Ruth Nettles

From: ROBERTS.BRENDA [ROBERTS.BRENDA@leg.state.fl.us]
Sent: Tuesday, February 17, 2009 2:10 PM
To: Filings@psc.state.fl.us
Cc: cecilia_bradley@oag.state.fl.us; James D. Beasley; Jean Hartman; Jennifer Brubaker; John McWhirter; John Moyle; Lee Willis; Mike Twomey; Paula K. Brown; Schef Wright; Vicki Gordon Kaufman
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Attachments: TECO 080317-EI POST-HEARING BRIEF.final.sversion.doc

Electronic Filing

a. Person responsible for this electronic filing:

Patricia A. Christensen, Associate Public Counsel
Office of Public Counsel
c/o The Florida Legislature
111 West Madison Street, Room 812
Tallahassee, FL 32399-1400
(850) 488-9330
Christensen.patty@leg.state.fl.us

b. Docket No. 080317-EI

In re: Petition for rate increase by Tampa Electric Company.

c. Document being filed on behalf of Office of Public Counsel

d. There are a total of 81 pages.

e. The document attached for electronic filing is Citizen's Post-Hearing Brief.
(See attached file: TECO 080317-EI POST-HEARING BRIEF.final.sversion.doc)

Thank you for your attention and cooperation to this request.

Brenda S. Roberts
Office of Public Counsel
Telephone: (850) 488-9330
Fax: (850) 488-4491

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Tampa Electric Company's Petition for an Increase in Base Rates and Miscellaneous Service Charges
--/

Docket No. 080317-EI

Filed: February 17, 2009

CITIZENS' POST-HEARING BRIEF

J. R. Kelly
Public Counsel

Patricia A. Christensen
Associate Public Counsel

Office of Public Counsel
c/o the Florida Legislature
111 West Madison Street
Room 812
Tallahassee, FL 32399-1400

Attorney for the Citizens
Of the State of Florida

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Tampa Electric Company's Petition for an Increase in Base Rates and Miscellaneous Service Charges	Docket No. 080317-EI
--/	Filed: February 17, 2009

CITIZENS' POST-HEARING BRIEF

The Citizens of the State of Florida, by and through the Public Counsel and undersigned counsel, pursuant to Order No. PSC-08-0557-PCO-EI, as modified by Order No. 08-0635-PCO-EI, hereby file this Post-hearing Statement in the above-referenced docket.

STATEMENT OF BASIC POSITION:

Tampa Electric Company's ("Tampa Electric" and "Company") base rate increase of $228 million is grossly overstated. Moreover, the Company's request for a 12.0% return on equity is excessive particularly in today's economy. Close scrutiny of the Company's MFRs shows that only approximately $38.6 million is needed for Tampa Electric to earn a fair rate of return on rate base and to meet its operation and maintenance expenses.

As stated above, Tampa Electric's requested return on equity of 12.0% is extremely inflated and unsupported by the evidence. Under today's market conditions a 9.75% return on equity is reasonable and is appropriate and correct ROE for Tampa Electric. Utilizing the 9.75% ROE, the reasonable and supported overall fair rate of return is 7.33%.

In addition to the cost of capital adjustments that should be made to the Company's requested amounts, numerous adjustments are warranted to the Company's projected 2009 test year rate base and operating expenses. Tampa Electric has significantly overstated certain amounts which if left uncorrected would result in customers paying rates in excess of rates that would be reasonable and necessary to provide safe and reliable service. The Company has failed to provide documentation sufficient to support the amounts of its requests or the need for requested items. In addition, Tampa Electric's request to establish a Transmission Base Rate Adjustment mechanism should be denied as there is no justifiable basis for removing these costs from base rates and creating another recovery clause. This request will, in effect, reduce the Company's risk to plan and properly build transmission facilities and provides no benefit to ratepayers.

Based upon the adjustments to rate base, cost of capital, and operation and maintenance expenses discussed below an overall reduction of $189 million to Tampa Electric's request is warranted. Citizen's adjustments are discussed in detail below.

ISSUES AND POSITIONS

TEST PERIOD

Issue 1: Is TECO's projected test period of the 12 months ending December 31, 2009 appropriate?

POSITION: No position.

Issue 2: Are TECO's forecasts of Customers, KWH, and KW by Rate Class for the 2009 projected test year appropriate?

POSITION: No position.

QUALITY OF SERVICE

Issue 3: Is the quality of electric service provided by TECO adequate?

POSITION: No position.

RATE BASE

Issue 4: Has TECO removed all non-utility activities from rate base?

POSITION: *No. As described in Issue 19, the Company has not removed all non-utility activities from rate base.*

DISCUSSION:

As discussed in detail in Issue 19, Citizens advocate removing the entire balance of Account 146 – Accounts Receivable from Associated Companies of $6,309,000. TR 2030.

Issue 5: Is the pro forma adjustment related to the annualization of five simple cycle combustion turbine units to be placed in service in 2009 appropriate?

POSITION: *No. Annualizations of plant additions should not be allowed. Two turbines are to be added in May 2009 and three in September 2009. When plant additions are revenue-producing or growth-related assets and no adjustment for increased customers or demand has been made, the revenue requirement is overstated. The Company's request to annualize the five simple cycle turbines should be denied. A reduction of $130,687,000 to rate base reflecting the actual in-service dates is warranted.*

DISCUSSION:

The Company is proposing to annualize the costs of the new combustion turbines (CTs) that are currently scheduled to go into service in May of 2009 (two CTs) and in September 2009 (three CTs). TR 2009. The Company is asking that these assets be treated as if they have gone into service as of January 1, 2009, not the actual in-service date. This request increases the Company's request by $29 million. TR 2009.

Pursuant to Section 366.06(1), Florida Statute, the Commission shall use the actual legitimate costs of the utility's property ". . . actually used and useful in the public service . . ." for ratemaking purposes. Tampa Electric witness Hornick testified that several older CT units will be retired over the next couple of years. Big Bend CT Unit 1 will be retired after Big Bend Unit 4 is placed into service in 2009. H.E. 13, No. 64, Hornick Deposition at p. 26. Big Bend CT Unit 2 and CT Unit 3 are being retired in 2008. Id. at 27. Tampa Electric's President, witness Black, admitted that Tampa Electric is in the process of re-evaluating the need to place into service the three CTs scheduled for service in September 2009. TR 107. Tampa Electric witness Black admitted that depending on what their next demand and energy forecast tells them, installation of some of the later of the CTs may be pushed out some. TR 107. To counter this testimony, the Company, in late-filed H.E. 112, claimed that it reached a final decision on February 2, 2009, attempting to leave the impression that all five CTs would be coming in service in 2009. However, for CTs 5 and 6, they mention coming into service in mid-April but no year is stated.[1] Yet the Company will not have done its demand and energy forecast until April 2009. So, it is likely that some of the May or September units will not come into service at all during the test year or pushed into mid-April 2010.

Witness Hornick stated that each CT has a nominal capacity of 60 megawatts for a total of 300 megawatts. He further indicated that after the retirements of the CTs currently in use, the

[1] Tampa Electric has inserted information that is beyond the scope of the late-filed request to "calculate the revenue requirement impact of removing the September combustion turbines ("CTs") from the 2009 test year" as such the last two paragraphs in the late-filed H.E. 112 should be stricken.

incremental generating capacity of the five new CTs would be 170 megawatts. H.E. 13, No. 64, Hornick Deposition pp. 26 -27. Therefore, should any of the CTs not be brought on-line, customers will end up paying for plant that is not in service at all during the test year. Even assuming that two of the combustion turbines are placed into service in May 2009 and three in September 2009 according to the Company's timeframe, they will not be used and useful to the public prior to those respective dates.

Until 1981, this Commission used a historical test year to set rates in rate cases. TR 2010. As witness Larkin pointed out, with a historical test year such adjustments are made to represent the costs that would be incurred when new rates were implemented. TR 2010-2011. However, when a projected test year is based on 12-months of forecasted data, it should be designed to match the Company's projected investment with its projected earnings during the future test period on a month-to-month basis and an annual basis. Witness Larkin stated Tampa Electric would not identify any Commission precedent (when asked in discovery) that would allow for the type of annualization in a projected test year that Tampa Electric is requesting. TR 2010.

Generally, a Company adds new plant as new customer growth can support the additional kilowatts generated by the new plant while maintaining the required reserve margin. TR 2010. Under Tampa Electric's request, new plant would be put into rates without accounting for the new customer growth that would otherwise support those costs. As a result, the increased costs are spread over a smaller customer base and the current customers pay more than their fair share. TR 2011-2012. This is a mismatch of projected revenues and expenses and the projected investment related to assets (such as the CTs) that generate the test period revenues. TR 2012.

This is why annualizations of plant additions should not be allowed when plant additions are revenue-producing or growth-related assets designed to increase the Company's ability to generate, transmit and deliver additional kilowatt hours of generation. TR 2012. If the Commission allows an adjustment for revenue-producing plant that increases capacity without an adjustment to recognize the increased customers and/or demand, this will overstate the revenue requirements used to create the rates charged to customers. TR 2012.

Moreover, by annualizing the CTs and pretending they went into service on January 1, 2009, any sales growth which the Company experiences in association with the availability of the CT's in 2010, will not have been reflected in the test year. Sales growth in the year 2010, when these units will provide a full year of service and beyond, will not be matched with the costs. The costs of the CTs will have been already reflected in rates established for the test year

2009 although these assets will only be in service for part of the year. Revenue generated from these facilities in 2010 and beyond will be a windfall to the Company. TR 2013.

As Tampa Electric witness Black testified that depending on what their next demand and energy forecast tells them, it may indicate that installation of some of the later CTs should be pushed out some. TR 107. Therefore, it is possible that some of the September 2009 units will not come into service at all during the test year. This would create an even greater windfall to the Company, because the Company is collecting rates for the CTs even if they are not put into service during the test year. Unfortunately, it will not be known if any of the three September CTs will be delayed beyond the test year because according to witness Black the decision is not typically made until the April time frame. TR 107. If it were known for certain that any of the CTs were not going to be place in service in the test year, the associated cost should be removed in its entirety.

Not only does the Company's proposal violate basic accounting/ratemaking matching principles, it also is inconsistent with Florida Statutes. Pursuant to Section 366.06(1), Florida Statute, the Commission shall use the actual legitimate costs of the utility's property ". . . actually used and useful in the public service . . ." for ratemaking purposes. Thus, the Company's request to annualize the five simple cycle turbines should be denied. A reduction of $130,687,000 to the Company's rate base to reflect the actual in-service dates of the CTs is warranted.

Issue 6: Should an adjustment be made for the credit from CSX for the Big Bend Rail Project?

POSTION: * Yes. The CSX credit should be used a CIAC or contributed capital to offset the capital cost of the Big Bend Rail facility. *

DISCUSSION:

As a result of a prior docket, the Company entered into a contract with CSX Transportation (CSXT) for the transport of coal. In the contract, CSXT agreed to make contributions, also referred to as credits, to offset the cost of a coal unloading at Tampa Electric's Big Bend Rail Facility (BBRF). According to the CSXT contract, these contributions will be paid over a five-year period based on certain per ton prices and agreed-upon tons of coal delivered. TR 938; H.E. 13, No. 66, Late-filed Deposition Exhibit (CSXT Contract). Witness Larkin noted that it is not uncommon for rail carriers to absorb at least some of the costs of building the rail facilities since the rail carrier stands to benefit significantly from the movement of additional coal. TR 2016.

Originally, the Company projected in its 2009 filing that the cost of the BBRF would cost $46.4 million to complete as witness Larkin noted. TR 2015. Witness Wehle revised the projected of the cost of the BBRF to approximately $64 million in her deposition conducted on January 9, 2009. H.E. 13, No. 66, Wehle Deposition at p. 36. Yet, in witness Hornick's rebuttal testimony filed December 17, 2008, the Company was still maintaining that the cost of the BBRF was approximately $45 million. TR 826. The Company provided zero explanation or justification for the increment of capital cost above the original $46.9 million of the BBRF costs that was inserted into the test year. H.E. 13, No. 66, Wehle Deposition at p. 36. By itself this is problematic.

Furthermore, Tampa Electric included none of the CSXT contributions, but did include all of the $46.4 million BBRF plant costs for rate setting purposes in this case. In her rebuttal testimony, witness Wehle requested that the CSXT capital contributions be used in to offset the any "excess" capital costs not allowed in the rate case and any remainder being credited to customers through the fuel clause. TR 939. Although, any credit through the fuel clause might not occur until the 2012 fuel clause cycle. H.E. 110. Tampa Electric's requested treatment is inconsistent with accounting practices under the USOA, the intent of the CSXT contribution, and its design fails to benefit customers. Moreover, it is patently unfair to customers and as discussed below violates the Commission's accounting rules.

Ironically, the Company demonstrated the appropriate treatment of the BBRF in the testimony and depositions of its witnesses. Witness Chronister admitted that the appropriate GAAP and USOA accounting would require that the funds provided by CSXT be treated as contributed capital and that they should be recorded as an offset to the plant to which they relate. TR 1522-1523. There appears to be little if any dispute that the CSXT credit is contributed capital and is not a discount applicable to fuel expense. Even witness Wehle acknowledged that CSXT expressly stated in a December 2007 letter that the credit was being offered to offset the entire capital cost of the facility. TR 952-953, 964. At that time the cost was estimated to be in the $46-51 million range. Only after the case was filed, did Tampa Electric apparently develop its plan to divert the benefit of the credit to shareholders while deferring any possible customer benefit for years.

For this reason alone, the full amount of the credit should be applied to offset the capital cost of the BBRF. This treatment would insure that the ratepayers receive the appropriate benefit of the funds that would not have been contributed but for the contracted coal transport services (for which the customers will pay for, dollar-for-dollar in the fuel clause) and construction of the facility. Unfortunately, by proposing to separate the ratemaking treatment of the lion's share of the cost of the facility from the entire capital contribution itself, the Company proposes to deprive the customers of the full benefit of the credit while proposing to guarantee that the customers will bear the full cost of the facility. If the CSXT credit is properly accounted for the Company's ultimate net investment in the BBRF will likely be zero and would cost the customer nothing.

Rule 25-6.014(1), F.A.C. incorporates by reference, the Federal Energy Regulatory Commission (FERC) uniform System of Accounts (USOA) as contained in Title 18, Subchapter C, Part, 101, C.F.R. Therein, it provides in relevant part under the heading "Electric Plant Instructions" [relating to Major Utilities]:

> 2. *Electric Plant To Be Recorded at Cost.*
>
> A. All amounts included in the accounts for electric plant acquired as an operating unit or system, except as otherwise provided in the texts of the intangible plant accounts, shall be stated at the cost incurred by the person who first devoted the property to utility service. ...
>
> ***
>
> D. The ***electric plant accounts shall not include the cost or other value of electric plant contributed to the company. Contributions in the form of money or its equivalent toward the construction of electric plant shall be credited to accounts charged with the cost of such construction***. Plant constructed from contributions of cash or its equivalent shall be shown as a reduction to gross plant constructed when assembling cost data in work orders for posting to plant ledgers of accounts. The accumulated gross costs of plant accumulated in the work order shall be recorded as a debit in the plant ledger of accounts along with the related amount of contributions concurrently be recorded as a credit.

Cleary, the recording of the contributed capital as an offset to plant cost is not a matter of Company discretion. Thus, to the full extent of the estimated $50 million contributions from CSXT, the Commission's rules prohibit the Company from recording, earning a return on and depreciating any of the $46.9 million of the BBRF cost as shown on MFR B-11, Line 13. H.E. 118.

In an attempt to correct the Company's inconsistent accounting treatment, for the first time and on the stand witness Chronister off-handedly asked the Commission for FAS 71 treatment, where an exception to Generally Accepted Accounting Principles (GAAP) and presumably the Commission's USOA requirements is allowed if approved by a rate setting body. TR 1600-1601. Thus, the sole basis for a FAS 71 exception would be witness Chronister's *ad hoc,* live testimony and a mere description of the proposed treatment first revealed in the rebuttal testimony of Wehle filed December 17, 2008.

However, Commission precedents relating to FAS 71 exceptions uniformly appear to have two critical components which are absent from this case. First, these cases involved an upfront, filed, written request squarely addressing the request for FAS 71 treatment, including any justifications, and second, the requests each involves deferral of an asset. See, e.g., *In Re: Petition for Authority to Use Deferral Accounting for Creation of a Regulatory Asset or Regulatory Liability to Record Charges or Credits that Would Have Otherwise been Recorded in Equity Pursuant to Balance Sheet Treatment Required by Statement of Financial Accounting Standards (SFAS) No. 158, by Florida Public Utilities Company., 2008 WL 821214 (Fla.P.S.C., Mar 03, 2008)(NO. 080029-PU, PSC-08-0134-PAA-PU, ID 155252); In re Tampa Elec. Co., 2006 WL 3797756 (Fla.P.S.C., Dec 18, 2006)(NO. 060733-EI, PSC-06-1040-PAA-EI, ID 150309)* In this case, no such request or justification was submitted for the Commission's approval. To the extent the Company's request cryptically asks that the $18 million increment above the $46.9 million be deferred pending receipt of the CSX contributions, it should be denied outright. Clearly, if asset deferral of a non-test year facility would be appropriate for the $18 million increment (which it wouldn't), it would be more appropriate for the base amount of $46.9 million. Neither condition is present in this case. As such any FAS 71 waiver makes no sense and should be rejected even when viewed in the light most favorable to the Company.

The Company's late filed proposal is self-serving and a bad deal for the customers. It is a great deal for the shareholders. It is directly contrary to the intent of the contributing party. It violates the accounting mandates of the Commission's Rule 25-6.014(1) which adopts the FERC Uniform system of Accounts. In short, it should be rejected.

With respect to Issues 6 & 7, the Company has proposed two unpalatable options. Neither is beneficial to customers. Neither is accounted for correctly. Neither should be accepted. Instead, the Commission should (as discussed in Issue 7) not include any of the projected, estimated BBRF cost in the test year. The Commission should also reject the late-filed request. The CSX credit should be used a CIAC or contributed capital to offset the capital cost of the Big Bend Rail facility.

Issue 7: Is the pro forma adjustment related to the annualization of the Big Bend Rail Project to be placed into service in December 2009 appropriate?

POSITION: * No. By annualizing the rail facility for the entire 2009 test year when it will have been in service for a month or less, would ignore lower fuel cost benefit and the productive benefit of the facility to the Company when it is fully in service, and shift any benefit to the shareholder. At least a $44,754,000 reduction to rate base reflecting the actual in-service date of December 2009 is warranted. *

DISCUSSION:

The Big Bend Rail Project is projected to go into service December 2009. The proposed annualization is subject to the similar criticism as Tampa Electric's proposal to annualize five CTs. The requested annualization would violate a basic ratemaking principle of matching costs with benefits. TR 2016. It would also violate the meaning and intent of Section 366.06(1), Florida Statute, that requires the Commission to use only the actual legitimate costs of the utility's property ". . . actually used and useful in the public service . . ." for ratemaking purposes.

Witness Larkin noted that Tampa Electric in response to OPC's Interrogatory No. 107, that "<u>A bimodal solution broadens Tampa Electric's fuel source options and provides a stimulus for lower delivered cost of fuel</u>." TR 2014 (Emphasis in testimony). He further noted that the benefit to customers from the rail project can only be a reduction in fuel costs. TR 2014-2015. By annualizing the rail facility for the entire 2009 test year when it will have been in service for a month or less, would allow the Company to earn a return as if the lower fuel costs did not exist in the future periods. TR 2015. Witness Larkin also testified that the future increases in sales in the year 2010 and beyond when the rail facility will be fully in-service and utilized for an entire 12-month period will only fall to the benefit of the shareholders while the ratepayers have the burden of providing the carrying cost as if this facility had no productive benefit to the Company. TR 2015.

As noted in witness Larkin's testimony, since the rail carrier stands to benefit significantly from the movement of additional coal it is appropriate for the rail carrier to absorb at least some of the cost. TR 2016.. As discussed in Issue 6, the CSX has, in fact, structured a reimbursement of the capital costs of the Big Bend Rail Facility. Furthermore, the Company could not state with any degree of certainty that the BBRF would be fully in service before the end of 2009. Witness Wehle offered that they had plans to have two test deliveries of coal in December, but she acknowledged that the contract would allow that the service commencement date for coal deliveries could be slipped to September of 2011 and still allow Tampa Electric to receive the benefits of the contract including the capital contributions. TR 960- 961. The facts also cast doubt on witness Chronister's standard for inclusion of the facility as "known and measurable." TR 1457.

Thus, to allow Tampa Electric to earn a rate of return on a capital investment from ratepayers when it may be reimbursed in large part by a third party and when it may not even go into service in the projected timeframe is fundamentally unfair and unreasonable. TR 953-954. As discussed in Issue 6, the Commission has competent substantial basis for treating the CSXT contributions in a way that would offset for all ratemaking purposes -- ***at a minimum*** -- the entire $46.9 million cost of the BBRF that the Company has requested in this case. The mere fact that there is an offsetting capital contribution from CSXT should ameliorate any concern that the Company would be financially harmed by not including the pro forma adjustment or annualization in this case.

If the Commission accepts the position of the Citizens by excluding the BBRF pro forma adjustment, annualization, or finds that the CSXT credit offsets a portion of the facility, there still may be the matter of the remaining late-filed $18 million increment above the $46.9 million. To the extent that the Commission considers it appropriate to include a partial amount of the BBRF in the test year, consistent with availability of the CSXT reimbursement and potential overestimation of the cost of the facility, the Commission should allow no more than $417,000 of the facility cost. Of course, Citizens would prefer that any relatively minor net investment of BBRF should be addressed in a subsequent earnings review or rate case since there is no certainty that it will go in service before January 1, 2010. TR 960-962.

Further, the Commission should not be concerned that any remaining BBRF plant investment would materially impact Tampa Electric's earnings. The Company's late filed estimate of $64 million would yield a plant-in-service amount of only $14 million if the CSXT credit is properly accounted for based on the Company's' publicly available estimate of a $50 million CSXT credit. H.E. 110. The project contingency padding is 10.6% of the overall cost of the project as presented to the TECO Energy Capital Leadership Team. TR 1520-1521, H.E. 110. When applied to the total project cost of $64 million, algebraically the contingency amounts to $5,786,618 ($64,000,000 = x + .106x; x = $5,786,618). When this estimate, itself embedded inside of an estimate, is ignored, the non-contingent BBRF plant-in-service estimate net of contributed capital would be approximately $8,200,000 before allocation of any costs to the Guatemalan operations that it also appears to benefit. TR 1521, H.E. 110.

The amount that the Commission should use as a starting point for consideration of how much, if any, of the BBRF investment should be included in the test year is $8.2 million. If only 5% of the total capital cost of the BBRF project or $3.2 million were to be allocated to TECO Guatemala, then the remaining amount for consideration would amount to approximately $5 million. Of this amount, only $417,000, or one month's worth, for the potential in-service month of December 2009, should be considered. Admittedly there may not be an explicit record basis for a 5% allocation to Guatemala. However, since the BBRF benefiting TECO Guatemala was significant enough to be mentioned in the financing approval document, this amount may even be conservative. TR 1521, H.E. 110. Even if no allocation was made to Guatemala, the maximum amount for inclusion on a one month basis assuming that the facility actually goes into service in December of the test year would be $683,333.

In sum, the record amply supports disallowance of the entire facility for rate setting in this case. However, after proper contributed capital offsets, the maximum amount that is justified would be one month of the net investment after removing contingency estimates, non-utility allocation, of $417,000. This treatment would have some benefit of addressing the accounting for the facility for all purposes – even beyond this particular rate case. Thus, a reduction of at least $44,754,000 to the Company's rate base to reflect the actual in-service date of the rail project is warranted.

Issue 8: Should any adjustments be made to TECO's projected level of plant in service?

POSITION: *Yes. An analysis of the projected level with the actual levels through September 2008 shows the projection trend for plant in service is overstated. Utilizing the average percentage difference between the projection and actual data (since the over-projection will be carried forward into the 13-month average ending December 31, 2009) results in a reduction to jurisdictional plant in service of $51,969,000. Depreciation and amortization on a jurisdictional basis should be reduced by $8,187,000.*

DISCUSSION:

The Company is utilizing a projected 2009 test year where the Company has projected by month each component of rate base (plant-in-service, accumulated depreciation, plant held for future use, and working capital). TR 2017. Witness Larkin conducted an analysis of the Company's projected balances. He testified that it is unlikely that the Company's projected balances almost two years into the future are without inaccuracies. TR 2017. Witness Larkin testified that the best method for testing the Company's projection methodologies is to compare actual results to projections; thus to conclude whether the projections are overstated or understated. TR 2017-2018.

While Tampa Electric witness Chronister disputes witness Larkin's adjustment, he does not demonstrate how an inaccuracy in Tampa Electric's projection methodology would not be carried forward into the test year, especially when its projection is unchanged. TR 1458. A comparison of actual balances, as reported in the Company's accounting records, to the Company's projected balances will indicate whether there is a trend in the Company's projection methodology. In other words, if all of the projections exceed the actuals in months in which the company only had to project expenditures and retirements for nine month into the future, then it is likely that the same trend relating to projected plant balances will continue into the future and will affect the test year 13-month average ending December 31, 2009. TR 2019. Witness Chronister's discussion of budget variances, delays and catching up on capital projects is irrelevant to whether the projection methodology used to project future plant is correct since you are identifying a trend. TR 1459-1460.

Based on an analysis of the Company's projected level of plant in service with the actual levels through September 2008, the comparison shows that the trend in the Company's projection is overstated. Witness Larkin's Schedule B-3 shows that the average percentage overstated for 2008 through September was 0.921%. H.E. 50. Based on this identified trend, witness Larkin applied the average percentage overstatement of 0.921% to the 13-month average ending December 31, 2009. TR 2020, H.E. 50. Utilizing the average percentage difference between the projection and the actual data (since the overstated projection trending will be carried forward into the 13-month average ending December 31, 2009) results in a reduction to jurisdictional plant in service of $51,969,000 ($53,958,000 total Company). TR 2020. Based on this reduction, depreciation and amortization on a jurisdictional basis should be reduced by $8,187,000 ($8,500,000 total Company).

Issue 9: Should TECO's requested increase in plant in service for the customer information system be approved?

POSITION: *No. The Customer Information System modifications are changes that are routinely done when rate adjustments are approved such as the annual fuel proceeding or a normal base rate case. Moreover, the anticipated billing adjustments may not be approved by the Commission. Therefore, the supposedly extraordinary CIS upgrade of $2,445,000 should be denied and depreciation expense decreased by $558,000. *

DISCUSSION:

Tampa Electric has requested an increase in rate base in an amount of $2,445,000 labeled as customer information system (CIS) upgrade. TR 2021. As witness Larkin noted, the Company is requesting this amount because of the changes in rate schedules that Company has asked for in this rate case and that these rate schedule adjustments will necessitate making changes to the customer rate schedules included within the CIS. TR 2021. However, as witness Larkin pointed out in response to OPC's POD No. 98, Tampa Electric's internal document only discusses in generalities the changes to the CIS. Witness Larkin further noted that none of the items identified in response to POD No. 98 were unusual changes to the CIS and would otherwise be done routinely when base or fuel rates are changed in the normal course of business for any changes. TR 2022. Moreover, all of requested adjustments in this rate case may not be granted. TR 2022.

Witness Chronister's position that any cost the Company asks for relating to CIS upgrades is appropriate irrespective of whether the Commission approves the changes is illogical. H.E. 13, No. 61, Chronister Deposition p. 98. Witness Chronister could not identify how much of these additional costs were, in fact, caused solely due to the rate schedule changes Tampa Electric requested. Id. at 94.

Ratepayers should only have to bear the cost of prudently incurred costs that benefit them. Therefore, the supposedly extraordinary CIS upgrade of $2,445,000 should be denied and depreciation expense decreased by $558,000.

Issue 10: Is TECO's requested level of Plant in Service in the amount of $5,483,474,000 for the 2009 projected test year appropriate?

POSITION: *No. The amount should reflect the adjustments recommended by OPC in this proceeding.*

DISCUSSION:

TECO's requested level of Plant in Service should be reduced by the adjustments recommended by OPC. The Plant in Service for the 2009 projected test should reflect the adjustments for the five CTs, the Big Bend Rail facilities, projected level of plant-in service, and CIS upgrade.

Issue 11: Is TECO's requested level of accumulated depreciation in the amount of $1,934,489,000 for the 2009 projected test year appropriate?

POSITION: *No. The reserve is overstated by $8,500,000 total Company ($8,187,000 jurisdictional).*

DISCUSSION:

TECO's requested level of accumulated depreciation in the amount of $1,934,489,000 is overstated. The reserve is overstated by $8,500,000 total Company ($8,187,000 jurisdictional).

Issue 12: Have all costs recovered through the Environmental Cost Recovery Clause been removed from rate base for the 2009 projected test year?

POSITION: *No position.*

Issue 13: Is TECO's requested level of Construction Work in Progress in the amount of $101,071,000 for the 2009 projected test year appropriate?

POSITION: *No. Based on an analysis of the Company's projected level of Construction Work in Progress with the actual levels for the first nine months of 2008, the comparison shows that the Company's projection is 1.90% understated. The CWIP balance should be increased by $2,608,000 on a jurisdictional basis, which results in a CWIP balance of $103,679,000.*

Discussion:

Similar to the recommended adjustments to plant and accumulated depreciation in Issues 8 and 11, OPC's witness Larkin testified that the projected jurisdictional balance of CWIP was understated by 1.90%. Witness Larkin also adjusted the Company's calculation CWIP that accrues AFUDC. Based on his testimony, the CWIP balance to include in rate base should be $103,679,000, which exceeds the Company's jurisdictional balance by $2,608,000. TR 2028-2029.

Issue 14: Is TECO's requested level of Property Held for Future Use in the amount of $37,330,000 for the 2009 projected test year appropriate?

POSITION: *No. The Company's Property Held for Future Use should be decreased by $2,328,354 on a jurisdictional basis to reflect the change the Company made to accurately reflect all plant placed in service in 2009.*

Discussion:

OPC witness Larkin testified that TECO's method of projecting plant held for future use (PHFU) was incorrect and inadequately explained. The Company only projected an annual balance of PHFU, not a monthly balance for additions, or used either 2008 or 2009 balances. Had the company projected monthly, the PHFU balance would not have remained the same for each month except for December of each of the years. In OPC Interrogatory No. 87, the Company was asked to provide a list of each PHFU project as of December 31, 2007, including the date each was acquired, the original cost, and projected use date. In that response, $1.5 million in projects were projected to be placed in service in 2008. Witness Larkin stated that $25 million of this PHFU property closed to plant in service in 2009 (when it was placed into service) would have reduced the PHFU balance substantially. When asked in OPC Interrogatory No.118, why the 2008 and 2009 projects were still in PHFU, the Company responded by changing the in service dates on major PHFU amounts and removing others from the balance. In response to OPC Interrogatory No. 118, the Company stated that the changes to PHFU would not impact rate base as the changes to PHFU would result in an increase to plant in service. Witness Larkin rightfully concluded that the Company's statement that both projected plant and PHFU are "accurate" cannot be true.

Witness Chronister attempted to rebut witness Larkin's assessment of the company's faulty projected PHFU but his logic is missing. TR 1465-1466. He claimed that witness Larkin was wrong only because witness Larkin failed to make a double-sided accounting entry to decrease both PHFU and then increase plant in service. All witness Chronister had to do to rebut this adjustment was show that the PHFU was not included in the projections of plant. If you were to transfer witness Larkin's adjustment from PHFU to plant, as witness Chronister suggested, then the Company's projected balance of plant will be overstated. The Company did not remove all of the plant placed into service into service in 2008-2009 for PHFU. As a result, PHFU should be reduced by $2,328,354 on a jurisdictional basis. TR 2025-2028.

Issue 15: Should an adjustment be made to TECO's requested deferred dredging cost?

POSITION: *Yes. The Company has failed to provide documentation to support that dredging costs will reach $6.9 million. Historical costs have been significantly less. The Company has not supported that any dredging will occur in 2009 test year. Therefore, the deferred dredging cost balance of $2,657,000 (jurisdictional) should be removed.*

DISCUSSION:

Tampa Electric contends that the costs to dredge out the channel at the Big Bend generating station will be "roughly" $6.9 million. TR 2022. Tampa Electric has removed from operating expenses $5,320,000 (jurisdictional) of the $6.9 million (total Company), which leaves an expense of $1,330,000 (jurisdictional). The Company has added to rate base an amount of $2,657,000 which it claims represents the 13-month average of the unamortized jurisdictional balance. TR 2022-2023.

However, the historical information indicates that dredging costs have never approached $6.9 million. In fact, in 2002, the total dredging costs were $2,346,105.81 with $1,288,169.73 allocated to Tampa Electric and $1,057,936.08 allocated to a separate organization, IMC. Previously in 1997-1998, the total dredging costs were $1,329,989.47, allocated at $1,101,589.47 to Tampa Electric and $228,400 allocated to IMC. TR 2023. Witness Larkin, in his demonstrative historical check, included only half of the $1,330,000 (jurisdictional) amount amortized over five years for comparison purposes only. TR 2023. But even if the whole amount were utilized for demonstrative purposes, Tampa Electric's currently requested $6.9 million amount is well beyond its adjusted historical costs of $1,330,000. TR 2023-2024. Even assuming the Company's estimate of the additional $2.8 million in disposal costs (for which there are no bids) were correct, the total for dredging would only have risen to $4,130,000. H.E. 13, No. 64, Hornick Deposition p. 43. In the event dredging activities actually occur in 2009, $4,130,000 amortized over a six year period would be $688,333.

The Company's witness Hornick in his deposition stated that $2.8 million of the total estimated $6.9 million costs was related to disposal costs to either build new dikes or dispose in landfills. H.E. 13, No. 64, Hornick Deposition at p. 43. However, he admitted that he did not know what the exact cost for disposal would be and the estimate was based on numbers developed by Tampa Electric's "understanding," not a third party estimate or competitive bids. H.E. 13, No. 64, Hornick Deposition at pp. 43-44. He further admitted that Tampa Electric would look at building up the dikes to a level that would accept multiple dredging. H.E. 13, No. 64, Hornick Depo. P. 45. As witness Hornick noted Big Bend was built in the 1970's and the disposal sites have been used since that time. H.E. 13, No. 64, Hornick Depo. P. 52. Therefore, the costs to improve to the disposal areas should reflect historical use of 30 years and be amortized over the useful life of the area ($2.8 million over 30 years).

Witness Hornick claimed that based on the 2006 estimate from a contractor, the costs to perform the work has increased significantly since 2002. He conceded that the 2006 contractor estimate was not provided in response to OPC POD No. 100, but rather as a late-filed deposition exhibit in January 2009. TR 842, H.E. 13, No. 64, Hornick Deposition at p. 47. He further admitted that Tampa Electric had not solicited any bids for dredging in 2009. H.E. 13, No. 64, Hornick Deposition at p. 48. He stated that the dredging costs were based on the Company's estimates from a 2006 contractor quote of cost per yard, a 2007 hydrographic estimate of total quantity of material to be removed and miscellaneous charges. H.E. 13, No. 64, Hornick Deposition at p. 47-48.

Thus, the Company has failed to provide documentation to support that dredging costs will reach a figure of $6.9 million. As witness Larkin testified, historical costs have been significantly less. The Company has not supported that any dredging will actually occur in 2009 test year. Therefore, the deferred dredging cost balance of $2,657,000 (jurisdictional) should be removed. TR 2025.

Issue 16: Should an adjustment be made to TECO's requested storm damage reserve, annual accrual and target level?

POSITION: *Yes. The requested $16 million annual accrual increase should be denied as the current $4 million accrual is sufficient. Working capital should be increased by $8 million and operating expenses reduced by $16 million to remove the effect of increasing the storm accrual. The target level should remain at the current level of $55 million. Current Commission rules and policy are sufficient to handle potential future storm costs.*

Discussion:

The current annual accrual of $4 million for storm damage is adequate given the Company's past history. Further, given the storm reserve accounting requirements spelled out in Rule 25-6. 0143, Florida Administrative Code, and the Commission's policy of prompt storm recovery, there is no likelihood that TECO or any other Florida utility would not fully recover any prudently incurred storm damage costs which exceed the storm damage reserve.

OPC witness Larkin and AARP witness Stewart testified that TECO's storm damage reserve and target level are large enough to handle most, but not all, storm seasons. In fact, in the 15 years since inception of TECO's storm accrual, TECO incurred storm damage only in 2004 and the reserve balance at that time was sufficient to provide recovery of the incremental storm damage costs. H.E. 50, Schedule C-2. Any future storm damage in excess of the reserve can be recovered through a surcharge or even securitization, if needed. Keeping the reserve level as low as is reasonably possible will minimize the financial impact on customer rates during these trying economic times, and will allow TECO and the Commission the flexibility to address TECO's prudent storm recovery costs from year to year. TR 2031-2032, 2137-2138.

TECO witness Carlson acknowledged that the Commission's current regulatory framework is "sound" and consists of three major components: (1) an annual storm accrual, adjusted over time as circumstances change; (2) a storm reserve adequate to accommodate most, but not all, storm years; and (3) a provision for utilities to seek recovery of costs that go beyond the storm reserve. As OPC witness Larkin and AARP witness Stewart both submit, all three of these components will be met with the existing accrual, and prompt consideration and approval of recovery by the Commission of reasonable storm costs incurred that exceed the storm reserve. TR 2032, 2139. Further, if storm damages do exceed the storm reserve, then the ratepayers will timely pay for the storm recovery instead of paying possibly years in advance for damages that may not occur. TR 2036.

Utility witness Harris' analysis is inherently subjective and utility witness Carlson's testimony supports no change in the Annual Accrual or the Storm Damage Reserve level. TR 2138-2139. The annual storm damage accrual of $4 million and the current $55 million Storm Damage Reserve target approved in 1994 offered sufficient coverage even including the abnormal storm season of 2004. Further, in the recent FPL storm docket, the Commission approved a storm damage reserve level of 3 times the expected annual storm damage assessment. In this case, the 3 times the expected damage correlates to a target reserve in this case of $54 million, as opposed to the current target of $55 million. AARP witness Stewart also argues that a smaller annual accrual allows for more analysis of the prudence of the expenses charged to the reserve. TR 2140-2142.

Witness Harris' analysis of the annual storm damage is based on an expected annual uninsured cost to Tampa Electric's system from all storms is estimated to be $17.8 million. While his analysis is based on an extremely complex projection methodology, the reality of TECO incurring this level of damage on an annual basis has not shown true based on its historical storm damage over the last 15 years. Further, one of his argument that the current storm accrual is too low is based on the establishment of the current accrual was set in 1994 when obviously the cost of the company's assets were much lower. Witness Larkin refutes this statement by explaining that the accrual and reserve balance has been sufficient in each of those 15 years. TR 2032-2033. Witness Harris' estimate of possible future storm damage was also based on a full cost recovery basis, not the incremental recovery basis required under Rule 25-6.0143, Florida Administrative Code. TR 2034. As shown above, in the Company's actual 2004 storm costs, more than 50 percent of the costs did not flow through the reserve and instead were accounted for in base rate recovery. TR 2023-2033.

The Company's argument that prepaying $14 million a year more for possible storm damage through the storm reserve is cheaper for the customers is unfounded. Witness Chronister lists several advantages to customers: spreading costs over a longer period, long-term overall costs are lower, and mitigated or avoided rate shock. TR 1476. If approved, customers will give up the use of their funds currently, and still pay more if a storm occurs that the recoverable damages exceed level in the storm reserve. TR 2036. He provides no evidence to show how long-term costs are lowered. From a financial point of view, it is more beneficial to the ratepayer to pay lower costs today and pay for storm costs that exceed the reserve when they occur, then having the Company collect huge amounts of reserves prior to the occurrence of a storm. As TECO's storm reserve is unfunded, the annual $20 million expense will not be set aside and be available in the form of cash or cash equivalents to fund storm damage restoration. The collected funds will be treated as normal cash flow to the Company and the company will have to incur interest on its lines of credit to fund the repairs if a storm occurs. TR 2037. Additionally, as insurers of potential storm damage, ratepayers should have the final say on how and when storm costs should be funded. Ratepayers always have a higher cost of capital than utilities. It is in the best interest of ratepayers to fund the reserve at the level which has historically proven to be adequate and to fund any excess over the storm reserve, should one occur, through surcharges when and if such an event occurs.

The current $4 million annual accrual of has proven adequate when a storm has actually hit the system and should be continued. If a storm occurs which is in excess of the reserve, the Commission should consider a surcharge on rates or securitization, if necessary. Operating expenses should be reduced by $16 million and working capital should be increased by $8 million to remove the effect of increasing the storm reserve.

Issue 17: Should an adjustment be made to prepaid pension expense in TECO's calculation of working capital?

POSITION: *Yes, any adjustment should be made in accordance with staff's recommendation.*

DISCUSSION: Any adjustment should be made in accordance with staff's recommendation.

Issue 18: Should an adjustment be made to working capital related to Account 143-Other Accounts Receivable?

POSITION: *Yes. The Company has yet to show that all of the accounts receivable in Account 143-Other Accounts Receivable are related to utility services and the cost or revenue associated with these accounts receivable have been included in jurisdictional operating income. The remainder of Other Accounts Receivable in the amount of $10,959,000 on a jurisdictional basis should be removed. *

DISCUSSION:

The Company included Account 143 - Other Accounts Receivable in its working capital requirement, less the $1,717,000 removed for job orders receivable consistent with prior Commission practice. Per the USOA, this account includes amounts due the utility upon opening accounts other than amounts due from associated companies and from current customers for utility service. Witness Larkin testified that the utility should be required to show that the remaining amounts included in this account are related to utility services and that the cost or revenue associated with these accounts receivable have been included in jurisdictional operating income. If the Company does not present evidence showing it is related to utility service, then the total $10,959,000 on a jurisdictional basis in the account should be removed from working capital. TR 2029-2031.

In his rebuttal testimony, witness Chronister stated that these receivables relate to activities related to utility service for jurisdictional customers, such as off-system sales, pole attachment revenue, rent revenue from fiber optic, by-product sales, and residual revenues. He contends that all of these revenues for these balances are properly reflected in net operating income. TR 1466-1467. What witness Chronister doesn't state is how much of these costs have been adjusted out of operating income in this rate case, nor does he explain how customers benefit from the Company incurring these receivables. Receivables related to off-systems sales make up approximately $8 million of the requested $10 million cost are not charged to ratepayers. H.E. 13, No. 61, Chronister Deposition at p. 12. These revenues are clearly non-utility and should not be charged to ratepayers nor should the related accounts receivables.

Further, in his deposition, witness Chronister stated that the revenue accounts associated with Other Accounts Receivable (Account 143) include account numbers 454 (rent from electric property), 455 (interdepartmental rents), some of 456 (SO2 allowances and other electric revenues) and 447 (off-system sales). Id. at p. 12. By looking at MFR Schedule C-5 for the projected test year, 63% of the Other Electric Revenues shown on line 29 were removed by the company as non-jurisdictional (See footnote 1 on line 35 regarding Firm Transmission Service).

H.E. 118, MFRs, Schedule C-5 at p. 25. Similar to off-system sales, these amounts are also non-jurisdictional and as such should not be recovered by ratepayers.

Clearly from the discussion in the deposition and review of MFRs Schedule C-5, the majority of the costs included in Other Accounts Receivable relate to non-jurisdictional revenues. There could also be other amounts that are non-jurisdictional but those amounts have not been provided. Certainly, the Company's requested jurisdictional percentage for this account of .967529 is overstated based on the above analysis. H.E. 118, MFRs, Schedule B-17, p. 109 at line 8. As to what amount if any should be included in this account is unknown as the Company has failed to meet its burden to show that its requested balance is reasonable. Therefore, the whole account balance of should be removed from working capital.

Issue 19: Should an adjustment be made to working capital related to Account 146-Accounts Receivable from Associated Companies?

POSITION: *Yes. The entire balance of Account 146-Accounts Receivable from Associated Companies of $6,309,000 is non-utility related and should be removed from working capital. The associated revenues and expenses if identified should also be excluded. The Company has not met its burden to show that these affiliated transactions are directly related to the provision of utility service or necessary for working capital that ratepayers bear. *

DISCUSSION:

Witness Larkin testified that the $6,309,000 balance in Account 146 - Accounts Receivable from Associated Companies should be excluded from working capital as the Company has not shown that this account is utility related and reasonable working capital requirement for ratepayers to bear. TR 2030. He continued that these affiliated receivables are unrelated to providing service to retail electric ratepayers and should be paid by the companies receiving the services. Witness Chronister has not shown that there is an offset in the payables for Peoples Gas nor has he justified why electric customers should pay more and the gas customers pay less. If an adjustment needs to be made in the gas rate case, then do so, but these receivables should not be included in TECO's working capital. TR 2047-2048.

Witness Chronister, in his rebuttal, stated that these affiliate transactions directly relate to the provision of utility service because they provide technology support, facility management, payroll and accounts payable services to Peoples Gas. Because the revenues and expenses are included above the line, then the related receivables should also be included in working capital. Witness Chronister also admits that $390,000 should be removed as non-utility intercompany receivables. TR 1467-1468. In his deposition, witness Chronister was asked if he has provided any support to show that the revenues and the expenses of providing these services to affiliates whether non-regulated, electric or gas companies are not subsidized by the regulated electric ratepayers. What he admitted is that the accounts included in the MFRs are netted for these affiliate transactions but those details would have to be reviewed in the budget detail. H.E. 13, No. 61, Chronister Deposition at pp. 59-60. While witness Chronister admits that it is inappropriate to include the accounts receivable related to other TECO energy affiliate transaction, he does not distinguish why the Peoples Gas affiliated transactions are any different than any other non-utility transaction. Witness Mr. Chronister has admitted that the decision to include the affiliate transactions is "a judgment call to be made by the Commission."

Based on the above, the Company has not met its burden to show that these affiliate transactions benefit ratepayers, that there is subsidy on the part of electric to provide services for the gas subsidiary, or why other non-affiliate costs should be removed but not the Peoples Gas portion. TECO has failed to do this in this docket. As such, the entire balance of Account 146-Accounts Receivable from Associated Companies of $6,309,000 should be removed from working capital.

Issue 20: Should an adjustment be made to rate base for unfunded Other Post-retirement Employee Benefit (OPEB) liability?

POSITION: *Yes, any adjustment should be made in accordance with staff's recommendation.*

DISCUSSION: Any adjustment should be made in accordance with staff's recommendation.

Issue 21: Should an adjustment be made to TECO's coal inventories?

POSITION: *Yes. The Company's fuel stock should be reduced by 10%, ($9,492,600 jurisdictional) to reflect current reductions which may have occurred in coal, oil, and gas prices.*

DISCUSSION:

The Company's fuel stock should be reduced by 10% to reflect current reductions which may have occurred in coal, oil, and gas prices. TR 2030. Witness Larkin testified that the Company should be required to re-price its fuel stock inventory to accurately reflect the current price of fuel. TR 2030. Witness Larkin noted that since he did not have all the necessary information, the Company should make an accurate reassessment of fuel inventory costs based on current prices. TR 2031.

Witness Wehle stated in her deposition that coal prices used as part of the MFRs were the contractual coal prices secured through 2009. H.E. 13, No. 66, Wehle Deposition at p.21. She stated that about 60%-70% of the coal contracts are long-term contracts and the balance is based upon the spot market. Id. at 43. She stated that the long-term contract prices were lower than the current spot market. Id. at 43. She noted that, while coal prices dramatically increased over the summer of 2008, these prices had declined, just not to the mid-March 2008 levels. Id. at 19. However, the actual spot coal prices used in March 2008 versus January 2009 were not provided. In fact, witness Wehle admitted that the Company had not actually re-projected its 2009 fuel inventory balances since the spring of 2008. Id. at 45.

When asked about his recommended adjustment, witness Larkin stated that "[t]he company's prices were not actual. They used an estimate of what they thought fuel prices would be in 2009. Those aren't actual paid-for prices. Those are estimated 2009 costs multiplied by inventory volumes." TR 2061. He clarified that his adjustment was not marking the inventory down from what they actually paid, but rather what the Company estimated the 2009 cost to be. TR 2062. He stated that the Company used a factor based on market prices and valued the inventory. TR 2062. Witness Larkin's recommendation is to apply the same methodology, but use the most current coal prices. TR 2062.

Issue 22: Should an adjustment be made to TECO's residual oil inventories?

POSITION: *Yes. The Company's fuel stock should be reduced by 10% ($9,492,600 jurisdictional) to reflect current reductions which may have occurred in coal, oil, and gas prices.*

DISCUSSION:

The Company's fuel stock should be reduced by 10% to reflect current reductions which may have occurred in coal, oil, and gas prices. TR 2030. Witness Larkin testified that the Company should be required to re-price its fuel stock inventory to accurately reflect the current price of fuel. TR 2030. Witness Larkin noted that since he did not have all the necessary information, the Company should make an accurate reassessment of fuel inventory costs based on current prices. TR 2030.

Witness Wehle stated in her deposition that residual oil prices increased through the summer and fall, and then decreased in price toward the end 2008. H.E. 13, No. 66, Wehle Deposition at pp.19. She conceded that the prices retreated down to lower levels as of late 2008, early 2009. Id. at 19. However, she stated that the Company did not re-price the 2009 fuel inventory because the mid-March 2008 prices they used were at the midpoint of the activity from March 2008 to January 2009. Id. at 21. Thereby, witness Wehle admitted that the current 2009 residual oil price was significantly lower than the numbers used for the Company's inventory.

When asked about his recommended adjustment, witness Larkin stated that "[t]he company's prices were not actual. They used an estimate of what they thought fuel prices would be in 2009. Those aren't actual paid-for prices. Those are estimated 2009 costs multiplied by inventory volumes." TR 2061. He clarified that his adjustment was not marking the inventory down from what they actually paid, but rather what the Company estimated the 2009 cost to be. TR 2062. He stated that the Company used a factor based on market prices and valued the inventory. TR 2062. Witness Larkin's recommendation is to apply the same methodology, but use the most current residual oil prices. TR 2062.

Issue 23: Should an adjustment be made to TECO's distillate oil inventories?

POSITION: *Yes. The Company's fuel stock should be reduced by 10% ($9,492,600 jurisdictional) to reflect current reductions which may have occurred in coal, oil, and gas prices.*

DISCUSSION:

The Company's fuel stock should be reduced by 10% to reflect current reductions which may have occurred in coal, oil, and gas prices. TR 2030. Witness Larkin testified that the Company should be required to re-price its fuel stock inventory to accurately reflect the current price of fuel. TR 2030. Witness Larkin noted that since he did not have all the necessary information, the Company should make an accurate reassessment of fuel inventory costs based on current prices. TR 2031.

Witness Wehle stated in her deposition that distillate oil prices increased through the summer and fall and then decreased in price toward the end of the year. H.E. 13, No. 66, Wehle Deposition at pp.19. She conceded that the prices retreated down to lower levels as of late 2008, early 2009. Id. at 19. However, she stated that the Company did not re-price the 2009 fuel inventory because the mid-March 2008 prices they used were at the midpoint of the activity from March 2008 to January 2009. Id. at 21. Thereby, witness Wehle admitted that the current 2009 distillate oil price was significantly lower than the numbers used for the Company's inventory.

When asked about his recommended adjustment, witness Larkin stated that "[t]he company's prices were not actual. They used an estimate of what they thought fuel prices would be in 2009. Those aren't actual paid-for prices. Those are estimated 2009 costs multiplied by inventory volumes." TR 2061. He clarified that his adjustment was not marking the inventory down from what they actually paid, but rather what the Company estimated the 2009 cost to be. TR 2062. He stated that the Company used a factor based on market prices and valued the inventory. TR 2062. Witness Larkin's recommendation was to apply the same methodology, but use the most current prices. TR 2062.

Issue 24: Should an adjustment be made to TECO's natural gas and propane inventories?

POSITION: *Yes. The Company's fuel stock should be reduced by 10% ($9,492,600 jurisdictional) to reflect current reductions which may have occurred in coal, oil, and gas prices.*

DISCUSSION:

The Company's fuel stock should be reduced by 10% to reflect current reductions which might have occurred in coal, oil, and gas prices. TR 2030. Witness Larkin testified that the Company should be required to re-price its fuel stock inventory to accurately reflect the current price of fuel. TR 2030. Witness Larkin noted that since he did not have all the necessary information the Company should make an accurate reassessment of fuel inventory costs based on current prices. TR 2031.

Witness Wehle stated in her deposition that natural gas followed a similar pattern as oil, in that, it increased in price through the summer and fall for natural gas, and then decreased in price toward the end of 2008. H.E. 13, No. 66, Wehle Deposition at pp. 20-21. She conceded that the prices retreated down to lower levels. Id. at 19. However, she stated that the Company did not re-price the 2009 fuel inventory because the mid-March 2008 prices they used were at the midpoint of the activity from March 2008 to January 2009. Id. at 21. Thereby, witness Wehle admitted that the current 2009 natural gas price was significantly lower than the numbers used for the Company's inventory.

When asked about his recommended adjustment, witness Larkin stated that "[t]he company's prices were not actual. They used an estimate of what they thought fuel prices would be in 2009. Those aren't actual paid-for prices. Those are estimated 2009 costs multiplied by inventory volumes." TR 2061. He clarified that his adjustment was not marking the inventory down from what they actually paid, but rather what the Company estimated the 2009 cost to be. TR 2062. He stated that the Company used a factor based on market prices and valued the inventory. TR 2062. Witness Larkin's recommendation is to apply the same methodology but use the most current prices. TR 2062.

Issue 25: Has TECO properly reflected the net overrecoveries or net underrecoveries of fuel and conservation expenses in its calculation of working capital?

POSITION: *No position.*

Issue 26: Should unamortized rate case expense be included in Working Capital?

POSITION: *No. The amount should reflect the adjustment for rate case expense recommended by OPC in this proceeding and the remaining balance should be reduced by one-half as has been the Commission's policy. This will reflect the fact that the balance will be reduced as the rate case expense is collected in rates.*

DISCUSSION:

See discussion on Issue 63 for OPC's recommended rate case expense. Consistent with prior Commission practice any balance of working capital to include in working capital should be one-half of the total amount of rate case expense allowed.[2]

Issue 27: Is TECO's requested level of Working Capital in the amount of ($30,586,000) for the 2009 projected test year appropriate?

POSITION: *No. The amount should reflect the adjustments recommended by OPC in this proceeding. *

DISCUSSION: The amount should reflect the adjustments recommended by OPC in this proceeding.

Issue 28: Is TECO's requested rate base in the amount of $3,656,800,000 for the 2009 projected test year appropriate?

POSITION: *No. The amount should reflect the adjustments recommended by OPC in this proceeding. *

DISCUSSION: The amount should reflect the adjustments recommended by OPC in this

[2] See Order No. PSC-08-0327-FOF-EI at page 33, issued May 19, 2008, in Dockets Nos. 070300-EI and 070304-EI.

proceeding.

COST OF CAPITAL

Issue 29: What is the appropriate amount of accumulated deferred taxes to include in the capital structure for the 2009 projected test year?

POSTION: *TECO's $1,894,000 reduction to ADITs should be denied as improper. The interpretation of decades-old law and non-binding letter rulings is improper as the test year averaging and projections methodologies comply with the IRS requirements. Any normalization inconsistency in Commission long-standing policy should have surfaced years ago. Prior to any rate setting change, the Commission should require TECO to obtain and submit a private letter ruling that indicates that the current methodology is inconsistent. *

DISCUSSION:

In witness Felsenthal's direct testimony, he described in great detail the accounting and ratemaking treatment related to accumulated deferred income taxes (ADIT). In a concise statement, deferred income taxes are generated when ratepayers pay income tax expenses in rates prior to the Company actually being required to make those payments to the U.S. Treasury. Recognizing the zero cost deferred taxes in the capital structure (normalization) reduces the overall rate of return charged to ratepayers. The FERC and the PSC have required "normalized" as opposed to "flow-through" accounting treatment for deferred income taxes as far back as the 1980's. TR 1334, 1337. Witness Larkin also testified that the Commission has been using projected test years since the early 1980's using a 13-month average methodology. TR 2011.

In his direct testimony, witness Felsenthal stated that in addition to projecting the test year 13-month average balance of deferred taxes, the IRS requires utilities with projected test years to make a specific computation to determine the maximum amount of deferred taxes to be treated as zero cost capital. He proposed that cost free deferred taxes be reduced by $1,894,000 as shown on Exhibit 28 (ADF-1, Document 2) to purportedly comply with the IRS requirements. To make his adjustment, witness Felsenthal counted the number of days after the implementation date of the proposed rate increase and reduced the amount of deferred taxes on a pro rata basis.

Witness Felsenthal stated that the ADIT balances in the cost of capital are based on a projected 13-month average; however, the IRC (Internal Revenue Code) requires a specific computation for projected test years to determine the maximum amount of ADIT to be allowed.

He stated that Treasury Regulation Section 1.167(1)-1(h)(6) addresses adjustments for forecasted test years. This subsection states:

> (6) ...a taxpayer does not use a normalization method of regulated accounting if, for ratemaking purposes, the amount of the reserve for deferred taxes under section 167(l) ... which is treated as no-cost capital ... exceeds the amount of such reserve for deferred taxes for the period used in determining the taxpayer's tax expense in computing cost of service in such ratemaking. (Emphasis added)

Witness Felsenthal stated that Tampa Electric uses an average rate base and cost of capital; however, expenses are based on year-end. Because of this and the fact that rates will go into effect prior to the end of the test year, he believed that this IRS code now should apply to Tampa Electric's rate case. Witness Felsenthal quoted 4 letter rulings from other utility companies to support his position, even though he admitted that these rulings "are not to be cited as precedent," yet he believed they should be followed because they reflect "IRS thinking on an issue and are consistently followed by the IRS." These letter rulings were issued in 1990 to 1992. TR 1347-1348.

OPC witness Schultz testified that this adjustment is unwarranted for many reasons. First, the Company relied on private letter rulings that are not applicable to anyone but the company requesting the ruling. These rulings are case specific and all facts have not been provided by the Company. Each of the letter rulings reference the fact that the ruling is based upon the taxpayers' representations and/or solely on the information provided by a specific company and those representations are not all known and may very well be different from the facts that would apply to Tampa Electric. One of the important factual differences is the type of test years that were used (historical, fully or partially projected, 13-month average or year-end). The definition of historic and future is not defined in the IRS regulations, and while defined in the referenced attached rulings, they could be applied differently to another company in another ruling. TR 2103-2107.

Second, witness Schultz stated that the Company has consistently accounted for deferred taxes for years under the method that witness Felsenthal now claims is incorrect, despite repetitive audits where no errors were found by the IRS. Moreover, why was this adjustment not appropriate for ADITs in Tampa Electric's last rate case, given the issue dates of the letter rulings. The 1992 rate case was based on a projected 1993 test year. See, Order No. PSC-93-0165-FOF-EI, issued February 2, 1993.

Third, witness Schultz described witness Felsenthal's faulty assumption that the projected ADITs in 2009 are part historic and part projected. This is clearly an erroneous assumption as the MFRs were prepared based upon budgeted 2009 and filed in 2008. None of the costs included in the projected test year are historical regardless of when the date the rate increase is implemented. Also, while there is no dispute that all the rulings supplied by witness Felsenthal use the same definition of historic and future, the IRS could apply a different definition in a subsequent letter ruling since each letter ruling only applies to an individual company.

Finally, witness Schultz pointed out that a 13-month average reflects the deferred tax balance at the beginning of a year and the pro rata portion of each month added during the year, which directly addresses the concerns in the IRS code. If witness Felsenthal's position is adopted, it would mean the Company has violated normalization requirements since February 1993 and should have known this based on the referenced letter rulings issued in 1991. If the Company still maintains its belief that the projected test year averaging methodology accepted by the Commission for almost 30 years is inaccurate, then it should be required to submit a letter ruling of its own. Until that happens, this adjustment should be denied. TR 1376-1385.

In his rebuttal witness Felsenthal stated that it is clear from the PLR 9202029 ruling that the IRS believes that proration and averaging are different concepts serving different purposes. TR 1379. However, this ruling also states that "ratemaking estimates or projections of tax expense, depreciation expense, and the reserve for deferred taxes must be consistent with each other and with the estimate or projection of rate base." The final paragraph of each letter ruling states that the ruling is directed only to the taxpayer who requests it and may not be used or cited as precedent. H.E. 13, No. 48, Bate 22204. Witness Felsenthal also admitted that the likelihood of an audit by the IRS on this issue is low as the IRS audits actual amounts and this is a ratemaking adjustment. TR 1385. Based upon this assertion, it appears unlikely that, even if the Commission denies this adjustment to ADITs, the Company would be penalized for this purported error in ratemaking.

Looking at the beginning of the section of the IRS code that witness Felsenthal referenced addresses the real meaning of this section:

> The rules provided in paragraph (h)(6) of this section are <u>to insure that the same time period</u> is used to determine the deferred tax reserve amount resulting from the use of an accelerated method of depreciation for cost of service purposes and the reserve amount that may be excluded from the rate base or included in no-cost capital in determining such cost of services. § 1.167(l)-1(1). (emphasis added)

Witness Felsenthal erroneously relied upon a section of a letter ruling that states it does not depend on the type or quality of the data used in the ratemaking process or whether the data used is actual or estimated, but instead when the utility's rates become effective during a projected test year. If witness Felsenthal is correct in his analysis of this code section and these letter rulings, then the FPSC has been incorrectly approving projected test years, specifically deferred taxes, since normalization and projected test years were instituted in the early 1980s. Another point that witness Felsenthal failed to mention is that depreciation charged to ratepayers is actually based upon a monthly basis just as revenues are projected monthly. So his statement that "expenses are calculated on a year-end basis" is incorrect. You just have to look at the MFRs Schedule C-2 to see that this is true. Why else would the company need to make depreciation expense annualization adjustments for its requested CIS, CT and rail projects. A truly year-end basis for depreciation would be calculated only by taking the year-end balance of plant and multiplying that times the depreciation rate for a given account.

The real issue here is whether the projected test year and averaging methodologies applied by the Company meet the normalization and consistency requirements required by the IRS. This IRS code section, issued in 1974, is extremely complex and the related letter rulings are to address the potential to violate the normalization requirements. PLR No. 9029040 discussed the intent of Congress when it instituted normalization and how some regulators were denying companies earnings with adjustments made to normalize ADITs. The statutory fix to that resulted in adding Section 1.167(l)-1(h)(6) to make sure that the timing of including the deferred taxes was consistent to prevent "flow-through of benefits" to ratepayers. H.E. 13, No. 48, Bates 22194-5.

If you make the adjustment that witness Felsenthal recommended, this will precisely unbalance the ADIT accruals that should be added to correspond to the company's projected plant additions, depreciation expense and deferred taxes. Not only will this adjustment falsely generate a "flow-through" benefit to customers, but in reality the adjustment alone will violate normalization since it will require ratepayers to pay the full effect of income tax expense on straight line depreciation while the Company receives the tax benefit of accelerated depreciation. This is patently unfair. Accordingly, Tampa Electric's attempt to raise the cost of capital by reducing cost free ADITs is fallacious and should be denied. ADITs should be increased by $1,894,000, which is consistent with the Commission's long-standing policy.

Issue 30: What is the appropriate amount and cost rate of the unamortized investment tax credits to include in the capital structure for the 2009 projected test year?

POSITION: *No position.*

Issue 31: What is the appropriate amount and cost rate for short-term debt for the 2009 projected test year?

POSITION: *Based on the three-month LIBOR rate (2.15%) plus the financing program fee of 18 basis points (0.18%), a short-term debt cost rate of 2.33% as of November 13, 2008 is appropriate.*

DISCUSSION:

The appropriate short-term debt cost rate is 2.33%. TR 1867. Dr. Woolridge based his short-term rate on three-month London Interbank Offered Rate (LIBOR) rate as of November 13, 2008 of 2.15% plus the financing program fee of 18 basis points. TR 1867.

The Company's short-term debt rate of 4.5% is inappropriate. In the last base rate case, the Commission determined it was appropriate to use the U.S. Fed Funds rate in effect when the record closed, calculating the short-term debt cost rate utilizing the current U.S. Fed Funds interest rate then adding 18 basis points to this rate to obtain an estimate of the LIBOR rate. Order No. PSC-08-0327-FOF-EI, issued May 19, 2008, at pp. 38-39. Dr. Woolridge pointed out that the Company based their rate on the historic LIBOR between 1991-2008 of 4.37% plus a program financing fee. TR 1867. As Dr. Woolridge noted the Company's proposed rate has very little to do with the current LIBOR rate. TR 1867.

Dr. Woolridge stated that during 2008, the LIBOR rates declined to the 2.75% range early in the summer in response to the Federal Reserve actions to lower interest rates. TR 1867. During the September timeframe in response to the credit crisis, the LIBOR briefly spiked to 4.75%. TR 1867-1868. However, due to the intervention of the Federal Reserve, the Treasury Department, and the U.S. government, the LIBOR significantly declined to the 2.15% level by November 13, 2008. TR 1868. Witness Gillette testified that the LIBOR rate as of January 2009 had dropped to the 1% range. TR 440-441. In the Commission's last decided rate case, the Commission used the most current short-term rate available at the close of the record. However, it is appropriate to use the three-month LIBOR rate as of November 13, 2008 of 2.15% plus the financing program fee of 18 basis points (0.18%), for a short-term debt cost rate of 2.33%.

Issue 32: Should the TECO's requested pro forma adjustment to equity to offset off-balance sheet purchased power obligations be approved?

POSITION: *No. The Company's proposed equity infusions related to the purchase power obligations are improper. Given the recovery mechanism for PPA payments, the financial condition of the Company is not impaired by entering these contracts. Thus, providing incremental revenues through a higher equity ratio and overall rate of return are unnecessary and would result in an unwarranted revenue benefit to the utility.*

DISCUSSION:

The Company's proposed equity infusions related to the purchase power obligations are improper. Given the fuel clause recovery mechanism for PPA payments, the financial condition of the Company is not impaired by entering into these contracts. TR 1910. Providing incremental revenues through a higher equity ratio and overall rate of return are unnecessary and would result in an unwarranted revenue benefit to the utility. TR 1910. There are several flaws with imputing debt from PPAs as noted by Dr. Woolridge. TR 1910.

As Dr. Woolridge pointed out, the Standard & Poor's (S&P) risk factor for imputing the debt is not well defined and cannot be assessed in this situation. TR 1910. He noted that S&P does not indicate how the risk factor that ranges from 0% to 100% is determined, rather, Tampa Electric's witness Gillette presumed that a risk factor of 25% is appropriate. TR 1910. Witness Gillette could only testify that S&P imputed a 25% risk factor for PPAs, and that he was guessing as to the reason S&P imputed the risk given the Commission's recovery mechanism. TR 288-290. Witness Gillette conceded that reading S&P's methodology, it speak more to regulatory recovery of such costs. He added that he "thought" that behind S&P's imputation of risk methodology was the ability to get the power the Company is purchasing. However, he qualified his answer by acknowledging it was based upon his "feeling," not S&P's explanation in its literature that talks only about regulatory recovery. TR 288-289.

As witness Woolridge correctly noted given the Commission's support for the collection of long-term contractual payments, the risk of non-recovery appears to extremely low (perhaps even zero percent), and a 25% risk factor seems high and out of line. TR 1910-1911. Witness Gillette admitted that he didn't even know whether S&P was attempting to quantify that there was a 25% chance the PPAs wouldn't be recovered. He said he thought S&P, in an abundance of conservatism, was simply attempting to quantify the fact that fixed obligations under PPAs are large and represent potential risk. However, Tampa Electric's proportional basis of PPAs to the other Florida utilities is very small. TR 292. Moreover, Witness Woolridge cited Moody's view that under a regulatory scheme like Florida Public Service Commission, a PPA might be viewed as being akin to operating cost and most likely no imputed adjustment would be made. TR 1911.

Second, even if debt were imputed up to 25% by S&P, it would have no effect on the Company's GAAP financial statements and investors would not see the impact of the S&P adjustment. TR 1911. Witness Woolridge stated that investors should be indifferent to a utility entering into a PPA. TR 1911.

Finally, under the regulatory scheme, a utility is given the opportunity to earn its cost of debt, as well as its overall cost of capital. TR 1912. Given the uncertainties associated with revenues and expenses in between rate cases, there is no guarantee that the overall cost of debt can be earned. However, as Dr. Woolridge pointed out with the long-term PPAs, the timely and certain recovery of fixed payments is assured. TR 1912. Thus, allowing the Company to make the PPA adjustment to the Company's capital structure is inappropriate and the Commission should deny the request. TR 1912.

Issue 33: What is the appropriate amount and cost rate for long-term debt for the 2009 projected test year?

POSITION: *As of November 26, 2008, the appropriate long-term debt cost is 6.80%.*

DISCUSSION:

Dr. Woolridge testified that the Company's long-term debt cost rate for the 2009 test year is 6.80%. He noted that the debt cost rate includes a 2009 bond issue with a 6.90% coupon rate. Dr. Woolridge adopted the Company's long-term debt rate. TR 1868.

Issue 34: What is the appropriate capital structure for the 2009 projected test year?

POSITION: *The appropriate common equity ratio is 48.89% that accurately reflects the Company's past financing, the capitalization of electric utility companies, and removes the improper equity infusions for the PPAs. The appropriate capitalization ratios for the weighted average cost of capital on a regulatory structure basis are as follows: long-term debt at 43.80%; short-term debt at 0.60%; customer deposits at 2.82%; common equity at 42.48%; tax credits-weighted cost at 0.33%; and deferred income taxes at 9.97%.*

DISCUSSION:

Tampa Electric has requested a capital structure of .24% short-term debt, 42.11% long-term debt, and a 55.32% common equity. Dr. Woolridge noted that this includes a 2009 test-year capital structure average and a number of adjustments as well as several equity infusions from TECO Energy. TR 1865.

Tampa Electric's request for a 55.32% in common equity is inappropriate for several reasons. TR 1865. First, Dr. Woolridge testified that Tampa Electric's proposed capital structure ratios do not reflect the actual capitalization of the company. TR 1865-1866. He stated that the average common equity ratio over the past three years was 49.02%. TR 1866. Dr. Woolridge testified that he used the average of the 2007 and 2008 capital structures which yields a common equity ratio of 48.89% (investor sources of capital). TR 1866, H.E. 36.

Second, Dr. Woolridge noted that his proposed common equity ratio of 48.89% is closer to the past three year average of 49.02%. TR 1867. Dr. Woolridge testified also that this more closely reflects the capitalization of the electric utilities in the Proxy Group. Tampa Electric witness Dr. Murray attempts to bootstrap the use of his capital structure by citing the increased risks associated with the global financial crises. TR 2423. The average common equity ratio for Dr. Woolridge's Electric Proxy Group in 2008 is 45.7%. TR 1867. Dr. Murray implied that as long as his common equity ratio falls within the high end of the ranges, his equity ratio is appropriate. TR 2423. While the high for Dr. Woolridge's Electric Proxy Group is 60.7% in 2008, the low is 29.7%. TR 1867, H.E. 36. Again, Dr. Murray states that the high for his proxy group is 55.6%, but he does not mention the average for his electric proxy group. TR 2423. Dr. Murray does not suggest that the capitalization should reflect the low 29.7% common equity ratio for both electric proxy groups, nor does he rebut Dr. Woolridge's point that the average common equity of the electric proxy groups is the appropriate comparison for Tampa Electric's proposed common equity ratio.

Third, witness Woolridge noted that his capital structure does not include a number of the questionable and uncertain adjustments and equity injections used by Tampa Electric. TR 1867. As discussed in Issue 32, Tampa Electric's request to make an equity adjustment for the PPAs is inappropriate. TR 1910-1912. As noted by witness Larkin, Dr. Woolridge has removed the specific adjustments which the Company has made to the equity component and short-term debt component because the actual capital structure for 2007 to 2008 timeframe does not included the rate case adjustment to capital structure the Company is proposing. TR 2942. Finally, Dr. Woolridge testified that his capital structure more accurately reflects the Company's capital structure as viewed by investors. TR 1867.

The appropriate common equity ratio is 48.89% (Investor Sources only) which accurately reflects Tampa Electric's past financing, the capitalization of electric utility companies, and the removal of the improper equity infusions for the PPAs. TR 1867, H.E. 36. The appropriate capitalization ratios for the weighted average cost of capital on a regulatory structure basis are as follows: long-term debt at 43.80%; short-term debt at 0.60%; customer deposits at 2.82%; common equity at 42.48%; tax credits-weighted cost at 0.33%; and deferred income taxes at 9.97%. H.E. 36.

Issue 35: Does TECO's requested return on common equity appropriately consider current economic conditions? [FIPUG Issue]

POSITION: *No. The amount should reflect the adjustments recommended by OPC in this proceeding. *

Issue 36: Does TECO's requested return on common equity appropriately consider its recovery of funds via the Commission's various cost recovery clauses? [FIPUG Issue]

POSITION: *No. The amount should reflect the adjustments recommended by OPC in this proceeding. *

Issue 37: What is the appropriate return on common equity for the 2009 projected test year?

POSITION: *The appropriate return on common equity for the 2009 projected test year is 9.75%. *

DISCUSSION:

The appropriate return on common equity for the projected test year is 9.75% as of November 26, 2008. TR 1857. Tampa Electric's witnesses testified the equity cost should be 12%, whereas Dr. Woolridge's analysis demonstrates the appropriate equity cost for Tampa Electric is 9.75%. TR 1857. As Dr. Woolridge noted both he and Dr. Murray used the Discount Cash Flow (DCF) model and the Capital Asset Pricing Model (CAPM) to estimate the appropriate equity cost. TR 1857. Dr. Woolridge's DCF and CAMP analyses for the Electric Proxy Group in his study indicates equity cost rates of 9.8% and 8.2%, respectively. Given the current economic conditions, Dr. Woolridge recommended using the upper end of his range, setting the equity cost rate at 9.75% as appropriate for Tampa Electric. TR 1907.

Models

Both witnesses used proxy groups of electric utility companies in making their determinations. TR 1858. Dr. Murray included the results for TECO Energy however; he did not use them in his reaching in conclusion. TR 1858, TR 728. He admitted that he did not consider them important. TR 731-732. On the other hand, Dr. Woolridge based his proxy group on six criteria: 1) listed as a electric utility in *AUS Utility Reports*; 2) listed as a electric utility in the Standard Edition of *Value Line Investment Survey*; 3) at least 75% regulated electric revenues; 4) operating revenues less than $10 billion; 5) investment grade bond rating by Moody's and S&P; and 6) a three-year history of paying dividends. TR 1865. Since the proxy group is a mechanism to approximate the market value of Tampa Electric, the proxy group should best emulate the characteristics of Tampa Electric. Tampa Electric receives more than 75% of its revenue from regulated utility service, it has $2 billion in revenue, it is investment grade, and it has paid 100% of its net income to its parent. H.E. 118, TR 572, 607.

Dr. Woolridge determined that witness Murray's proxy electric group was not appropriate because it included a number of companies that received their operating revenues from sources other than regulated electric utility services. The companies Dr. Woolridge identified as inappropriate for the proxy group based upon their low percentage of revenues realized from regulated electric services are: OGE Energy Corp. – 48%, revenues from regulated electric services; PEPCO Holdings – 55%, SCANA Corp. - 42%, and Wisconsin Energy – 62%. TR 1913.

Reviewing the results of Dr. Murray's DCF model, shows a range of 9.14%, using his Dividend Growth Rate DCF 52-Week Share Prices, to a high of 13.27%, using his Projected Growth Rate DCF Using 52-Week Share Prices. Dr. Woolridge testified that projected growth rates are upwardly biased as shown in his exhibit JRW-13, panel C. TR 1920, H.E. 45. Dr. Woolridge noted that Dr. Murray did not use 75% of his own DCF results, in reaching his conclusions but rather choose a range of 11.12% to 13.27%. TR 1944. In fact, Dr. Murray ignored the low end of the results that were the vast majority of his results. TR 1944. When asked why he did not use the lower results of his DCF model, Dr. Murray admitted that it was his testimony the only relevant DCF equity cost rates are in the 11.12% to 13.27% range. TR 731. When pressed whether he "used" the vast majority of his DCF results his recommendation or ignored them, he conceded he did not consider them (the majority of his results) as important. TR 732. He also conceded that the 11.12% to 13.27% equity cost rates were, in fact, the high results for those particular methods of calculations. TR 734. Dr. Woolridge did not selectively use parts of his DCF results to bias his recommendation to the low end of his calculations. In fact, he utilized the higher end of his DCF results, in recognition of the market volatility experienced in the fourth quarter of 2008. TR 1947.

Regarding his application of the CAPM model, Dr. Murray's results utilized equity risk premiums of 7.1% and 8.5% based solely on historic stock and bond returns. TR 1945. Again, historic results have several problems, including: 1) historic results are not the same as future expectations – especially since market conditions can change such that historic returns become a poor estimate of future expectations; and 2) market risk premiums change over time – increasing when investors become more risk-adverse and decreasing when investors become less risk-adverse; as noted by Dr. Woolridge. TR 1893. Dr. Woolridge testified that numerous academic studies have criticized the use of historic returns for predicting market expectations. TR 1893. He further criticized Dr. Murray's historical approach noting that it is outdated, and used 20 years ago. Quoting Professor Jay Ritter, Dr. Woolridge testified that it is one of the biggest mistakes taught in the world of finance. TR 1946. Dr. Woolridge further testified that he used 30 different studies that included historical approaches, studies by leading scholars in finance, investment banks, and surveys of CFOs, etc. TR 1945. Utilizing Dr. Woolridge's approach, his equity risk premium was 4.56% with an overall CAPM result of 8.2%.

Dr. Woolridge noted that his and Dr. Murray's risk-free rate were approximately the same, 4.6% for Dr. Murray and 4.5% for Dr. Woolridge at the time they prepared their testimonies. However, the risk-free rate has dropped from the 4.6% used by Dr. Murray to a current long-term Treasury rate of 3%. TR 736. This is an approximately 160 basis point difference in the risk-free rate used by Dr. Murray. TR 736. Dr. Murray would not concede that his CAPM results would decrease by 160 basis points based upon the current risk free rate because other factors might have changed. TR 736. However, using the Commission's logic from the last decided rate case, that the most current interest rates at the close of the record, it is instructive to apply the 160 basis point difference to Dr. Murray's CAPM results. Order No. PSC-08-0327-FOF-EI, issued May 19, 2008, at pp. 38-39. As a result, Dr. Murray's Size Adjusted CAPM would be reduced to 9.64% (11.24% - 1.6%) and his Historical CAPM would be reduced to 10.82% (12.42% - 1.6%). Dr. Murray's adjusted CAPM results for the current long-term Treasury rate support Dr. Woolridge's recommendation of 9.75% as reasonable and the appropriate ROE to apply to Tampa Electric.

Dr. Woolridge tested the reasonableness of his recommended 9.75% ROE by examining the relationship between the ROEs and market-to-book ratios of the Electric Proxy Group. TR 1908. His analysis showed that the mean current return on equity and market-to-book ratio for the Electric Proxy Group were 8.9% and 1.36, respectively. He noted that these results indicate that on average these companies are earning returns on equity above their equity cost rates. As Dr. Woolridge testified, this supports the reasonableness of his 9.75% recommended ROE and is fully consistent with the financial performance and market valuation of the proxy group. TR 1908. As a further reality check, according to RRA which tracks commissions nationally, over the year 2008 the range of approved ROEs is 9.10% (Consolidated Edison, New York) to 11.0% (Detroit Edison, Michigan). H.E. 93. Moreover, in the latest decision of the State of Connecticut's Department of Public Utility Control in Docket No. 08-07-04, Application of the United Illuminating Company to Increase its Rates and Charges, a ROE of 8.75% with a range of 7.8% to 9.4% was approved, based upon the finding it should produce operating income sufficient for United Illuminating to operate successfully and serve its ratepayers, maintain its financial integrity, and compensate investors for risks assumed. Id. at p. 2.

Crediting Rating Agencies

Tampa Electric has put forth its proposition that if the Commission grants its high ROE request of 12%, they will get a higher credit rating, lower cost of debt for the betterment of the ratepayers, and better access to capital markets. However, Tampa Electric has not supported any of these contentions.

Tampa Electric engaged Susan Abbott to testify regarding the credit rating agencies. She stated that her testimony was to provide support for Tampa Electric's targeted credit rating of a single A from its current triple B, S&P rating. TR 585. However, she agreed that even if Tampa Electric was given everything they asked for in the petition, this would not guarantee that the credit rating agencies will raise Tampa Electric from a triple B to single A. TR 608. Although she contended this would put the Company in a position to be considered for a single A, she had to concede that S&P's rating methodology is not a mathematical application of its matrix and that discretion is involved. TR 608. She further conceded that a triple B rating was not a bad rating and that the average electric utilities rating is, in fact, triple B rated. TR 608. As witness, witness Herndon testified S&P, Fitch, and Moody's are not the only information he has relied upon as an institutional investor. TR 2190. He also noted that the distinction between single A and triple B ratings is a data point that should be taken into consideration; in and of itself, it is not that critical. TR 2190.

The Company's next contention that customers will benefit from the higher 12% ROE, allowing them to get a single A rating because it would lower the cost of its future capital projects, also does not hold water. The parties were asked to do a debt and equity costs analysis "Bang for the Buck," to show the cost of Tampa Electric's proposal. H.E. 123. Tampa

Electric's Late-Filed Exhibit 123 is non-responsive to the Commission's request, in that, it includes no analysis of the costs of its request. H.E. 123. However, Florida Retail Federation (adopted by OPC) and FIPUG provided an analysis of the costs to customers if Tampa Electric's request is granted. According to the FRF analysis, even if all of Tampa Electric's assumptions were taken at face value, the cost to customers in the worst case scenario of a 200 basis point cost differential between the cost of debt for a single A rated company versus a triple B rated company where the customers are paying a 12% ROE would be $144,033,000 net present value for 2009-2013. H.E. 123, FRF. The cost to customers under the same scenario for just 2009 would be $39,439,000 net present value. H.E. 123, FRF. In FIPUG's analysis, under the 12% ROE scenario, it would cost ratepayers $360,000,000 with zero savings to ratepayers. H.E. 123, FIPUG. Tampa Electric witness Gillette admitted that, if the Company achieved a 200 basis point savings on its debt cost, it would result in an approximate $5 million dollar savings. TR 511. He conceded that the cost difference for 100 basis points for ROE would equate to $30 million. TR 511. Witness Gillette admitted that taking the $30 million ROE costs divided by $5 million debt savings would result in an equivalent value of only 16.6 basis points. TR 512. When asked why ratepayers would pay more than $5 million to save $5 million in debt issuance cost, he argued that it would give them better access to capital (TR 512); not that it would necessarily be a costs savings to ratepayers.

As to witness Gillette's contention that Tampa Electric's request would result in better access to capital, his own exhibit Rebuttal Exhibit GLG-2, Document 2, refutes this supposition. H.E. 80. Although there was a two week period where no new utility issuances occurred during 2008 it is clear from the exhibit that triple B rated companies were able to access the capital market after the September shut down. H.E. 80, Document 2. Witness Gillette agreed that, given current economic conditions, a lot of capital in the U.S. and the world was taking flight to security or safety that provided almost no returns. TR 514-515. He further agreed he would generally expect as the economy starts to turn around that it would free up some of the institutional investor money that would feel more secure in regulated monopoly utilities and seek out the higher returns than they would be achieving today in the almost no return investments. TR 515. Witness Herndon pointed out that, as an institutional investor, he would recommend that his client invest in an electric utility if it had an 8.75% ROE. TR 2188. Witness Herndon testified that he did not believe that the existence of one rating or the other would weigh on whether Tampa Electric would access the capital markets. TR 2190-2191. In fact, witness Gillette conceded that Tampa Electric has not had any difficulty accessing capital markets, in that, Tampa Electric raised $100 million of debt in May of 2008. TR 437. He conceded that the Company renewed its credit facilities in late December 2008 at a "higher rate" of 175 basis point above LIBOR compared to the last rate which was only 34 basis points above the LIBOR rate. TR 438- 439. However, he admitted that the over the last five years the LIBOR has been as high as 5% (TR 440), which would result in a credit line rate of as high as 5.34% versus the current rate of 2.75% (1% current LIBOR plus 175 basis points). TR 440-441. So, it appears that Tampa Electric not only has had access to capital markets, but at lower costs.

Conclusion

Tampa Electric has not supported its request for a 12% ROE either through the modeling or through its bootstrap argument regarding its credit ratings. As far as the credit rating, the evidence shows that even if given the 12% ROE, it would not necessarily result in a higher credit rating. Moreover, the cost to customers is significant ($144,033,000 net present value for 2009-2013) without any actual evidence that Tampa Electric needs better access to capital markets. As Tampa Electric's witness Dr. Murray modeling results show that a DCF ROE range of 9.14% to 13.27% and a CAPM range (adjusted to today's U.S. treasury rate) of 9.64% to 10.82% supports that the 9.75% ROE as proposed by Dr. Woolridge is the correct ROE. As Dr. Woolridge testified, the recommendation of 9.75% takes into account today's market conditions.

Issue 38: What is the appropriate weighted average cost of capital for the 2009 projected test year?

POSITION: *The appropriate weighted average cost of capital on a regulatory structure, rate of return, is 7.33%. *

DISCUSSION:

Based on Dr. Woolridge's recommended capital structure, short-term debt, long-term debt, common equity, in addition to customer deposits, tax credits, deferred income taxes, the appropriated weighted average cost of capital on a regulatory structure is a rate of return of 7.33%. H.E. 33. The appropriate the weighted average cost of capital on a regulatory structure basis are as follows: long-term debt at 2.98%; short-term debt at 0.01%; customer deposits at 0.17%; common equity at 4.14%; tax credits-weighted cost at 0.03%; and deferred income taxes at 0.00%; for a 7.33% rate of return. H.E. 33.

NET OPERATING INCOME

Issue 39: Is TECO's projected level of Total Operating Revenues in the amount of $865,359,000 for the 2009 projected test year appropriate?

POSITION: *No. The Total Operating Revenues should reflect the adjustments recommended by OPC in this proceeding. *

DISCUSSION:

The projected level of Total Operating Revenues should reflect the adjustments recommended by OPC in this proceeding.

Issue 40: What are the appropriate inflation factors for use in forecasting the test year budget?

POSITION: *No position. *

Issue 41: Is TECO's requested level of O&M Expense in the amount of $370,934,000 for the 2009 projected test year appropriate?

POSITION: *No. The O&M Expense amount should reflect the adjustments recommended by OPC in this proceeding.*

DISCUSSION:

The O&M Expense amount should reflect the adjustments recommended by OPC in this proceeding.

Issue 42: Has TECO made the appropriate test year adjustments to remove fuel and purchased power revenues and expenses recoverable through the Fuel and Purchased Power Cost Recovery Clause?

POSITION: *No position. *

Issue 43: Has TECO made the appropriate test year adjustments to remove conservation revenues and expenses recoverable through the Conservation Cost Recovery Clause?

POSITION: *No position. *

Issue 44: Has TECO made the appropriate test year adjustments to remove capacity revenues and expenses recoverable through the Capacity Cost Recovery Clause?

POSITION: *No position.*

Issue 45: Has TECO made the appropriate test year adjustments to remove environmental revenues and expenses recoverable through the Environmental Cost Recovery Clause?

POSITION: *No position.*

Issue 46: Should an adjustment be made to advertising expenses for the 2009 projected test year?

POSITION: *Yes, any adjustment should be made in accordance with staff's recommendation.*

DISCUSSION: Any adjustment should be made in accordance with staff's recommendation.

Issue 47: Has TECO made the appropriate adjustments to remove lobbying expenses from the 2009 projected test year?

POSITION: *No, any adjustment should be made to remove lobbying expenses in accordance with staff's recommendation.*

DISCUSSION: Any adjustment should be made in accordance with staff's recommendation.

Issue 48: Should an adjustment be made to TECO's requested level of Salaries and Employee Benefits for the 2009 projected test year?

POSITION: *Yes. Overtime dollars have not been identified or tracked by the Company. 2009 executive pay raises of at least $437,289 should be removed. A reduction for the overstated request for new employees above 2007 historical levels warrants elimination of 90 positions totaling $3,568,109 (jurisdictional) and related employee benefits should reduced by $1,420,208 (jurisdictional). The Company's request to increase its 401(k) matching contributions despite today's economic condition is unreasonable and should be reduced by $1.991 million. *

DISCUSSION:

There are several issues with respect to payroll and employee benefits. First, the overtime dollars included in the filing have not been identified or tracked by the Company. TR 2073. As witness Schultz noted, the problem with the Company's proposed overtime dollars is that we have no idea what amount is included in the test year. TR 2074. In response to OPC Interrogatory No. 35, the Company's budget system does not provide a detailed breakout of overtime and other pay for 2008 and 2009. TR 2074. Witness Schultz testified that he was astonished that a company the size of Tampa Electric did not have a budgeting system sophisticated enough to identify overtime in its budget. TR 2074. Moreover, he stated that this raised serious concerns about how the Company could measure performance when an important component of payroll is not tracked and/or monitored. TR 2074.

Second, witness Merrill testified that no increases for executive salaries would occur for 2009. TR 1196. She conceded that Tampa Electric's original response did not include the Company's decision on the merit increase for 2009. TR 1195-1196. Tampa Electric's original response to Staff's Interrogatory No. 1, showed a 4% pay raise for executives. Tampa Electric revised its response to Staff's Interrogatories Nos. 1 and 2, showing the executive salaries without the merit raises for 2009. H.E. 107. The difference between the two illustrates that the executive pay should be reduced by $437,289 (not including further reductions for related employee benefits and taxes).

Third, the number of new employees above the 2007 historical data is not justified by the historical data and the reduction in Tampa Electric's expected annual growth. TR 2073. Based on the response to OPC Interrogatory No. 56, the Company has decreased its employee complement in 11 of the last 15 years (since 1992). TR 2074. Witness Schultz pointed out that the projected annual customer growth rate for the next 10 years of 2.1% is less than the historic 2.8% customer growth rate for the last 16 years. He noted that over the last 16 years Tampa Electric has reduced the number of required employees by approximately 24%. While he acknowledged that a minimal addition to the workforce may be needed, he testified that based upon his analysis the additional request for 151 positions contained in the MFRs are not justified. TR 2075. Witness Merrill contended that the 151 additional employees was based upon an average of 2007 level, not the actual year end 2007 number which creates a difference of 107. TR 1168. However, witness Schultz made his adjustment based upon year end 2007 and September 30, 2008, employee levels. TR 2075. Even though witness Merrill took exception to witness Schultz' total additional employee number, she confirmed on the witness stand that the year end 2007 employee level was 2,531 and the test year projected employee level was 2,638. TR 1168-1169. Furthermore, she did not rebut witness Schultz' contention that the 2009 projected test year employee level was overstated.

Witness Schultz has recommended a reduction of 90 positions to the Company's requested 2009 projected request of 2,638 to a level of 2,548. TR 2075. This includes 17 additional positions more than the 2007 year end and September 30, 2008 employee level of 2,531. TR 2075. The elimination of the overstated 90 additional positions reduces O&M

expense by $3,676,382 to a more reasonable expense level of $104,082,450. A reduction of $3,568,109 on a jurisdictional basis is warranted. TR 2076.

The Company has requested $73,804,000 for employee benefits with the amount expensed of $44, 030,377. TR 2084. A reduction to employee benefits to reflect the elimination of the 90 overstated employee positions in 2009 should be $1,461,650 ($1,420,208 on a jurisdictional basis). TR 2085, 2088, H.E. 52.

Fourth, the Company request to increase its 401(k) matching contributions in light of today's economic condition is unreasonable. TR 2085. Effective April 2007, the fixed match was increased from .30 to .50. TR 2085. As witness Schultz noted, because of today's economic conditions, some utilities have changed from a defined benefit retirement plan to a cash plan. He noted that still others have ended the enrollment of employees in the defined benefit plans and opted for cash plans or enhanced 401(k) plans. TR 2085. Witness Schultz testified it is inappropriate to require customers to pay for the Company increasing contributions to its employee's second retirement plan when some ratepayers do not even have one plan, especially in today's economy. TR 2085.

Witness Schultz recommends reducing the 401(k) contribution rate back to the pre-April 2007 rate of .30, or a reduction of 40%. TR 2086. Witness Schultz testified that a 40% reduction to the 2009 fixed contribution results in a range that is reasonable for 2009. TR 2087. Accordingly a reduction of $1.991 million to the Company's 2009 401(k) plan is appropriate. This reduces the total employee benefits from $73,804,000 to $71,813,000.

Furthermore, the costs shown in the filing may not reflect a proper level of employee medical contribution; however, an adjustment cannot be recommended due the insufficiency of Tampa Electric's responses. TR 2008.

Issue 49: Should an adjustment be made to Other Post Employment Benefits Expense for the 2009 projected test year?

POSITION: *Yes, any adjustment should be made in accordance with staff's recommendation.*

DISCUSSION: Any adjustment should be made in accordance with staff's recommendation.

Issue 50: Should operating expense be reduced to take into account budgeted positions that will be vacant?

POSITION: *Yes. A reduction of the 2009 projected test year employee level by 90 positions reduces the possibility of an excessive amount of vacant positions. The allowed employee level should be limited to the employee compliment as of year-end 2007 and as of September 30, 2008 of 2,531 plus an additional 17 positions.*

DISCUSSION:

As discussed in Issue 48, the allowed employee level should be limited to the employee complement as of year-end 2007 and September 30, 2008, of 2,531 plus an additional 17 positions. TR 2075. Tampa Electric witness Merrill acknowledged that Tampa Electric does not track vacancies. TR 1166. However, she testified that Tampa Electric does tract actual head count. TR 1166. Adopting Witness Schultz' adjustment to a 2,548 employee level for 2009 test year will reduce the possibility of an excessive amount of vacant positions in the projected test year since it allows for only 17 additional positions over those already filled as of September 30, 2008.

Issue 51: Should operating expense be reduced to take into account TECO's initiatives to improve service reliability?

POSITION: *Yes, any adjustment should be made in accordance with staff's recommendation.*

DISCUSSION: Any adjustment should be made in accordance with staff's recommendation.

Issue 52: Should operating expense be reduced to remove the cost of TECO's incentive compensation plan?

POSITION: *Yes. The Company has not shown that the pay is required or designed to attract, retain, and/or motivate employees. The goals and/or targets are not set to improve performance that benefits customers. Ratepayers are being requested to pay more than their fair share, assuming that this incentive plan is reasonable. The entire $11,574,843 ($11,233,952 on a jurisdictional basis) should be disallowed. However, under no circumstances should ratepayers bear more than 50% of the cost. *

DISCUSSION:

The Company is requesting recovery of $11,574,843 for its incentive compensation program. TR 2076. While the Company has claimed that this type of incentive compensation program is necessary to attract and retain employees and is "at risk" pay because it is based upon meeting performance goals, these claims are problematic. TR 2076.

First, the Company has not shown that the pay is required or designed to attract, retain, and/or motivate employees. TR 2077. As witness Schultz opined, the Company has not conducted any studies that demonstrate the compensation levels prior to the initiation of the incentive compensation program are inadequate to attract and retain employees. TR 2081.

More importantly, based on the response to OPC Interrogatory No. 30, the goals and/or targets set for the incentive compensation program are not set to improve performance that would benefits customers. The plan heavily favors shareholder oriented objectives/goals. TR 2076, 2077. Witness Schultz cited several examples of goals that were set at levels that did not require improvement to actually receive an incentive pay. TR 2077-2079. He also pointed out that even when goals were not achieved, the Company still paid out incentive pay in excess of the budgeted incentive compensation levels by 18%-49% for 2004-2007. TR 2080. When asked for an explanation of why incentive compensation budget levels could be exceeded, the Company responded that because some goals may have been achieved above the target level, that those better than expected results could offset the below target results. TR 2080. Witness Schultz noted that this response did not explain how the 2004-2007 incentive costs were above the budget targets when approximately half of the goals in each of the respective years were not achieved. TR 2081. In fact, he opined based upon Tampa Electric's answer regarding determining eligibility for compensation under the Success Sharing plan (the major component of the incentive compensation) that the majority of the weighting was on the two shareholder financial goals with less weighting on the five non-financial goals that dealt with customer concerns. TR 2081.

When witness Merrill was asked about the results of these goals, she attempted to alter the meaning of Tampa Electric's discovery response to Interrogatory No. 30 on the witness stand. TR 1156-1157, H.E. 88. She tried to diminish the impact of the clearly missed safety and environmental goals defined year-to-date on Tampa Electric's exhibit, by suggesting the results were quarterly; thus, asserting that the annual goals were met. TR 1156 - 1157. She finally acknowledged that, for the 2005 safety goal, 126 employees did not meet that goal for the year. TR 1156-1157. She also conceded that the 2005 SAIDI was not met, nor was Tampa Electric's 2005 cash flow goal meet. TR 1157-1158. Ms. Merrill also conceded that under her interpretation of Tampa Electric's response to Interrogatory No. 30, it would be difficult to assess because the response is not straightforward enough to pick it up and say what was achieved. TR 1158. Although Ms. Merrill claimed it could lead to some incorrect conclusions, it is clear according to Tampa Electric's own interrogatory response that the goals were not met.

TR 1159. Ms. Merrill acknowledged (per the Company in its response to Interrogatory No. 53) that of the 2,429 eligible employees in 2005, all employees received awards under the incentive compensation program. TR 1152, H.E. 88. In fact, only six eligible employees did not receive incentive compensation under the plan during the entire period 2003 thorough 2007. TR 1152-1153.

As witness Schultz testified, ratepayers are being requested to pay more than their fair share, even assuming that this incentive plan is reasonable. TR 2076. Even if the Company could demonstrate some benefit to ratepayers from the plan, the target level cost of the plan should be shared equally. TR 2077. As stated by witness Schultz, it is not appropriate for ratepayers to pay for incentive compensation that places shareholder benefits above customer benefits. TR 2081. Moreover, based upon the method Tampa Electric has used to set goals, it appears that none of the incentive compensation pay in application has been "at risk." TR 2083. Rather, it appears that the incentive compensation is just extra compensation added to base compensation. TR 2083. Witness Schultz also noted that incentive compensation should be subject to capitalization where appropriate, yet 100% has been expensed. TR 2083.

The entire $11,574,843 ($11,233,952 on a jurisdictional basis) should be disallowed. However, under no circumstances should ratepayers bear more than 50% of the cost.

Issue 53: Should operating expense be reduced to take into account new generating units added that are maintained under contractual service agreements?

POSITION: *Yes. The operating expense should be reduced by the amount the Company has included in O&M expense of $792,000 for the period that the CTs will actually be in service and will be covered by the CSAs. *

DISCUSSION:

As discussed in Issues 5 and 71, Tampa Electric is planning to place five new CTs into service in May 2009 and September 2009. TR 822. Tampa Electric witness Hornick testified that several older CT units will be retired over the next couple of years. Big Bend CT Unit 1 will be retired after Big Bend Unit 4 is placed into service in 2009. H.E. 13, No. 64, Hornick Deposition at p. 26. Big Bend CT 2 and CT 3 are being retired in 2008. Id. at 27. Tampa Electric witness Black admitted that depending upon what their next demand and energy forecasts show, some of the later CTs may have their service dates pushed out. TR 107. Since only three older CT units are scheduled to be retired, it is possible that some of the September 2009 units will not come into service at all during the test year.

Witness Hornick stated in his deposition that Tampa Electric entered into contractual services agreements, (CSAs) with General Electric to perform on-going maintenance of the Polk and Bayside units. H.E. 13, No. 64, Hornick Deposition at p. 31. He also stated that the new CTs that are going to be added in 2009 will be covered by the CSAs. Id. However, witness Hornick could not testify as to the amount of O&M expenses included in the filing related to the annualization of the five CTs. Id. at 32-33. He did state that due to the CSAs, Tampa Electric's headcount has been reduced. Id. at 33. Two additional operating personnel have been included in the 2009 projection for Bayside (Id. at 33); however, it is unclear how this would be impacted if any of the new CT units are pushed out passed 2009. Nevertheless, it is clear that Tampa Electric would not need as many of its own employees to perform maintenance on the CTs because maintenance is performed under the CSA. Id. at 33. Not only should the O&M be reduced to match the date the units become used and useful for public service, the O&M should also be reduced to reflect that the maintenance for these unites is essentially covered by the Company's CSAs. The response to OPC POD 101 indicates that the Company has included $792,000 in O&M expense for the period that these CTs will actually be in service. These costs will be covered by the CSAs.

Issue 54: Should an adjustment be made to TECO's generation maintenance expense?

POSITION: *Yes. The Company did not justify its requested increase above indexed historical 2007 levels. The Company's request is overstated by $8.48 million ($8.173 million on a jurisdictional basis). See Issue 69 for a discussion of the normalization of outage O&M expense which results in the same adjustment. *

DISCUSSION:

Tampa Electric has indicated that cost increases have incurred and that the planned maintenance forecasted for 2009 is typical of the past and expected to continue in the future. TR 2097. Witness Schultz stated that to evaluate the historic changes in cost and the Company's significant increase in 2009 expense (which is not typical of the past), the Company was requested to provide historic data and a detailed listing of 2008-2009 maintenance projects. Witness Schultz testified that the Company did not provide sufficient detail to justify the projected increases in 2008 and 2009. TR 2098. Although there is no dispute that prices have increased for material and services over the years (TR 2097), the Company did not provide documentation to support the need for the increase over and above an indexed increase in historic costs. TR 2098.

When witness Schultz examined accounts 511, 512, 513, the Company's costs for the time period 2003-2007 averaged \$49 million. The \$69 million of costs requested by the Company for these accounts was an increase of approximately \$10 million over the 2009 indexed historical average of \$59.3 million. TR 2098. Witness Schultz used the information for OPC Interrogatory No. 48 to calculate the difference of \$6.88 million between the 2009 costs and the 2007 actual project costs. TR 2009. Then he added this \$6.88 million increase for 2009 to the indexed 2007 cost of \$53.791 million, resulting in a 2009 cost estimate of \$60.671 million. Since this was greater that the indexed historic 2007 cost of \$59.291, he utilized the more generous amount to make the adjustment. TR 2009.

Witness Hornick's criticism regarding witness Schultz' adjustment was that he did not recognize account 511 was abnormally high due to the inclusion of the \$6.9 million for dredging. TR 854. Witness Hornick stated that the Company made a pro forma adjustment to remove \$5.5 million of the \$6.9 million to reach an annual amount of \$1.4 million. TR 854. He further contends that once this adjustment is made, witness Schultz' allowable expense of \$60.671 million should be compared to \$63.631 million which would only result in a disallowance of \$2.96 million. TR 854.

According to Schedule C-2, however, only a \$5.32 million pro forma adjustment was made. TR 885. Even accounting for the \$5.32 million pro forma adjustment, the steam power maintenance expense would result in approximately \$66.5 million in costs. TR 885. Thus, the budgeted 2009 steam power maintenance expense is approximately \$8.8 million higher than the next highest maintenance year of 2003. TR 885-886.

Based upon the calculated estimate for 2009 (which factors in price increases and the Company's detailed project information) the Tampa Electric's request of \$69.151million is overstated by \$8.48 million. TR 2009. This is the same adjustment that would result from normalizing the planned outages as discussed in Issue 69.

Issue 55: Should an adjustment be made to TECO's substation preventive maintenance expense?

POSITION: *Yes. The Company has unreasonably increased its 2009 projected test year levels almost twice the historical 2007 level and three times the last five year average. Since the Company should have been maintaining its system in a safe and reliable manner over the years, the maintenance expense should be based on indexed 2007 historical levels. This results in a reduction of \$1,057,185 (\$973,201 on a jurisdictional basis). *

DISCUSSION:

The Company is asking for significantly increased preventive maintenance on substation infrastructure due to aging. TR 2096. As the Company's response to discovery showed, the Company spent an average of $761,581 for preventive maintenance over the five years 2003-2007. TR 2096. As witness Schultz pointed out, with an increase in the rates being requested, the Company has increased the annual expense to $2,256,610. This is almost three times the average spent over the last five years and more than two times the amount expensed in 2007. He also noted that the Company planned to spend approximately 69% of the 2009 requested amount in the interim year 2008. TR 2096. Witness Schultz testified the Company should be spending the needed amount on maintenance to provide safe and reliable service. He noted that it is not appropriate for a Company to limit maintenance expenditures over the years and, then when a rate case is filed, simply claim that a significant increase in spending is required. He stated that the Company should have to prove that it is spending what is needed to provide safe and reliable service, and then with an established effort shown, they will have justified the needed increase. TR 2097.

Witness Schultz testified that the Company's requested amount of $2,256,610 should be reduced to $1,199,425, a reduction of $1,057,185 ($973,201 jurisdictional). TR 2097. He stated that the recommended spending for 2009 is based on an indexed 2007 expense of $1,118,958. TR 2097. Witness Hornick did not refute witness Schultz' adjustment.

Issue 56: Should an adjustment be made to TECO's request for Dredging expense?

POSITION: *Yes. The Company has failed to provide documentation to support that its dredging cost will reach $6.9 million. Further, the Company has not supported that any dredging will occur in the 2009 test year. Therefore, the operating expense of $1,330,000 for dredging should be removed. *

DISCUSSION:

The Company has included $6.9 million (total Company) in its 2009 production O&M budget for channel dredging expense. TR 20022. Tampa Electric removed from operating expense $5,320,000 (jurisdictional) of the $6.9 million, leaving an operating expense of $1,330,000 million. TR 2023. Tampa Electric added to rate base an amount of $2,657,000 that the Company stated is the 13-month average of the unamortized jurisdictional balance. TR 2023.

However, the Company failed to provide documentation to support that the dredging cost will reach \$6.9 million. Company witness Hornick confirmed that the \$6.9 million for dredging was comprised of estimates basically created by the Company's personnel. TR 861-862. He claimed that his estimates were based upon an approximately two year old dredging proposal and hydrographic survey (which the Company could not produce) of the amounts to be removed. TR 862. He admitted that he did not provide the two year old dredging proposal in response to OPC's Interrogatory No. 100 that requested documentation regarding the bid the Company received for dredging costs for 2009. Instead the document was produced as a late-filed exhibit to witness Hornick's January 2009 deposition. TR 860. In fact, witness Hornick conceded that Tampa Electric has not solicited for, nor received competitive bids for the proposed dredging work in 2009. TR 860.

Without any independent bids for the work, it is difficult to determine the appropriateness of costs. Witness Larkin conducted a check of the proposed cost against the historical cost. TR 2023. He noted that in 2002, the last year dredging was done, the Company incurred a total cost of \$2,346,105 with \$1,288,169 allocated to Tampa Electric and \$1,057,936 allocated to IMC which shared the common area of the channel. TR 2023. In the prior 1998 dredging, Tampa Electric incurred \$1,101,589 in costs. TR 2023. The difference between 1998 and 2002 was a 14% increase to Tampa Electric over five years. Adding 20% to the 2002 dredging costs would result in an increase of only \$1,378,349. Witness Larkin, in his demonstrative historical check, included half of the \$1,330,000 (jurisdictional) amount amortized over five years for comparison purposes only. TR 2023. Yet, even if the whole amount was utilized for demonstrative purposes, Tampa Electric's currently requested \$6.9 million amount is well beyond its adjusted \$1,330,000 in historical costs. TR 2023-2024. Even assuming the Company's estimate of the additional \$2.8 million in disposal costs, for which there are no bids or other support, was correct, the total for dredging would have increased only to \$4,130,000. H.E. 13, No. 64, Hornick Deposition p. 43. Assuming dredging was actually to occur in 2009, \$4,130,000 amortized over a six year period would be \$688,333. However, the Company has not supported that any dredging will actually occur in the 2009 test year.

The historical information indicates that if dredging costs were incurred in the 1997-1998 timeframe and then again in 2002, the next five year period should have been in the year 2007, not 2009. TR 2024. Tampa Electric witness Hornick claimed that dredging was a deferrable project and that the five year cycle was a rough number. TR 867. However, during the timeframe when the Company was not contemplating a rate case, witness Hornick admitted that the typical expectation was that approximately every five years the channel needed to be dredged. TR 866.

Since the Company has not supported its requested $6.9 million for the deferred dredging or provided any documentation through competitive bids that dredging will actually occur in the 2009 test year, the total cost should be removed. TR 2025. Accordingly, rate base associated with the Company's deferral of dredging cost balance of $2,657,000 (jurisdictional) should be removed. The operating expense of $1,330,000 related to the deferred dredging should also be removed. TR 2025.

Issue 57: Should an adjustment be made to TECO's Economic Development Expense?

POSITION: *Yes, any adjustment should be made in accordance with staff's recommendation.*

DISCUSSION: Any adjustment should be made in accordance with staff's recommendation.

Issue 58: Should an adjustment be made to Pension Expense for the 2009 projected test year?

POSITION: *Yes, any adjustment should be made in accordance with staff's recommendation.*

DISCUSSION: Any adjustment should be made in accordance with staff's recommendation.

Issue 59: Should an adjustment be made to the accrual for property damage for the 2009 projected test year?

POSITION: *Yes, the storm damage accrual should remain at $4,000,000. *

DISCUSSION: See OPC's discussion on Issue 16.

Issue 60: Should an adjustment be made to the accrual for the Injuries & Damages reserve for the 2009 projected test year?

POSITION: *Yes, any adjustment should be made in accordance with staff's recommendation.*

Issue 61: Should an adjustment be made to remove TECO's requested Director's & Officer's Liability Insurance expense?

POSITION: *Yes. Director's & Officer's Liability (DOL) insurance expense of $1,605,815 (jurisdictional) should be removed as it provides no ratepayer benefits and protects shareholders from the decisions of its directors and officers whom they hired. Further, ratepayers receive no recovery of proceeds from settlements or decisions and removal of this shareholder benefit is consistent with Commission practice. *

DISCUSSION:

OPC witness Schultz stated that the requested $1,700,908 ($1,650,815 jurisdictional) in DOL insurance cost allocated to Tampa Electric for 2009 should be denied. The insurance protects officers and directors for the risk of their business decisions with the primary plaintiffs being shareholders. Further, DOL insurance provides shareholders protection against their own decisions such as the hiring of the Board of Directors who, in turn hire the officers of the Company. Witness Schultz stated that the benefits from these insurance settlements flow to shareholders and as such, they should be responsible for this cost not the ratepayers. Additionally, in 2003, Tampa Electric expensed $654,392 which ballooned by 169.5% to $1,763,351 in 2007, mostly because of claims against officers and directors. TR 2089-2090.

Witness Schultz stated that in other proceedings, companies have claimed that ratepayers benefit because the insurance is necessary to attract and retain competent directors and officers. However, he said no evidence was presented to show that any of these companies were unable to attract and/or retain officers and directors when shareholders paid for the coverage. Because ratepayers do not receive any of the proceeds from decisions and/or settlements in these types of litigation, they should not bear the cost of protecting shareholders from their own decisions. If the Commission decides that the customers derive some benefit, witness Schultz recommended that the expense be limited to the 2003 level of $654,392, a reduction of $1,046,516. TR 2090.

In his rebuttal, witness Chronister contended that the requested DOL insurance is reasonable and should be recovered from the ratepayers. TR 1487. While he disagreed about the timing of the increases in the insurance, he did agree that numerous changes in market conditions began in the late 1990's. While witness Chronister disagreed with disallowing the expense to be recovered from rate payers, he did not dispute that shareholders are the primary beneficiaries of these policies and that shareholders hire the directors and the board hires the officers. TR 1542.

Further, it is Commission practice to remove DOL insurance because it provides no primary benefit to the ratepayers.[3]

Issue 62: Should an adjustment be made to reduce meter expense (Account 586) and meter reading expense (Account 902)?

OPC: *No position. *

Issue 63: What is the appropriate amount and amortization period for TECO's rate case expense for the 2009 projected test year?

OPC: *The rate case expense should be reduced to $2.032 million and amortized over five years. Since J.M. Cannell did not provide any service, $116,000 for her services should be removed. The Huron Consulting Services amount should be reduced to the contract amount of $468,000 from the requested $1.31 million. Ms. Abbott's consulting fees are excessive and should be no more than $61,000, a reduction of $164,000 from the requested $225,000.*

DISCUSSION:

The rate case expense requested by Tampa Electric is excessive. The Company projected rate case expense of $3.153 million with $2.123 million of contracted services other than legal. TR 2100. The Company is not a small company with limited human resources that would require significant assistance in assembling a rate filing. TR 2100. Several of the outside rate case consultant contracts raise a serious concern, and require a reduction to the projected amount of rate case expense.

Since the Company has not entered into a contract with J.M. Cannell, the $116,000 for her services should be removed. TR 2101. In rebuttal testimony, witness Chronister admitted that Tampa Electric erroneously included rate case expenses for Ms. Cannell's services because it was not until intervener testimony was filed on November 26, 2008, that it became clear her services were not needed. TR 1492.

Tampa Electric was projecting rate case expense of $1.3 million for Huron Consulting Services. TR 2100. Contributing to the cost for Huron consulting was the excessive average

[3] See Order Nos. PSC-07-0505-SC-WS, p. 44, issued June 13, 2007, in Docket No. 060253-WS, In re: Application for increase in water and wastewater rates in Marion, Orange, Pasco, Pinellas, and Seminole Counties by Utilities, Inc. of Florida; PSC-03-1440-FOF-WS, p. 84, issued December 22, 2003, in Docket No. 020071-WS, In re: Application for rate increase in Marion, Orange, Pasco, Pinellas, and Seminole Counties by Utilities, Inc. of Florida; and PSC-99-1912-FOF-SU, pp. 20-22, issued September 27, 1999, in Docket No. 971065-SU, In re: Application for rate increase in Pinellas County by Mid-County Services, Inc.

hourly rate of $425 per hour that the Company agreed to pay. TR 1514, 2100. Moreover, witness Chronister admitted that the MFRs were prepared by a number of individuals within Tampa Electric. TR 1516. He conceded that Huron Consulting only reviewed, checked and advised Tampa Electric on the MFRs. TR 1516. In fact, he acknowledged that the Company had not disclosed that Tampa Electric and Huron Consultant shared common directors on schedule C-31 of the MFRs for 2005-2007. TR 1512. He indicated that the affiliated relationship would have been disclosed on schedule C-31 for 2008. TR 1513. In part, witness Chronister attempted to justify the outside expense because Tampa Electric's Director of Taxes was on medical leave during the rate case time, suggesting no other Company employee could address tax issues. TR 1507. As witness Schultz noted, generally in a rate case, the company's employees will respond to discovery and the lawyers will review the response. The addition of Huron Consulting added an extra layer of review inserted into the process, adding extra costs above and beyond what may be necessary. TR 2101. Customers should not be required to pay for an extra layer of rate case review because the Company wants to give business to the affiliated director's company. The Huron Consulting Services amount should be reduced to the amount specified in the contract from the requested $1.31 million. TR 2100. On top of the $1.3 million, an additional $50,000 for travel and $210,000 for other additional expenses for Huron Consulting that the Company was seeking should also be denied. TR 1507-1509.

Ms. Abbott testified that her fee arrangement with Tampa Electric was a flat fee of $25,000 per month plus costs for a total cost to date of $225,000. TR 636-637. Ms. Abbott admitted on the stand that, in a case in which she testified before the Oklahoma Commission, she was paid a $4,000 per month retainer and $25,000 for prepared testimony. TR 638. While Ms. Abbott testified that her fee agreement was not contingent upon what the Commission allows for recovery from customers (TR 639), Tampa Electric's customers should not be required to pay her excessive fees just because the Company negotiated a bad contract. Assuming that the Commission does not just deny Ms. Abbott fees outright as witness Pollack suggests, the allowed recovery from ratepayers should be no more than $61,000 of the requested $225,000.

These recommendations reduce the projected costs from $3.153 million to $2.032 million. In addition, rate case expense should be amortized over a five year period instead of three years. As witness Schultz noted, if Tampa Electric was allowed to amortize the cost over a three year period and was fortunate enough to stay out half as long as the last rate case (8 years), they would continue to recover rate case expense when no expense is being incurred. He noted that even a five year amortization period is short given Tampa Electric's history of long time periods between rate cases. TR 2102.

Utilizing a five year amortization period results in a reduction to amortization expense of $645,000 and a reduction of $799,000 to the amount included in rate base for unamortized rate case expense.

Issue 64: Should an adjustment be made to Bad Debt Expense for the 2009 projected test year?

POSITION: *Yes. The $7,971,000 (44%) increase above 2007 levels for the projected test year is unjustified. A 5-year historical average reflects a reasonable estimate of the projected and normal write-offs for the future. The bad debt expense should be reduced by $2,342,000 (jurisdictional) with a corresponding adjustment in the revenue conversion factor for the bad debt factor. *

DISCUSSION:

Witness Larkin testified that the 2009 projected uncollectible expense of $7,971,000 was 44% higher than the historical 2007 expense of $5,527,000. The Company indicated in its response to OPC Interrogatory No. 43 that the deteriorating economic conditions in its service area are the basis for the significant increase in projected net write-offs. Witness Larkin stated that the filing is not clear as to how the 2009 bad debt factor of 3.49% was derived in determining projected uncollectible expense. TR 2039.

Witness Larkin explained that he reviewed MFR Schedule C-11, which reflects the calculated bad debt factor. For the projected 2008 and 2009 factors, the Company added several erroneous accounts: Sales for Resale, Unbilled Revenue and Deferred Clause Revenues. Sales for Resale are non-jurisdictional sales to municipalities and wholesale customers that are unlikely to have bad debt write-offs. Unbilled and deferred clause revenues have been included in retail billed sales for accruals and deferrals made in prior periods and should not be included for bad debt write-off calculations. TR 2039 – 2040.

He recalculated a 5-year historical average percentage of bad debts and applied that to projected gross revenues from sales of electricity (Accounts 440-446 and 451). He testified that this will yield a more consistent and representative test year level of uncollectible expense for write-offs expected in future periods. Witness Larkin contended that rates set using declining economic factors such as bad debts will protect shareholders from the effects of the economy but will continue to impact customers negatively when the temporary effects of the economy reverse. An historical average will reflect ongoing bad debt expense which is not unduly influenced by unusual temporary economic downturns. Witness Larkin proposed a decrease of $2,342,000 (jurisdictional) to reflect a more reasonable level of uncollectible expense on a going forward basis, along with an adjustment to the revenue conversion factor. TR 2041-2042.

On cross-examination, witness Larkin was asked whether his recommended adjustment takes the Company's level of bad debt expense back to the 2007 levels without any recognition of any subsequent increased customers or sales. Witness Larkin rightfully explained how he applied the average historical factor to the 2009 level of sales revenues and that it is appropriate to use an average. TR 2057-2059.

Witness Chronister agreed that the bad debt factors were calculated wrong on MFR Schedule C-11, but that the projected expense was correctly calculated consistent with witness Larkin's methodology. The only impact that MFR C-11 has is on the Bad Debt Factor that is used for the revenue conversion factor. Witness Chronister did not disagree with witness Larkin's historical average calculation, but merely disagreed with using an historical average. He admitted that bad debts are expected to peak at the highest level ever in 2009. He argued that witness Larkin's use of a historical factor could have been applied to other types of expenses which peaked prior to the test year; however, the Company did not made such a request in this rate case. He concluded that blindly cutting an increasing expense in isolation, without considering whether other expenses should be increased if they are well below previous high points, is one-sided and unfair. TR 1477-1480

What witness Chronister misses in his analysis is that by <u>not using</u> those peaked levels of the "other expenses" he listed in a test year is appropriate and consistent with the Commission's use of a "normal test year level" of expenses. If we could look further at the "other expenses" that he used as examples, we might find that the corresponding levels requested in the test year were not "well below previous high points," but instead any averaging adjustment might lower those amounts as well. Corroborating evidence supporting historical averages of those "other expenses" is not in the record.

Witness Chronister's rebuttal inadvertently provided additional support for using a historical average which recognizes that peaks or valleys are inappropriate for rate-setting. Instead the Commission should use a normalized level that will represent the expected factor to apply to revenues for 5 to possibly 15 years in the future. Leaving the bad debt expense in the test year based upon the highest level that has ever occurred will certainly overstate the bad debt expense factor and resulting expense once the economy improves.

Issue 65: Should an adjustment be made to Office supplies and expenses for the 2009 projected test year?

OPC: *Yes. The Company failed to provide documentation to support its requested 39% increase in the 2009 projected test year over the 2007 historical level of $8.067 million for office supplies. Therefore, office supplies and expense should be reduced by $2.363 million ($2.295 million on a jurisdictional basis) to $8.818 million. *

DISCUSSION:

The Company was requested to provide a detailed analysis that showed how the projected test year amount for office supplies and expenses in Account 921 was determined. TR 2102-2103. However, the Company did not provide any analysis or documentation to support the increase in its response to Interrogatory No. 51. As witness Schultz noted, the response simply asserted that the amount was based upon historical spending adjusted for contractual agreements, additions for new activities, and removal of activities no longer applicable. TR 2103. He also testified that the response went on to say that the primary drivers for the increase were increases in training, higher information technology costs, building maintenance and miscellaneous expenses. TR 2103. While witness Chronister claims that Tampa Electric provided a detailed breakdown of the $3.1 million increase in response to Interrogatory No. 116 (TR 1494), witness Schultz testified that although it added some detail, the response was quite general. TR 2103.

Witness Chronister complained that witness Schultz was picking and choosing certain expenses by comparing the lower pension expense for 2009 with the higher projected office supplies expense. TR 1494. However, this is an attempt to obfuscate the obvious issue which is whether the Company has provided documentation to support its requested increase for office supplies expense. Pension expense would need to be independently supported by the Company at the requested level and is irrelevant to whether the office supplies expense was supported. Further, witness Chronister conceded that it is appropriate for the Commission to review the individual expense in isolated and detailed fashion (TR 1495), which is what witness Schultz has done and why he is recommending an adjustment. Since the Company failed to provide documentation to support the requested 39% increase for the 2009 projected test year over the 2007 historical level of $8.067 million for office supplies, the requested office supplies and expense should be reduced by $2.363 million ($2.295 million on a jurisdictional basis) to $8.818 million.

Issue 66: Should an adjustment be made to reduce TECO's tree trimming expense for the 2009 projected test year?

OPC: *Yes. Tree trimming should be based on the $7,897 cost rate per mile for trimming 1,530 miles in 2009, resulting in a total cost of $12,084,876 for 2009. This is the number of miles that realistically will be trimmed in 2009 based upon the Company's tree trimming history. This results in is a reduction of $3,988,568 to the Company's requested amount of $16,073,444.*

DISCUSSION:

The Company is requesting $16,073,444 for distribution tree trimming and $1,797,519 for transmission vegetative management. TR 2091. While the transmission request appears reasonable, the distribution tree trimming request of $16,073,044 is excessive. TR 2091.

The Company's request is overstated for several reasons. Witness Schultz noted that the Company's witness Haines stated the increase in tree trimming was due to the proposed three-year tree trimming cycle and the increase in contractor rates "mainly caused by escalating fuel costs." TR 2091. First, the increased cost the Company attributed to increased fuel costs at the end of summer 2008 has returned to 2005 levels. TR 2093. While the Company has identified 6,121 of overhead distribution miles, witness Schultz pointed out not all of those miles require tree trimming. He noted that the Company appeared to be close to a three-year trimming cycle from 1998 to 2000 when they trimmed a combined 5,382 miles. TR 2092. In fact, the Company was trimming at a three and half year cycle.

Witness Schulz testified that his position of using the 2007 cost per mile rate of $7,897 based upon trimming 1,530 miles per year is a reasonable cost to use. He calculated a more aggressive cost of $5,993 per mile that recognized the recent reduction in fuel costs which demonstrated his 2007 cost was more than reasonable given today's economic conditions and the volatility in cost per mile over the past ten years. TR 2093- 2094. Using 1,530 miles per year would result in an approximate four year cycle. TR 2112-2113. Based upon this adjustment, the allowed cost for tree trimming would be $12,084,876, a reduction of $3,988,568 to the Company's request. TR 2093.

Second, even though the Company sought funding for a specific trim cycle, when money got tight, that target was not maintained. TR 2117. Witness Haines testified that, although Tampa Electric requested a two-year tree trimming cycle in 1992, the Commission approved funding for a four-year cycle. TR 1034. Moreover, witness Haines testified that, when the Company was given money for a four year cycle (TR 1034), they did not maintain a four year cycle during the 2002-2005 timeframe. TR1062. The Company only trimmed 1,141 miles (18% of total system miles) in 2008 and 1,307 miles (21% of total system miles) in 2007. TR 1059.

Witness Haines testified that $16 million would be required to trim approximately 33% of the distribution system by 2010. TR 1037-1038. He claimed that the Company plans to ramp up the additional tree trim resources needed to trim 29% of the distribution system (TR 1038), which is notably less than needed 33% to meet a three-year cycle. Witness Haines admitted that the Company budgeted to trim only 1,753 miles. TR 1060. He noted that by applying a 4% increase in contractor cost each year, it would only cost the Company $11.2 million to trim 22% of the total system miles.

As witness Schultz noted, it would be presumptuous to assume that the Company would be on a three-year cycle in 2009. TR 2116. While he was not opposed to a three-year tree trimming cycle per se, he was opposed to including the cost of a three-year tree trimming cycle when it was unlikely the Company would actually reach it during the 2009 test year. Using the Company's budgeted 1,753 miles to be trimmed in 2009 would result in a total cost of $13,843,441 for 2009 tree trimming, a reduction of $2,230,003 of the Company's request.

Based upon witness Schultz's recommended adjustment to a $7,897 per mile rate for trimming 1,530 miles (24% of the total system miles) in 2009, this results in $12,084,876 for tree trimming. Since other Florida utilities have longer approved tree trimming cycles, the Company based upon the outcome of this proceeding can ask to revise its storm hardening plan from a three year cycle to a four year cycle. A reduction of $3,988,568 to the Company's requested amount of $16,073,444 for 2009 tree trimming by $3,988,568 is appropriate.

Issue 67: Should an adjustment be made to reduce TECO's pole inspection expense for the 2009 projected test year?

POSITION: *Yes. The Company's request for $1,573,778 should be reduced by $236,013 to $1,337,765. This reflects an eight year inspection cycle of 40,750 per year times the indexed 2007 average cost per pole of $32.83 which represents the most recent annual rate available. *

DISCUSSION:

The Company's request for pole inspection expense of $1,573,778 should be reduced by $236,013 to $1,337,765. TR 2094. As with the tree trimming, the Company has not historically attempted to inspect a high number of poles in any one year. TR 2094. As witness Schultz noted, now that the Commission has approved a pole inspection program, the Company has an eight year cycle. TR 2094. Witness Schultz noted that an eight-year inspection cycle requires inspection of 40,750 poles per year. TR 2095. He testified that indexing the 2007 average cost per pole of $30.63, results in an average cost per pole of $32.83 for 2009. Multiplying the 2009 index costs of $32.83 by the annual inspection requirement of 40,750 equals a cost of $1,337,765. TR 2095.

Tampa Electric criticized this adjustment because its witness claimed the costs for comprehensive pole loading in the 2009 budget were missed, the contractor's escalated rates are greater than the indexed price, and that distribution and transmission poles have different rates. TR 1039. Using the numeric calculation provided by witness Haines in his rebuttal testimony of $1,288,170 – distribution poles, plus $147,844 – transmission poles, and $95,892- loading analysis, totals to $1,531,906. TR 1039. This is still $41,872 less than the Company requested. Using the 2008 cost of $33.03 per distribution pole that witness Haines included in his rebuttal would cost a total of $1,238,625, resulting in a further reduction of $49,545 to Tampa Electric's overall request. There is no documentation that the contractor prices are inflated 4% for 2009. Given that there is not generally an invoice of actual costs to back up a projection, it is important that Tampa Electric be required to provide some type of written documentation that can be tested to support any deviation from indexed historic costs. Even assuming witness Haines' criticism that 2007 prices did not include the load analysis, adding the pole inspection cost pieced out by witness Haines to witness Schultz' indexed 2009 cost would result in a total cost of $1,433,657, a reduction of $140,121 to Tampa Electric's request.

However, as witness Schultz pointed out, the indexed 2007 costs represent the most recent annual actual rate available and are just slightly above the average of the previous four years that fluctuated annually. TR 2095. The Company's request for $1,573,778 should be reduced by $236,013 to $1,337,765. This reflects an eight year inspection cycle of 40,750 per year times the indexed the 2007 average cost per pole of $32.83 which represents the most recent annual rate available.

<u>Issue 68</u>: Should an adjustment be made to reduce TECO's transmission inspection expense for the 2009 projected test year?

<u>POSITION:</u> *Yes. The Company's request for $642,773 should be reduced by $318,846 ($268,233 on a jurisdictional basis) to $323,927. This reflects indexing the 2007 expense of $302,195. *

<u>DISCUSSION:</u>

The Company has requested $642,773 for transmission inspection. TR 2095. Witness Schultz testified that this was more than twice the five year average of $277,769 that had been expended for transmission inspection. TR 2095. Witness Schultz testified that it is appropriate to use the 2007 costs indexed to 2009 for a cost of $323,927. TR 2095. As he noted, Tampa Electric provided no documentation that supports the doubling of costs from 2007 historic costs to the 2009 projected test year. TR 2095. Again, projected costs are not backed up by documentation like historic costs; therefore, it is important that Tampa Electric be required to provide some type of written documentation that can be tested to support any deviation from indexed historic costs.

Witness Haines criticized the adjustment to Tampa Electric's requested transmission costs stating the costs have increased due to increased inspections required under the Company's storm plan. Although witness Haines stated that the Company's transmission inspection program was filed and approved by the Commission in its Ten Point Storm Hardening Plan in December 2007, he cited the order wrong. It is important to note that Tampa Electric was ordered to implement an eight year pole inspection program by Order No. PSC-06-0144-PAA-EI, issued February 27, 2006, in Docket No. 060078-EI, Consummating Order No. PSC-06-0251-CO-EI, issued March 24, 2006. In fact, witness Haines admitted that the new inspection requirements were first put into place in 2007. Witness Haines further admitted that witness Schultz' adjustment used the numbers provided by Tampa Electric in response to OPC Interrogatory No. 69 which was the actual 2007 cost of $302,195. TR 1072. Witness Schultz testified that it is appropriate to use the 2007 costs indexed to 2009 for a cost of $323,927. TR 2095.

Looking at the Company's 2008 projected cost included in witness Schultz Schedule C-8, the projected pole inspection cost was only $368,743. The Company's projected cost for 2009 pole inspections was almost double from the 2008 level. H.E. 52. Witness Haines explanation that infrared and above-ground inspection costs have increased 33% and 29% since 2005 is meaningless because the 2005 prices are unknown, and supposedly Tampa Electric was not doing these types of inspections in 2005. TR 1040. In fact, the Company has included an additional $300,000 for repairing old infrastructure (TR 1040) as though the Company was not keeping its infrastructure in good repair prior to 2008 and that the costs were not already part of O&M expenses. TR 1040-1041.

The Company's request for $642,773 should be reduced by $318,846 ($268,233 on a jurisdictional basis) to $323,927. This reflects indexing the 2007 expense of $302,195.

Issue 69: Should an adjustment be made to O&M expenses to normalize the number of outages TECO has included in the 2009 projected test year?

POSITION: *Yes, Tampa Electric has admitted that an atypical level of major outages was included in the 2009 projected test year rather than a normal major outage level. An adjustment of approximately $8,000,000 (7,710,000) should be made to normalize outages as is discussed here and in Issue 54.*

DISCUSSION:

The Company is requesting $20.2 million in scheduled outage expense for the test year. TR 853. However, as witness Pollack stated, the O&M related to the outage expense is overstated because it reflects an abnormal number of scheduled (or planned) outages. Therefore, he recommends the O&M expenses be adjusted to reflect a more normal level. TR 2238.

Witness Pollack testified that the 2009 projected test year has the highest number of scheduled outages since 2003. He noted that the planned Big Bend outages increased from 22.5 weeks in 2008 to 32 weeks in 2009, an increase of more than 30%. Further, overall plant outages would increase from 43 weeks at a cost of $13.7 million in 2008 to 54 weeks at a cost of $20.2 million in 2009. TR 2238, 2239. Witness Pollack noted that two of the three scheduled outages are to install SCR at Units 1 and 2 which are non-recurring. TR 2238. Witness Pollack testified that the average outage expense for 2002-2009 is $12.2 million dollars. Thus, Tampa Electric should be allowed $12.2 million for planned outages during the test year, a reduction of $8 million to its request. TR 2239.

Tampa Electric's witness Hornick complained that costs have escalated; thus, the simple averaging is not reflective of future costs. However, he did acknowledge that the 2009 planned outage weeks are slightly higher than other years. TR 849. While he claimed that Tampa Electric is moving in the direction of a two-year major outage interval on the Big Bend units in the future, he conceded that it has been Tampa Electric's *modus operandi* to plan major outages for each of the Big Bend units each year in sequence. TR 904. This would be four-year interval for major outages on the four Big Bend units. TR 904. He admitted that because of the requirement of the SCR installations, Tampa Electric had to sequence the four units in long duration outages over a four-year period. TR 907. Finally, he agreed that SCR installations are stand-alone capital projects. TR 902-903.

Since the SCR installations are long duration, non-recurring outages that have been included in the test year, it is appropriate to reduce the overstated test year outage expense. Tampa Electric has included, by its own admission, an atypical level of outages in the 2009 projected test year. TR 886. Witness Pollack's adjustment of $8,000,000 ($7,710,000) should be made to normalize outages or the $8.48 million ($8.173 million jurisdictional) proposed by Witness Schultz in Issue 54, which addresses generation maintenance expense.

Issue 70: Is the pro forma adjustment related to amortization of CIS costs associated with required rate case modifications appropriate?

POSITION: *No. The Customer Information System changes are changes that are routinely done when rate changes are approved such as the annual fuel proceeding or a normal base rate case. Moreover, the anticipated billing changes may not be approved by the Commission. Therefore, the supposedly extraordinary CIS upgrade should be denied and the related depreciation expense decreased by $558,000. *

DISCUSSION:

As discuss in Issue 9, the Company's requested increase for Customer Information System (CIS) upgrades is inappropriate. TR 2021. The CIS changes are routinely done when rate changes are approved such as the annual fuel proceeding or a normal base rate case. TR 2021-2022. Moreover, the anticipated billing changes may not be approved by the Commission. TR 2021. Therefore, the supposedly extraordinary CIS upgrade should be denied and the related depreciation expense decreased by $558,000. TR 2022.

Issue 71: Is the pro forma adjustment related to the annualization of five simple cycle combustion turbine units to be placed in service in 2009 appropriate?

OPC: *No annualization of plant additions should be allowed. Two of the combustion turbines are to be added in May 2009 and three in September 2009, if at all. The Company's request to annualize the five simple cycle turbines should be denied and the respective O&M of $870,000, depreciation of $5,425,000 and tax expenses of $5,453,000 should be removed.*

DISCUSSION:

As discussed in Issue 5, no annualization of plant additions should be allowed when plant additions are revenue-producing or growth-related assets designed to increase the Company's ability to generate, transmit and deliver additional kilowatt hours of generation. TR 2012. If the Commission allows an adjustment for revenue-producing plant that increases capacity without an adjustment to recognize the increased customers and/or demand, this will overstate the revenue requirements used to create the rates charged to customers. TR 2012.

Further, as Tampa Electric witness Black admitted, depending upon what their next demand and energy forecast shows, installation of some of the later CTs may be delayed to a future date. TR 107. Therefore, it is possible that some of the September 2009 units will not come into service at all during the test year. This would create an even greater windfall to Tampa Electric because the Company would be collecting rates for the CTs even if they are not placed in service during the year. According to witness Black, it will not be known if any of the three September CTs will be delayed beyond the test year because the decision is not typically made until the April time frame. TR 107. If it were known for certain that any of the CTs were not going to be placed in service in the test year, the associated cost should be totally removed.

Two of the combustion turbines are to be added in May 2009 and three may be added in September 2009. At a minimum, the Company's request to annualize the five simple cycle turbines should be denied and the respective O&M of $870,000, depreciation of $5,425,000 and tax expenses of $5,453,000 should be removed. H.E. 50.

Issue 72: Is the pro forma adjustment related to the annualization of rail facilities to be placed in service in 2009 appropriate?

POSITION: *No. As discussed in Issue 7, annualizing the rail facility for the entire 2009 test year when it will have been in service for a month or less and substantially funded by contributed capital would be inappropriate. The Company's request should be denied and the respective depreciation expense of $906,000 and tax expenses of $1,039,000 should be removed.*

DISCUSSION:

As discussed in Issue 7, the Company's annualization request for the Big Bend Rail Project projected to go into service December 2009 should be denied. TR 2014. The benefit to customers from the rail project can only be a reduction in fuel costs. TR 2014. By annualizing the rail facility for the entire 2009 test year when it will have been in service for a month or less, would allow the Company to earn a return as if the lower fuel costs did not exist in the future periods. TR 2015. Annualization of the rail facility further violates basic ratemaking principles by ignoring the productive benefit of the facility to the Company when it is fully in service by burdening ratepayers with the carrying costs and allowing the benefits to fall only to the shareholders. TR 2015. Also, as discussed in Issues 6 and 7, the facilities will be substantially funded by contributions from CSXT and may be used by a non-utility affiliate. Thus, The

Company's request should be denied and the respective depreciation expense of $906,000 and tax expenses of $1,039,000 should be removed.

Issue 73: Should any adjustments be made to the 2009 test year depreciation expense to reflect the depreciation rates approved by the Commission in Docket No. 070284-EI?

POSITION: *No position. *

Issue 74: What is the appropriate amount of Depreciation Expense for the 2009 projected test year?

POSITION: *The appropriate amount is subject to the resolution of other issues. Adjustments are necessary to remove depreciation expense associated with the annualization of the CTs of $5,425,000, the rail project of $906,000, the overstated reserve for depreciation of $8,187,000 and the CIS Upgrade of $558,000.*

DISCUSSION:

The appropriate amount is subject to the resolution of other issues. Adjustments are necessary to remove depreciation expense associated with the annualization of the CTs of $5,425,000, the rail project of $906,000, the overstated reserve for depreciation of $8,187,000 and the CIS Upgrade of $558,000.

Issue 75: Should an adjustment be made to Taxes Other Than Income Taxes for the 2009 projected test year?

POSITION: *Yes. The appropriate amount is subject to the resolution of other issues. Adjustments are necessary to remove taxes other than income associated with the annualization of the CTs of $5,453,000 and the rail project of $1,039,000.*

DISCUSSION:

The appropriate amount is subject to the resolution of other issues. Adjustments are necessary to remove taxes other than income associated with the annualization of the CTs of $5,453,000 and the rail project of $1,039,000.

Issue 76: Is it appropriate to make a parent debt adjustment as per Rule 25-14.004, Florida Administrative Code?

POSITION: *Yes. The Company has not met its burden to show that the debt of the parent is not invested in the equity of its subsidiary and thus a parent debt adjustment should be made per Rule 25-14.004, Florida Administrative Code. The proper adjustment should be a decrease to income tax expense of $8,140,774.*

DISCUSSION:

Witness Gillette contended that a parent debt adjustment is not appropriate in this case. The $404 million of long-term debt of the parent is related to TECO Energy's investments in its failed TPS merchant power projects and was not used to invest as equity in Tampa Electric. He asserted that the intent of the rule is to require an adjustment to the income tax expense of a regulated company to reflect the income tax expense benefit of the parent debt that may have been invested as equity of the subsidiary. The rule states that it shall be a rebuttable presumption that a parent's investment in any subsidiary or in its own operations shall be considered to have been made in the same ratios that exist in the parent's overall capital structure. However, the rule allows a utility to demonstrate to the Commission that in certain circumstances it is inappropriate to make the adjustment. Witness Gillette contended that TECO Energy did not raise debt to invest in Tampa Electric, nor did it invest the proceeds of the debt it did raise as equity in Tampa Electric. Therefore, he argued that a parent company debt adjustment is not appropriate. TR 206-207.

Because the assets of the failed TPS projects no longer exist on TECO Energy's balance sheet, this debt has to be paid from corporate funds other than the purpose for which the debt was raised. It is a "rebuttable presumption" that TECO Energy has to repay this debt with corporate funds, which could include funds generated by Tampa Electric. Once this presumption is made, one does not have to stretch too far to see that the tax benefit for the interest expense will have to be shared with corporate funds since the assets to which the debt related no longer exist. Regardless of all of the testimony that witness Gillette puts forth in an attempt to dissuade the Commission from making this required adjustment, the parent debt rule adjustment should be made. If the assets still remained on the company's books, the circumstances might be different. The fact that the parent company has the debt, pays the interest from internally generated funds, including possibly from Tampa Electric, and receives the tax benefit without any specific corporation with which to trace those funds, the parent debt rule should be applied.

Another important consideration is that pursuant to Order No. PSC-03-0038-FOF-GU, issued January 6, 2003, in Docket No. 020384-GU, (final rate case order for Peoples Gas), the Commission recognized a parent debt adjustment of $1.32 million. Peoples Gas is an operating division of Tampa Electric, which in turn is a wholly-owned subsidiary of TECO Energy. Given that the two utilities use essentially the same capital structure, if it was appropriate to make the parent debt adjustment in 2003, right at the same time that TECO Energy had its highest investment in the TPS projects (TR 209), it is just as appropriate in this case.

Issue 77: Should an adjustment be made to Income Tax expense for the 2009 projected test year?

POSITION: *Yes, adjustments are appropriate to reflect the recommended interest synchronization increase of $3,388,000, the decrease of $8,140,774 for the parent debt adjustment, and the $29,522,000 increase related to OPC's other recommended adjustments. The appropriate amount is subject to the resolution of other issues.*

DISCUSSION:

Adjustments are appropriate to reflect the recommended interest synchronization increase of $3,388,000, the decrease of $8,140,774 for the parent debt adjustment, and the $29,522,000 increase related to OPC's other recommended adjustments. The appropriate amount is subject to the resolution of other issues.

Issue 78: Is TECO's projected Net Operating Income in the amount of $182,970,000 for the 2009 projected test year appropriate?

POSITION: *No. The amount should reflect the adjustments recommended by OPC and is subject to the resolutions of other issues in this proceeding.*

DISCUSSION:

The amount should reflect the adjustments recommended by OPC and is subject to the resolutions of other issues in this proceeding.

REVENUE REQUIREMENTS

Issue 79: What is the appropriate 2009 projected test year net operating income multiplier for TECO?

POSITION: *The appropriate net operating income multiplier is 1.633202. *

DISCUSSION:

The appropriate net operating income multiplier is 1.633202. H.E. 50.

Issue 80: Is TECO's requested annual operating revenue increase of $228,167,000 for the 2009 projected test year appropriate?

POSITION: *No. The amount should reflect the adjustments recommended by OPC and is subject to the resolutions of other issues in this proceeding.*

DISCUSSION:

The amount should reflect the adjustments recommended by OPC and is subject to the resolutions of other issues in this proceeding.

RATE ISSUES

Issue 81: Did the utility correctly calculate the projected revenues at existing rates?

POSITION: *No position.*

Issue 82: Is TECO's proposed Jurisdictional Separation Study appropriate?

POSITION: *No position.*

Issue 83: What is the appropriate retail Cost of Service methodology to be used to allocate base rate and cost recovery costs to rate classes?

POSITION: *No position.*

Issue 84: Should the investment and expenses related to the Polk Unit 1 gasifier and the environmental costs of the Big Bend Unit scrubber be classified as energy or demand?

POSITION: *No position.*

Issue 85: Is TECO's calculation of unbilled revenues correct?

POSITION: *No position.*

Issue 86: What is the appropriate allocation of any change in revenue requirements?

POSITION: *No position.*

Issue 87: Should the interruptible rate schedules IS-1, IS-3, IST-1, IST-3, SBI-1 and SBI-3 be eliminated? If so, how should rates for customers currently taking service on interruptible rate schedules be designed, including whether a credit approach is appropriate, and if so, how such an approach should be implemented?

POSITION: *No position.*

Issue 88: Should the GSD, GSLD and IS rate schedules be combined under a single GSD rate schedule?

POSITION: *No position.*

Issue 89: Is the change in the breakpoint from 49 kW to 9,000 kWh between the GS and GSD rate schedules appropriate?

POSITION: *No position.*

Issue 90: What is the appropriate meter level discount to be applied for billing, and to what billing charges should that discount be applied?

POSITION: *No position.*

Issue 91: Should an inverted base energy rate be approved for the RS rate schedule?

POSITION: *No position.*

Issue 92: Should the existing RST rate schedule be eliminated and the customers currently taking service under the schedule be transferred to service under the RS or RSVP rate schedule?

POSITION: *No position.*

Issue 93: Should TECO's proposed single lighting schedule, and associated charges, terms, and conditions be approved?

POSITION: *No position.*

Issue 94: Are the two new convenience service connection options and associated connection charges appropriate?

POSITION: *No customer service fees should be increased at the current time. At a minimum, the standard fee should not be increased and the new convenience fees should be limited to the proposed convenience fees of $40 and $275, without additional charge of the standard connection fee. *

DISCUSSION:

The Company has proposed two new "convenience" connection fees. TR 1652. One of the fees is to be applied to the re-establishment of service to accommodate a special customer request for same day service. According to the Company, such special requests must be made before 6 p.m. of that day. This will cost a customer an additional $40 more than the proposed fee for standard connection, which according to the Company, generally occurs on the next business day. TR 1652. The second new charge is for re-establishment of service on Saturdays from 8 a.m. to noon. These requests need to be made by noon the prior Friday. The Company's witness Ashburn testified that currently connections are only made during normal business days, while this new service would necessitate calling out crews to perform the work. TR 1652. The Saturday service would cost an additional $275 on top of the fee for standard connections. TR 1652.

Witness Ashburn testified that the Company is proposing an increase in the standard reconnection charge from $16 to $25. TR 1774, 1776. He clarified that, for after hours reconnections, a $40 fee would be added on top of the increased standard reconnection charge for a total of $65. TR 173-1774, 1776. He clarified that the total for a Saturday service fee would be $275 plus the increased standard connection fee of $25 for a total of $300. TR 1776-1777. Witness Ashburn testified that no fee would be charged if the disconnect was the Company's error. TR 1777.

Customers testified at the customer service hearings that they are struggling in these tough economic times. While Tampa Electric is creating new fees for the convenience of its customers to get service turned back on after hours, it is asking for an increase in its standard charge of $9, or a 36% increase. Since electric service is a basic necessity, it is important to keep re-connection fees to a minimum. While there may be customers that can afford to pay the extremely high convenience fees associated with getting service re-established after hours, there are customers who would have difficulty affording it. At a minimum, the standard fee should not be increased and the new convenience fees should be limited to the proposed fees of $40 and $275. The increase in the standard fee is not justified, especially in these economic times.

Issue 95: Are TECO's proposed Reconnect after Disconnect charges at the point of metering and at a point distant from the meter appropriate?

POSITION: *No customer service fees should be increased at the current time. The reconnection fee should remain at $35. The Company should not be allowed to create two separate charges that increase the current rate by $15 (at the meter) and by $105 (at a point distant from the meter), especially when no explanation or justification has been provided.*

DISCUSSION:

Currently, Tampa Electric charges \$35 service charge for reestablishment of service after service has been discontinued. H.E. 118, MFRs Schedule E, p. 108. Tampa Electric is proposing to change its current reconnection charge to the following as seen on MFRs Schedule E, p. 109, that states:

> 3. The appropriate Reconnect after Disconnect Charge shown below shall apply to the reestablishment of service after service has been disconnected due to non-payment or violation of Company or Commission Rules:
>   a. For service which has been disconnected at the point of metering. the Reconnect after Disconnect Charge is \$50.00.
>   b. For service which has been disconnected at a point distant from the meter, the Reconnect after Disconnect Charge is \$140.00.

H.E. 118. While Tampa Electric claims that all existing service charges have been increased to reflect the increased cost of providing the service, it did not give any detailed explanation or breakdown that demonstrates that the costs have actually increased. TR 1654. Given the current economic conditions, the current fees should not be increased. Customers are struggling and adding an increased burden of additional costs for those customers already at the end of their means is unreasonable. Tampa Electric is requesting to increase its current charge by \$15, a 70% increase, and by \$105, a 250% increase. TR 1776. The Company has not provided any satisfactory explanation as to why different reconnect fees are necessary, let alone a justification of the cost differential for a point of meter versus point distant from the meter.

Since electric service is a basic necessity, it is important to keep re-connection fees to a minimum. The Company has not met its burden to raise the fees by \$15 over the current rate, let alone a \$105 increase. Thus, no customer service fee should be increased at the current time.

<u>Issue 96</u>: Is the proposed new meter tampering charge appropriate?

<u>POSITION:</u> *No position.*

<u>Issue 97</u>: Is the proposed new \$5 minimum late payment charge appropriate?

<u>POSITION:</u> *No customer service fee should be increased in these economic times. The new \$5 minimum late payment charge hurts customers and unfairly charges more than they would otherwise pay for balances under \$300. The Company should not be allowed to change the returned check tariff language to allow automatic increases if the law changes because it is unnecessary. *

<u>DISCUSSION:</u>

Tampa Electric has proposed that a \$5.00 minimum charge be established for any bills subject to a late payment of $10.00 or more. The Company claimed that this is not a change in the Late Payment charge itself which allows for a 1.5% fee on unpaid balances, but rather such minimums have been approved for PEF, FPL, and FPUC. TR 1654, H.E. 118, MFR Schedule E, p. 108. Not only does the Company want to impose a new minimum late charge, they also want to change the return check language of their tariff to read "A return Check Charge as allowed by Section 68.065, Florida Statutes, shall apply for each check or draft dishonored by the bank upon which it is drawn." TR 1654. They admitted that Tampa Electric's return check charge is already set to the limit allowed by law. This change in language would allow for an automatic change in fees without changing the tariff if the law is modified to allow an increase in the authorized maximum amounts. TR 1654.

Tampa Electric has not demonstrated that it needs to impose a $5 minimum to support the costs associated with late payments. Under the current 1.5% charge, it would require an unpaid balance over $300 before the minimum $5 fee was reached. Currently, for a $10 unpaid balance, the customers' maximum fee would be $0.15 for a total of $10.15. Under the Company's proposal, this same customer would pay $15 dollars, $4.85 more. Tampa Electric's only justification is all the other companies have it. However, the economic times have changed and it is unreasonable to place an additional burden on customers, especially when it is so easy to have a payment that is late by a couple of days due to delayed mail, etc.

Second, the Company has not shown why they should be allowed to automatically increase a return check fee if the statute is amended. Tampa Electric conceded that it already charges the maximum allowed by law. TR 1654. The change would allow them to collect additional revenues without the scrutiny of a base rate case or a review of the cost justification for any requested increase . Moreover, this is unnecessary to allow this change at this time, since they are already allowed the maximum recovery permitted by law.

Issue 98: What are the appropriate service charges (initial connection, normal reconnect subsequent subscriber, field credit visit, return check)?

POSITION: *No customer service fee should be increased in these economic times. The existing charges should remain unchanged since Tampa Electric has not provided documentation that supports its requested increase in these charges as further discussed in Issues 94, 95, and 97. *

DISCUSSION:

Tampa Electric claims that all existing service charges have been increased to reflect the increased costs of providing the service. TR 1654. The Company has proposed the following increases to services (other than those discussed in the previous Issues 94, 95, and 97): initial service connection from $38 to $75, a 75% increase; normal reconnection fee from $16 to $25, a 36% increase; field credit visit from $8 to $20, a 40% increase. Tampa Electric did not provide any detailed explanation or breakdown that demonstrates that these costs have increased. TR 1654.

Given the current economic conditions, these fees should not be increased. Customers are struggling and adding an increased burden of additional cost for those customers already at the end of their means is unjustifiable.

Issue 99: What is the appropriate temporary service charge?

POSITION: *No position.*

Issue 100: What are the appropriate customer charges?

POSITION: *No position.*

Issue 101: What are the appropriate demand charges?

POSITION: *No position.*

Issue 102: What are the appropriate Standby Service charges?

POSITION: *No position.*

Issue 103: Is TECO's proposed change in the application of the transformer ownership discount appropriate?

POSITION: *No position.*

Issue 104: What is the appropriate transformer ownership discount to be applied for billing?

POSITION: *No position.*

Issue 105: What are the appropriate emergency relay service charges?

POSITION: *No position.*

Issue 106: What are the appropriate contributions in aid for time of use rate customers opting to make a lump sum payment for a time-of-use meter in lieu of a higher time-of-use customer charge?

POSITION: *No position.*

Issue 107: What are the appropriate energy charges?

POSITION: *No position.*

Issue 108: What changes in allocation and rate design should be made to TECO's rates established in Docket Nos. 080001-EI, 080002-EG, and 080007-EI to recognize the decisions in various cost of service rate design issues in this docket?

POSITION: *No position.*

Issue 109: What are the appropriate monthly rental factor and termination factors to be approved for the Facilities Rental Agreement, Appendix A?

POSITION: *No position.*

Issue 110: Is it appropriate to establish a customer specific rate schedule for county (K-12) public schools in this proceeding?

POSITION: *No position.*

Issue 111: What is the appropriate effective date for the rates and charges established in this proceeding?

POSITION: *No position.*

OTHER ISSUES

Issue 112: Should TECO's request to establish a Transmission Base Rate Adjustment mechanism be approved?

POSITION: *No. Removing transmission costs from base rates will, in effect, reduce the Company's risk to plan and properly build transmission facilities. There is also no benefit to ratepayers to remove these costs from base rates. 60% of the Company's revenues are recovered through clauses; shifting transmission costs to a clause will shift more risk to ratepayers, and add additional administrative costs unnecessarily. Therefore, the Company's request to create this new clause should be denied. *

DISCUSSION:

The Company has proposed the creation of a new clause-type mechanism to allow them to recover the costs of building new transmission facilities in between rate cases, irrespective of the Company's earnings at the time. TR 1448. The Company claims that this is needed because it anticipates making significant investments in transmission projects in Florida. TR 1448. The Company claims that due to the uncertainty of the costs and timing, they are proposing this Transmission Base Rate Adjustment (TBRA) mechanism that would act like a cost recovery clause. TR 1447-1448. The only examples that Tampa Electric cited as a basis for this type of mechanism are two settlements agreements reached in Docket Nos. 050045-EI and 0500078-EI, rate cases for Florida Power & Light and Progress Energy. These settlements cannot be treated as precedent since they do not even address a TBRA mechanism.

The Company's claim that the increased requirements of the Florida Reliability Coordinating Council (FRCC) and North American Electric Reliability Corporation (NERC) associated with reliability and transmission and planning are analogous to mandates similar to environmental compliance requirements is without merit. TR 1500-1501. Witness Haines claimed that the development of transmission projects has changed dramatically due to the Energy Policy Act of 2005, new standards and requirements, and regional transmission planning through the FRCC. H.E. 13, No. 63, Haines Deposition at p. 14. Witness Chronister further claimed that the Company would not be able to entirely manage the need and timing of the transmission investment to coincide with rate cases. TR 1501. However, Tampa Electric has overstated its case that they lack control regarding transmission planning and cost recovery.

Under the Federal Power Act, the "reliability standard" term does not include any requirement for bulk-power systems to enlarge such facilities or to construct new transmission capacity or generation capacity. 16 USC 824, Section 215(a)(3). Nothing in the reliability standards section of The Federal Power Act would authorize the Electric Reliability Organization (ERO) or the Commission to order the construction of additional generation or transmission capacity, set and enforce compliance with standards for adequacy or safety of electric facilities or services, or preempt state authority regarding safety, adequacy, and reliability of electric service as long as it is consistent with the reliability standards. 16 USC 824, Section 215(i)(2) and (3).

As Tampa Electric's witness Haines noted, during the planning process, Tampa Electric is developing a five-year construction plan identifying near term projects required to provide reliable service. TR 1501. That five-year plan gets incorporated into the FRCC's planning process. TR 992. While FERC developed several new standards, it delegated its authority and oversight of those standards to NERC, which then delegated its authority to FRCC for Florida. H.E. 13, No. 63, Haines Deposition at p. 11. Witness Haines conceded that Tampa Electric is part of the FRCC. TR 1084. He further conceded that, as part of the FRCC, Tampa Electric has a voice in the process of determining what, when, and how transmission is developed in Florida. TR 1084. Moreover, Tampa Electric is one of the members that sits on the FRCC planning committee and also on the board of directors of the FRCC that review annual transmission plans and has a vote in approving the FRCC plans. TR 1085. Witness Haines agreed that NERC cannot directly force Tampa Electric to construct transmission (TR 1085), although they could theoretically impose fines.

As witness Larkin noted, transmission facilities are planned several years in advance. TR 2008. He stated that a cost benefit analysis to determine whether the proposed transmission facility is needed and necessary must first be performed. Then, the rights-of-way must be purchased and environmental concerns addressed. TR 2008. As witness Larkin points out, the process takes several years and the costs are not unknown or uncontrollable by the utility. He also pointed out that should base rates be determined to be insufficient to provide a return on the facilities, the Company would have ample time to file a rate request which incorporates the projected cost of the construction and any operating expense. TR 2008. Since there is sufficient time to request changes in base rates if needed, no automatic clause type adjustment is necessary. TR 2008. As witness Larkin noted, the Commission has already provided for recovery of certain costs outside of a base rate case. TR 2008. Although the costs associated with the existing clauses are within the utility's control, the Commission or the Legislature has decided to diminish the utilities exposure to the under-recovery of these costs. TR 2008. Some of the clauses even provide a benefit to ratepayers through a reduction of costs. TR 2008. The Company presently recovers almost 60% of its revenues through clauses.

Thus, there is no need to remove transmission costs from base rates which will, in effect, reduce the Company's risk to plan and properly build transmission facilities. Given the long time frame required to build transmission, the utility has ample time to request a base rate change if needed. There is also no benefit to ratepayers to remove these costs from base rates. TR 2008.

FIPUG's witness Pollack testified that, any time you shift cost recovery from base rates to adjustment clauses that basically get trued up dollar for dollar every year, that is a pretty significant reduction in the regulatory risk of the utility. TR 2326. Adding another clause will shift additional risk to ratepayers, and cause increased administrative costs to Commission staff and OPC, unnecessarily. TR 2009. Witness Larkin also noted that the timeframe for reviewing and auditing another clause would be relatively short and would place an additional burden on the Commission. TR 2009.

Witness Haines conceded that he was not aware of any commission that had approved a transmission base rate adjustment mechanism. TR 1086. While FIPUG's witness Pollack noted that Texas has allowed some of their utilities which provide delivery service only to recover the increases in transmission investment between rate cases, he testified that Texas' mechanism allows recovery in a way that recognizes the dynamics of ratemaking. TR 2323-2324. When asked to explain those dynamics, he stated that mechanism recognizes customer growth that generates additional revenues which offsets or defrays costs as well as the effect of depreciation on rate base. TR 2325. He explained that rate base is reduced due to depreciation and revenues are increased due to utility growth generated since the last rate case. TR 2324-2325. Because of these two offsetting adjustments, one for growth and one for additional depreciation, only the incremental cost, if any, for additional transmission investment could be recovered through this mechanism. TR 2325. The mechanism Tampa Electric is proposing does not recognize these offsetting adjustments like the mechanism in Texas and is another reason not to allow its proposed TBRA.

Since removing transmission costs from base rates will reduce the Company's risk to plan and properly build transmission facilities and will not provide a benefit to ratepayers, Tampa Electric's proposal should be denied. Moreover, 60% of the Company's revenues are already recovered through clauses, and shifting additional costs for transmission to a clause will only serve to shift more risk to ratepayers and add additional administrative costs, unnecessarily. Therefore, the Company's request to create this new clause mechanism should be denied.

Issue 113: Should TECO be required to file, within 90 days after the date of the final order in this docket, a description of all entries or adjustments to its annual report, rate of return reports, and books and records which will be required as a result of the Commission's findings in this rate case?

OPC: *Yes.*

<u>Issue 114</u>: Should this docket be closed?

<u>OPC:</u> No position.

Respectfully submitted,

J. R. KELLY
PUBLIC COUNSEL

<u>s/ Patricia A. Christensen</u>
Patricia A. Christensen
Associate Public Counsel

Office of Public Counsel
c/o The Florida Legislature
111 West Madison Street, Room 812
Tallahassee, FL 32399-1400
(850) 488-9330

Attorneys for the Citizens of the
State of Florida

CERTIFICATE OF SERVICE
DOCKET NO. 080317-EI

I HEREBY CERTIFY that a true and correct copy of the foregoing Citizen's Post – hearing Brief to Tampa Electric Company has been furnished by electronic mail and U.S. Mail to the following parties on this 17th day of February, 2009.

James Beasley/Lee Willis
Ausley Law Firm
P.O. Box 391
Tallahassee, FL 32302

Jean Hartman/Jennifer Brubaker
Keino Young/ Martha Brown
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, Florida 32399-0850

Vicki Kaufman/Jon Moyle
Florida Industrial Power Users Group
Anchors Law Firm
118 N. Gadsden Street
Tallahassee, FL 32301

R. Scheffel Wright
Young Law Firm
225 S. Adams Street, Ste. 200
Tallahassee, FL 32308

Paula Brown
Tampa Electric Company
P.O. Box 111
Tampa, FL 33602

Michael B. Twomey
P.O. Box 5256
Tallahassee, FL 32314-5256

Cecilia Bradley
Office of the Attorney General
The Capitol – PL 01
Tallahassee, FL 32399-1050

John W. McWhirter, Jr.
McWhirter, Reeves & Davidson, P.A.
P.O. Box 3350
Tampa, FL 33601-3350

s/ Patricia A. Christensen
Patricia A. Christensen
Associate Public Counsel