State of Florida

Public Service Commission

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TALLAHASSEE, FLORIDA 32399-0850

-M-E-M-O-R-A-N-D-U-M-

DATE: August 31, 2018

TO: Carlotta S. Stauffer, Commission Clerk, Office of Commission Clerk

FROM: Samantha Cibula , Office of the General Counsel S.M.C.

RE: Docket No. 20030714-EI

Please file the attached materials in the docket file listed above.

Thank you.

Attachment

20030714

STATE OF FLORIDA

OFFICE OF THE GENERAL COUNSEL
RICHARD MELSON
GENERAL COUNSEL
(850) 413-6199

Public Service Commission

November 13, 2003

Mr. John Rosner
Joint Administrative Procedures Committee
Room 120 Holland Building
Tallahassee, FL 32399-1300

Re: Rule 25-6.04364, F.A.C.

Dear Mr. Rosner:

This letter is in response to your letter of October 30, 2003, asking for an explanation about the following subsections of Rule 25-6.04364, F.A.C.:

(1) The Commission will approve a dismantlement accrual if it finds that it is sufficient to recover the costs and accumulate the reserve needed to meet all estimated expenses at the time of dismantlement.

(3) The Commission will require a dismantlement study for a generating site less often or more often on a case-by-case basis if the evidence shows a shorter or longer period is justified because of such things listed in subsection (1) of the rule: "new developments, additional information, technological improvements, and forecasts", which may render inaccurate the existing cost estimates.

(6) The Commission will approve new or revised accruals or transfers of reserves on a case-by-case basis if the evidence justifies a change; for instance, based on current cost estimates which come from the study, if the current accrual is too much or too little to recover costs by the time of dismantlement. A new accrual is needed when there isn't an existing one and a new generating plant becomes commercially operational. Since the accruals have to be approved by the Commission in the first instance, the utility cannot change the accrual or transfer reserves without Commission approval.

It is important to understand that none of the above actions are taken without consideration by the Commissioners at a public agenda conference in which the utility has the opportunity to participate, unless there has already been a section 120.569 or 120.57, Florida Statutes, hearing. If there has not been a hearing, then the Commission's decision at the agenda conference is proposed agency action that affords the affected parties an opportunity for a section 120.569 or 120.57 hearing. As I think you can see from the enclosed orders, establishment of dismantlement accruals requires an individualized inquiry and a decision based on the individual circumstances, and further detail in the establishment of criteria for approval is not reasonable.

I hope this letter satisfactorily responds to your inquiry.

Sincerely,

Christiana T. Moore

Christiana T. Moore
Associate General Counsel

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for 1999 depreciation study by Tampa Electric Company.	DOCKET NO. 990529-EI ORDER NO. PSC-00-0603-PAA-EI ISSUED: March 29, 2000

The following Commissioners participated in the disposition of this matter:

JOE GARCIA, Chairman
J. TERRY DEASON
SUSAN F. CLARK
E. LEON JACOBS, JR.
LILA A. JABER

NOTICE OF PROPOSED AGENCY ACTION
ORDER REVISING DEPRECIATION RATES AND APPROVING RECOVERY/AMORTIZATION SCHEDULES

AND

ORDER APPROVING PRELIMINARY IMPLEMENTATION ASSOCIATED WITH REPOWERING OF GANNON STATION

BY THE COMMISSION:

NOTICE is hereby given by the Florida Public Service Commission that the action discussed herein, except for those matters addressing the planned repowering of Gannon Station, is preliminary in nature and will become final unless a person whose interests are substantially affected files a petition for a formal proceeding, pursuant to Rule 25-22.029, Florida Administrative Code. The actions associated with the planned repowering of Gannon Station will be proposed for final action, with a point of entry to a proceeding pursuant to Sections 120.569 and 120.57, Florida Statutes, in a future order.

I. CASE BACKGROUND

Rule 25-6.0436, Florida Administrative Code, requires investor-owned utilities to file comprehensive depreciation studies at least once every four years. On April 28, 1999, Tampa Electric Company (TECO or company) filed its regular depreciation study in accordance with this rule. TECO also requested preliminary implementation of its proposed depreciation rates, general plant amortizations, recovery schedules, and fossil dismantlement accrual as of January 1, 1999, in accordance with Rule 25-6.0436(5), Florida Administrative Code. By Order No. PSC-99-1398-PCO-EI, issued July 21, 1999, this request was approved. The docket remained open pending review and Commission action concerning the appropriate depreciation rates and recovery schedules under consideration and a true-up.

On December 16, 1999, TECO and the Florida Department of Environmental Protection (DEP) entered into a Consent Final Judgement (CFJ). DEP had claimed that TECO modified and then operated its generating units at Big Bend and Gannon without first obtaining permits authorizing the modifications and without installing the best available technology to control nitrogen oxides, sulfur dioxides, and particulate matter. The CFJ requires TECO to cease burning coal at the Gannon Station by year-end 2004 and repower some of the units with natural gas. Docket No. 992014-EI was opened to address TECO's request for approval of its planned implementation of the CFJ.

On February 29, 2000, TECO entered into an agreement with the United States Environmental Protection Agency (EPA) and the United States Department of Justice (DOJ) concerning alleged environmental violations in the operation of TECO's power plants. TECO's agreement with EPA and DOJ is in the form of a consent decree. TECO states that the requirements of the consent decree are substantially the same as the earlier agreement with DEP. One difference is that TECO's obligations under the consent decree are not conditioned upon appropriate regulatory approval. TECO has since filed a Notice of Withdrawal of its Petition in Docket No. 992014-EI.

The planned repowering of Gannon Station will result in a significant portion of the coal-related assets at the Gannon Station being retired by December 31, 2004. This was not reflected in the filed depreciation study. On December 21, 1999, TECO submitted an update to its depreciation study addressing recovery of the planned near-term retirements at the Gannon Station. The company requested that the coal-related assets at Gannon Common and Units 1 through 6 planned for retirement by year-end 2004 be considered in the instant docket and a recovery schedule be implemented effective January 1, 2000 to account for the changes from the initial depreciation study.

On January 11, 2000, TECO filed its response to the staff's initial report regarding TECO's depreciation study. TECO submitted several updates to its data and analyses on January 14, 26, 28, and February 3, 2000.

By Order No. PSC-99-1398-PCO-EI, preliminary implementation of depreciation rates, general plant amortizations, recovery schedules, and fossil dismantlement accrual was approved. We have completed our analysis and review of the Company's depreciation study and, the preliminary implemented expenses approved in Order No. PSC-99-1398-PCO-EI shall be trued-up if this proposed action becomes final.

II. <u>CORRECTIVE RESERVE ALLOCATIONS</u>

We find after a comprehensive review of the depreciation study, that certain corrective reserve allocations are required to address certain accounts with major imbalances. The corrective reserve allocations shall be made as shown on Attachment A, pages 27-29.

This study afforded us the opportunity to review the reserve status of all production sites and all transmission, distribution, and general plant accounts to determine the need for corrective reserve measures. Due to the effects reserve transfers may have on jurisdictional separations, purchase power agreements, or other lease arrangements, our approach to reserve allocations is that, ideally they are made between accounts of a given unit or function.

In TECO's 1995 depreciation study, reserve allocations were approved as a result of the company's further stratification of the Big Bend and Gannon sites and the related Big Bend combustion turbines to an account level within each unit. For the remaining plant sites, investment and reserve activity continued to be maintained by unit at each plant. In the current study, the company has introduced another refinement by stratifying each unit of the remaining production plants to an account level. With the development of remaining life rates at the account level, TECO proposed a reallocation of the total reserve for each unit to an account level. The company also proposed additional reserve allocations for several accounts within the Distribution and General Plant functions. Each account's reserve was aligned with its theoretically correct level, as developed using the rates and parameters proposed in the company's originally filed study.

The reserve allocations we now approve incorporate the depreciation parameters approved in Section VI and address major imbalances generally brought about through the stratification of site investments and reserves to an account by unit level and past mis-estimates of life and salvage factors. Further, the allocations address imbalances between accounts of a given unit or function or between accounts and units of the same site. The allocations bring each affected account's reserve more in line with its calculated theoretically correct position. Additionally, we are not approving reserve allocations within the Gannon Station due to the near-term retirement of the coal related assets. While there are imbalances between accounts, the station has an overall reserve surplus which can be used to reduce the net unrecovered costs of the coal related retiring assets. We, thereby, approve the allocations shown on Attachment A.

III. IMPLEMENTATION DATE

As a result of the planned repowering of Gannon Station, TECO provided an update of the depreciation provision for the Gannon Station on December 21, 1999. In the update, TECO proposed that depreciation rates approved on a preliminary basis by Order No. PSC-99-1398-PCO-EI, be used for all accounting and ratemaking purposes in 1999. Additionally, the company proposed that any revisions to the interim approved depreciation rates as well as provision for the Gannon retiring assets be implemented January 1, 2000, rather than January 1, 1999.

In support of its proposal, the company asserts that the Gannon repowering was not known until the end of 1999, and therefore it would be inappropriate to begin recovery of the resulting retiring assets in 1999. Additionally, the company submits that the Stipulation between the Office of Public Counsel, the Florida Industrial Power Users Group, and TECO that was approved by Order No. PSC-96-1300-S-EI precludes proforma adjustments when determining the actual return on equity for calendar year 1999. The company claims that a February 29, 2000, Commission decision in this docket necessitates that its 1999 surveillance report include a proforma adjustment which is not allowed by the Stipulation.

We do not agree that a January 1, 1999, implementation date results in a proforma adjustment. Use of our stated implementation date results in the anticipated true-up to actual of an earlier estimate. The earlier estimate is already included in TECO's 1999 operations. There is no restatement of 1999 operations due to abnormal events. The true-up was anticipated and was provided for at the time of preliminary implementation which was effective back to January 1, 1999, as filed by TECO. No adjustments are being made that spread partial period effects over all of 1999. No out-of-period adjustments are involved. The January 1, 1999 implementation date is not the result of nor does it create an adjustment for attrition. Implementation of the true-up at January 1, 1999, is simply not a proforma adjustment.

Preliminary implementation was approved by Order No. PSC-99-1398-PCO-EI, which also approved the January 1, 1999, implementation date proposed by TECO, for revised rates, recovery/amortization schedules, and dismantlement accruals. Further, the order clearly states that a final recommendation regarding appropriate rates and recovery schedules was to be brought before the Commission in early 2000. It was not until late December that we received a proposal for a January 1, 2000, implementation date.

The purpose of preliminary implementation of depreciation rates is to permit a more accurate statement of expected expenses during the year. The caveat, as stated in the order, is that these preliminary approved rates and expenses will be trued-up when final action is taken by the Commission. This supports a January 1, 1999, implementation date.

Additionally, Rule 25-6.0436, Florida Administrative Code, requires that data submitted in a depreciation study, including plant and reserve balances or company planning involving estimates, be brought to the effective date of the proposed rates. Reserve sensitive rates (remaining life) are calculated by dividing the amount recovered to date by the estimated remaining years to recover. Therefore, the date of implementation must match the date net plant is calculated. Further, to the extent that unusual plant activity occurs, the average age of the surviving investments can change and, therefore, so will the average remaining life. Except for the impact of the CFJ on the Gannon Station, the only data submitted in this case is as of January 1, 1999. It is clear that these rates and schedules were designed for a January 1, 1999 implementation date.

Depreciation rates should theoretically be revised as soon as circumstances dictate the need for a revision. Since the planned repowering of Gannon Station was not announced until December 16, 1999, we agree with TECO that the earliest practicable date for preliminary implementation of a recovery schedule and revised depreciation rates for the Gannon Station is January 1, 2000. Further, the company provided the necessary data and calculations abutting this date in its December 21, 1999, update.

Therefore, we find that the implementation date of the approved rates and schedules for depreciation rates, amortizations, recovery schedules, and fossil dismantlement accruals shall be January 1, 1999, except for those assets associated with the planned repowering of Gannon Station. To recognize the impact of the planned repowering of the Gannon Station units, the implementation date for the preliminary implementation of the associated recovery schedule addressing the now planned retiring assets and additional revised depreciation rates for those assets remaining in service with the repowering shall be January 1, 2000.

IV. RECOVERY SCHEDULES

The appropriate recovery schedules shall be set forth below. Recovery schedules are shown on Attachment B, page 30, addressing the unrecovered investments associated with TECO's planned retirement of its Energy Management System, coal classifiers, and the planned retirements associated with the coal related assets at the Gannon Station.

Energy Management System

TECO's Energy Management System (EMS) is an installation designed for the specific purpose of facilitating the systematic transmission, distribution, and delivery of electric energy to customers. It monitors the power network, automatically controls generation and interchange, forecasts the power network state, and performs other specialized functions. The current environment of open transmission access and transmission constraints demands flexibility and speed in the company's daily operations. The present EMS technology is approximately 18 years old. Since 1995 TECO has pursued an EMS Strategic Plan to phase out this obsolete equipment by migrating from a mainframe work environment to decentralized, individual workstations which will provide more advanced software applications with greater flexibility. This migration will be complete by year-end 2000 resulting in the retirement of the existing EMS equipment. The company proposed recovery schedule is designed to recover the associated net investment over a two year period beginning January 1, 1999. This schedule will match recovery to the remaining service of the equipment and is acceptable to us. The investment and reserve as of January 1, 1999 are $33,144,637, and $26,703,342, respectively, resulting in a net unrecovered amount of $6,441,295 to be amortized over two years. The annual expense associated with this recovery schedule is $3,220,648.

Coal Classifiers

According to the study narrative, the replacement of coal classifiers and the addition of the Big Bend Unit 1 & 2 Scrubber are being installed in connection with the Clean Air Act. The January 1, 1999, investment subject to retirement as a result of this installation is $414,272 with an associated reserve of $279,158. It is our understanding from information TECO submitted in the Environmental Cost Recovery Clause docket (Docket No. 990007-EI) that the replacement of the coal classifiers occurred at Big Bend Unit No. 1 and Unit No. 2 and at Gannon Unit No. 5 and Unit No. 6 in December and May, 1998 for the Big Bend units, and December, 1997 and June, 1999 for the Gannon units. The associated $135,114 unrecovered investment relates to a plant no longer in service. For this reason, we believe it is necessary to implement a recovery schedule designed to recover the investment as fast as economically practicable for the company.

TECO disagrees with the need for a recovery schedule addressing these net remaining investments. The company believes the related net unrecovered investment is not significant enough to warrant a recovery schedule. Furthermore, the company asserts that such a recovery schedule will result in increased expenses greater than the related annual recovery from base rates. TECO therefore believes that, if a recovery schedule is approved, the incremental revenue recovery should be provided through the ECRC.

We find that a recovery schedule is needed in this instance even though the net investment is only $135,114. These assets have already retired and the resulting under-recovery relates to a negative component in the reserve. The company will continue earning a return on this plant no longer in service until the deficiency is corrected. At this time, recovery will be achieved over each unit's remaining life averaging about 17 years. Ratepayers who do not receive continuing benefits from these assets will continue to bear the burden of their recovery. This argues for recovery as fast as economically practicable. A review of the company's 1999 earnings indicates that the company can amortize this deficiency during 1999 and still earn within is currently authorized range of rate of return. We therefore order these net investments be amortized during 1999.

<u>Gannon Retirements</u>

According to the company, the effect of the planned repowering at Gannon Station will result in the retirement of many of the coal related assets at Gannon. The current plan is to repower the coal-fired Units 3, 4, and 5 with gas fired combined cycle technology using the existing combustion steam turbines. After these units are repowered, the original boilers of Units 1 through 5 and the station's coal handling system will be retired and the Gannon Station will be natural gas fueled with fuel oil capability.

According to the company, initial detailed engineering for the project will begin this month. Phase I will place Unit 5 into commercial operation in mid-2003. Phase II will include the repowering of Units 3 and 4, currently anticipated in mid-2004.

The steam turbine equipment at Units 1 and 2 will be placed on reserve standby by year-end 2004 in expectation of a need for additional phases. At the completion of Phase II, the total station capacity will increase from about 1,150 MW to 1,475 MW.

At this time, TECO plans to place Unit 6 on reserve standby to be used as emergency capacity. The company asserts that this unit can be quickly converted to burn natural gas if additional capacity is needed for a time while other units are on an unplanned outage or if load growth exceeds current projections. Additionally, the capacity provides back-up while the new, repowered units are in the initial period of operation. TECO states that keeping the assets and Unit 6 in service will provide the operating flexibility needed to ensure reliability. Further, the company will continue to monitor the viability of the plan for Unit 6 and will provide details of any changes to the Commission.

The company has estimated the investment and reserve as of January 1, 2000, associated with the plant currently anticipated to be retired as a result of the repowering project to be $287,686,788 and $221,428,929, respectively. No removal costs are anticipated as the company states that it will be unnecessary to physically remove the retired assets in order to complete the repowering project. These assets are anticipated to remain at the station and be removed when the station is retired and dismantled. The company has proposed a recovery schedule for the net investment of $66,257,859 for the retiring assets to begin January 1, 2000, and conclude December 31, 2004, coinciding with the date coal will no longer be burned at Gannon pursuant to the agreement with the DEP. Additionally, the company believes January 1, 2000, is the earliest, most practical date to implement recovery given approval of the agreement with the DEP in December, 1999.

The company forecasts that $7.5 million will be added at the Gannon Station prior to repowering. These short-lived additions are needed to maintain the reliability of the system and to protect the safety of the employees at the site. The company proposes that these additions be recovered over the period the equipment will be serving the public; i.e., 2000 additions amortized over the 2000-2004 period, 2001 additions amortized over the 2001-2004 period, 2002 additions amortized over the 2002-2004 period, 2003 additions amortized over the 2003-2004 period, and the 2004 additions amortized during 2004.

To assure full recovery of the net investment and forecasted additions subject to retirement by year-end 2004, the expense for each month shall be obtained by dividing net plant of each unit for that month by the months remaining in the amortization period. We believe this will provide flexibility of retirement recovery in the event of changes in estimates. Additionally, this recovery approach has been followed by the Commission in prior telecommunications depreciation cases.

A recovery schedule is therefore approved, on a preliminary basis, effective January 1, 2000. We will review this schedule for a true-up of associated investments and expenses for 2000 after a thorough analysis of the repowering.

V. APPROPRIATE ANNUAL PROVISION FOR DISMANTLEMENT

We approve a 1999 provision for dismantlement of $7,153,489 as shown on Attachment C, page 31.

Additionally, beginning January 1, 2000, an annual dismantlement provision for the Gannon Station of $711,297 to reflect the plan for repowering shall be established. Further, we approve an annual dismantlement provision of $235,177 for the Big Bend Unit 1 & 2 Scrubber with an in-service date of January 1, 2000. The effect of repowering the Gannon Station and the addition of the Big Bend Unit 1 & 2 Scrubber will result in a 2000 provision for dismantlement of $5,660,618.

For other plant under construction, we approve an annual provision for dismantlement of $109,196 for Polk Unit No. 2 and for any other new combined cycle units planned for service during the 1999-2002 period to begin when each unit goes into service.

By Order No. 24741, issued July 1, 1991, in Docket No. 890186-EI, we established the methodology for accruing the costs of dismantlement. Electric utilities are required to file dismantlement studies at least once every four years in connection with their depreciation studies. The methodology depends on three factors: estimated base costs of dismantling the fossil-fueled plants, projected inflation, and a contingency factor.

By Order No. PSC-99-1398-PCO-EI, an annual dismantlement provision of $7,531,503 that incorporated a 20% contingency factor was approved for preliminary implementation purposes. This provision was subsequently found to be understated by about

$451,000 because of our reliance on data believed to be the Winter 1999 inflation forecast. TECO's proposed annual accrual for the provision of dismantlement of fossil-fueled generating plants is $6,295,975 and represents a decrease of $3,822,825 from the annual accrual of $10,118,800 approved in the last dismantlement study. The accrual decrease is attributed to use of a lower contingency factor and lower inflation forecasts.

In TECO's last dismantlement study, a reduction in the dismantlement provision was indicated, but the company requested that the annual accrual remain at the previous level and an accrual be approved for the Polk Power Station. The company believed that reducing the annual dismantlement accrual was premature due to the limited recovery at that time for dismantlement, and the uncertainty of the long-term outlook of the Data Resources Incorporated indices. At this time, the company believes that after an additional four year period the reduction is warranted based on its dismantlement reserve position and the continued trend of the DRI indices.

Since the last study, TECO's base cost estimates for the various dismantlement activities have changed. The 1994 study indicated base cost estimates of $85.6 million excluding Polk Unit 1; current cost estimates are $92.4 million excluding Polk Unit 1 and $110.3 million including Polk Unit 1. According to the company, Wharton Econometrics Forecasts Associates (WEFA) inflation indices were used rather than DRI indices in the calculation of its proposed dismantlement accrual. Additionally, the company used a 20% contingency factor in the last study; a 10% contingency factor is used in the current study.

In the current filing, TECO has proposed that the Commission recognize the decrease in projected inflation as indicated by an additional four year period of DRI indices. The company believes that the continued trend of the DRI indices warrants a reduction in the annual dismantlement accrual. Additionally, the company proposes decreasing the contingency factor from 20% to 10%.

TECO's proposed 10% contingency factor is comprised of 5% for quantity variations and 5% for pricing variances. The company states that as of December 31, 1998, the accumulated dismantlement reserve is $85,465,982 compared to a total dismantling estimate of

$121,366,655, inclusive of a 10% contingency. TECO believes this position provides it with a reserve ratio of over 70% and enough capital to dismantle all of its units with the exception of the Polk Power Station and the Big Bend Unit No. 4, the newest units. For this reason, the company believes a 10% contingency factor is appropriate.

The company believes that a contingency factor is not really necessary since a professional dismantlement contractor provided the necessary information and rates to complete the dismantlement study. According to TECO, the contractor would contract the dismantlement of its units for the prices quoted and a final true-up for actual quantities removed as compared to the estimated quantities depicted in the dismantlement studies. Although TECO does not believe any contingency is necessary, the company asserts that a 10% contingency factor was included because of recent Commission decisions regarding dismantlement. TECO maintains that any higher contingency is not warranted based on the preparation of the dismantlement study, the current dismantlement reserve status, and the continued forecast of favorable escalation indices in the short term and long term future.

We note that in TECO's last dismantlement study, increases in base costs were more than offset by decreases in projected inflation. At that time, TECO stated "with the uncertainties inherent in estimating the cost of dismantling a plant fifty years in the future, the company feels it is too early to begin to reduce accruals for this cost." Further, the company opined that if the decrease in inflation projections were recognized, a 20% contingency factor should be used to mitigate the reduction to the annual accrual. As a result, no change in the dismantlement accrual levels was made. The assumptions inherent in the 1995 prescribed accruals were base cost estimates resulting from a 1991 site specific dismantlement cost study, a 20% contingency factor, and inflation indices based on the 1991 DRI Summer forecast.

A contingency is defined in the American Association of Cost Engineers' Cost Engineers' Notebook as a "specific provision for unforeseeable elements of cost within the defined project scope; particularly important where previous experience relating estimates and actual costs has shown that unforeseeable events which will increase costs are likely to occur." Such unforeseeable events include bad weather, labor strikes, equipment failure, and other unforeseen circumstances. Contingencies are not a means to "cushion" estimates or to account for inflation. They are used solely to assure that adequate funds are available in the event that something unpredictable, as well as costly, occurs while in the process of dismantling a fossil-fueled generating plant.

The contingency factor is commonly a weighted average of the item-by-item contingency factors applied to plant-specific categories in the cost estimate. The individual item contingency factors usually reflect the degree of uncertainty associated with each cost estimate. We agree with TECO that updating dismantlement cost estimates every four years should certainly minimize the unforeseen components of costs but, we also believe that such updates will not completely eliminate unforeseen events. Contingency factors are found in nearly all engineering, consulting, construction, and demolition estimates as an appropriate provision in cost estimates.

We note that initial dismantlement cost estimates filed by utilities in accordance with Order No. 24741 included a 20% contingency factor. Since that time, contingency factors have generally decreased. The most recent utility to revise its dismantlement accruals was Florida Power and Light Company(FPL) in Docket No. 981166-EI. Order No. PSC-00-0293-PAA-EI, issued February 14, 2000, approved a revised dismantlement provision for FPL that included a 16% contingency factor. By Order No. PSC-98-0921-FOF-EI, issued July 7, 1998, in Docket No. 970643-EI, the Commission approved a revised dismantlement provision for Gulf Power Company that included a 10% contingency factor. The current dismantlement provision for Florida Power Corporation was approved by Order No. PSC-94-1331-FOF-EI, issued October 27, 1994, in Docket No. 931142-EI, where we denied a decrease in the contingency factor and maintained the factor at 20%.

We remain concerned with decreasing the annual accrual when the decrease is totally due to projections of inflation and a decrease in the contingency factor. The preliminary implementation resulted in an annual decrease in the dismantlement provision of approximately $2.6 million, all of which is related to lower DRI forecasts even though the actual dismantlement base cost estimates increased. Nevertheless, it does appear that the 20% contingency estimate has decreased over time. For this reason, we order the use of a 15% contingency factor. Updating for the most current DRI indices, Summer 1999, and using a 15% contingency results in an annual dismantlement accrual of $7,153,489, as shown on page 31. This reflects a decrease of $378,014 from the annual accrual approved on a preliminary basis of $7,531,503. Given that the preliminary approved provision was understated by about $451,000, the impact of changes in DRI forecasts is a net increase of about $138,000. The impact of moving from a 20% to a 15% contingency factor is about $500,000.

TECO has proposed a dismantlement provision be approved for new plants that are expected to be in-service during the next four year period. The annual provision will be implemented at the in-service date of the given plant. Detailed site specific dismantlement studies will be provided upon completion of the property unit records. For the Big Bend Unit 1 and 2 Scrubber that went into service January 1, 2000, dismantlement base cost estimates of $2,418,000 have been estimated based on dismantlement estimates for the Big Bend Unit No. 4 FGD. The annual dismantlement provision using a 15% contingency factor and the Summer 1999 DRI inflation forecast results in an annual provision of $235,177. For Polk Unit 2 with an expected in-service date of 2001 and any other new combined cycle plants, the company has estimated dismantlement base costs of $1,863,000 which is consistent with estimates for Polk Unit 1. The annual dismantlement provision using a 15% contingency and the Summer 1999 DRI inflation forecasts results in an annual provision of $109,196.

Additionally, we approve a revised annual dismantlement accrual for the Gannon Station to recognize the impact of the planned repowering. As discussed in Section III, the revised accrual should be implemented January 1, 2000. The repowering is expected to result in an extended 40-year life span for the station which results in a $1.7 million (approximately) decrease in the annual dismantlement provision.

VI. APPROPRIATE DEPRECIATION RATES AND AMORTIZATION SCHEDULES

The approved lives, net salvages, reserves, and resultant depreciation rates are shown on Attachment D, pages 32-37.

The approved lives, net salvages, reserves, and resulting rates for the investments remaining in service at the repowered Gannon Station and also for the new Big Bend Unit 1 & 2 Scrubber are shown on Attachment E, pages 38-39.

The approved depreciation rates and recovery/amortization schedules are the result of a comprehensive review of the Company's submitted study. Reserve positions have been restated to reflect the corrective action recommended in Section II.

As a result of the review and analytical process, TECO has agreed to many of the life and salvage parameters for the transmission, distribution, and general plant accounts. Differences between TECO's position and our decision are mainly found in the production function and reserve allocations.

Investment/Reserve Transfers

As part of the company's data submitted with its depreciation study, we note that transfers of plant do not always include a commensurate transfer of reserve. TECO responded that in instances where no reserve was transferred with transfers of investment, it was considered to be immaterial.

The Federal Code of Regulations, Subchapter C, Part 101, Electric Plant Instructions, Section 1, Transfers of Property, provides that when property is transferred from one plant account to another, there is also a transfer of the accumulated reserve. There is no materiality threshold mentioned. Also, from conversations with the Federal Energy Regulatory Commission (FERC) staff, it is our understanding that no materiality threshold regarding such transfers should be allowed.

We believe that the company's practice of not transferring the reserve associated with transferred investment is in conflict with standard depreciation principles and practices, as well as FERC's Uniform System of Accounts. As long as the investment dollars are in a given account, those dollars are accruing depreciation, and that accumulated amount should be transferred with the associated plant amount. The practice TECO appears to be following essentially assumes that the investment transferred is new plant without any reserve. This will overstate the reserve for the account from which the transfer originated and will understate the reserve for the receiving account.

In TECO's January 11, 2000, response to staff's report regarding the current depreciation study, TECO has agreed to transfer the accumulated reserve when property is transferred from one plant account to another, regardless of materiality.

Plant Under Construction

TECO currently has major additions under construction - Big Bend Unit No. 1 & 2 Scrubber and Polk Unit No. 2. The Big Bend Unit No. 1 & 2 Scrubber has a planned in-service date of January 1, 2000 with an estimated retirement date of 2023, coinciding with the expected retirement of Unit 2. Polk Unit No. 2 is planned for service year-end 2000 with an estimated retirement date of 2041. Additionally, TECO plans to place additional combustion turbines within the next few years, although the exact type of generation and cost estimates are not available. The company has proposed depreciation rates to be used when the respective equipment is placed into service with detailed life analyses to be performed upon completion of the property records.

Because the related equipment is not in-service at this time, the approved rates reflect whole life depreciation rates.

Big Bend Unit 1 & 2 Scrubber: TECO's life and salvage proposals (23-year life, negative 13% net salvage, and 4.9% depreciation rate) are based on stratification similar to that used for the Big Bend Unit No. 4 FGD System with an interim retirement rate similar to that used for Account 312, Boiler Plant Equipment, since the majority of investment is anticipated to be recorded in this account. Our order for a 24-year life and negative 11% net salvage resulting in a 4.6% depreciation rate assumes a mix of investment similar to that for the Big Bend Unit No. 4 FGD System and a corresponding interim rate relating to that mix.

Polk Unit No. 2: Polk Unit No. 2 is to be a natural gas-fired unit and will not be subject to the same corrosive conditions as Polk Unit No. 1 since it is not expected to have a coal gasification process. TECO's proposals (26-year life, negative 11% net salvage, and 4.3% depreciation rate) are based on stratification similar to that used for Polk Unit No. 1. An interim retirement rate and net salvage value similar to that used for Polk Unit No. 1, Turbogenerator Units, Accounts 343, was assumed since the majority of investment is expected to be recorded in this account. Assuming a similar mix of investment as for Polk Unit No. 1 without being subject to the same corrosive conditions, we accept these proposals.

<u>New Combustion Turbines:</u> TECO proposes that any new combustion turbines placed in service during the next four-year period use the same life and salvage values as it proposed for Polk Unit No. 2. The company proposed lives are in the range of lives estimated for new combined cycle units in the state and are acceptable.

<u>Production Plant</u>

The most significant changes in depreciation rates are seen in the production plant area. This is also the area where there are differences between our decision and the company's study.

TECO has utilized its continuing property record system to develop stratified categories expected to have homogenous life characteristics. The life of the account is then arrived at by compositing the life expectations of the various strata. This approach provides a more accurate determination of the required depreciation components than the historical approach of arriving at the pattern of interim retirement and life expectancy of the generating plant without identifying the contents or quantifying the varying life characteristics of the contained assets.

The main difference between our decision and the company's position is in the development of the interim net salvage. We utilized an interim retirement pattern for net salvage matching the retirement pattern the company used in its life analyses. For example, the life analyses submitted in the study for Big Bend assumes an interim retirement pattern indicating that about 6% of the current investment will retire over the remaining life span of the unit. However, the company's net salvage analyses indicates 10% of the investment will retire over the remaining life span. According to the company, the retirement patterns used in its life analyses were based on input from production plant engineers whereas the retirement assumptions for the net salvage analyses were not. We believe that the same retirement assumptions used in the development of life factors should be used in the net salvage analyses. Therefore, the approved net salvage requirements are based on similar interim retirement patterns that were used in the company's development of life factors.

A recovery schedule addressing the net investment associated with the replaced coal classifiers recommended in Section IV requires removal of the investment and reserve remaining in Account 312 from each affected unit.

Steam Production - Our conclusions for the steam production plants are based on the underlying elements of the company's proposals which reflect a refinement of the stratification to the account level for each unit at the Hookers Point and Dinner Lake stations. The company's proposed life factors are within the range of reasonableness although we believe the projected pattern of interim retirements is rather conservative. Our net salvage requirements are developed using the same interim retirement pattern as the company used in its development of life factors.

Hookers Point has an estimated date of final retirement of year-end 2003. The company points out in the study narrative that the retirement date is consistent with its ten-year site plan, but does not represent firm plans. It appears to us that firm planning should exist for a retirement anticipated in the company's 5-year horizon. In the case where such planning supports the retirement date, we agree with the company that a recovery schedule designed to amortize the associated remaining net unrecovered investment over a period matching the remaining years of service would be the most appropriate action. However, without such firm plans, the lives are those shown on Attachment D. Where the average age of the given life category exceeded the estimated life, we rolled the related investments into the next longer life category. When retirement plans become firm, the company should review the recovery status of these assets and petition the Commission for any revisions necessary to assure recovery by the time of retirement.

Miscellaneous Production - The company proposed life factor for Structures and Improvements is acceptable. In developing a net salvage factor, we utilized the same interim retirement pattern as the company used in the determination of the remaining life.

Other Production - The company proposals reflect a refinement of its stratification to the account level for each unit.

Big Bend and Gannon Combustion Turbines: The life parameters for each account recognize the underlying elements of the company's proposal. We note that some of the 25 and 20-year life categories have ages exceeding 25 and 20 years. In cases such as these, a longer lived category should be considered as the company did for the steam production plants unless there are firm plans for near-term retirement. Our life requirements reflect the reassignment of these assets to the next longer life category. Our net salvage proposals have been developed using the same interim retirement pattern as used in the development of the remaining lives.

Phillips Station: The only difference in the company's position and our decision relates to the net salvage development. Our requirements are in accord with using similar retirement patterns as used in the life development.

Polk Power Station: At the time of TECO's last depreciation review, the company expected Polk Unit No. 1 to experience similar life characteristics as its other major generating units. This unit went into service in September, 1996, and has an estimated retirement date of year-end 2036.

According to the study narrative, Polk Unit No. 1 is different from TECO's other units. The company asserts that the nature of this plant with its chemical processes requires a life analysis that is sensitive to the more corrosive atmosphere under which this type of unit will be operating. The life analysis presented in the current study represents the company's first analysis of this unit at an asset level as the life analysis presented in the previous study was at a site level. This initial stratification may need some revision with experience; the estimated service lives may likewise need to be revised with time. As with other units, TECO stratified the assets at Polk Unit 1 into various categories expected to live in different patterns. Those assets expected to be common facilities as other units are placed in-service at the Polk site were assigned a full life span of 50 years. A 5-year life was assigned the combustion section of the combustion turbine and other equipment most exposed to a corrosive environment. A 40-year life span was assigned to the power block structures and other long life assets. TECO believes that this plant should have a full life span of 40 years rather than 50 years assigned to its other major units.

We find the company's life proposals within the range of reasonableness. For net salvage, we utilized the same approach as used with other production plants. The interim retirement pattern utilized in the life analyses was also utilized in the net salvage analyses.

Gannon Repowering - Attachment E, pages 38-39, shows the approved depreciation factors and estimated expenses for the assets now expected to remain in-service with the Gannon repowering. The approved lives reflect that repowering will extend the life of the station by about 40 years while various stratified asset categories will continue to experience a shorter life. The company's proposed life factors are within the range of reasonableness and acceptable to us. In developing the net salvage factors, we utilized the same interim retirement patterns as used in the determination of lives.

Distribution, Transmission, And General Plant

The life and salvage parameters TECO proposed for many of the accounts in these functions reflect the status quo. In other words, the service life and salvage values approved in the last represcription are being maintained. The approved remaining lives simply reflect an update of activity.

Minor differences between the Company's and our position with respect to remaining lives exist in Account 355 (Poles and Fixtures), Account 356 (Overhead Conductors and Devices), Account 364 (Poles, Towers, and Fixtures), and Account 365 (Overhead Conductors). The lives we have required are the result of utilizing mortality dispersion curves that are more indicative of the expected retirement pattern for the related equipment as generally seen from electric utilities in the state.

For Account 369.1 (Overhead Services), there is a difference between the company's study and our decision with respect to the remaining life and the net salvage value. This account has experienced very little retirement activity with the most recent five years averaging less that 1%. This type of activity makes reliance on industry averages for life and salvage necessary. While the 33-year service life is within the range of reason, we used a retirement pattern that is more indicative of the expected activity as seen from other electric utilities in the state.

TECO proposes maintaining the currently prescribed negative 50% net salvage for overhead services. Typically, this type of equipment incurs removal costs and realizes little scrap salvage upon retirement. Although the removal of overhead plant is generally labor intensive, TECO has experienced minimal negative net salvage, with the last four years averaging near zero. Other Florida utility companies have prescribed net salvage factors ranging from negative 15% to negative 60%. We believe some decrease in net salvage is appropriate. Therefore, we approve a negative 20%, with careful monitoring of the account.

The accounting treatment utilized for meters, Account 370, is cradle-to-grave in which a meter is capitalized upon purchase and is not retired until the meter can no longer be refurbished and is finally junked. The Federal Code of Regulations, Subchapter C, Part 101, Electric Plant Accounts, Account 370, Meters, states that the cost of removing and resetting meters shall be charged to Account 586, Meter Expenses. Accordingly, one would expect very little gross salvage and removal cost to be realized upon retirement unless there are special conditions. TECO asserts that its removal costs are due to labor and transportation charges incurred with removing the meter from the customer's premise. We believe that these removal costs should be expensed under the Code of Federal Regulations. The decision whether the meter can be refurbished is not made until the meter is taken to the shop for inspection. At that time, if it is determined that the meter cannot be refurbished, it is retired and junked. We believe that the cost of removal, as applicable to meters, relates to final disposal costs when the meters can no longer be repaired and are thus retired. Removal costs should not include costs incurred with removing the meter from the location and sending it to the repair shop. Accordingly, we adopt a zero net salvage.

Our recommendation for the remaining life for Account 392.01

(Automobiles) is the result of using a 7-year average service life which is in line with the weighted average age of the automobiles retired during the most recent three-year period. Using an R3 curve shape and a 6.6 year average age results in an average remaining life of 1.6 years.

VII. <u>AMORTIZATION OF INVESTMENT TAX CREDITS (ITCs) AND THE FLOWBACK OF EXCESS DEFERRED INCOME TAXES</u>

In this order, we have approved revisions to the company's remaining lives, to be effective January 1, 1999. Revising a utility's book depreciation lives generally results in a change in its rate of ITC amortization and flowback of EDIT in order to comply with the normalization requirements of the Internal Revenue Code (IRC) and underlying Regulations (REGs) found in Sections 46, 167, and 168 and 1.46, 1.67, and 1.68, respectively.

Section 46(f) (6), IRC, states that the amortization of ITCs should be determined by the period of time actually used in computing depreciation expense for rate making purposes and on the regulated books of the utility. Since we are ordering a change in remaining lives, it is also important to change the amortization of ITCs to avoid violation of the provisions of sections 46 and 1.46, IRC and REGs, respectively.

Section 203(3) of the Tax Reform Act of 1986 (the Act) prohibits rapid flowback of depreciation related (protected) EDIT. Further, Rule 25-14.013, Accounting for Deferred Income Taxes Under SFAS 109, Florida Administrative Code, generally prohibits EDIT from being written off any faster than allowed under the Act. The Act, SFAS 109, and Rule 25-14.013, Florida Administrative Code regulate the flowback of EDIT. Therefore, we order that the flowback of EDIT be adjusted to comply with the Act, SFAS 109, and Rule 25-14.013, Florida Administrative Code.

The Commission, the Internal Revenue Service, and independent outside auditors look to a company's books and records and at the orders and rules of the jurisdictional regulatory authorities to determine if the books and records are maintained in the appropriate manner and to determine the intent of the regulatory bodies in regard to normalization. Therefore, we order that the current amortization of ITCs and the flowback of EDIT be revised to reflect the approved remaining lives. In order for there to be a clear audit trail, a prudent utility will revise ITCs and EDIT amortization and produce work papers to show how the revisions were made.

Therefore, we find that the current amortization of ITCs and the flowback of excess deferred income taxes (EDIT) shall be revised to match the actual recovery periods for the related property. The utility shall file detailed calculations of the revised ITC amortization and flowback of EDIT at the same time it files its surveillance report covering the period ending December 31, 2000.

VII. PRELIMINARY IMPLEMENTATION

This order addresses changes associated with the planned repowering of Gannon Station, as well as final depreciation rates, recovery/amortization schedules, and fossil dismantlement accruals for all other accounts and plant sites. This docket shall remain open, pending a final decision on those revisions (the preliminary implementation of a recovery schedule, fossil dismantlement accruals, and depreciation rates) implemented on a preliminary basis, associated with the repowering of the Gannon Station. The final decision regarding the Gannon Station will be issued as Proposed Agency Action affording a point of entry for substantially affected persons.

Based on the foregoing, it is,

ORDERED by the Florida Public Service Commission that the reserve allocations shown in Attachment A shall be implemented as of January 1, 1999. It is further

ORDERED that the new depreciation rates, amortizations, recovery schedules, and fossil dismantlement accruals, shown in Attachments B, C, D, and E, except those associated with the planned repowering of Gannon Station, shall be implemented as of January 1, 1999. It is further

ORDERED that the new depreciation rates, recovery schedule, and fossil dismantlement accrual shown on Attachments B, C, D, and E, reflecting the planned repowering of the Gannon Station shall be implemented on a preliminary basis, as of January 1, 2000. It is further

ORDERED that all matters contained in the schedules attached hereto are by reference incorporated herein. It is further

ORDERED that the utility file detailed calculations of the revised ITC amortization and flowback of excess deferred taxes at the time it files its December, 2000 surveillance report. It is further

ORDERED that the provisions of this Order, issued as proposed agency action, shall become final and effective unless an appropriate petition, in the form provided by Rule 25-22.036, Florida Administrative Code, is received by the Director, Division of Records and Reporting, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850, by the close of business on the date set forth in the "Notice of Further Proceedings or Judicial Review" attached hereto. It is further

ORDERED that this Docket shall remain open pending final action on the revisions associated with the repowering of the Gannon Station.

By ORDER of the Florida Public Service Commission this 29th day of March, 2000.

/s/ Blanca S. Bayó
BLANCA S. BAYÓ, Director
Division of Records and Reporting

This is a facsimile copy. A signed copy of the order may be obtained by calling 1-850-413-6770.

(S E A L)

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NOTICE OF FURTHER PROCEEDINGS OR JUDICIAL REVIEW APPLICABLE TO ALL PROVISIONS OF THIS ORDER EXCEPT AS TO GANNON STATION REPOWERING

The Florida Public Service Commission is required by Section 120.569(1), Florida Statutes, to notify parties of any administrative hearing that is available under Section 120.57, 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 will be granted or result in the relief sought.

Mediation may be available on a case-by-case basis. If mediation is conducted, it does not affect a substantially interested person's right to a hearing.

The action proposed herein is preliminary in nature. Any person whose substantial interests are affected by the action proposed by this order may file a petition for a formal proceeding, in the form provided by Rule 28-106.201, Florida Administrative Code. This petition must be received by the Director, Division of Records and Reporting, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850, by the close of business on April 19, 2000.

In the absence of such a petition, this order shall become final and effective upon the issuance of a Consummating Order.

Any objection or protest filed in this docket before the issuance date of this order is considered abandoned unless it satisfies the foregoing conditions and is renewed within the specified protest period.

NOTICE OF FURTHER PROCEEDINGS OR JUDICIAL REVIEW APPLICABLE TO GANNON STATION REPOWERING

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.

Mediation may be available on a case-by-case basis. If mediation is conducted, it does not affect a substantially interested person's right to a hearing.

Any party adversely affected by this order, which is preliminary, procedural or intermediate in nature, may request: (1) reconsideration within 10 days pursuant to Rule 25-22.0376, Florida Administrative Code, if issued by a Prehearing Officer; (2) reconsideration within 15 days pursuant to Rule 25-22.060, Florida Administrative Code, if issued by the Commission; or (3) judicial review by the Florida Supreme Court, in the case of an electric, gas or telephone utility, or the First District Court of Appeal, in the case of a water or wastewater utility. A motion for reconsideration shall be filed with the Director, Division of Records and Reporting, in the form prescribed by Rule 25-22.060, Florida Administrative Code. Judicial review of a preliminary, procedural or intermediate ruling or order is available if review of the final action will not provide an adequate remedy. Such review may be requested from the appropriate court, as described above, pursuant to Rule 9.100, Florida Rules of Appellate Procedure.

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Attachment A
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TAMPA ELECTRIC COMPANY
1999 DEPRECIATION STUDY
RESERVE ALLOCATIONS

ACCOUNT	COMMISSION APPROVED 1/1/199 RESERVE ($)	RESERVE ALLOCATION ($)	RESTATED RESERVE ($)
STEAM PRODUCTION			
BIG BEND STATION			
Common			
312400 Boiler Plant	22,551,227	(551,897)	21,999,330
Unit 1			
311410 Structures	3,390,052	438,624	3,828,676
312410 Boiler Plant	21,567,995	2,696,876	24,264,871
314410 Turbogenerators	12,651,164	(380,978)	12,270,186
315410 Acces. Electric Equipment	4,479,198	(57,646)	4,421,552
Unit 2			
312420 Boiler Plant	21,090,104	1,977,089	23,067,193
Unit 3			
312430 Boiler Plant	43,852,977	(2,353,888)	41,499,089
Unit 4			
312440 Boiler Plant	67,246,424	8,238,512	75,484,936
Unit 4 FGD			
311450 Structures	6,805,375	(120,904)	6,684,471
312450 Boiler Plant		(10,006,692)	44,561,162
316450 Miscellaneous	105,567	120,904	226,471
HOOKERS POINT STATION			
Common			
311600 Structures	1,717,293	1,902,610	3,619,903
312600 Boiler Plant	2,023,729	2,093,153	4,116,882
314600 Turbogenerators	444,210	328,585	772,795
315600 Acces. Electric Equipment	695,889	1,482,294	2,178,183
316600 Miscellaneous	862,335	543,001	1,405,336
311670 Amortizable Tools	104,481	87,858	192,339
			12,285,438
Unit 1			
311610 Structures	2,020,291	(989,600)	1,030,691
312610 Boiler Plant	2,603,084	404,471	3,007,555
314610 Turbogenerators	2,716,981	(561,906)	2,155,075
315610 Acces. Electric Equipment	921,757	(251,567)	670,190
316610 Miscellaneous	150,599	(75,192)	75,407
Unit 2 & 3			
311620 Structures	1,589,274	(837,874)	751,400
312620 Boiler Plant	8,455,549	(2,939,936)	5,515,613
314620 Turbogenerators	5,296,078	(1,352,771)	3,943,307
315620 Acces. Electric Equipment	1,173,632	(195,418)	978,214
316620 Miscellaneous	75,047	(30,286)	44,761
Unit 4			
311640 Structures	1,211,929	(427,619)	784,310
312640 Boiler Plant	2,566,791	(302,708)	2,264,083
314640 Turbogenerators	3,505,355	(415,583)	3,089,772
315640 Acces. Electric Equipment	737,332	(58,315)	679,017
316640 Miscellaneous	56,296	(16,426)	39,870
Unit 5			
311650 Structures	1,634,826	(497,947)	1,136,879
312650 Boiler Plant	3,066,051	2,102,889	5,168,940
314650 Turbogenerators	4,112,708	162,069	4,274,777
315650 Acces. Electric Equipment	1,182,820	(136,253)	1,046,567
316650 Miscellaneous	61,882	(17,529)	44,353
TOTAL HOOKERS POINT	48,986,219	0	61,271,657

TAMPA ELECTRIC COMPANY
1999 DEPRECIATION STUDY
RESERVE ALLOCATIONS

	ACCOUNT	COMMISSION APPROVED 1/1/199 RESERVE ($)	RESERVE ALLOCATION ($)	RESTATED RESERVE ($)
DINNER LAKE STATION				
	311110 Structures	12,590	543,959	556,549
	312110 Boiler Plant	3,406,380	(1,964,941)	1,441,439
	314110 Turbogenerators	10,538	1,050,166	1,060,704
	315110 Acces. Electric Equipment	10,098	340,104	350,202
	316110 Miscellaneous	1,059	30,712	31,771
	TOTAL DINNER LAKE	3,440,665	0	3,440,665
TOTAL STEAM PRODUCTION		310,734,821	0	323,020,259
OTHER PRODUCTION				
BIG BEND STATION				
	Combustion Turbine 1			
	341410 Structures	81,793	(12,914)	68,879
	342410 Boiler Plant	112,440	(14,372)	98,068
	344410 Turbogenerators	1,257,844	(51,703)	1,206,141
	345410 Acces. Electric Equipment	137,353	80,309	217,662
	346410 Miscellaneous	3,302	(1,320)	1,982
	Combustion Turbine 2 & 3			
	341420 Structures	1,353,022	65,357	1,418,379
	342420 Boiler Plant	903,961	(153,259)	750,702
	344420 Turbogenerators	12,795,802	163,381	12,959,183
	345420 Acces. Electric Equipment	2,093,714	(84,871)	2,008,843
	346420 Miscellaneous	17,139	9,392	26,531
	TOTAL BIG BEND	18,756,370	0	18,756,370
GANNON STATION				
	Combustion Turbine 1			
	341510 Structures	68,714	(10,449)	58,265
	342510 Boiler Plant	95,937	23,606	119,543
	344510 Turbogenerators	1,346,794	(118,843)	1,227,951
	345510 Acces. Electric Equipment	189,456	105,686	295,142
	TOTAL GANNON	1,700,901	0	1,700,901
PHILLIPS STATION				
	341280 Structures	50,502	5,736,155	5,786,657
	342280 Boiler Plant	1,214	16,148,337	16,149,551
	343280 Turbogenerators	38,415,196	(25,724,181)	12,691,015
	345280 Acces. Electric Equipment	7,100	3,497,247	3,504,347
	346280 Miscellaneous	4,324	342,442	346,766
	TOTAL PHILLIPS	38,478,336	0	38,478,336
POLK POWER STATION				
	341810 Structures	4,126,651	2,970,821	7,097,472
	342810 Boiler Plant	36,064,474	(10,600,967)	25,463,507
	343810 Turbogenerators	4,326,239	3,660,217	7,986,456
	345810 Acces. Electric Equipment	2,195,470	2,447,846	4,643,316
	346810 Miscellaneous	354,843	208,493	563,336
	Amortizable Tools	0	1,313,590	1,313,590
	TOTAL POLK	47,067,677	0	47,067,677
TOTAL OTHER PRODUCTION		106,003,284	0	58,935,607
TOTAL PRODUCTION		416,738,105	0	381,955,866

TAMPA ELECTRIC COMPANY
1999 DEPRECIATION STUDY
RESERVE ALLOCATIONS

			COMMISSION APPROVED		
		ACCOUNT	1/1/199 RESERVE ($)	RESERVE ALLOCATION ($)	RESTATED RESERVE ($)
TRANSMISSION PLANT					
	353	Station Equipment	41,374,948	(9,406,303)	31,968,645
	355	Poles and Fixtures	20,583,333	5,452,500	26,035,833
	356	Overhead Conductors & Devices	22,791,466	3,953,803	26,745,269
TOTAL TRANSMISSION			84,749,747	0	84,749,747
DISTRIBUTION PLANT					
	362	Station Equipment	38,138,860	(4,628,554)	33,510,306
	364	Poles, Towers, & Fixtures	43,046,450	3,561,891	46,608,341
	365	Overhead Conductors & Devices	64,874,069	3,311,515	68,185,584
	366	Underground Conduit	17,901,947	(845,990)	17,055,957
	368	Line Transformers	91,481,148	(5,643,294)	85,837,854
	369	Overhead Services	17,657,121	(1,604,287)	16,052,834
	370	Meters	14,129,128	2,433,236	16,562,364
	373	Street Lights & Signal Systems	23,659,879	3,415,483	27,075,362
TOTAL DISTRIBUTION			310,888,602	0	310,888,602
GENERAL PLANT					
	392	Automobiles	704,287	(220,283)	484,004
	392	Heavy Trucks	8,674,343	220,283	8,894,626
TOTAL GENERAL PLANT			9,378,630	0	9,378,630

Attachment B
Page 1 of 1

Tampa Electric Company
1999 Study
Recovery Schedules

	EFFECTIVE JANUARY 1, 1999			
	1/1/99 Investment	1/1/99 Reserve	Recovery Period	Annual Expenses
	($)	($)	(Yrs.)	($)
Energy Management System	33,144,637	26,703,342	2 Years	3,220,648
Ciak Classifiers	414,272	279,158	1 Year	135,114

	EFFECTIVE JANUARY 1, 2000			
	1/1/00 Investment	1/1/00 Reserve	Recovery Period	Annual Expenses
	($)	($)	(Yrs.)	($)
Gannon Retiring Assets	287,686,788	221,428,919	5 Years	13,874,690

Attachment C

TAMPA ELECTRIC COMPANY
FOSSIL DISMANTLEMENT

	COMMISSION APPROVED 1999 ACCRUAL ($)	COMMISSION APPROVED 2000 ACCRUAL ($)
Big Bend Common	404,053	404,053
Big Bend Unit 1	718,455	718,455
Big Bend Unit 2	511,891	511,891
Big Bend Unit 3	450,083	450,083
Big Bend Unit 4	816,545	816,545
Big Bend Unit 4 FGD	310,903	310,903
Big Bend Unit 1&2 Scrubber		235,177
Gannon Common	360,978	143,974
Gannon Unit 1	438,994	78,866
Gannon Unit 2	343,618	69,065
Gannon Unit 3	358,761	87,701
Gannon Unit 4	321,558	99,781
Gannon Unit 5	305,098	108,149
Gannon Unit 6	310,338	123,761
Hookers Point	(31,278)	(31,278)
Dinner Lake	67,442	67,442
Big Bend CT 1, 2 & 3	130,966	130,966
Gannon CT 1	23,522	23,522
Phillips Station	143,385	143,385
Polk Unit 1	1,168,177	1,168,177
TOTAL	7,153,489	5,660,618

Plant Under Construction	
Polk Unit 2 (2001)	109,196

Attachment D
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TAMPA ELECTRIC COMPANY
1999 STUDY
EFFECTIVE JANUARY 1, 1999

ACCOUNT		COMMISSION APPROVED AVERAGE REMAINING LIFE (YRS)	NET SALVAGE (%)	1/1/99 RESERVE (%)	REMAINING LIFE RATE (%)
STEAM PRODUCTION					
BIG BEND STATION					
	- Common -				
311400	Structures	32.0	(4.0)	36.40	2.1
312400	Boiler Plant	27.0	(14.0)	37.81 *	2.8
314400	Turbogenerators	32.0	(3.0)	49.64	1.7
315400	Access. Electric Equipment	16.4	(6.0)	49.31	3.5
316400	Miscellaneous	17.2	(16.0)	56.54	3.5
	- Unit 1 -				
311410	Structures	21.0	(1.0)	52.70 *	2.3
312410	Boiler Plant	18.5	(8.0)	43.25 *	3.5
314410	Turbogenerators	17.9	(4.0)	52.09 *	2.9
315410	Access. Electric Equipment	16.5	(3.0)	53.51 *	3.0
316410	Miscellaneous	20.0	(3.0)	50.65	2.6
	- Unit 2 -				
311420	Structures	24.0	(1.0)	42.76	2.4
312420	Boiler Plant	20.0	(10.0)	44.00 *	3.3
314420	Turbogenerators	20.0	(5.0)	46.45	2.9
315420	Access. Electric Equipment	19.2	(3.0)	48.72	2.8
316420	Miscellaneous	23.0	(7.0)	41.03	2.9
	- Unit 3 -				
311430	Structures	26.0	(2.0)	47.91	2.1
312430	Boiler Plant	22.0	(12.0)	48.20 *	2.9
314430	Turbogenerators	19.3	(8.0)	64.81	2.2
315430	Access. Electric Equipment	18.1	(4.0)	50.65	2.9
316430	Miscellaneous	26.0	(5.0)	41.91	2.4
	- Unit 4 -				
311440	Structures	35.0	(2.0)	35.09	1.9
312440	Boiler Plant	27.0	(17.0)	38.70 *	2.9
314440	Turbogenerators	29.0	(7.0)	38.57	2.4
315440	Access. Electric Equipment	24.0	(4.0)	38.51	2.7
316440	Miscellaneous	31.0	(7.0)	45.81	2.0
	- Unit 4 FGD -				
311450	Structures	33.0	(3.0)	31.05 *	2.2
312450	Boiler Plant	29.0	(13.0)	31.80 *	2.8
315450	Access. Electric Equipment	25.0	(4.0)	36.29	2.7
316450	Miscellaneous	31.0	(8.0)	30.50 *	2.5

*Restated reserve after corrective measures.

TAMPA ELECTRIC COMPANY
1999 STUDY
EFFECTIVE JANUARY 1, 1999

ACCOUNT		COMMISSION APPROVED			
GANNON STATION		AVERAGE REMAINING LIFE (YRS)	NET SALVAGE (%)	1/1/99 RESERVE (%)	REMAINING LIFE RATE (%)
	- Common -				
311500	Structures	17.4	(2.0)	43.13	3.4
312500	Boiler Plant	17.0	(5.0)	36.64	4.0
314500	Turbogenerators	18.1	(1.0)	31.77	3.8
315500	Access. Electric Equipment	15.1	(4.0)	25.03	5.2
316500	Miscellaneous	11.0	(11.0)	61.29	4.5
	- Unit 1 -				
311510	Structures	8.3	(1.0)	81.81	2.3
312510	Boiler Plant	7.0	(3.0)	85.53	2.5
314510	Turbogenerators	7.4	(1.0)	71.86	3.9
315510	Access. Electric Equipment	6.9	(1.0)	80.36	3.0
316510	Miscellaneous	7.8	(2.0)	93.68	1.1
	- Unit 2 -				
311520	Structures	9.3	(1.0)	74.73	2.8
312520	Boiler Plant	7.5	(3.0)	79.89	3.1
314520	Turbogenerators	8.4	(1.0)	73.36	3.3
315520	Access. Electric Equipment	8.1	(1.0)	73.81	3.4
316520	Miscellaneous	7.9	(2.0)	73.58	3.6
	- Unit 3 -				
311530	Structures	11.1	(1.0)	72.89	2.5
312530	Boiler Plant	10.2	(3.0)	64.09	3.8
314530	Turbogenerators	9.2	(2.0)	76.11	2.8
315530	Access. Electric Equipment	8.8	(1.0)	72.41	3.2
316530	Miscellaneous	8.9	(4.0)	92.58	1.3
	- Unit 4 -				
311540	Structures	14.2	(1.0)	62.25	2.7
312540	Boiler Plant	12.6	(6.0)	49.82	4.5
314540	Turbogenerators	11.0	(3.0)	77.07	2.4
315540	Access. Electric Equipment	11.6	(1.0)	61.13	3.4
316540	Miscellaneous	14.1	(2.0)	22.91	5.6
	- Unit 5 -				
311550	Structures	16.3	(1.0)	37.01	3.9
312550	Boiler Plant	14.4	(5.0)	43.27	4.3
314550	Turbogenerators	14.3	(2.0)	56.13	3.2
315550	Access. Electric Equipment	13.5	(3.0)	49.42	4.0
316550	Miscellaneous	15.6	(4.0)	43.20	3.9
	- Unit 6 -				
311560	Structures	18.1	(1.0)	55.20	2.5
312560	Boiler Plant	16.5	(6.0)	44.06	3.8
314560	Turbogenerators	17.5	(2.0)	43.49	3.3
315560	Access. Electric Equipment	14.6	(2.0)	46.50	3.8
316560	Miscellaneous	16.9	(5.0)	66.02	2.3

*Restated reserve after corrective measures.

COMMISSION APPROVED

ACCOUNT		AVERAGE REMAINING LIFE (YRS.)	NET SALVAGE (%)	1/1/99 RESERVE (%)	REMAINING LIFE RATE (%)
GANNON OBO					
	- Common -				
311700	Structures	16.6	(3.0)	75.21	1.7
312700	Boiler Plant	16.8	(7.0)	74.42	1.9
314700	Turbogenerators	0.0	0.0	0.00	0.0
315700	Access. Electric Equipment	13.9	(3.0)	58.30	3.2
316700	Miscellaneous	17.0	(3.0)	29.96	4.3
	- Unit 1 -				
311710	Structures	8.2	(2.0)	66.05	4.4
312710	Boiler Plant	8.4	(1.0)	71.45	3.5
314710	Turbogenerators	8.5	0.0	69.79	3.6
315710	Access. Electric Equipment	8.4	0.0	69.78	2.8
316710	Miscellaneous	8.3	(1.0)	69.78	3.8
	- Unit 2 -				
311720	Structures	9.2	(2.0)	71.25	3.3
312720	Boiler Plant	9.4	(1.0)	72.90	3.0
314720	Turbogenerators	9.5	0.0	71.26	3.0
315720	Access. Electric Equipment	9.3	0.0	71.25	3.1
316720	Miscellaneous	9.3	(1.0)	71.25	3.2
	- Unit 3 -				
311730	Structures	10.8	(2.0)	70.00	3.0
312730	Boiler Plant	11.3	(2.0)	71.27	2.7
314730	Turbogenerators	11.3	(1.0)	70.00	2.7
315730	Access. Electric Equipment	11.2	0.0	71.17	2.6
316730	Miscellaneous	11.2	(1.0)	70.00	2.8
	- Unit 4 -				
311740	Structures	12.9	(4.0)	70.28	2.6
312740	Boiler Plant	14.0	(3.0)	71.35	2.3
314740	Turbogenerators	13.8	(3.0)	70.29	2.4
315740	Access. Electric Equipment	13.9	(1.0)	70.28	2.2
316740	Miscellaneous	14.0	(2.0)	70.28	2.3

*Restated reserve after corrective measures.

ACCOUNT		COMMISSION APPROVED			
HOOKERS POINT STATION		AVERAGE REMAINING REMAINING LIFE	NET SALVAGE	1/1/99 RESERVE	REMAINING LIFE RATE
		(YRS.)	(%)	(%)	(%)
	- COMMON -				
311600	Structures	4.3	0.0	91.96 *	1.9
312600	Boiler Plant	4.4	0.0	91.96 *	1.8
314600	Turbogenerators	4.5	0.0	91.96 *	1.8
315600	Access. Electric Equipment	4.4	0.0	91.96 *	1.8
316600	Miscellaneous	3.4	(4.0)	91.96 *	3.5
	- Unit 1 -				
311610	Structures	4.5	0.0	91.96 *	1.8
312610	Boiler Plant	4.5	0.0	91.96 *	1.8
314610	Turbogenerators	4.5	0.0	91.96 *	1.8
315610	Access. Electric Equipment	4.5	0.0	91.96 *	1.8
316610	Miscellaneous	4.4	0.0	91.96 *	1.8
	- Unit 2 & 3 -				
311620	Structures	4.5	0.0	91.96 *	1.8
312620	Boiler Plant	4.3	(1.0)	91.96 *	2.1
314620	Turbogenerators	3.8	0.0	91.96 *	2.1
315620	Access. Electric Equipment	4.5	0.0	91.96 *	1.8
316620	Miscellaneous	4.4	0.0	91.96 *	1.8
	- Unit 4 -				
311640	Structures	4.5	(1.0)	91.96 *	2.0
312640	Boiler Plant	4.5	(1.0)	91.96 *	2.0
314640	Turbogenerators	4.5	(1.0)	91.96 *	2.0
315640	Access. Electric Equipment	3.9	0.0	91.96 *	2.1
316640	Miscellaneous	3.4	(1.0)	91.96 *	2.7
	- Unit 5 -				
311650	Structures	4.5	(1.0)	91.96 *	2.0
312650	Boiler Plant	4.5	(1.0)	91.96 *	2.0
314650	Turbogenerators	3.7	0.0	91.96 *	2.2
315650	Access. Electric Equipment	4.0	0.0	91.96 *	2.0
316650	Miscellaneous	4.5	(1.0)	91.97 *	2.0
DINNER LAKE STATION					
311110	Structures	6.3	(6.0)	88.15 *	2.8
312110	Boiler Plant	6.3	(6.0)	98.34 *	1.2
314110	Turbogenerators	6.4	(3.0)	95.39 *	1.2
315110	Access. Electric Equipment	6.2	(2.0)	92.43 *	1.5
316110	Miscellaneous	6.3	(6.0)	95.13 *	1.7
MISC. PRODUCTION					
311010	STRUCTURES & IMPROVEMNETS	15.2	(5.0)	42.96	4.1

*Restated reserve after corrective measures.

COMMISSION APPROVED

		AVERAGE REMAINING LIFE (YRS.)	NET SALVAGE (%)	1/1/99 RESERVE (%)	REMAINING LIFE RATE (%)
OTHER PRODUCTION					
BIG BEND STATION					
	- Combustion Turbine 1 -				
341410	Structures	10.4	(1.0)	83.16 *	1.7
342410	Boiler Plant	10.3	(2.0)	86.28 *	1.5
344410	Turbogenerators	10.3	(2.0)	92.10 *	1.0
345410	Access. Electric Equipment	10.3	(1.0)	87.21 *	1.3
346410	Miscellaneous	10.2	(1.0)	73.07 *	2.7
	- Combustion Turbine 2 & 3 -				
341420	Structures	5.4	(1.0)	88.01 *	2.4
342420	Boiler Plant	5.4	(2.0)	90.26 *	2.2
344420	Turbogenerators	4.9	(1.0)	82.20 *	3.8
345420	Access. Electric Equipment	4.8	(1.0)	77.94 *	4.8
346420	Miscellaneous	5.4	(8.0)	95.72 *	2.3
GANNON STATION					
	- Combustion Turbine 1 -				
341510	Structures	9.4	(1.0)	77.31 *	2.5
342510	Boiler Plant	6.0	(3.0)	90.34 *	2.1
344510	Turbogenerators	6.4	(1.0)	92.76 *	1.3
345510	Access. Electric Equipment	6.6	(1.0)	89.86 *	1.7
PHILLIPS STATION					
341280	Structures	11.6	(13.0)	64.28 *	4.2
342280	Boiler Plant	11.8	(13.0)	63.44 *	4.2
343280	Turbogenerators	12.2	(5.0)	67.61 *	3.1
345280	Access. Electric Equipment	11.1	(4.0)	59.60 *	4.0
346280	Miscellaneous	11.6	(12.0)	62.12 *	4.3
POLK POWER STATION					
341810	Structures	32.0	(4.0)	6.41 *	3.0
342810	Boiler Plant	19.6	(16.0)	12.12 *	5.3
343810	Turbogenerators	22.0	(10.0)	6.92 *	4.7
345810	Access. Electric Equipment	24.0	(4.0)	7.93 *	4.0
346810	Miscellaneous	22.0	(9.0)	10.01 *	4.5

TAMPA ELECTRIC COMPANY
1999 STUDY
EFFECTIVE JANUARY 1, 1999

	ACCOUNT	COMMISSION APPROVED AVERAGE REMAINING LIFE (YRS.)	NET SALVAGE (%)	1/1/99 RESERVE (%)	REMAINING LIFE RATE (%)
TRANSMISSION PLANT					
350.01	Land Rights	36.0	0.0	24.49	2.1
352.00	Structures & Improvements	40.0	(3.0)	20.04	2.1
353.00	Station Equipment	34.0	(5.0)	26.80	2.3
354.00	Towers and Fixtures	20.0	(15.0)	63.06	2.6
355.00	Poles and Fixtures	24.0	(30.0)	38.80	3.8
356.00	Overhead Conduct. & Devices	23.0	(20.0)	40.80	3.4
356.01	Clearing Rights-of-Way	28.0	0.0	40.82	2.1
357.00	Underground Conduit	43.0	0.0	17.25	1.9
358.00	Underground Conductors & Devices	29.0	0.0	21.40	2.7
359.00	Roads & Trails	36.0	0.0	26.17	2.1
DISTRIBUTION PLANT					
361.00	Structures & Improvements	30.0	(3.0)	31.92	2.4
362.00	Station Equipment	25.0	(10.0)	32.50	3.1
364.00	Poles, Towers & Fixtures	24.0	(35.0)	36.60	4.1
365.00	Overhead Conductors & Devices	21.0	(20.0)	46.50	3.5
366.00	Underground Conduit	39.0	0.0	22.01	2.0
367.00	Underground Conduct. & Devices	24.0	0.0	27.81	3.0
368.00	Line Transformers	8.3	30.0	35.97	4.1
369.01	Overhead Services	24.0	(20.0)	33.60	3.6
369.02	Underground Services	26.0	(15.0)	29.32	3.3
370.00	Meters	15.1	0.0	39.60	4.0
373.00	Street Lights & Signal Systems	12.4	0.0	34.28	5.3
GENERAL PLANT					
390.00	Structures & Improvements	28.0	(20.0)	25.02	3.4
392.01	Transportation Equip.-Automobiles	1.6	24.0	69.04	4.3
392.02	Transportation Equip.-Light Trucks	6.0	20.0	54.52	4.2
392.03	Transportation Equip.-Heavy Trucks	8.9	20.0	32.83	5.3
393.01	Stores Equipment		7 Yr. Amort		
394.01	Tools, Shop & Garage Equip.		7 Yr. Amort		
395.01	Laboratory Equipment		7 Yr. Amort		
396.00	Power Operated Equipment		7 Yr. Amort		
397.25	Communication Equipment - Fixed	11.5	(10.0)	48.75	5.3
GENERAL PLANT - AMORTIZED					
391.01	Office Furniture & Equipment		7 Yr. Amort		
391.02	Office Equipment - Workstation		3 Yr. Amort		
391.04	Computer Equipment - Mainframe		5 Yr. Amort		
393.00	Stores Equipment - Portable		7 Yr. Amort		
394.00	Tools,Shop, & Garage Equip.		7 Yr. Amort		
395.00	Laboratory Equipment		7 Yr. Amort		
397.00	Communication Equipment		7 Yr. Amort		
398.00	Miscellaneous Equipment		7 Yr. Amort		
RECOVERY SCHEDULE					
397.01	Energy Management System		2 Yr. Recovery Period		
	Coal Classifiers		1 Yr. Recovery Period		

*Restated reserve after corrective measures.

TAMPA ELECTRIC COMPANY
GANNON REPOWERING
EFFECTIVE JANUARY 1, 2000

ACCOUNT		PRELIMINARY APPROVED AVERAGE REMAINING LIFE (YRS)	NET SALVAGE (%)	01/01/2000 RESERVE (%)	REMAINING LIFE RATE (%)
GANNON STATION					
	- Common -				
311500	Structures	39.0	(5.0)	26.63	2.0
312500	Boiler Plant	42.0	(5.0)	30.02	1.8
314500	Turbogenerators	41.0	(3.0)	16.15	2.1
315500	Acces. Electric Equipment	26.0	(5.0)	33.30	2.8
316500	Miscellaneous	13.0	(19.0)	59.51	4.6
	- Unit 1 -				
311510	Structures	7.2	(1.0)	84.75	2.3
312510	Boiler Plant				
314510	Turbogenerators	6.5	(1.0)	71.21	4.6
315510	Acces. Electric Equipment	5.8	(1.0)	77.65	4.0
316510	Miscellaneous	7.3	(1.0)	82.41	2.5
	- Unit 2 -				
311520	Structures	8.4	(1.0)	63.94	4.4
312520	Boiler Plant				
314520	Turbogenerators	7.6	(1.0)	71.05	3.9
315520	Acces. Electric Equipment	7.3	(1.0)	72.78	3.9
316520	Miscellaneous	6.6	(2.0)	85.07	2.6
	- Unit 3 -				
311530	Structures	37.0	(4.0)	48.57	1.5
312530	Boiler Plant				
314530	Turbogenerators	24.0	(6.0)	52.65	2.2
315530	Acces. Electric Equipment	16.6	(5.0)	60.97	2.7
316530	Miscellaneous	22.0	(8.0)	62.00	2.1
	- Unit 4 -				
311540	Structures	33.0	(8.0)	47.81	1.8
312540	Boiler Plant				
314540	Turbogenerators	22.0	(6.0)	56.57	2.2
315540	Acces. Electric Equipment	15.1	(3.0)	56.52	3.1
316540	Miscellaneous	41.0	(6.0)	23.31	2.0
	- Unit 5 -				
311550	Structures	40.0	(5.0)	22.42	2.1
312550	Boiler Plant	11.1	(32.0)	90.30	3.8
314550	Turbogenerators	28.0	(8.0)	40.38	2.4
315550	Acces. Electric Equipment	21.0	(5.0)	40.68	3.1
316550	Miscellaneous	30.0	(15.0)	36.72	2.6
	- Unit 6 -				
311560	Structures	17.1	(1.0)	58.21	2.5
312560	Boiler Plant	15.8	(5.0)	42.47	4.0
314560	Turbogenerators	16.6	(2.0)	44.14	3.5
315560	Acces. Electric Equipment	13.3	(3.0)	51.85	3.8
316560	Miscellaneous	16.9	(2.0)	28.82	4.3

TAMPA ELECTRIC COMPANY
GANNON REPOWERING/BIG BEND UNIT 1 & 2 SCRUBBER
EFFECTIVE JANUARY 1, 2000

		PRELIMINARY APPROVED			
	ACCOUNT	AVERAGE REMAINING LIFE (YRS)	NET SALVAGE (%)	01/01/2000 RESERVE (%)	REMAINING LIFE RATE (%)
GANNON OBO					
	- Common -				
311700	Structures	45.0	(2.0)	29.21	1.6
312700	Boiler Plant	42.0	(5.0)	25.96	1.9
	- Unit 1 -				
311710	Structures	7.5	0.0	65.80	4.6
	- Unit 2 -				
311720	Structures	8.5	0.0	62.94	4.4
	- Unit 3 -				
311730	Structures	45.0	(2.0)	25.67	1.7
	- Unit4 -				
311740	Structures	44.0	(2.0)	27.19	1.7
BIG BEND UNIT 1 & 2 SCRUBBER		24.0	(11.0)	0.00	4.6

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Request for approval of revised fossil dismantlement studies by Florida Power & Light Company.	DOCKET NO. 030558-EI ORDER NO. PSC-03-0872-PCO-EI ISSUED: July 29, 2003

The following Commissioners participated in the disposition of this matter:

LILA A. JABER, Chairman
J. TERRY DEASON
BRAULIO L. BAEZ
RUDOLPH "RUDY" BRADLEY
CHARLES M. DAVIDSON

ORDER GRANTING PRELIMINARY APPROVAL
FOR DISMANTLEMENT ACCRUALS

BY THE COMMISSION:

In Order No. 24741, issued July 1, 1991, in Docket No. 890186-EI, the Commission established the methodology for accruing the costs of dismantlement for fossil fueled production plants. The methodology is dependent on three factors: estimated base costs for dismantlement, projected inflation, and a contingency factor. Order No. 24741 required electric companies to file site specific dismantlement studies at least once every four years in connection with their comprehensive depreciation studies. On June 20, 2003, Florida Power & Light Company (FPL) filed its revised fossil dismantlement site-specific cost studies. FPL has requested preliminary implementation of its proposed revised annual dismantlement accruals, effective January 1, 2003.

The Commission approved FPL's current fossil dismantlement accruals in Order No. PSC-00-0293-PAA-EI, issued February 14, 2000, in Docket No. 981166-EI. The annual accruals were effective January 1, 1999. In that Order, the Commission directed FPL to file its next regularly scheduled fossil dismantlement site-specific studies no later than September 17, 2002. In Order No. PSC-01-2376-PAA-EI, issued December 10, 2001, in Docket No. 011088-EI, the Commission granted FPL an extension until April 30, 2004, to file its updated fossil dismantlement studies. FPL needed the extension of time because of staffing limitations brought about by the review of its retail rates in Docket No. 001148-EI. In approving the extension of time, the Commission stated that in the event of a settlement in Docket No. 001148-EI, the filing date should be revisited. Thereafter, on March 14, 2002, the parties in Docket No. 001148-EI, In Re: Review of the Retail Rates of Florida Power & Light Company, filed a Stipulation and Settlement (Stipulation) that extended FPL's existing revenue sharing plan through the end of 2005. The Commission approved the Stipulation by Order No. PSC-02-0501-AS-EI, issued April 11, 2002. The Stipulation precludes the revision of FPL's depreciation rates for the term of the Stipulation, but does not preclude the revision of FPL's dismantlement accruals. As a result of the Settlement, FPL has filed its dismantlement studies one year earlier than anticipated.

We approve FPL's proposed annual dismantlement accruals, as shown on Attachment A, on a preliminary basis. FPL's dismantlement expenses will increase by an estimated $918,000 for 2003. The expenses should be trued-up when we take final action in this docket, which we expect to occur in November, 2003.

Preliminary implementation does not imply that we will automatically accept FPL's proposals when we complete our review of its study. Preliminary implementation only means that the proposed accruals shown on attachment A are likely to result in more appropriate expenses than the current dismantlement accruals. In either case, the accruals will be trued-up upon final Commission action in this docket.

Since FPL's 1998 dismantlement study, base cost estimates for the various dismantlement activities have changed as shown below:

FOSSIL DISMANTLEMENT BASE COST ESTIMATES		
	1998 Study	2003 Study
	($)	($)
Cape Canaveral	11,310,465	12,698,822
Cutler	7,204,220	7,890,950

FOSSIL DISMANTLEMENT BASE COST ESTIMATES		
	1998 Study	2003 Study
	($)	($)
Fort Lauderdale	16,234,272	21,013,706
Ft. Myers	23,015,656	19,659,288
Manatee	30,454,351	38,735,568
Martin	48,610,494	57,422,630
Port Everglades	29,028,327	36,502,177
Putnam	7,821,728	7,774,579
Riviera	15,323,103	17,066,500
Sanford	27,583,232	27,356,897
Scherer	19,144,381	25,868,542
St. Johns River Power Park	16,136,613	17,652,261
Turkey Point	22,577,038	24,277,678
Total	274,443,880	313,919,598

Both the 1998 cost estimates and the 2003 cost estimates include a 16% contingency factor. According to FPL, the increase in cost estimates is due in part to changes in labor rates, an extension of the recovery periods to recognize the repowering of certain units, the addition of the simple cycle Martin Unit 8, and an increase in burial costs at Manatee, Fort Lauderdale, and Port Everglades.

As mentioned above, we expect to complete the final review of FPL's fossil dismantlement study in November, 2003. Until then, we approve the implementation of the proposed dismantlement accruals shown on Attachment A on a preliminary basis, effective January 1, 2003.

Based on the foregoing, it is

ORDERED that Florida Power and Light Company may implement the proposed fossil dismantlement accruals specified in this Order on a preliminary basis, beginning January 1, 2003, with provision for a true-up of expenses when the Commission takes final action on the dismantlement study. It is further

ORDERED that this docket shall remain open.

By ORDER of the Florida Public Service Commission this 29th Day of July, 2003.

Blanca S. Bayó

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

(S E A L)

MCB

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.

Mediation may be available on a case-by-case basis. If mediation is conducted, it does not affect a substantially interested person's right to a hearing.

Any party adversely affected by this order, which is preliminary, procedural or intermediate in nature, may request: (1) reconsideration within 10 days pursuant to Rule 25-22.0376, Florida Administrative Code; or (2) judicial review by the Florida Supreme Court, in the case of an electric, gas or telephone utility, or the First District Court of Appeal, in the case of a water or wastewater utility. A motion for reconsideration shall be filed with the Director, Division of the Commission Clerk and Administrative Services, in the form prescribed by Rule 25-22.060, Florida Administrative Code. Judicial review of a preliminary, procedural or intermediate ruling or order is available if review of the final action will not provide an adequate remedy. Such review may be requested from the appropriate court, as described above, pursuant to Rule 9.100, Florida Rules of Appellate Procedure.

Attachment A

FLORIDA POWER AND LIGHT COMPANY
PRELIMINARY IMPLEMENTATION

Plant Site	Current Annual Accrual	Proposed Annual Accrual	Change in Annual Accrual
Steam Production	**($)**	**($)**	**($)**
Cape Canaveral	641,593	606,925	(34,668)
Cutler	374,541	269,549	(104,992)
Ft. Myers Units 1 & 2	1,243,132	0	(1,243,132)
Manatee	1,638,834	2,543,323	904,489
Martin Units 1 & 2	2,029,877	2,359,945	330,068
Port Everglades	1,688,214	2,129,323	441,109
Riviera	853,591	629,946	(223,645)
Sanford	1,490,155	195,558	(1,294,597)
Scherer	1,155,529	1,276,972	121,443
St. Johns River Power Park	867,729	776,659	(91,070)
Turkey Point	1,230,794	1,106,183	(124,611)
Total Steam Production	13,213,989	11,894,383	(1,319,606)
Other Production			
Fort Lauderdale	1,044,362	1,386,450	342,088
Putnam	442,534	349,433	(93,101)
Martin CC Units 3, 4, & 8	685,841	902,683	216,842
Ft. Myers CC Unit 2	0	787,337	787,337
Sanford CC Units 4 & 5	0	1,004,179	1,004,179
Port Everglades GTs	29,961	19,564	(10,397)
Ft. Lauderdale GTs	20,347	34,554	14,207
Ft. Myers GTs	136,981	112,952	(24,029)
Total Other Production	2,360,026	4,597,152	2,237,126
Total Dismantlement Provision	15,574,015	16,491,535	917,520

Pat Lee

From: Don_Babka@fpl.com
Sent: Thursday, February 13, 2003 8:14 AM
To: Pat Lee
Cc: Tony_Cuba@fpl.com; Dave_Huss@fpl.com
Subject: Re: Fossil Dismantlement Rule

Pat we have a few comments for your consideration shown on the attached.
Thanks

(See attached file: Dismantlement-Rule#2.wpd)

"Pat Lee"
<PLee@PSC.STATE.F   To: "Kim McDaniel (E-mail)"
<kemcdani@southernco.com>, "Don Babka (E-mail)"
L.US>   <Don_Babka@fpl.com>, "Javier Portuondo (E-
mail)" <javier.j.portuondo@fpc.com>, "Chrys
Remmers (E-mail)"
<caremmers@tecoenergy.com>, "Cheryl Martin (E-mail)"
02/10/03 12:09 PM   <cmmartin@fpuc.com>
cc: "Chris Moore"
<CMoore@PSC.STATE.FL.US>, "Betty Gardner"
<BGARDNER@PSC.STATE.FL.US>, "John
Slemkewicz" <JSlemkew@PSC.STATE.FL.US>
Subject: Fossil Dismantlement Rule

Attached is a draft rule addressing fossil dismantlement. The purpose of the rule is to codify existing Commission practice and policy.

A Rule Development Workshop has been scheduled for March 25, beginning at 9:30 am in room 182. Please e-mail any questions, comments, or suggested rule language revisions to me by March 19.

If you need for a dial-in number, please let me know and we will make arrangements.

Pat Lee
Florida Public Service Commission
850-413-6453

(See attached file: Dismantlement-Rule#2.wpd)

25-6.04364 Electric Utilities Dismantlement Studies

(1) The purpose of this rule is to ensure that each utility that owns a fossil fuel generating unit is required to establish a dismantlement accrual to accumulate ~~maintains~~ a reserve that is sufficient to meet all removal expenses at the time of dismantlement. ~~by establishing dismantlement accruals.~~ The purpose of the study required by (3) is to obtain sufficient information to update cost estimates based on new developments, additional information, technological improvements, and forecasts; to evaluate alternative methodologies; and to revise the annual accrual needed to recover these costs.

(2) For the purpose of this rule, the following definitions shall apply:

(a) "Contingency Costs." A specific provision for unforeseeable elements of cost within the defined project scope.

(b) "Dismantlement." The process of safely managing, removing, demolishing, disposing, or converting for reuse the materials and equipment that remain at the fossil fuel generating unit following its retirement from service and restoring the site to a marketable or useable condition.

(c) "Dismantlement Costs." The costs for the ultimate physical removal and disposal of plant and site restoration, minus any attendant gross salvage amount, upon final retirement of the site or unit from service.

(3) Each utility shall file a site-specific dismantlement

CODING: Words underlined are additions; words in ~~struck through~~ type are deletions from existing law.

study for each generating site once every 4 years from the submission date of the previous study unless otherwise required by Commission order. A utility may file a study sooner than 4 years. Each utility's dismantlement study shall include:

(a) A narrative describing each fossil fuel generating unit, including the in-service date and estimated retirement date.

~~(b) A list of all entities owning an interest in each generating unit, the percentage of ownership by each entity, and documentation showing the status of each entity in providing its share of the total dismantlement costs.~~

(c) The dismantlement study methodology.

(d) A summary of the major assumptions used in the study.

(e) The methodology selected to dismantle each generating unit and support for the selection.

(f) The methodology and escalation rates used in converting the current estimated dismantlement costs to future estimated dismantlement costs and supporting documentation and analyses.

i. Each utility should use the same set of indices to escalate labor, materials and supplies, disposal and salvage. The appropriate index to use is Compensation Per Hour Index for labor, the Intermediate Materials, Supplies and Component Index for materials, supplies, and salvage and the GNP Price Deflator Index for disposal. These indices should come from the most current " The U.S. Economy" as published by DRI WEFA, Inc. that is available or as otherwise authorized by the Commission.

(g) The total utility and jurisdictional dismantlement cost estimates in current dollars for each unit.

(h) The total utility and jurisdictional dismantlement cost estimates in future dollars for each unit.

(i) For each year, the estimated amount of dismantlement expenditures.

(j) The projected date each generating unit will cease operations.

(k) For each site, a comparison of the current approved annual dismantlement accruals with those proposed. Current accruals shall be identified as to the effective date and proposed accruals to the proposed effective date.

(l) A summary and explanation of material differences between the current study and the utility's last filed study including changes in methodology and assumptions.

(m) Supporting schedules, analyses, and data, including the contingency allowance, used in developing the dismantlement cost estimates and annual accruals proposed by the utility. Supporting schedules shall include the inflation analysis.

(4) The dismantlement annual accrual shall be calculated using the current cost estimates escalated to the expected dates of actual dismantlement. The future costs less amounts recovered to date shall then be discounted in a manner that accrues the costs over the remaining life span of the unit.

(5) Dismantlement accruals shall be recorded ~~accumulated~~

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monthly to assure that the costs for dismantlement have been provided for at the time the production unit or site ceases operations.

(6) A utility shall not establish a new ~~annual~~ dismantlement accrual or transfer a dismantlement reserve without prior Commission approval.

(7) A utility shall not change its ~~annual~~ dismantlement accrual without prior Commission approval.

(8) The annual dismantlement accrual shall be a fixed dollar amount and shall be based on a 4-year average of the accruals related to the years between the dismantlement study reviews.

(9) The accumulated dismantlement reserve and accruals shall be maintained ~~as a subaccount for each site separate from the accumulated depreciation reserve and expense.~~ in a subacount of Account 108 "Accumulated Depreciation" and separate from the accumulated depreciation reserve and expenses. The subaccount will be segregated further by unit so that each units dismantlement reserves and expenses are accounted for separately.

Specific Authority: 350.127(2), 350.115, F.S.

Law Implemented: 366.041, 366.06(1), F.S.

History: New ______________.

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Pat Lee

From: Burg, Heidi [Heidi.Burg@pgnmail.com]
Sent: Wednesday, March 19, 2003 1:57 PM
To: plee@psc.state.fl.us
Cc: Portuondo, Javier J; Roderer, Michael
Subject: Proposed Fossil Dismantlement Rule

Dismantlement-Rule#2(PEF).doc

Pat -

Attached are Progress Energy Florida's comments on the proposed Fossil Dismantlement Rule.

Please call me with any questions.

Thank you,
Heidi

Heidi D. Burg, CPA
Lead Business Financial Analyst
Regulatory Services
Progress Energy - St. Petersburg, FL
Internal: 7-230-5302
External: 727-820-5302
Cell: 727-420-3112

<<Dismantlement-Rule#2(PEF).doc>>

25-6.04364 Electric Utilities Dismantlement Studies

(1) The purpose of this rule is to ensure that each utility that owns a fossil fuel generating unit maintains a reserve that is sufficient to meet all removal expenses at the time of dismantlement by establishing dismantlement accruals. The purpose of the study required by (3) is to obtain sufficient information to update cost estimates based on new developments, additional information, technological improvements, and forecasts; to evaluate alternative methodologies; and to revise the annual accrual needed to recover the costs.

(2) For the purpose of this rule, the following definitions shall apply:

(a) "Contingency Costs." A specific provision for unforeseeable elements of cost within the defined project scope.

(b) "Dismantlement." The process of safely managing, removing, demolishing, disposing, or converting for reuse the materials and equipment that remain at the fossil fuel generating unit following its retirement from service and restoring the site to a marketable or useable condition.

(c) "Dismantlement Costs." The costs for the ultimate physical removal and disposal of plant and site restoration, minus any attendant gross salvage amount, upon final retirement of the site or unit from service.

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(3) Each utility shall file a site-specific—dismantlement study where possible (per Order 24741, page 4, paragraph 3) for each generating site once every 4 years from the submission date of the previous study unless otherwise required by Commission order. A utility may file a study sooner than 4 years. Each utility's dismantlement study shall include:

(a) A narrative describing each fossil fuel generating unit, including the in-service date and estimated retirement date.

(b) A list of all entities owning an interest in each generating unit and~~,~~ the percentage of ownership by each entity.~~, and documentation showing the status of each entity in providing its share of the total dismantlement costs.~~

(c) The dismantlement study methodology.

(d) A summary of the major assumptions used in the study.

(e) The methodology selected to dismantle each generating unit and support for the selection.

(f) The methodology and escalation rates used in converting the current estimated dismantlement costs to future estimated dismantlement costs and supporting documentation and analyses.

(g) The total utility and jurisdictional dismantlement cost estimates in current dollars for each unit.

(h) The total utility and jurisdictional dismantlement cost estimates in future dollars for each unit.

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(i) For each year, the estimated amount of dismantlement expenditures.

(j) The projected date each generating unit will cease operations.

(k) For each site, a comparison of the current approved annual dismantlement accruals with those proposed. Current accruals shall be identified as to the effective date and proposed accruals to the proposed effective date.

(l) A summary and explanation of material differences between the current study and the utility's last filed study including changes in methodology and assumptions.

(m) Supporting schedules, analyses, and data, including the contingency allowance, used in developing the dismantlement cost estimates and annual accruals proposed by the utility. Supporting schedules shall include the inflation analysis.

(4) The dismantlement annual accrual shall be calculated using the current cost estimates escalated to the expected dates of actual dismantlement. The future costs less amounts recovered to date shall then be discounted in a manner that accrues the costs over the remaining life span of the unit.

(5) Dismantlement accruals shall be accumulated monthly to assure that the costs for dismantlement have been provided for at the time the production unit or site ceases operations.

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(6) A utility shall not establish a new annual dismantlement accrual without prior Commission approval.

(7) A utility shall not change its annual dismantlement accrual without prior Commission approval.

(8) The annual dismantlement accrual shall be a fixed dollar amount and shall be based on a 4-year average of the accruals related to the years between the dismantlement study reviews.

(9) The total accumulated dismantlement reserve and accruals shall be maintained as a subaccount ~~for each site~~ separate from the accumulated depreciation reserve and expenses. Records shall include sufficient detail to allow for separate site reporting.

Specific Authority: 350.127(2), 350.115, F.S.

Law Implemented: 366.041, 366.06(1), F.S.

History: New ______________.

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