 40.00	$ 35.00
GSDT	$ 31.88	$ 45.80	$ 40.00	$ 35.00
GSTOU	$ 31.88	N/A	$ 40.00	$ 35.00
LP, LPT	$154.72	$ 226.98	$ 226.00	$ 155.00
PX, PXT	$416.64	$ 575.01	$ 566.38	$ 566.38
RTP	$452.37	$1000.00	$1000.00	$1000.00

Customer charges are flat monthly per-customer rates that do not vary with energy usage. They are designed to recover costs that typically vary with the number of customers served, rather than with kilowatt hour consumption. Customer costs include metering, billing, and customer service.

To the extent practicable, the customer charges are be set to reflect the customer unit costs developed in the cost of service study approved by us. With the exception of the PX, PXT, and RTP rate schedules, the customer charges meet this objective. The PX, PXT, and RTP customer charges are left at current levels because no increase is being made to these classes.

The RS and RSVP customer charges are being increased from their current level of $8.07 to $10.00. While this is below the unit cost of $11.43, we find that because the customer charge is a large portion of the customer bill for these classes, the increase in the customer charge should be limited in order to avoid an excessive increase to low-use customers. Similarly for the GS and

OS-IV classes, the customer charges shall be increased from their current level of $10.09 to $13.00, which is below the unit cost of $17.50.

G. CHARGES UNDER THE INTERRUPTIBLE STANDBY SERVICE (ISS) RATE SCHEDULE

The appropriate Interruptible Standby Service charges are shown in Attachment 7, page 4. Because no increase was allocated to this rate class, the ISS rates approved by us have been adjusted only to remove the embedded 1.5% Florida gross receipts taxes.

H. CHARGES UNDER THE STANDBY AND SUPPLEMENTARY SERVICE (SBS) RATE SCHEDULE

The appropriate Standby and Supplementary Service charges are shown in Attachment 7, page 3. Because no increase was allocated to this rate class, the SBS rates approved by us have been adjusted only to remove the embedded 1.5% Florida gross receipts taxes.

I. RATE DESIGN FOR REAL TIME PRICING (RTP) RATE SCHEDULE

Because no rate increase was allocated to this rate class, the existing rate design shall be retained. Under the RTP rate, customers pay a unique rate for each hour of the day based on the Southern Company's incremental cost to serve the next kilowatt hour.

J. EFFECTIVE DATE

By stipulation, the revised rates are to become effective for bills rendered on or after the commercial in-service date of Smith Unit 3, or 30 days after the date of the our vote in this docket, whichever is later. Smith Unit 3 entered into commercial operation on April 22, 2002. The new rates will therefore become effective on June 7, 2002, which is 30 days after our vote on May 8, 2002.

K. APPROVAL OF TARIFF SHEETS

Gulf shall submit its tariff sheets showing gross receipts tax removed from base rates and from the recovery clause factors. Our staff shall approve the tariff sheets administratively.

IX. FINDINGS OF FACT AND CONCLUSIONS OF LAW

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

2. The adjustments to rate base made herein are reasonable and proper. The value of Gulf's rate base for rate making purposes is $1,199,732,000.

3. The adjustments made to the calculation of required net operating income are reasonable and proper. Gulf's required net operating income for rate making purposes is $95,019,000.

4. The fair rate of return on the equity capital of Gulf is 11.75%.

5. Gulf has provided superior service in the past and is expected to continue to do so in the future. In recognition of Gulf's accomplishment, we increased rate of return on equity capital to 12.00%.

6. Gulf Power Company is authorized to increase its rates and charges by $53,240,000 in gross annual revenues effective June 7, 2002.

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

8. The new rate schedules shall be reflected upon billings rendered for meter readings taken on or after June 7, 2002.

Based on the foregoing, 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 Gulf Power Company's Petition for Rate Increase is granted in part and denied in part as described herein. It is further

ORDERED that Gulf Power Company is authorized to submit revised tariff sheets consistent with the rate schedules approved herein. The Commission staff shall administratively approve the tariff sheets. It is further

ORDERED that Gulf Power Company shall include in each customer's bill, in the first billing for which the rate 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 for those charges. The bill stuffers shall be submitted for review and approval to the Florida Public Service Commission before they are mailed. It is further

ORDERED that if Gulf Power Company wishes to file an Earnings Sharing Plan or other type of incentive plan, it shall do so within 90 days of April 26, 2002, the date of the vote on revenue requirements. It is further

ORDERED that the stipulations contained in Appendix A to this Order are hereby approved. It is further

ORDERED that this docket shall be closed 32 days after the issuance of this Order to allow the time for filing an appeal to run.

By ORDER of the Florida Public Service Commission this 10th day of June, 2002.

BLANCA S. BAYÓ, Director
Division of the Commission Clerk
and Administrative Services

(S E A L)

MKS

CONCURRING AND DISSENTING OPINIONS

Chairman Jaber concurs in part and dissents in part with the following opinion:

I commend Gulf Power for its good service and consumer relations program. I truly believe that this company has attempted to ensure that its customers receive the best affordable electric service. With that said, Gulf Power sought the approval of an incentive program (Late Filed Hearing Exhibit 25) that would have rewarded the company for past performance and service. As I stated during our deliberation on this case, I believe that properly balanced incentive-based approaches to regulation, where feasible, are appropriate. An incentive-based program that both rewards and penalizes the company for service performance may be appropriate. I prefer that such a program be based upon consensus which maximizes the creative ideas of all of the stakeholders. Here, because Gulf Power's proposal crystalized during a witness' summary, OPC and FIPUG successfully argued that they were not afforded sufficient time and opportunity to review and respond to the proposal. Therefore, I concur in the majority's decision to grant OPC's and FIPUG's objections to the admission of Gulf's Late-filed Exhibit 25.

I also concur with the decision to allow Gulf Power to file a new balanced incentive plan within 90 days. However, because I believe the majority's decision to reward Gulf Power at this time by adjusting the company's return on equity upward may have taken away one of the tools that was available to the parties in negotiating the incentive program, I respectfully dissent with regard to the majority's decision to add 25 basis points to the midpoint return on equity.

Finally, I must point out that Gulf Power's last full rate case was conducted in 1990. After 11 years, Gulf Power filed this request for rate relief to include the addition of Smith Unit 3, a combined cycle generating unit designed to provide 574 megawatts of power to meet growing demand. Prior to the hearing, Gulf Power, the parties, and our staff reached many stipulations on issues and witness testimony, resulting in a shortening of the hearing from five scheduled days to only a day and a half. The company and the parties are to be commended for this cooperation and coordination, which minimized rate case expense that ultimately would have been borne by customers though their rates.

Commissioner Palecki concurred in part with the Commission's decision regarding advertising expenses with the following opinion:

ADVERTISING EXPENSES

I concur with the majority's opinion regarding the *level* of advertising expenses Gulf should be allowed to recover. The per customer expense for this activity is within the range of reasonableness that I would approve. However, I believe that the Commission's scrutiny of every advertisement, television commercial, and public relations expenditure for a conservation, safety, or customer information message amounts to micro-management. Furthermore, constant audits on this matter are not a good use of the Commission's time and resources.

Ratepayers are concerned about the dollars companies spend on these ads -- not the detail of the message. Whether ads are designed to build customer confidence, to enhance the company's image, or to help them compete, companies should have the flexibility to appropriately manage the subject matter of the ads. Although I would encourage our companies to continue to use advertisements to educate customers regarding safety, conservation, and energy efficiency, I think we should recognize that utilities are in the best position to determine the messages that need to be sent to their customers.

Commissioner Palecki dissented from the Commission's decisions on two issues with the following opinion:

REWARD FOR GULF'S PAST PERFORMANCE

I dissent from the majority's decision to adjust Gulf's return on equity (ROE) upward to 12% for Gulf's performance. In this Order, we have suggested that the parties, including Gulf and OPC, negotiate an incentive plan, and we have given Gulf until July 26, 2002, to file a petition for approval of such a plan. I believe that the Commission's decision to reward Gulf at this time for its performance in the form of a higher ROE undermines the ability of the parties to craft an effective incentive sharing proposal.

I applaud Gulf for its superior performance. I have recognized this performance by voting to allow Gulf an ROE of 11.75%, instead of 11.6% as recommended by our staff. I believe that 12% is too high unless authorized by the Commission as part of a comprehensive incentive program designed to improve efficiency by allowing a sharing of revenues between Gulf and its ratepayers.

EXPENSES FOR PROGRAM TO CONVERT GAS WATER HEATERS TO ELECTRIC

I dissent from the majority's decision to allow Gulf to include expenses for its program to allow customers to replace existing gas-fired water heaters with free, energy-efficient electric water heaters (Water Heating Conversion Program). This decision contrasts starkly with long-standing Commission precedent designed to encourage the opposite - conversion of electric water heaters to gas - in order to reduce the need for additional power plants in Florida.

The Commission has historically approved gas companies' expenditures to convert electric water heaters to gas as a means of reducing the state's consumption and the need for additional generation under the Florida Energy Efficiency and Conservation Act (FEECA). The legislative intent of FEECA states in part that FEECA is "to be liberally construed in order to meet the complex problems of reducing and controlling the growth rates of electric consumption . . . ." Section 366.81, Florida Statutes. The majority's decision undermines the purpose of FEECA by encouraging Gulf to engage in behavior to increase generation needed to serve our state. It is significant that the primary driver of this rate increase is Gulf's need to build a new power plant.

The Commission's actions here send conflicting signals. On one hand, we uphold the purpose of FEECA by encouraging ratepayers to conserve and convert from electric to gas. On the other hand, we allow Gulf to spend ratepayer money to undermine the purpose of FEECA by promoting consumption that could result in the need for more power plants. I believe that the majority's decision to allow Gulf to include Water Heating Conversion Program expenses violates the letter and spirit of FEECA and sets a poor precedent. I hope that the Commission will reconsider this policy if similar requests are filed by other Florida electric utilities in the future.

NOTICE OF FURTHER PROCEEDINGS OR JUDICIAL REVIEW

The Florida Public Service Commission is required by Section 120.569(1), Florida Statutes, to notify parties of any administrative hearing or judicial review of Commission orders that is available under Sections 120.57 or 120.68, Florida Statutes, as well as the procedures and time limits that apply. This notice should not be construed to mean all requests for an administrative hearing or judicial review will be granted or result in the relief sought.

Any party adversely affected by the Commission's final action in this matter may request: 1) reconsideration of the decision by filing a motion for reconsideration with the Director, Division of the Commission Clerk and Administrative Services, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850, within fifteen (15) days of the issuance of this order in the form prescribed by Rule 25-22.060, Florida Administrative Code; or 2) judicial review by the Florida Supreme Court in the case of an electric, gas or telephone utility or the First District Court of Appeal in the case of a water and/or wastewater utility by filing a notice of appeal with the Director, Division of the Commission Clerk and

Administrative Services and filing a copy of the notice of appeal and the filing fee with the appropriate court. This filing must be completed within thirty (30) days after the issuance of this order, pursuant to Rule 9.110, Florida Rules of Appellate Procedure. The notice of appeal must be in the form specified in Rule 9.900(a), Florida Rules of Appellate Procedure.

APPENDIX A

APPROVED STIPULATIONS

The stipulations listed below are approved.

I. Depreciation Stipulation

The Stipulation for Settlement of Depreciation Related Issues between OPC, FEA, FIPUG, and Gulf filed on February 22, 2002, was accepted. The Stipulation reflects a compromise settlement between the parties regarding depreciation rates and dismantlement accrual levels. It is not construed as an admission by any party that these rates or dismantlement provisions are appropriate in any other proceeding.

The accepted settlement reflects the depreciation rates and dismantlement accruals initially proposed by Gulf in its May 29, 2001, filing in Docket No. 010789-EI. For Smith Unit 3, the agreement reflects the depreciation rate and dismantlement accrual proposed by Gulf in Docket No. 010949-EI, except the depreciable life for the unit is set at 25 years (instead of the 20 years initially proposed by Gulf). As a result, the May 2003, depreciation expense will be reduced $2,041,000 ($2,117,000 system); the level of accumulated depreciation will be reduced by $1,019,000 ($1,057,000 system).

The Depreciation Stipulation also provides that the depreciation rates and dismantlement provisions be effective on January 1, 2002, except for Smith Unit 3. The depreciation rate and dismantlement provision relating to Smith Unit 3 will be effective on the commercial in-service date of the unit. Finally, the Stipulation provided that the prefiled testimony of witnesses Majoros, Zaetz, and Roff would be inserted into the record as though read.

Accordingly, Issues 17, 73, and 74 are fully resolved. Although, with respect to depreciation rates and dismantlement accruals, the Depreciation Stipulation likewise resolves Issues 18 and 75, those issues remain open for the purpose of identifying adjustments to accumulated depreciation and depreciation expense that fallout from other issues.

In addition, on its own motion, the Commission voted that acceptance of the Depreciation Stipulation rendered moot the Commission's vote in Docket No. 010789-EI made at the February 19, 2002 Agenda Conference. That vote had not been issued as a Proposed Agency Action Order at the time this Stipulation was accepted (February 25, 2002). Accordingly, the Commission voted that Docket No. 010789-EI should be closed administratively.

II. Motion for Judicial Notice

A Motion for Judicial Notice was filed by the Federal Executive Agencies on February 22, 2002, which requested judicial notice for certain parts of the Electric Utility Cost Allocation Manual published by NARUC in 1992. The parts to be noticed were the cover pages, table of contents, preface, and Chapter Six. The parties agreed to stipulate the material into the record as an exhibit, which was accepted by the Commission and so the Motion was effectively withdrawn.

III. Stipulated Issues

A. Category One Stipulations

Category One stipulations are those to which Gulf, Staff, FEA, FIPUG, and OPC agree and for which FCTA takes no position.

1. The testimony and exhibits of OPC's witness, Michael J. Majoros, including his deposition testimony, shall be stipulated into evidence without cross examination by any party.

B. Category Two Stipulations

Category Two stipulations are those to which Gulf and Staff agree, and for which FCTA, FEA, FIPUG, and OPC have no position.

2. Gulf shall be required to file, within 90 days after the date of the final order in this docket, a description of all entries or adjustments to its annual report, rate of return reports, and books and records which will be required as a result of the Commission's findings in this rate case. (Issue 124)

C. Category Three Stipulations

Category Three stipulations are those to which Gulf, FEA, OPC, and Staff agree and for which FIPUG and FCTA have no position.

3. The appropriate cost of short-term debt for the May 2003 projected test year is 4.61%. The short-term debt cost rate has been revised from 6.02% as originally filed based on the most recent forecast of short-term interest rates for the test year. (Issue 32)

4. The appropriate cost rate for long-term debt for the May 2003 projected test year is 6.44%. The long-term debt cost rate has been revised from 7.08% as originally filed to 6.44%. The Company has completed the issuance of all permanent financing impacting the May 2003 projected test year. Therefore, the long-term debt cost rate was revised to reflect the actual rates of senior notes issued. In addition, the cost rates for the Company's variable rate pollution control bonds were revised based on the most recent forecast of short-term interest rates for the test year. (Issue 33)

D. Category Four Stipulations

Category Four stipulations are those to which Gulf, FEA, FIPUG, and Staff agree, and for which FCTA and OPC have no position or no opposition.

5. Based upon the Stipulation approved in Order No. PSC-99-2131-S-EI, the rates approved in this docket will be effective for bills rendered on or after (i) the commercial in-service date of Smith Unit 3, or (ii) 30 days after the date of the Commission's vote in this docket, whichever is later. (Issue 123)

E. Category Five Stipulations

Category Five stipulations are those to which Gulf and Staff agree, and for which FEA, FCTA, FIPUG, and OPC have no position.

6. Gulf's forecasts of Customers, KWH, and KW by Rate Class, for the May 2003 projected test year are appropriate. (Issue 2)

7. No adjustments shall be made to Gulf's projected test year due to customer complaints. (Issue 4)

8. The quality of electric service provided by Gulf is adequate as evidenced by Gulf's complaint activity being low and its rankings across all service and reliability attributes in customer surveys being consistently among the best in the industry. (Issue 5)

9. No adjustment shall be made to Smith Unit 3. The $220,495,000 requested for the construction of Plant Smith Unit 3 is reasonable, prudent, and should be allowed. (Issue 10)

10. The company has removed from rate base all non-utility activities, including the investment, accumulated depreciation, and working capital amounts related to the Company's non-utility activities. (Issue 15)

11. The requested level of construction work in progress in the amount of $15,850,000 jurisdictional ($16,361,000 system) is appropriate for purposes of computing base rate revenue requirements. This amount properly reflects the construction expenditures and plant clearings that are expected in the May 2003 projected test year. (Issue 19)

12. No adjustment shall be made to Plant Held for Future Use for Gulf's inclusion of the Caryville site in rate base. While Gulf has allowed the Caryville site to be used for various non-utility activities in recent years, the site was certified by the Power Plant Siting Board in 1976 and continues to be viable for building coal-fired capacity in the future. It is anticipated that certifying new plant sites will become increasingly more difficult in the future. Caryville has been in Gulf's rate base as Plant Held for Future Use for well over 35 years. Inclusion of this site in rate base is still a prudent decision. (Issue 20)

13. The requested level of Property Held for Future Use in the amount of $3,065,000 ($3,164,000 system) is appropriate for purposes of computing base rate revenue requirements. (Issue 21)

14. No adjustment shall be made to prepaid pension expense. The projected balance of prepaid expense has been properly reflected in the calculation of working capital. (Issue 22)

15. No adjustment shall be made to rate base for unfunded Other Post-retirement Employee Benefit (OPEB) liability. The projected balance of Other Post-retirement Employee Benefits has been properly reflected in the calculation of working capital. (Issue 23)

16. Gulf's projected level of Total Operating Revenues in the amount of $372,714,000 ($379,009,000 system) for the May 2003 test year should be reduced by $1,652,000 to reflect the impact of the Commission approved change to the Purchased Power and Capacity Cost Recovery Clause calculation as discussed in Issue 45. Total Operating Revenues should also be reduced if the Commission chooses to remove gross receipts tax from revenues and expenses in the calculation of Net Operating Income, rather than removing gross receipts tax from total revenue requirements in the calculation of proposed base rates. (Issue 38)

17. The appropriate inflation factors are those shown on Gulf's response to Staff Interrogatory No. 192. This results in a $100,000 reduction to O&M expense. (Issue 39)

18. Gulf has made the appropriate test year adjustments to remove fuel revenues and fuel expenses recoverable through the Fuel Adjustment Clause. As shown on Mr. Labrato's direct testimony Exhibit RRL-1, Schedule 8 and Schedule 9, the Company has removed from NOI the fuel revenues and expenses recoverable through the Fuel Clause for purposes of determining base rate revenue requirements. (Issue 43)

19. Gulf has made the appropriate test year adjustments to remove conservation revenues and conservation expenses recoverable through the Conservation Cost Recovery Clause. As shown on Mr. Labrato's direct testimony Exhibit RRL-1, Schedule 8 and Schedule 10, the Company has removed from NOI the conservation revenues and expenses recoverable through the Energy Conservation Cost Recovery Clause for purposes of determining base rate revenue requirements. (Issue 44)

20. Gulf has not made the appropriate test year adjustments to remove capacity revenues and capacity expenses recoverable through the Capacity Cost Recovery Clause. Gulf made adjustments to remove capacity revenues and expenses from NOI currently recoverable through the Capacity Cost Recovery Clause. Included in

the adjustments are $1,652,000 in revenues currently embedded in base rates. Pursuant to Order No. PSC-01-2516-FOF-EI in Docket No. 010001-EI an adjustment should be made in this docket to Gulf's new base rate request. Accordingly, revenues shall be reduced by $1,652,000 to ensure that new base rates and the clause factors are calculated on a consistent basis. (Issue 45)

21. Gulf has made the appropriate test year adjustments to remove environmental revenues and environmental expenses recoverable through the Environmental Cost Recovery Clause. As shown on Mr. Labrato's direct testimony Exhibit RRL-1, Schedule 8 and Schedule 12, the Company has removed from NOI the environmental revenues and expenses recoverable through the Environmental Cost Recovery Clause for purposes of determining base rate revenue requirements. (Issue 46)

22. Gulf has not made the appropriate adjustments to remove lobbying expenses from the May 2003 projected test year. As shown on Mr. Labrato's direct testimony Exhibit RRL-1, Schedule 8, page 3 of 3, adjustments 13 and 24 were made consistent with the Commission's direction in the last rate case to exclude lobbying expenses. However, an additional adjustment in the amount of $7,000 jurisdictional ($7,000 system) shall also be made to remove the industry association dues for Associated Industries of Florida, as noted in the Commission Staff's audit report Exception No. 2, since these dues relate to lobbying activities. (Issue 49)

23. The appropriate amount for other post employee benefits expense is included in the May 2003 projected test year, and no adjustment shall be made. (Issue 52)

24. No adjustment shall be made to pension expense for the May 2003 projected test year. (Issue 53)

25. No adjustment shall be made to the accrual for the Injuries and Damages reserve for the May 2003 projected test year. The appropriate amount for the injuries and damages reserve accrual of $1,144,000 jurisdictional ($1,200,000 system) is included in the May 2003 projected test year. (Issue 56)

26. No interest on tax deficiencies for the May 2003 projected test year shall be included above-the-line, and the net operating income for the May 2003 projected test year does not

include any interest on tax deficiencies. (Issue 57)

27. No adjustment shall be made to Transmission Expenses for the May, 2003 projected test year. The total requested transmission O&M expenses of $7,922,000 jurisdictional ($8,210,000 system) for the May 2003 projected test year are under the benchmark and are reasonable, prudent, and necessary in order for Gulf to provide a high level of reliability to its growing number of customers. (Issue 63)

28. No adjustment shall be made to Bad Debt Expense for the May, 2003 projected test year. The amount of bad debt expense of $1,544,000 jurisdictional ($1,544,000 system) included in the May 2003 projected test year is appropriate for purposes of determining base rate revenue requirements. (Issue 70)

29. Gross receipts tax shall be removed from base rates and shown on customer bills as a separate line item. (Issue 78)

30. No adjustment shall be made to the consolidating tax adjustments for the May 2003 projected test year. (Issue 80)

31. The appropriate revenue expansion factor for Gulf is 60.3110 and the appropriate net operating income multiplier is 1.658072. These factors are different from the factors included in the Company's original filing. The numerator of the bad debt rate calculation, as shown on MFR Schedule C-58, was found to be in error. A revised calculation of the revenue expansion factor and NOI multiplier was provided in response to Staff's Interrogatory No. 75. These factors also include the gross receipts tax rate of 1.5%. The gross receipts tax was removed from total revenue requirements in the calculation of proposed base rates, since the Company is proposing to remove the gross receipts tax from base rates and show it as a separate line item on the bill.

If the Commission were to choose to remove gross receipts tax from revenues and expenses in the calculation of NOI, then the appropriate revenue expansion factor for Gulf is 61.2323 and the appropriate net operating income multiplier is 1.633125, and it would no longer be necessary to remove gross receipts tax from total revenue requirements in the calculation of proposed base rates. (Issue 83)

32. Gulf's proposed separation of costs and revenues between wholesale and retail jurisdictions is appropriate. Wholesale allocations are predominantly based upon the 12 MCP methodology with some revenues and expenses allocated upon the energy allocator. These methods are based upon cost causation. This is consistent with Gulf's prior rate case and was approved by this Commission. It also has traditionally been FERC's preferred methodology. (Issue 85)

33. Gulf has accurately applied the appropriate tariffs to the billing determinants projected for the May 2003 test year. The resulting estimated revenues from sales of electricity by rate class at present rates for the May 2003 test year as filed in this docket are appropriate. (Issue 86)

34. The method used by Gulf to develop its estimate by rate class of the 12 monthly coincident peak hour demands and the class non-coincident peak hour demands is appropriate. The method is reflected in the Cost of Service study attached to Mr. McGee's late-filed deposition exhibit no. 2. (Issue 87)

35. The appropriate service charges are listed below: (Issue 94)

Connection of Initial Service	\$27.00
Connection of Existing Service	\$27.00
Restoration of Service (after violation of rules)	\$35.00
Restoration of Service After Hours (after violation of rules)	\$55.00
Restoration of Service at Pole (after violation of rules)	\$95.00
Premise Visit	\$20.00
Connection of Temporary Service	\$110.00
Investigation of Unauthorized Use	\$75.00
Returned Item Charge \$50	\$25.00
Returned Item Charge > \$50 and \$300	\$30.00

Returned Item Charge > $300	$40.00

36. The OS-I and OS-II energy charges shall be set to recover the total non-fuel energy, demand and customer-related costs, allocated to the classes in the Commission-approved cost of service study. The maintenance charges shall be set to recover the total maintenance and associated A&G costs allocated to the classes in the Commission-approved cost of service study. The fixture, pole and other additional facilities charges shall be set to recover the remaining revenue requirement for the OS-I and OS-II classes. (Issue 95)

37. Gulf's time-of-use rates shall be designed using the Existing Time-of-Use Modification (ETM) method, as described in the response to Staff Interrogatory No. 21, for revising incumbent, or existing, commercial/industrial Time-of-Use Rates. (Issue 96)

38. The appropriate monthly charge under Gulf's GoodCents Surge Protection (GCSP) rate schedule is $3.45? (Issue 100)

39. The distribution primary and transmission transformer ownership discounts shall be calculated in the same manner they were calculated in Gulf's last rate case, using the Commission-approved cost of service study. (Issue 101)

40. The minimum monthly bill demand charge under the PX rate shall be set using the methodology described in Gulf's response to Interrogatory No. 233, as adjusted to reflect the final rates established for the PX rate. (Issue 102)

41. The minimum monthly bill demand charge under the PXT rate should be set using the methodology described in Gulf's response to Interrogatory No. 234, as adjusted to reflect the final rates established for the PXT rate. (Issue 103)

42. Gulf Power's proposed rates are designed recognizing that customers may migrate, or move, to different rates for which they are eligible but are not currently on. This occurs when rate changes make alternative rates more economical. Recognition of this migration should be handled by allowing consideration of such migrations in the rate design process, as Gulf has done. (Issue 104)

43. Gulf's GST and RST rate schedules shall be eliminated because of the historically minimal participation in these optional rates. (Issue 105)

44. Gulf's Supplemental Energy Rate Rider shall be eliminated. Gulf's Commercial/Industrial customers have other options, including Time of Use rates and the Real Time Pricing rate, that allow them to change their consumption in response to price signals. Gulf currently has no customers on the SE Rider. (Issue 106)

45. The Optional Method of Meter Payment provision in Gulf's GSDT rate schedule shall be eliminated. The Optional Method of Meter Payment is not necessary since the proposed customer charge for rate GSDT is identical to that for rate GSD. These customer charges are the same because there is no longer additional cost to the Company associated with time-of-use metering for GSDT. (Issue 107)

46. Gulf shall eliminate its OS-IV rate schedule and transfer the customers served under the rate to an otherwise applicable rate no later than 24 months after the final order in this Docket, 010949-EI. (Issue 108)

47. Gulf has proposed to eliminate the SE Rider option available to SBS customers. Consistent with Gulf's proposed elimination of the SE Rider, the proposed changes to the SBS rate should be approved. (Issue 109)

48. The monthly fixed charge carrying rate to be applied to the installed cost of OS-I and OS-II additional lighting facilities shall be calculated based on the methodology shown in Gulf's response to Staff's Interrogatory No. 42, and shall reflect the Commission-approved rate of return including the Commission-approved rate setting point ROE. (Issue 110)

49. The proposed revisions to the estimated KWH consumption of Gulf's high pressure sodium and metal halide lighting fixtures are based on manufacturer's specifications for the equipment involved, and are appropriate. (Issue 111)

50. Gulf shall add a provision to its OS-I and OS-II lighting schedules that allows customers to change to different fixtures

prior to the expiration of the initial contract lighting term. This change, requested by Gulf's customers, allows greater flexibility to customers in choosing lighting offerings during the term of their contracts. (Issue 112)

51. The Street Lighting (OS-I) and Outdoor Lighting (OS-II) subparts of Gulf's Outdoor Service rate schedule shall be merged. Merging the subparts of OS-I and OS-II serves to simplify the tariff and avoid unnecessary complication for customers and employees. (Issue 113)

52. The proposed methodology for determining the price of new street and outdoor lighting offerings shall be approved and shall be used to determine the monthly charges incorporating the Commission-approved rate of return including the rate setting point return on equity (ROE). (Issue 114)

53. Gulf's new FlatBill pilot program shall be approved provided that: 1) the fuel and other cost recovery clauses revenues associated with FlatBill customers are credited to the clauses at the then-current tariffed adjustment clause rates, and based on the customer's actual metered kWh usage; and 2) any shortfall in base rate revenues between the customer's bill at standard rates and the FlatBill revenues will be absorbed by the company. (Issue 115)

54. Gulf's new rate schedule, GSTOU, shall be approved. This is an additional option for the GSD/GSDT customers with a different structure since it does not contain a distinct demand charge. The rate is simpler for customers to understand and would allow customers to more effectively manage energy costs. (Issue 116)

55. Gulf's proposed reduction in the contract term required under its Real Time Pricing rate schedule from five years to one year is appropriate. (Issue 117)

56. Gulf's GoodCents Select Program incorporating the proposed changes to Gulf's Rate Schedule RSVP continues to be cost-effective. (Issue 118)

57. The RSVP rate schedule shall be designed so that the RSVP charges are compatible with the RS rate schedule, enhance the GoodCents Select program, and are designed consistent with the currently approved charges, as described in response to Staff's

Interrogatory No. 271. (Issue 119)

58. Gulf's proposed change to the P2 and P3 pricing periods under the RSVP rate schedule is appropriate. This change removes a disincentive for participation, and does so without negatively affecting conservation benefits. (Issue 120)

59. Gulf's proposed changes to the Participation Charge and Reinstallation Fee charged under the RSVP rate schedule are appropriate. The proposed amounts represent updated costs of the equipment that is installed and maintained in participating households. (Issue 121)

60. The proposed addition of the RSVP, GSTOU, PX, PXT, and RTP rate schedules to the Budget Billing optional rider is appropriate. (Issue 122)

61. Gulf shall be required to file, within 90 days after the date of the final order in this docket, a description of all entries or adjustments to its annual report, rate of return reports, and books and records which will be required as a result of the Commission's findings in this rate case. (Issue 124)

F. Miscellaneous

62. Staff, Gulf and OPC agree that the wholesale related costs allocated to Gulf were properly allocated and support the sale and purchase of energy and capacity for the benefit of Gulf's retail customers. Therefore, no adjustment to NOI is needed to remove wholesale costs allocated to Gulf. FIPUG, FEA and FCTA take no position. (Issue 42)

DOCKET NO. 010949-EI
DATE: April 26, 2002

ATTACHMENT 1

JURISDICTIONAL
COMPARATIVE AVERAGE RATE BASES

GULF POWER COMPANY
DOCKET NO. 010949-EI
PROJECTED TEST YEAR ENDING MAY 31, 2003
($000)

ISSUE NO.		JURIS. PER BOOKS	COMPANY ADJS.	ADJUSTED COMPANY	COMMISSION VOTE ADJS.	COMMISSION VOTE ADJUSTED
	PLANT IN SERVICE	2,037,530				
C	Remove Appliance Sales		(289)			
C	Remove ECRC Amounts		(65,763)			
C	Remove ECCR Amounts		(4,986)			
12	Security Measures (Net)				683	
16	House Power Panels				(641)	
64	Cable Injection Expense				83	
	Total Plant In Service	2,037,530	(71,038)	1,966,492	125	1,966,617
	ACCUMULATED DEPRECIATION AND AMORTIZATION	(870,595)				
C	Remove Appliance Sales		115			
C	Depreciation Study Adjustment		(1,170)			
C	Smith CC Life Adjustment		(1,690)			
C	Remove ECRC Amounts		19,037			
C	Remove ECCR Amounts		204			
S	Smith Unit 3 - 25 Year Life				1,019	
16	House Power Panels				698	
64	Cable Injection Expense				(1)	
	Total Accumulated Derpreciation & Amort.	(870,595)	16,496	(854,099)	1,716	(852,383)
	NET PLANT IN SERVICE	1,166,935	(54,542)	1,112,393	1,841	1,114,234
	CONSTRUCTION WORK IN PROGRESS	27,081				
C	Remove CWIP Eligible for AFUDC		(8,734)			
C	Remove ECRC Amounts		(414)			
C	Remove ECCR Amounts		(2,083)			
S-11	Total Construction Work in Progress	27,081	(11,231)	15,850	0	15,850
S-13	**PLANT HELD FOR FUTURE USE**	3,065	0	3,065	0	3,065
	NET UTILITY PLANT	1,197,081	(65,773)	1,131,308	1,841	1,133,149
	WORKING CAPITAL	66,244				
C	Remove Non-Utility Investments		(55)			
C	Environmental Cost Recovery Clause		583			
C	Funded Property Insurance Reserve		(8,095)			
C	Employee Loans		(797)			
C	Interest and Dividends Receivable		(180)			
C	Loss on Railcars		522			
C	Non-Current Liabilities		8,973			
9A	Office Building - 3rd Floor				(611)	
	Total Working Capital	66,244	950	67,194	(611)	66,583
	TOTAL RATE BASE	1,263,325	(64,823)	1,198,502	1,230	1,199,732

DOCKET NO. 010949-EI
DATE: April 26, 2002

ATTACHMENT 2

JURISDICTIONAL
COMPARATIVE AVERAGE CAPITAL STRUCTURES

GULF POWER COMPANY
DOCKET NO. 010949-EI
PROJECTED TEST YEAR ENDING MAY 31, 2003

GULF POWER COMPANY

	Amount ($000)	Ratio	Cost Rate	Weighted Cost Rate
Long-Term Debt	437,913	36.54%	7.08%	2.59%
Short-Term Debt	17,801	1.49%	6.02%	0.09%
Preferred Stock	99,565	8.31%	5.01%	0.42%
Common Equity	491,919	41.04%	13.00%	5.34%
Customer Deposits	13,249	1.11%	5.98%	0.07%
Deferred Taxes	121,471	10.14%	0.00%	0.00%
Investment Cr. - Wt. Cost	16,584	1.38%	9.70%	0.13%
Total	1,198,502	100.00%		8.64%

COMMISSION VOTE
Capital Structure:

	Amount ($000)	Adjustments ($000) Specific	Pro Rata	Adjusted Total ($000)	Ratio	Cost Rate	Weighted Cost Rate
Long-Term Debt	437,913	(14,957)	229	423,185	35.27%	6.44%	2.27%
Short-Term Debt	17,801	15,895	18	33,714	2.81%	4.61%	0.13%
Preferred Stock	99,565	(938)	53	98,680	8.23%	4.93%	0.41%
Common Equity	491,919		267	492,186	41.02%	12.00%	4.92%
Customer Deposits	13,249		0	13,249	1.10%	5.98%	0.07%
Deferred Taxes	121,471	662	0	122,133	10.18%	0.00%	0.00%
Investment Cr. - Wt. Cost	16,584		0	16,584	1.38%	8.99%	0.12%
Total	1,198,502	662	568	1,199,732	100.00%		7.92%

Investment Credit Weighted Cost:

	Amount	Ratio	Cost Rate	Wtd. Cost
Long Term Debt	$423,185	41.73%	6.44%	2.69%
Preferred Stock	98,680	9.73%	4.93%	0.48%
Common Equity	492,186	48.54%	12.00%	5.82%
Total	$1,014,052	100.00%		8.99%

Interest Synchronization:

	Adjustments	Cost Rate	Effect on Interest Exp.	Tax Rate	Effect on Income Taxes
Long Term Debt	($14,728)	6.44%	($948)	38.575%	$366
Short Term Debt	15,913	4.61%	734	38.575%	(283)
Customer Deposits	0	5.98%	0	38.575%	0
Investment Cr. - Wt. Cost	(134)	6.44%	(9)	38.575%	3
Total	$1,052		($223)		$86
Change in Cost Rates:					
Long Term Debt	$437,913	-0.64%	($2,803)	38.575%	$1,081
Short Term Debt	17,801	-1.41%	(251)	38.575%	97
Investment Cr. - Wt. Cost	7,055	-0.64%	(45)	38.575%	17
Total	$455,714		($3,054)		$1,195
Total Interest Synchronization					$1,282

DOCKET NO. 010949-EI
DATE: April 26, 2002

ATTACHMENT 3
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JURISDICTIONAL
COMPARATIVE NET OPERATING INCOME

GULF POWER COMPANY
DOCKET NO. 010949-EI
PROJECTED TEST YEAR ENDING MAY 31, 2003
($000)

ISSUE NO.		JURIS. PER BOOKS	COMPANY ADJS.	ADJUSTED COMPANY	COMMISSION VOTE ADJS.	COMMISSION VOTE ADJUSTED
	OPERATING REVENUES	633,347				
C	Remove Franchise Fee Revenues		(18,934)			
S-18	Remove Fuel Revenues		(221,901)			
S-19	Remove ECCR Revenues		(5,414)			
S-20	Remove PPCC Revenues		(3,455)			
S-20	Remove PPCC Revenues in Base Rates				(1,652)	
S-21	Remove ECRC Revenues		(10,929)			
78	Gross Receipts Tax				(11,110)	
	Total Operating Revenues	633,347	(260,633)	372,714	(12,762)	359,952
	OPERATING EXPENSES:					
	OPERATION & MAINTENANCE EXPENSE	411,649				
C	Remove Industry Association Dues		(15)			
C	Remove Economic Development Expenses		(53)			
C	Remove Management Tax Preparation Expenses		(4)			
C	Remove Tallahassee Liaison Office Expenses		(221)			
C	Remove Purchased Transmission Expenses		(135)			
C	Remove Marketing and Wholesale Expenses		(304)			
C	Depreciation Study Adjustment		547			
S-17	Inflation Factors				(100)	
S-18	Remove Fuel Expenses		(218,280)			
S-19	Remove ECCR Expenses		(4,312)			
S-20	Remove PPCC Expenses		(3,367)			
S-21	Remove ECRC Expenses		(3,086)			
S-22	Remove Lobbying Expenses				(7)	
47	Security Measures				744	
48	Advertising Expenses				(539)	
50A	Relocation Expense				(16)	
51	Hiring Lag				(324)	
58	Rate Case Expenses				(30)	
59	Marketing Expense				0	
64	Cable Injection Expense				(166)	
66	Tree Trimming Expenses				(930)	
68	Street & Outdoor Lighting Expenses				(320)	
	Total Operating & Maintenance Expense	411,649	(229,230)	182,419	(1,688)	180,731
	DEPRECIATION & AMORTIZATION EXP.	75,942				
C	Depreciation Study Adjustment		795			
C	Smith CC Life Adjustment		3,383			
S-19	Remove ECCR Expenses		(144)			
S-21	Remove ECRC Expenses		(2,412)			
S	Smith Unit 3 - 25 Year Life				(2,041)	
16	House Power Panels				(49)	
47	Security Measures				101	
64	Cable Injection Expense				2	
72	Office Building - 3rd Floor				(535)	
	Total Depreciation & Amortization Expense	75,942	1,622	77,564	(2,522)	75,042

DOCKET NO. 010949-EI
DATE. April 26, 2002

ATTACHMENT 3
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JURISDICTIONAL
COMPARATIVE NET OPERATING INCOME

GULF POWER COMPANY
DOCKET NO. 010949-EI
PROJECTED TEST YEAR ENDING MAY 31, 2003
($000)

ISSUE NO.		JURIS. PER BOOKS	COMPANY ADJS.	ADJUSTED COMPANY	COMMISSION VOTE ADJS.	COMMISSION VOTE ADJUSTED
	TAXES OTHER THAN INCOME	58,498				
C	Remove Franchise Fee Expenses		(18,446)			
C	Smith CC Property Tax Annualization		1,787			
C	Remove Recovery Clause Revenue Taxes		(4,307)			
C	Remove Tallahasse Office Property Taxes		(10)			
S-19	Remove ECCR Expenses		(164)			
S-21	Remove ECRC Expenses		(389)			
51	Hiring Lag				(19)	
78	Gross Receipts Tax				(11,110)	
79	Smith Unit 3 Property Taxes				(1,206)	
	Total Taxes Other Than Income	58,498	(21,529)	36,969	(12,335)	24,634
	CURRENT/DEFERRED INCOME TAXES	16,599				
C	Effect of NOI Adjustments		(4,435)		1,460	
C	Interest Synchcronization		3,682		1,282	
	Total Current/Deferred Income Taxes	16,599	(753)	15,846	2,742	18,588
	INVESTMENT TAX CREDIT	(1,462)				
	Total Investment Tax Credit	(1,462)	0	(1,462)	0	(1,462)
	(GAIN)/LOSS ON SALE OF PROPERTY	0				
	Total (Gain)/Loss on Sale of Property	0	0	0	0	0
	TOTAL OPERATING EXPENSES	561,226	(249,890)	311,336	(13,803)	297,533
	NET OPERATING INCOME	72,121	(10,743)	61,378	1,041	62,419

DOCKET NO. 010949-EI
DATE: April 26, 2002

ATTACHMENT 4

COMPARATIVE NET OPERATING INCOME MULTIPLIERS

GULF POWER COMPANY
DOCKET NO. 010949-EI
PROJECTED TEST YEAR ENDING MAY 31, 2003

	Company As Filed	**Stipulation 30** W/O Gross Receipts Tax
Revenue Requirement	100.0000%	100.0000%
Gross Receipts Tax	-1.5000%	0.0000%
Regulatory Assessment Fee	-0.0720%	-0.0720%
Bad Debt Rate	-0.1583%	-0.2416%
Net Before Income Taxes	98.2697%	99.6864%
Income Taxes @ 38.575%	-37.9075%	-38.4540%
Revenue Expansion Factor	60.3622%	61.2323%
Net Operating Income Multiplier	1.656667	1.633125

DOCKET NO. 010949-EI
DATE: April 26, 2002

ATTACHMENT 5

COMPARATIVE REVENUE REQUIREMENTS

GULF POWER COMPANY
DOCKET NO. 010949-EI
PROJECTED TEST YEAR ENDING MAY 31, 2003

	Company As Filed ($000)	**COMMISSION VOTE ($000)**
Jurisdictional Adjusted Rate Base	1,198,502	1,199,732
Required Rate of Return	8.64%	7.92%
Required Net Operating Income	103,551	95,019
Achieved Net Operating Income	(61,378)	(62,419)
Net Operating Income Deficiency/(Excess)	42,173	32,600
Net Operating Income Multiplier	1.656666	1.633125
Operating Revenue Increase/(Decrease)	69,867	53,240

GULF POWER COMPANY
DOCKET NO. 010949-EI
COMMISSION APPROVED REVENUE INCREASE BY RATE CLASS
SUMMARY OF CLASS RATES OF RETURN AND PERCENTAGE INCREASES
($ 000s)

(1)	(2)	(3)	(4)		(5)	(6)	(7)	(8)	(9)		(10)	
											% INCREASE IN REVENUE FROM SALES OF ELECTRICITY	
RATE CLASS	RATE BASE	PRESENT NOI	PRESENT ROR	PRESENT INDEX	INCREASE FROM SERVICE CHARGES	INCREASE FROM SALES OF ELECTRICITY	TOTAL INCREASE IN REVENUE	REQUIRED NOI	APPROVED ROR	APPROVED INDEX	WITH ADJUSTMENT CLAUSES	BASE
RS/RSVP	$675,728	$31,853	4.71%	0.91	$1,808	$35,348	$37,156	$54,604	8.08%	1.02	11.7%	18.6%
GS	$46,505	$3,617	7.78%	1.50	$152	$109	$261	$3,777	8.12%	1.03	0.5%	0.6%
GSD/GSDT/GSTOU	$238,613	$13,875	5.81%	1.12	$80	$8,768	$8,848	$19,292	8.09%	1.02	7.4%	13.3%
LP/LPT	$148,389	$8,611	5.80%	1.12	$0	$5,596	$5,596	$12,037	8.11%	1.02	6.6%	13.8%
OS-I/II	$36,234	$1,346	3.72%	0.71	$0	$1,343	$1,343	$2,169	5.99%	0.76	13.1%	16.9%
OS-III	$2,452	$290	11.82%	2.27	$0	$0	$0	$290	11.82%	1.49	0.0%	0.0%
OS-IV	$771	$36	4.62%	0.89	$0	$36	$36	$58	7.48%	0.94	13.2%	20.6%
CSA	$20,504	($263)	-1.28%	-0.25	$0	$0	$0	($263)	-1.28%	-0.16	0.0%	0.0%
SBS, ISS, RTP, PX, PXT	$30,537	$3,055	10.00%	1.92	$0	$0	$0	$3,055	10.00%	1.26	0.0%	0.0%
TOTAL RETAIL	**$1,199,732**	**$62,419**	**5.20%**	**1.00**	**$2,040**	**$51,200**	**$53,240**	**$95,019**	**7.92%**	**1.00**	**8.9%**	**15.2%**

GULF POWER COMPANY
DOCKET NO. 010949-EI
COMMISSION APPROVED RATES

RATE COMPONENT	PRESENT	COMMISSION APPROVED
RESIDENTIAL SERVICE (RS)		
CUSTOMER CHARGE (PER MO.):	$8.07	$10.00
NON-FUEL ENERGY CHARGE (PER KWH):	$0.03413	$0.03930
RESIDENTIAL SERVICE VARIABLE PRICING (RSVP)		
CUSTOMER CHARGE (PER MO.).	$8.07	$10.00
PARTICIPATION CHARGE (PER MO.): *	$4.53	$4.95
NON-FUEL ENERGY CHARGES (PER KWH):		
LOW	$0.01164	$0.01785
MEDIUM	$0.02301	$0.03021
HIGH	$0 07029	$0.07598
CRITICAL	$0.26746	$0.28500
GENERAL SERVICE - NON-DEMAND (GS)		
CUSTOMER CHARGE (PER MO.):	$10.09	$13.00
NON-FUEL ENERGY CHARGE (PER KWH):	$0.05026	$0.04637
GENERAL SERVICE - DEMAND (GSD)		
CUSTOMER CHARGE (PER MO.)	$40.35	$35.00
DEMAND CHARGE (PER KW):	$4.56	$5.42
NON-FUEL ENERGY CHARGE (PER KWH):	$0.01195	$0 01396
TRANS. OWNERSHIP DISCOUNT - PRIMARY (PER KW): *	($0.35)	($0 44)
GENERAL SERVICE - DEMAND TIME-OF-USE CONSERVATION (GSDT)		
CUSTOMER CHARGE (PER MO.):	$45.80	$35.00
DEMAND CHARGES (PER KW):		
MAXIMUM DEMAND	$2.17	$2.58
ON-PEAK DEMAND	$2.45	$2.91
NON-FUEL ENERGY CHARGE (PER KWH):	$0.01195	$0 01396
TRANS OWNERSHIP DISCOUNT - PRIMARY (PER KW): *	($0.35)	($0.44)
GENERAL SERVICE -TIME-OF-USE CONSERVATION (GSTOU)		
CUSTOMER CHARGE (PER MO.).	N/A	$35.00
NON-FUEL ENERGY CHARGES (PER KWH)		
SUMMER - ON-PEAK	N/A	0.16088
SUMMER INTERMEDIATE	N/A	0.05785
SUMMER - OFF-PEAK	N/A	0.02201
WINTER - ALL HOURS	N/A	0.03221

* Stipulated

GULF POWER COMPANY
DOCKET NO. 010949-EI
COMMISSION APPROVED RATES

RATE COMPONENT	PRESENT	COMMISSION APPROVED
LARGE POWER (LP)		
CUSTOMER CHARGE (PER MO.)	$226.98	$155.00
DEMAND CHARGE (PER KW):	$8.57	$8.75
NON-FUEL ENERGY CHARGE (PER KWH):	$0.00428	$0.00668
TRANS. OWNERSHIP DISCOUNT - PRIMARY (PER KW) *	($0.42)	($0.53)
TRANS. OWNERSHIP DISCOUNT - TRANS. (PER KW): *	($0.52)	($0.67)
LARGE POWER - TIME-OF-USE CONSERVATION (LPT)		
CUSTOMER CHARGE (PER MO.):	$226.98	$155.00
DEMAND CHARGES (PER KW)		
MAXIMUM DEMAND	$1.83	$1.77
ON-PEAK DEMAND	$7.27	$7.03
NON-FUEL ENERGY CHARGE (PER KWH):	$0.00316	$0.00668
TRANS. OWNERSHIP DISCOUNT - PRIMARY (PER KW): *	($0.42)	($0.53)
TRANS. OWNERSHIP DISCOUNT - TRANS (PER KW): *	($0.52)	($0.67)
**LARGE HIGH LOAD FACTOR POWER (PX) ** **		
CUSTOMER CHARGE (PER MO.):	$575.01	$566.38
DEMAND CHARGE (PER KW):	$8.32	$8.20
NON-FUEL ENERGY CHARGE (PER KWH)	$0.00308	$0.00303
TRANS. OWNERSHIP DISCOUNT - TRANS. (PER KW): *	($0.11)	($0.18)
MINIMUM BILL MAXIMUM DEMAND CHARGE (PER KW). *	$10.581	$9.859
**LARGE HIGH LOAD FACTOR POWER TIME-OF-USE CONSERVATION (PXT) ** **		
CUSTOMER CHARGE (PER MO.):	$575.01	$566.38
DEMAND CHARGES (PER KW)		
MAXIMUM DEMAND	$0.69	$0.68
ON-PEAK DEMAND	$7.73	$7.61
NON-FUEL ENERGY CHARGE (PER KWH):	$0.00305	$0.00300
TRANS. OWNERSHIP DISCOUNT - TRANS. (PER KW): *	($0.11)	($0.18)
MINIMUM BILL MAXIMUM DEMAND CHARGE (PER KW): *	$9.980	$9.819
**OTHER OUTDOOR SERVICE (OS-III) ** **		
NON-FUEL ENERGY CHARGE (PER KWH):	$0.03679	$0.03624
OUTDOOR SERVICE RECREATIONAL LIGHTING (OS-IV)		
CUSTOMER CHARGE (PER MO.):	$10.09	$13.00
NON-FUEL ENERGY CHARGE (PER KWH):	$0 03639	$0.04239

* Stipulated.
** No increases were allocated to these classes. The revised rates reflect only the removal of embedded Florida gross receipts taxes of 1 5%.

RATE COMPONENT	PRESENT	COMMISSION APPROVED
STANDBY AND SUPPLEMENTARY (SBS) **		
100 - 499 KW		
CUSTOMER CHARGE (PER MO.):	$251.98	$248.20
LOCAL FACILITIES CHARGE (PER KW OF NC AND BC):	$1.69	$1.66
RESERVATION CHARGE (PER KW OF BC):	$1.01	$0.99
DAILY DEMAND CHARGE (PER KW):	$0.47	$0.46
ON-PEAK DEMAND CHARGE (PER KW):	$2.45	$2.41
NON-FUEL ENERGY CHARGE (PER KWH):	$0.01195	$0.01177
TRANS. OWNERSHIP DISCOUNT - PRIMARY (PER KW):	($0.27)	($0.27)
500 - 7,499 KW		
CUSTOMER CHARGE (PER MO.):	$251 98	$248.20
LOCAL FACILITIES CHARGE (PER KW OF NC AND BC):	$1.25	$1.23
RESERVATION CHARGE (PER KW OF BC):	$1.01	$0.99
DAILY DEMAND CHARGE (PER KW):	$0.47	$0.46
ON-PEAK DEMAND CHARGE (PER KW):	$7.27	$7.16
NON-FUEL ENERGY CHARGE (PER KWH):	$0.00316	$0 00311
TRANS. OWNERSHIP DISCOUNT - PRIMARY (PER KW).	($0.41)	($0.41)
TRANS. OWNERSHIP DISCOUNT - TRANS. (PER KW):	($0.48)	($0.48)
ABOVE 7,499 KW		
CUSTOMER CHARGE (PER MO.):	$600.01	$591.01
LOCAL FACILITIES CHARGE (PER KW OF NC AND BC):	$0.52	$0.51
RESERVATION CHARGE (PER KW OF BC):	$1.00	$0.98
DAILY DEMAND CHARGE (PER KW):	$0.47	$0.46
ON-PEAK DEMAND CHARGE (PER KW):	$7.73	$7.61
NON-FUEL ENERGY CHARGE (PER KWH):	$0 00305	$0.00300
TRANS. OWNERSHIP DISCOUNT - TRANS. (PER KW):	($0 07)	($0.07)

** No increase was allocated to this class. The revised rates reflect only the removal of embedded Florida gross receipts taxes of 1.5%.

GULF POWER COMPANY
DOCKET NO. 010949-EI
COMMISSION APPROVED RATES

RATE COMPONENT	PRESENT	COMMISSION APPROVED
INTERRUPTIBLE STANDBY SERVICE (ISS) **		
100 - 499 KW		
CUSTOMER CHARGE (PER MO.) *	$25.00	$24.62
LOCAL FACILITIES CHARGE (PER KW OF IC):	$1.69	$1.66
RESERVATION CHARGE (PER KW OF IC):	$0.81	$0.80
SUMMER DAILY DEMAND CHARGE (PER KW):	$0.46	$0.45
WINTER DAILY DEMAND CHARGE (PER KW):	$0.34	$0.33
NON-FUEL ENERGY CHARGE (PER KWH):	$0.00357	$0.00352
TRANS. OWNERSHIP DISCOUNT - PRIMARY (PER KW):	($0.27)	($0.27)
500 - 7,499 KW		
CUSTOMER CHARGE (PER MO.) *	$25.00	$24.62
LOCAL FACILITIES CHARGE (PER KW OF IC):	$1.25	$1 23
RESERVATION CHARGE (PER KW OF IC)·	$0.81	$0.80
SUMMER DAILY DEMAND CHARGE (PER KW):	$0.46	$0.45
WINTER DAILY DEMAND CHARGE (PER KW):	$0.34	$0.33
NON-FUEL ENERGY CHARGE (PER KWH):	$0.00357	$0.00352
TRANS OWNERSHIP DISCOUNT - PRIMARY (PER KW):	($0.41)	($0.41)
TRANS. OWNERSHIP DISCOUNT - TRANS. (PER KW):	($0.48)	($0.48)
ABOVE 7,499 KW		
CUSTOMER CHARGE (PER MO) *	$25.00	$24.62
LOCAL FACILITIES CHARGE (PER KW OF IC):	$0.52	$0.51
RESERVATION CHARGE (PER KW OF IC)·	$0.81	$0.80
SUMMER DAILY DEMAND CHARGE (PER KW):	$0.46	$0.45
WINTER DAILY DEMAND CHARGE (PER KW):	$0 34	$0.33
NON-FUEL ENERGY CHARGE (PER KWH):	$0.00357	$0.00352
TRANS. OWNERSHIP DISCOUNT - TRANS. (PER KW).	($0 07)	($0.07)

* Customers also pay LP/LPT customer charge, except those taking supplementary service under PX/PXT. These customers pay the PX/PXT customer charge in addition to the ISS customer charge.

** No increase was allocated to this class. The revised rates reflect only the removal of embedded Florida gross receipts taxes of 1.5%.

GULF POWER COMPANY

DOCKET NO. 010949-EI

COMMISSION APPROVED STREET (OS-I) AND OUTDOOR (OS-II) LIGHTING RATES

			Fixture Charge		Maintenance Charge		Energy Charge		Total Monthly Charge	
Type of Facility	Description		Present	Commission Approved	Present	Commission Approved	Present	Commission Approved	Present	Commission Approved
HIGH PRESSURE SODIUM										
5,400 LUMEN	Open Bottom		$1.97	$2 42	$0 85	$1 30	$0.71	$0 56	$3.53	$4 28
8,800 LUMEN	Open Bottom		$1.77	$2.07	$0 80	$1 18	$1 02	$0 79	$3 59	$4 04
8,800 LUMEN	Acorn		$3.98	$10.32	$1 83	$3.48	$1.02	$0.79	$6 83	$14 59
8,800 LUMEN	Colonial		$3.15	$2 78	$0 77	$1.37	$1.02	$0 79	$4.94	$4.94
8,800 LUMEN	English Coach		$10 10	$11 27	$3 59	$3 74	$1.02	$0.79	$14 71	$15 80
5,400 LUMEN	Cobrahead		$1.97	$3.40	$1.35	$1 57	$0.71	$0.56	$4 03	$5 53
8,800 LUMEN	Cobrahead		$1.98	$2 84	$1 07	$1.39	$1.02	$0.79	$4.07	$5 02
20,000 LUMEN	Cobrahead		$2.28	$3.91	$1.57	$1.70	$2.06	$1.54	$5.91	$7.15
25,000 LUMEN	Cobrahead		$2.83	$3.80	$2.05	$1.68	$2.60	$1.92	$7.48	$7.40
46,000 LUMEN	Cobrahead		$3.20	$4.00	$1.62	$1.73	$4.10	$3.15	$8.92	$8 88
20,000 LUMEN	Coastal ORL	**	$4.35	N/A	$1.81	N/A	$2 06	N/A	$8.22	N/A
20,000 LUMEN	Small ORL		N/A	$9.03	N/A	$3 13	N/A	$1 54	N/A	$13.70
25,000 LUMEN	Small ORL		N/A	$8 69	N/A	$3 04	N/A	$1.92	N/A	$13 65
46,000 LUMEN	Small ORL		$7.23	$9 10	$3.29	$3.15	$4.10	$3.15	$14.62	$15.40
20,000 LUMEN	Large ORL		$9.37	$14.71	$1.81	$4 71	$2.06	$1.54	$13 24	$20 96
46,000 LUMEN	Large ORL		$9.17	$16 57	$2 02	$5.23	$4 10	$3.15	$15 29	$24 95
46,000 LUMEN	Shoebox A	**	$5.20	N/A	$2.20	N/A	$4.10	N/A	$11 50	N/A
46,000 LUMEN	Shoebox B	**	$5.12	N/A	$2.14	N/A	$4.10	N/A	$11.36	N/A
46,000 LUMEN	Shoebox	*	N/A	$7 60	N/A	$2 73	N/A	$3 15	N/A	$13 48
20,000 LUMEN	Directional		$4.31	$6.17	$1.94	$2 34	$2.14	$1.54	$8.39	$10.05
46,000 LUMEN	Directional		$3 84	$4.58	$1.81	$1 89	$4 26	$3 15	$9.91	$9.62

* *Combined rate offering*

** *Discontinued rate offering*

GULF POWER COMPANY
DOCKET NO. 010949-EI
COMMISSION APPROVED STREET (OS-I) AND OUTDOOR (OS-II) LIGHTING RATES

Type of Facility	Description		Fixture Charge Present	Fixture Charge Commission Approved	Maintenance Charge Present	Maintenance Charge Commission Approved	Energy Charge Present	Energy Charge Commission Approved	Total Monthly Charge Present	Total Monthly Charge Commission Approved
<u>HIGH PRESSURE SODIUM - PAID UP FRONT</u>										
8,800 LUMEN	Open Bottom PUF		N/A	N/A	$0.80	$1.18	$1.02	$0.79	$1.82	$1.97
8,800 LUMEN	Acorn PUF		N/A	N/A	$1.83	$3.48	$1.02	$0.79	$2.85	$4.27
8,800 LUMEN	Colonial PUF		N/A	N/A	$0.77	$1.37	$1.02	$0.79	$1.79	$2.16
8,800 LUMEN	English Coach PUF		N/A	N/A	$3.59	$3.74	$1.02	$0.79	$4.61	$4.53
8,800 LUMEN	Cobrahead PUF		N/A	N/A	$1.07	$1.39	$1.02	$0.79	$2.09	$2.18
20,000 LUMEN	Cobrahead PUF		N/A	N/A	$1.57	$1.70	$2.06	$1.54	$3.63	$3.24
25,000 LUMEN	Cobrahead PUF		N/A	N/A	$1.62	$1.68	$2.60	$1.92	$4.22	$3.60
46,000 LUMEN	Cobrahead PUF		N/A	N/A	$1.11	$1.73	$4.10	$3.15	$5.21	$4.88
46,000 LUMEN	Small ORL PUF		N/A	N/A	$3.29	$3.15	$4.10	$3.15	$7.39	$6.30
20,000 LUMEN	Large ORL PUF		N/A	N/A	$1.81	$4.71	$2.06	$1.54	$3.87	$6.25
46,000 LUMEN	Directional PUF		N/A	N/A	$1.81	$1.89	$4.26	$3.15	$6.07	$5.04
46,000 LUMEN	Shoebox PUF		N/A	N/A	$2.20	$2.73	$4.10	$3.15	$6.30	$5.88
20,000 LUMEN	Coastal ORL PUF	**	N/A	N/A	$1.81	N/A	$2.06	N/A	$3.87	N/A

** Discontinued rate offering

GULF POWER COMPANY
DOCKET NO. 010949-EI
COMMISSION APPROVED STREET (OS-I) AND OUTDOOR (OS-II) LIGHTING RATES

Type of Facility	Description		Fixture Charge Present	Fixture Charge Commission Approved	Maintenance Charge Present	Maintenance Charge Commission Approved	Energy Charge Present	Energy Charge Commission Approved	Total Monthly Charge Present	Total Monthly Charge Commission Approved
METAL HALIDE (OS-II)										
12,000 LUMEN	Acorn - NEW	+	N/A	$10.42	N/A	$4.38	N/A	$1.38	N/A	$16 18
12,000 LUMEN	Colonial - NEW	+	N/A	$2 88	N/A	$2 29	N/A	$1.38	N/A	$6 55
12,000 LUMEN	English Coach - NEW	+	N/A	$11.37	N/A	$4.65	N/A	$1 38	N/A	$17 40
32,000 LUMEN	Small Flood		$2.75	$4 68	$1 92	$2.03	$4 10	$3.13	$8.77	$9.84
32,000 LUMEN	Parking Lot A	**	$8.17	N/A	$3.48	N/A	$4 10	N/A	$15 75	N/A
32,000 LUMEN	Parking Lot B	**	$8 10	N/A	$3 38	N/A	$4.10	N/A	$15.58	N/A
32,000 LUMEN	Parking Lot	*	N/A	$8.65	N/A	$3.14	N/A	$3.13	N/A	$14.92
100,000 LUMEN	Large Flood		$4.48	$6 72	$3 79	$4.02	$9.46	$7 27	$17 73	$18.01
100,000 LUMEN	Large Parking Lot		$11 81	$14 93	$5 14	$5.57	$9 46	$7.27	$26.41	$27.77
METAL HALIDE (OS-II) PAID UP FRONT										
32,000 LUMEN	Parking Lot PUF		N/A	N/A	$3.48	$3 14	$4 10	$3.13	$7.58	$6 27
32,000 LUMEN	MTRD Pk Lot PUF		N/A	N/A	$3 48	$3.14	N/A	N/A	$3.48	$3 14
MERCURY VAPOR										
7,000 LUMEN	Open Bottom		$1 42	$1 68	$0 66	$1 04	$1 71	$1 29	$3.79	$4.01
3,200 LUMEN	Cobrahead		$1 45	$3.11	$1.41	$1.46	$0 99	$0 75	$3.85	$5.32
7,000 LUMEN	Cobrahead		$1.44	$2.83	$1.05	$1.36	$1 71	$1.29	$4.20	$5.48
9,400 LUMEN	Cobrahead		$1 93	$3.71	$1 67	$1.66	$2.42	$1 83	$6 02	$7 20
17,000 LUMEN	Cobrahead		$2.24	$4.05	$1.75	$1.73	$3.87	$2.92	$7.86	$8 70
48,000 LUMEN	Cobrahead		$6 08	$8.14	$3.19	$3.00	$9.48	$7 15	$18 75	$18.29
17,000 LUMEN	Directional		$4.15	$6 10	$1.86	$2.31	$4.15	$3.13	$10 16	$11 54
CUSTOMER-OWNED MISC. STREET/ OUTDOOR LIGHTING (OS-I/II)			N/A	N/A	N/A	N/A	$0 02549 per KWH	$0.01923 per KWH	$0.02549 per KWH	$0.01923 per KWH

+ New rate offering
* Combined rate offering
** Discontinued rate offering

GULF POWER COMPANY

DOCKET NO. 010949-EI

COMMISSION APPROVED STREET (OS-I) AND OUTDOOR (OS-II) LIGHTING RATES

		Fixture Charge		Maintenance Charge		Energy Charge		Total Monthly Charge	
Type of Facility	Description	Present	Commission Approved	Present	Commission Approved	Present	Commission Approved	Present	Commission Approved
CUSTOMER OWNED W/RELAMPING SERVICE AGREEMENT - HIGH PRESSURE SODIUM VAPOR									
8,800 LUMEN	Unmetered	N/A	N/A	$0.32	$0 53	$1.02	$0.79	$1.34	$1 32
20,000 LUMEN	Unmetered	N/A	N/A	$0 34	$0.54	$2.06	$1 54	$2.40	$2.08
25,000 LUMEN	Unmetered	N/A	N/A	N/A	$0 55	N/A	$1.92	N/A	$2 47
46,000 LUMEN	Unmetered	N/A	N/A	$0.34	$0 54	$4 10	$3 15	$4 44	$3 69
8,800 LUMEN	Metered	N/A	N/A	$0 32	$0 53	N/A	N/A	$0 32	$0.53
20,000 LUMEN	Metered	N/A	N/A	N/A	$0.54	N/A	N/A	N/A	$0 54
25,000 LUMEN	Metered	N/A	N/A	$0.35	$0 55	N/A	N/A	$0.35	$0 55
46,000 LUMEN	Metered	N/A	N/A	$0.34	$0 54	N/A	N/A	$0.34	$0.54
CUSTOMER OWNED W/RELAMPING SERVICE AGREEMENT - METAL HALIDE									
32,000 LUMEN	Unmetered	N/A	N/A	$0 76	$0 65	$4 10	$3.13	$4.86	$3 78
32,000 LUMEN	Metered	N/A	N/A	N/A	$0 65	N/A	N/A	N/A	$0.65
HIGH PRESSURE SODIUM VAPOR - CUSTOMER OWNED/CUSTOMER MAINTAINED									
8,800 LUMEN	Customer-Owned	N/A	N/A	N/A	N/A	$1.02	$0.79	$1 02	$0.79
20,000 LUMEN	Customer-Owned	N/A	N/A	N/A	N/A	$2.06	$1.54	$2 06	$1.54
46,000 LUMEN	Customer-Owned	N/A	N/A	N/A	N/A	$4.10	$3.15	$4.10	$3.15
METAL HALIDE - CUSTOMER OWNED/ CUSTOMER MAINTAINED									
32,000 LUMEN	Customer-Owned	N/A	N/A	N/A	N/A	$4.10	$3.13	$4 10	$3.13

GULF POWER COMPANY

DOCKET NO 010949-EI

COMMISSION APPROVED STREET (OS-I) AND OUTDOOR (OS-II) LIGHTING RATES

Type of Facility		Fixture Charge Present	Fixture Charge Commission Approved	Maintenance Charge Present	Maintenance Charge Commission Approved	Energy Charge Present	Energy Charge Commission Approved	Total Monthly Charge Present	Total Monthly Charge Commission Approved
ADDITIONAL FACILITIES									
13 Ft Decorative Concrete Pole		N/A	N/A	N/A	N/A	N/A	N/A	$9 29	$12.20
20 Ft. Fiberglass Pole		N/A	N/A	N/A	N/A	N/A	N/A	$3.05	$4.53
30 Ft. Wood Pole		N/A	N/A	N/A	N/A	N/A	N/A	$2.02	$2.93
30 Ft Concrete Pole		N/A	N/A	N/A	N/A	N/A	N/A	$4 54	$6.15
30 Ft. Fiberglass Pole w/Pedestal		N/A	N/A	N/A	N/A	N/A	N/A	$22 33	$29.08
35 Ft. Concrete Pole		N/A	N/A	N/A	N/A	N/A	N/A	$4 36	$8.94
35 Ft Concrete Pole (Tenon Top)	+	N/A	N/A	N/A	N/A	N/A	N/A	N/A	$12 35
35 Ft. Wood Pole		N/A	N/A	N/A	N/A	N/A	N/A	$2.17	$4.27
40 Ft. Wood Pole		N/A	N/A	N/A	N/A	N/A	N/A	$3 74	$5 24
45 Ft Concrete Pole (Tenon Top)		N/A	N/A	N/A	N/A	N/A	N/A	$7 10	$16 22
Single Arm - Shoebox	**	N/A	N/A	N/A	N/A	N/A	N/A	$0 80	N/A
Single/Double Arm - Parking Lot	**	N/A	N/A	N/A	N/A	N/A	N/A	$0 78	N/A
Single Arm - Shoebox/Small Parking Lot	*	N/A	N/A	N/A	N/A	N/A	N/A	N/A	$1.69
Double Arm - Shoebox	**	N/A	N/A	N/A	N/A	N/A	N/A	$1 80	N/A
Double Arm - Shoebox/Small Parking Lot	*	N/A	N/A	N/A	N/A	N/A	N/A	N/A	$1.88
Triple Arm - Shoebox	**	N/A	N/A	N/A	N/A	N/A	N/A	$1.89	N/A
Triple Arm - Small Parking Lot	**	N/A	N/A	N/A	N/A	N/A	N/A	$2 51	N/A
Triple Arm - Shoebox/Small Parking Lot	*	N/A	N/A	N/A	N/A	N/A	N/A	N/A	$2.56
Quadruple Arm - Shoebox	**	N/A	N/A	N/A	N/A	N/A	N/A	$2.10	N/A
Quadruple Arm - Small Parking Lot	**	N/A	N/A	N/A	N/A	N/A	N/A	$2.53	N/A
Quadruple Arm - Shoebox/Small Parking L	*	N/A	N/A	N/A	N/A	N/A	N/A	N/A	$3.22
Tenon Top Adapter		N/A	N/A	N/A	N/A	N/A	N/A	$2.76	$3.14
Optional 100 Amp Relay		N/A	N/A	N/A	N/A	N/A	N/A	$14.51	$17.58
25 KVA Padmount Transformer C		N/A	N/A	N/A	N/A	N/A	N/A	$24 28	$34 67
25 KVA Padmount Transformer NC		N/A	N/A	N/A	N/A	N/A	N/A	$18.71	$24.33
Miscellaneous Additional Facilities		N/A	N/A	N/A	N/A	N/A	N/A	1 78% of installed cost	1.74% of installed cost

+ New rate offering
* Combined rate offering
** Discontinued rate offering