KA GM Keefe, Anchors Gordon & Moyle

February 17, 2009

Via Hand Delivery

Ms. Ann Cole, Director
Office of Commission Clerk
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, FL 32399-0850

Re: In re: Petition for Rate Increase by Tampa Electric Company
Docket No. 080317-EI

Dear Ms. Cole:

Enclosed for filing on behalf of the Florida Industrial Power Users Group is the original and seven copies of FIPUG Post-Hearing Statement of Issues and Positions and Post-Hearing Brief. Also enclosed is an extra copy for you to stamp and return as well as a disk with the document on it in Word.

Thank you for your assistance.

Sincerely,

Vicki Gordon Kaufman

Vicki Gordon Kaufman

VGK/lt

Enclosures

COM ___
ECR ___
GCL 1 co forwarded to GCL
OPC ___
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BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for Rate Increase
by Tampa Electric Company.
_______________________________/

DOCKET NO. 080317-EI
FILED: February 17, 2009

THE FLORIDA INDUSTRIAL POWER USERS GROUP'S POST-HEARING STATEMENT OF ISSUES AND POSITIONS AND POST- HEARING BRIEF

The Florida Industrial Power Users Group (FIPUG),[1] by and through its undersigned counsel, pursuant to Order No. PSC-09-0033-PHO-EI, file this Post-Hearing Statement of Issues and Positions and Post-Hearing Brief.[2]

BASIC POSITION

The evidence in this case clearly demonstrates that TECO's request for a $228 million rate increase is grossly overstated. This overstatement is due to a number of factors, summarized below and discussed in detail in this Post-Hearing Brief, including the excessive return on equity (ROE) TECO seeks. This Commission should set TECO's ROE no higher than 7.5%, should allow TECO to raise its rates no more than $38.6 in keeping with the adjustments recommended by the Office of Public Counsel and other intervenors, should retain the current cost of service methodology, and should establish a stable and appropriate credit for interruptible customers.

RETURN ON EQUITY

In this case, TECO seeks to increase rates by over $228 million. A significant portion of this increase is due to TECO's request for a 12% ROE. Given the current financial situation, this request should be rejected outright. Every one percentage point of ROE represents a $30 million rate burden placed squarely on the backs of ratepayers. Reducing the requested ROE from 12%

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[1] FIPUG was granted intervenor status in Order No. PSC-08-0597-PCO-EI (Sept. 16, 2008).

[2] Throughout this brief, Tampa Electric Company is referred to as TECO or the company. TECO Energy, Inc. is referred to as TECO Energy. The Office of Public Counsel is referred to as Public Counsel. The Florida Retail Federation is referred to as FRF. References to the transcript are designated Tr., followed by the page number.

to 9.75%, as urged by Public Counsel, would decrease TECO's revenue request by $67.5 million. If the Commission used an 8% ROE, TECO's revenue request would be reduced by $120 million. Clearly, reducing the requested ROE to a reasonable level commensurate with the difficult economic times confronting Floridians will greatly mitigate the impact of any ultimate revenue requirement the Commission approves.

The basis for TECO's ROE request appears to be the unsupported assertion that a higher ROE will lead to significantly lower borrowing costs in the future. Not only was this not shown to be the case, but even if taken as true, the costs to ratepayers of the excessive ROE far outweigh any potential future savings realized from reduced borrowing costs. (See FIPUG Exhibit No. 113, attached hereto). In addition, ratepayers would see no benefit from the alleged reduced borrowing rates until TECO's next rate case, while they would begin paying for TECO's inflated ROE the moment new rates take effect. Similarly, there was a paucity of evidence to support TECO's contention that it might not be able to access capital markets. In its 100 year plus history, TECO has never been unable to attract capital. Additionally, even in these difficult economic times, electric companies like TECO regularly access the capital markets.

As FIPUG and FRF witness Tom Herndon testified, given the favorable regulatory treatment provided to Florida utilities, as well as the fact that TECO collects billions of dollars outside of base rates through guaranteed cost recovery clauses,[3] a 12% ROE is plainly excessive. Further, TECO, in contrast to businesses with which it must compete in the open market, is a monopoly with a captive customer base. All these factors greatly reduce its risk and indicate that an ROE of 7.5% is more than sufficient to allow TECO to access capital markets and reliably serve its customers.

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3 The Commission-approved sum for 2009 is $1,203,627. *See*, Order No. PSC-08-0030-FOF, Order No. PSC-07-0922-FOF-EI.

REVENUE ISSUES

Many of the revenue requests TECO seeks are inappropriate and/or overstated and should be rejected or adjusted. FIPUG highlights some of these issues below and describes them in more detail in its later discussion in this Brief.

Storm damage accrual: TECO seeks to increase its storm damage accrual by *400%*, increasing the accrual from $4 million per year to $20 million per year. It also seeks to increase its target reserve from $55 million to $120 million. This request should be rejected outright.

As the evidence showed, TECO's current accrual and target levels are appropriate and should not be increased. Any increase would needlessly result in additional expense to ratepayers. Should TECO need additional funds to address storm damage in the future, this Commission has expressed a willingness and has an established history of dealing expeditiously with appropriate storm recovery requests.

Annualization of Five Combustion Turbines: The Commission should reject TECO's request to annualize the costs of five combustion turbines (CTs) which may or may not come into service in the test year. Even if all the CTs are brought on line as projected, they still will not be in service for the full test year. Ratepayers should not be required to pay for plant that is not used and useful. Further, the evidence demonstrated that the CTs are not needed to meet reliability requirements.

Annualization of Big Bend Rail Facility: Like the CTs discussed above, TECO seeks to annualize the cost of a rail facility that will be in service *only one month* of the 2009 test year. Because such facilities cannot possibly provide any benefit to ratepayers during the vast majority of the test year, this adjustment should be rejected.

<u>Overstatement of Big Bend Outages</u>: TECO has included abnormally high expenses for plant outages in its test year. TECO witness Hornick admitted this when he described the number of Big Bend outages in the test year as "atypical." Thus, $8 million in reductions should be made to reflect the removal of these abnormally high expenses for plant outages.

<u>Incentive Compensation:</u> TECO has an overly generous incentive compensation plan, much of which is tied, not to ratepayer benefit, but to shareholder benefit, through the requirement to achieve certain financial goals for TECO and TECO Energy. The achievement of financial goals – such as percentage of net income – does not benefit ratepayers, but benefits shareholders. Therefore, the Commission should exclude incentive compensation related to the achievement of financial goals which do not benefit ratepayers.

<u>Rate Case Expense/Amortization Period:</u> The Commission should reduce the rate case expense submitted for Huron Consulting (over $1 million and over one third of the total rate case expense) and the compensation submitted for Ms. Abbott to reasonable levels.

In addition, the Commission should require TECO to provide a compliance filing reflecting *actual*, not projected, rate case expense. It is more appropriate to include actual known expenses in rates rather than expenses which are merely projected.

Finally, given the long period of time between TECO rate cases and the fact that TECO could not provide concrete information as to when it intended to come in for its next rate case, the Commission should provide for a five-year amortization of actually incurred rate case expense.

COST OF SERVICE

TECO has asked this Commission to approve a cost of service methodology which it has never used, but which, more importantly, fails to appropriately assign and allocate cost. The Commission should reject TECO's class cost-of-service study and rate design and maintain the current separate homogeneous (GSLD and IS) customer classes. In addition, it should classify the Big Bend scrubber and Polk gasifier costs to demand, apply the Commission-approved 12CP-1/13th AD method of allocation, and treat interruptible customers as firm for both pricing and costing purposes.

The Commission should recognize that interruptible customers receive a lower quality of service from TECO, that TECO's reserve margin is maintained for the benefit of firm (not interruptible) customers, and that the load factor of interruptible customers enables TECO to better utilize its capacity for the benefit of all customers.

It is critical that interruptible customers have a stable rate design in place that does not fluctuate between rate cases and that the value assigned to the interruptible credit appropriately reflect the inferior type of service interruptible customers receive. Thus, the Commission should permanently set the credit at $13.70 as recommended and supported by FIPUG witness Mr. Pollock in his testimony.

OTHER ISSUES

Transmission Base Rate Adjustment Clause: TECO seeks approval of yet another adjustment clause which would allow it to collect for transmission improvements, which are traditionally rate base items, in between rate cases. Transmission costs are not volatile, material or beyond TECO's control. TECO has shown no need for yet another adjustment clause. Therefore, the Commission should reject TECO's request for this new and unnecessary cost recovery clause.

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.*[4]

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. See Issue 19.

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. It is inappropriate to annualize the cost of the 5 CTs. If the Commission allows this annualization without an adjustment to recognize increased growth in sales, the company's revenue requirements will be overstated. Further, the CTs are not needed to meet reliability requirements. Rate base should be reduced to remove the CTs from the test year.*

DISCUSSION:

TECO seeks to annualize the cost of two CTs scheduled to go into service in May 2009 and three CTs (perhaps) scheduled to go into service in September 2009. Essentially, TECO wants to treat these CTs as those they were in service on January 1, 2009. (Tr. 423). Such an adjustment is inappropriate and should be denied.

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[4] In those instances where FIPUG takes "no position" on an issue, this should not be interpreted to mean that FIPUG concurs with TECO's position; rather, FIPUG simply takes "no position" on that issue.

TECO's proposal should be rejected because it would have the effect of putting the cost of the CTs into rates without accounting for the customer growth that would support this additional cost. (Tr. 2011). This would result in increased costs being spread over a smaller customer base and current customers would be required to pay more than their fair share of the new plant. (Tr. 2012). Permitting TECO to annualize these plants will overstate the company's revenue requirement and create a mismatch between the projected test year revenues and expenses and the projected investment related to the assets (in this case the CTs) that generated the test period revenues. (Tr. 2012).

TECO President Black testified that the CTs are needed to meet peak demand. (Tr. 105). That is, they are needed to address customer growth. However, as Mr. Larkin testified, if as TECO claims, the CTs are needed to meet reserve margins (though this does not appear to be the case as discussed below), there must be growth in sales causing the reserve margin to decline. This sales growth will generate additional income because the CTs would have to be in service to meet this demand. By treating the plants as though they went into service on January 1, 2009 and ignoring sales growth the company experiences in 2010, a mismatch is created. Sales growth in 2010 will not be matched with cost because the cost will have been reflected in 2009. Revenues from these facilities in 2010 will be a windfall to the company. (Tr. 2013).

On the other hand, if the CTs are not needed to meet customer demand, they are not used and useful and should not be included in rate base. TECO's Mr. Hornick testified that even if *none* of the 5 CTs went on line in 2009, the company would still be over its 20% reserve margin. (Tr. 896). Therefore, it does not appear that such units are necessary for reliability purposes and as such should not be included in the 2009 test year.

At hearing, TECO President Black said that all five CTs may not come on line in 2009.

(Tr. 105, 107). He testified that TECO was considering pushing out the in-service date of at least three of the CTs to 2010. (Tr. 106). Mr. Black testified that this decision would not be made until April.[5]

Regardless of what TECO does regarding the CTs, the facts do not change. Either the CTs are not needed for reliability purposes and thus are not used and useful or the CTs have not been matched with customer growth and should not be included in the test year. The CTs should not be included in the test year for the purposes of setting rates.

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

POSITION: *Yes. All contributions from CSX made to offset the capital cost of the rail facility should be immediately and directly credited to ratepayers to reduce an allowed increase, not to shareholders, to offset revenue requirements.*

DISCUSSION:

TECO originally projected the cost of the Big Bend rail project to be $46 million. (MFR Schedule B-11). It included that amount in the MFRs in this case and is seeking full recovery of this amount from ratepayers. That is, TECO is asking the Commission to approve recovery of this full amount as well as a return on the investment, depreciation expense, and related tax expense. (Tr. 1517). Subsequently, the projected cost of the rail facility increased to $64 million. (Tr. 947). The contract between TECO and CSX Transportation (CSX) requires CSX to reimburse TECO for a substantial portion of the Big Bend rail facility. (Tr. 946).

Pursuant to the contract, TECO will receive capital contributions from CSX tied to the amount of coal transportation provided under the contract with CSX. (Tr. 959; Exhibit No. 13, #66, Wehle late-filed deposition exhibit). In addition, CSX has agreed to fund some portion of

[5] Late-filed Exhibit No. 112 shows that the revenue impact of removing the 3 September CTs from the test year reduces TECO's revenue request by $27.7 million. This exhibit also appears to show that three of the CTs are coming on even later than the company originally testified and that two CTs are being moved to 2010.

the difference between the $46 million, which was the originally estimated cost of the facility, and the $64 million, the current projected cost. (Tr. 955).

However, rather than applying the CSX contributions to cover the capital cost of the facility and reducing the burden on ratepayers, TECO proposes to credit such contributions to the company (the shareholders). Only when the entire facility is paid for, including the difference between the $46 million and $64 million that TECO will receive from CSX, will the excess, if any, flow back to ratepayers. (Tr. 1528). If any additional monies are received under the coal transportation contract between CSX and TECO, such monies (at some future point in time) would flow back to ratepayers through the fuel clause. (Tr. 955, 969).

In essence, TECO asks the Commission to recognize in rates the full cost of the facility while not including any of CSX's capital contributions to offset such costs to ratepayers. Under this scheme, shareholders are made entirely whole, while ratepayers carry the entire burden of the cost of the rail facility. The Commission should not approve this treatment because it unfairly requires ratepayers to bear the entire cost of the facility while shareholders are receiving substantial contributions to recover the facility's capital cost from CSX.

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. This project is not anticipated to come into service until December 2009. It appears that its purpose is to attempt to reduce fuel costs. However, annualization for all of 2009, when the facility will be in service for only a month, violates the well known principle of matching costs to benefits. A reduction should be made to reflect the actual in service date of the facility.*

DISCUSSION:

TECO seeks to recover the full amount for rail facilities that will be in service for less than a month of the test year. TECO President, Mr. Black, admitted that such facilities will not provide any benefits at all to customers before December 2009. (Tr. 131). Therefore, TECO's proposed treatment – in which it treats the rail facilities as though they had been in service for the entire twelve months of the test year -- violates fundamental ratemaking principles.

TECO chose to use 2009 as its test year, rather than 2010 when the facilities would have been in service for the entire year. (Tr. 131). Permitting annualization will result in a mismatch between costs and any benefits which the project may provide in the future and should not be permitted.

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

POSITION: *Yes. TECO's requested plant in service is overstated. The adjustments submitted by intervenors should be implemented and projected plant in service, depreciation and amoritization should be reduced accordingly.*

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

POSITION: *No. The Customer Information System (CIS) changes that TECO seeks to recover are routine changes done whenever rate changes are approved. Thus, the expense of this extraordinary upgrade and related depreciation expense should be denied.*

DISCUSSION:

TECO seeks to include $2,445,000 to rate base for a Customer Information System (CIS) update. The company supports this request by saying that implementation of changes in rates necessitate upgrades to its CIS. (Tr. 1462). However, none of the changes to CIS are unusual and such changes are routinely done when rates change. These types of changes are incurred in the normal course of business in any year in which base rates and/or fuel rates change. (Tr. 2022).

Further, the company began to make CIS changes based on rate issues and changes that it is *asking* the Commission to approve. (Exhibit No. 13, #61, Chronister deposition at 96-97). To the extent that such changes are not approved, as explained in the testimony of the numerous intervenors in this case, ratepayers should not be required to pay for unnecessary changes which TECO made to its CIS.

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. This amount should be adjusted to reflect the adjustments recommended by Intervenors and discussed in specific issues throughout this Brief.*

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. Accumulated depreciated should reflect the amounts recommended by intervernor witnesses.*

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. Agree with Public Counsel.*

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. Agree with Public Counsel.*

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

POSITION: *Yes. Agree with Public Counsel.*

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

POSITION: *Yes. The Commission should deny the company's request to increase its annual accrual from $4 million to $20 million and to increase the target level of the reserve from $55 million to $120 million. The Commission has a history of permitting timely recovery of prudently incurred storm expenses and this is sufficient to deal with any future storm cost.*

DISCUSSION:

TECO has requested that it be permitted to increase its annual storm accrual from $4 million per year to $20 million per year. In addition, it seeks to increase the storm damage reserve from $55 million to $120 million. Both requests should be denied.

It is unnecessary to increase the annual storm damage accrual as TECO has requested. In the event that a storm occurs and TECO's storm reserve is insufficient to cover prudently incurred restoration costs, the company may petition the Commission to recover such costs. (Tr. 1231). This Commission has a history of promptly responding to such requests. As Mr. Larkin testified, when some companies incurred damage that exceeded their reserves in 2004 and 2005, the Commission expeditiously authorized companies to collect surcharges from customers to recover costs in excess of the storm accruals. (Tr. 2032).

TECO's Mr. Carlson testified that when TECO experienced storm damage in 2004, TECO was able to arrive at a practical and workable solution that worked well for the company and the ratepayers. He further testified that he had no reason to believe that a similarly reasonable solution could not be arrived at in the future if necessary. (Tr. 1232). Mr. Carlson also testified that he had no reason to believe that the Commission would not continue its policy of permitting customer surcharges, if appropriate. (Tr. 1236). Additionally, TECO President Black acknowledged that the Commission has ensured that the utilities it regulates recover, in one way or another, the reasonable and prudent costs associated with restoring service following a hurricane. (Tr. 140).

Therefore, it is highly unlikely that TECO will not recover prudently incurred costs, (Tr. 2032), if and when such costs are actually incurred. If a storm event occurs, at that point in time, the Commission can hold a hearing to determine the appropriate mechanism and amount of any necessary recovery.

In addition, TECO Chief Financial Officer Gillette testified that TECO has a line of credit that it can look to in the event of a hurricane in the TECO service territory. That line of credit provides TECO with the ability to deal with any adverse effects from a hurricane. (Tr. 363, 1236). Witness Gillette further testified that he was comfortable that the Commission would ensure that TECO had adequate money to repay reasonable and prudent storm restoration costs. (Tr. 468-469). Thus, there is no need to burden ratepayers with expenses now that may not be necessary.

Given the difficult financial times and the already very high fuel adjustment charges to which TECO customers are currently subject, it makes more sense to evaluate and collect prudently incurred storm charges, if and when it becomes necessary, rather than burdening ratepayers with additional (and perhaps unnecessary) expense at this time. As Mr. Larkin testified:

> From a financial point of view, this [having ratepayers pay when the reserve has been exceeded] is more beneficial to the ratepayer then having the Company collect huge amounts of reserves prior to the occurrence of a storm.

(Tr. 2036).

The level of TECO's storm reserve should not be increased. The current reserve was adequate to cover 2004 storm damage, (Tr. 2035), and as noted above, if it is insufficient in the future, the company may petition the Commission for relief.

The fact that the value of company's transmission and distribution system is higher than when the initial reserve amount was established, does not lead to the conclusion that the reserve target amount should be increased. First, electric utilities are not entitled to full cost recovery for storm damage but only the incremental cost of damage. *See,* rule 25-6.0243, Florida Administrative Code. Second, recovery may always be sought after the storm damage is incurred. Third, the company has the option of obtaining securitization financing to address excessive storm damage costs. *See*, section 366.8260, Florida Statutes.

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

POSITION: *Yes. Agree with Public Counsel.*

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

POSITION: *Yes. As recommended by Public Counsel witness Larkin, $10,959,000 should be removed because the company has failed to demonstrate that the revenues and costs related to these accounts are related to utility service.*

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

POSITION: *Yes. As recommended by Public Counsel witness Larkin $6,309,000 should be excluded as the company has not shown it is directly related to the provision of utility service.*

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

POSITION: *Yes. Agree with Public Counsel.*

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

POSITION: *Yes. The company's fuel stock should be reduced by 10% to reflect current reductions in the price of coal, oil and other fuel prices that have occurred since the rate case was filed.*

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% to reflect current reductions in the price of coal, oil and other fuel prices that have occurred since the rate case was filed.*

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% to reflect current reductions in coal, oil, and other fuel prices that have occurred since the company filed its case.*

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% to reflect current reductions which have occurred in coal, oil, and gas prices.*

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. Agree with Office of Public Counsel.*

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. Agree with Office of Public Counsel.*

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. Rate base should include the adjustments recommended by intervenors in this case.*

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?

POSITION: *Agree with Public Counsel.*

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: *Agree with Public Counsel.*

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

POSITION: *No. This is an unwarranted adjustment and should be rejected. TECO bears no risk regarding PPAs as the costs of PPAs are automatically recovered through the Commission's recovery clauses. Approval of this request would simply result in a higher rate of return for TECO.*

DISCUSSION:

TECO has imputed a $77 million debt adjustment to equity associated with its purchase power agreement (PPA) obligations.[6] This unwarranted imputation translates into an additional $5 million in rates which ratepayers must cover. (Tr. 276).

The basis for TECO's request appears to be Standard & Poor's practice of imputing debt in this way.[7] In essence, TECO asks this Commission to blindly accept an unwarranted adjustment without appropriate analysis or support.

It appears that Standard & Poor's makes an equity risk adjustment to "reflect the credit exposure that is added by PPAs." (Exhibit No. 18, GLG-2). But as Dr. Woolridge testified, Standard & Poor's does not indicate how the risk factor is determined and it may range from 0% to 100%. No witness from Standard and Poor's testified at hearing. Thus, it is impossible to predict how PPAs will be viewed by Standard & Poor's in the Florida regulatory climate. (Tr. 1909).

More importantly, TECO's proposed PPA adjustment totally ignores the regulatory regime in Florida. It does not take into account the important fact that the costs of PPAs are flowed directly through to ratepayers and collected annually by TECO via the automatic fuel

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[6] TECO arrives at this "adjustment" by multiplying the present value of its PPAs by a factor of 25%. (Tr. 1909).
[7] TECO CFO Gillette testified that he did not know the specifics of what adjustments might be made by Fitch (Tr. 285) or by Moody's. (Tr. 286).

adjustment and capacity cost recovery clauses. The risk to TECO of any disallowance is nil. (Tr. 1909).

As Mr. Gillette admitted, this Commission has *never* denied TECO's request for recovery of the costs of a PPA. (Tr. 286-287). Thus, it is hard to imagine what risk Mr. Gillette (or Standard & Poor's) is concerned about vis-à-vis Florida's regulatory environment. Mr. Gillette further admitted that it is the Commission's policy that having approved a PPA for cost recovery, it does not subsequently disallow payment under the contract. (Tr. 415). Nor is risk of non-performance by a non-utility generator borne by TECO. Mr. Gillette admitted that he was not aware of any instance in Florida where a utility was required to make capacity payments if the seller of the power was not performing under the contract. (Tr. 415-416).

Thus, as Dr. Woolridge testified, under the circumstances present in Florida, a PPA is much more like an operating cost (as recognized by Moody's) than like debt:

> If a utility enters into a PPA for the purpose of providing an assured supply of electricity and there is reasonable assurance that regulators will allow the cost to be recovered in regulated rates, Moody's may view the PPA as being most akin to an operating cost. In this circumstance, there most likely will be no imputed adjustments to the obligations of the utility.

(Tr. 1910), *quoting*, Moody's Rating Methodology: Global Regulated Electric Utilities, March 2005 at 10. Therefore, the Commission should reject TECO's requested $77 million adjustment.

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

POSITION: *Agree with FRF.*

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

POSITION: *Agree with FRF as adjusted to account for Mr. Herndon's recommended ROE of 7.5%.*

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

DROPPED
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]**

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

POSITION: *The appropriate return on equity, given financial current conditions, is 7.5%. TECO will be able to attract equity capital at this rate because TECO is a secure utility that operates in a very low risk environment due to its monopoly position, its captive customer base, and guaranteed cost recovery clauses. Further, in these economic times, undue reliance should not be placed on computer modeling; rather, common sense and sound judgment must be used to determine an appropriate ROE.*

DISCUSSION:

TECO's request for a 12% ROE – which is actually a 19% return on a pre-tax basis (Tr. 252, 635) -- utterly fails to recognize the financial realities of today's world and the tremendous financial hardships that all TECO customer segments face. Such a request is not reasonable in today's financial times[8] and should be rejected outright. Instead the Commission should adopt the ROE recommended by witness Herndon of 7.5%.

The Standard

As the Commission conducts its deliberations on the critical issue of ROE, it is important to bear in mind the principles which must guide its decision. These principles, as articulated by the United States Supreme Court, do not embrace the mechanical application of formulae or models. Rather, they call for the decision maker to make an informed and reasonable decision considering all facts and circumstances.

[8] TECO looks for 8.25% return on its own pension fund, (Tr. 373), but seeks a much higher return in this case when ratepayers are responsible.

In *Bluefield Waterworks & Improvement Co. v. Public Service Commission of West Virginia,* 262 U.S. 679, 692 (1923), the United States Supreme Court discussed the appropriate standard to be applied in deciding upon an appropriate rate of return. The Court said:

> What annual rate will constitute just compensation depends upon many circumstances, and must be determined by the exercise of a fair and enlightened judgment, having regard to all relevant facts.

The *Bluefield* Court went on to note that whether a return on equity is appropriate "depends upon circumstances, locality and risk, and that no proper rate can be established for all cases." *Id.* at 693.[9]

Similarly, in *Federal Power Commission v. Hope Natural Gas Co.*, 320 U.S. 591, 602 (1944), the Court held that the regulatory authority (in that case, the Federal Power Commission), "was not bound to the use of any single formula or combination of formulae in determining rates. Its rate-making function, moreover, involves the making of 'pragmatic adjustments.'" (citation omitted). In this matter, the Commission should keep these time-honored principles at the forefront of its decision.

<u>Mr. Herndon's ROE Recommendation</u>

In stark contrast to TECO's position, FIPUG and FRF presented the testimony of Mr. Tom Herndon, a former PSC Commissioner and former institutional investor for the Florida State Board of Administration. Mr. Herndon, based on his extensive financial expertise and experience, took a real world look at the current financial situation to determine what would be a reasonable ROE in today's times. Mr. Herndon urged the Commission to not rely solely on formulaic models but to apply its judgment in this case.[10] While Mr. Herndon recognized that

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[9] TECO CFO Gillette agreed that a judgment about ROE is dependent on market conditions at the point in time at which the decision is made. (Tr. 309).

[10] Dr. Murry also recognized that models are not the only tools that should be used in arriving at an appropriate ROE and that both the DCF model and the CAPM model have weaknesses. (Tr. 741). He further agreed that the exercise

such models are a tool for the Commission, he opined that they should not be the sole determinant of ROE in this matter.

Mr. Herndon's recommendation of a 7.5% ROE is based on a reasoned consideration of many factors. Mr. Herndon testified that TECO is much less risky than companies that must compete in the market. TECO is a monopoly provider and not subject to any competition in its service territory. (Tr. 2177). Interest rates are at an all time low. Further, current market conditions mean that there will be access to capital and that investor expectations regarding returns on equity will be reasonable. (Tr. 2178). In addition, TECO recovers over half of its expenses through Commission authorized cost recovery clauses. Such recovery is virtually guaranteed, making an investment in TECO one of low risk. (Tr. 2178). Utility stocks have performed much better than the Dow, S&P 500 or NASDAQ because they are a higher quality, more desirable investment. (Tr. 2178).

The action the Commission should take as to ROE is best summarized by Mr. Herndon below:

> Your decision about the return on equity is not a matter of artificial rule, models or formulas, but should be based on reasonable judgment based on consideration of all relevant facts. The Commission should pay particular attention to current market conditions which do not support an equity return of 12 percent.

(Tr. 2179).

<u>TECO's Financial Situation is Strong and Stable</u>

It is important to recognize that, despite TECO's dismal portrayal of its financial condition, the evidence at hearing demonstrated that TECO is far from dire financial straits. TECO President Black testified that TECO can meet debt its obligations, (Tr. 133), and that he is

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of judgment was appropriate in establishing ROE. (Tr. 740).

confident that the Commission will ensure TECO has sufficient funds to cover its debt. (Tr. 139; 461).

Chief Financial Officer Gillette testified that TECO can cover its operating expenses. (Tr. 133). Mr. Black testified that TECO will have a positive net income, (Tr. 137), and that the company does not face a significant risk of being unable to cover its operating costs. (Tr. 138). Mr. Gillette testified that TECO has an excellent business risk profile (Tr. 426). Ms. Abbott testified that TECO is viewed as fiscally sound. (Tr. 619). Dr. Murry testified that TECO has a very favorable business risk profile and that Standard & Poors classifies TECO business risk as excellent. (Tr. 758). Thus, TECO's dire predictions seem suspect at best.

A Lower Borrowing Rate Does Not Justify TECO's Excessive ROE Request — Ratepayers Would Not Get Much "Bang for Their Buck"

TECO President Black explained that the primary justification for the 12% ROE TECO has requested is to attempt to achieve an A bond rating that *may* allow the company to access capital at lower costs in the future. (Tr. 136). There are numerous flaws in this theory, which, if accepted, would result in ratepayers paying excessive and unreasonable rates as soon as rates take effect.

First, despite TECO's insistence that it must raise its ROE to (perhaps) achieve a higher bond rating to access the capital markets and borrow at lower rates, it performed *no study* that in any way quantified the probability of TECO being denied access[11] to the capital markets. TECO President Black testified: "I'm not aware of a study that provided a quantitative probability as

[11] In each of TECO's annual reports for a number of years, TECO has included the following statement, putting the investment community on notice regarding TECO's access to capital: "We are vulnerable to interest rate changes and may not have access to capital at favorable rates, if at all." (Tr. 368-369; Exhibit No. 95). However, this has never occurred. When credit markets were closed in September 2008, they were closed to *everyone*, even those companies with A ratings. (Tr. 750). In this instance, a AAA rating would not have helped TECO access the capital markets.

much as a qualitative assessment of the markets...." (Tr. 159). TECO CFO Gillette confirmed this. (Tr. 526).

Second, and most importantly, even if TECO were correct -- that the Commission's award of a 12% ROE would result in lower borrowing costs in the future -- such lower costs would not outweigh the cost burden to customers of a 12% ROE. Witness O'Donnell succinctly provided an apt analogy to illustrate the absurdity of TECO's request. He testified that "paying excessive ROEs to achieve a lower cost of debt is similar to asking customers to pay $30,000 for a $15,000 car in order to get a $500 manufacturer's rebate." (Tr. 2382).

The fallacy of TECO's position is illustrated in FIPUG's late-filed "bang for the buck" exhibit (Exhibit No. 123) as well as in the testimony of Mr. Herndon. The difference between the borrowing cost for a BBB bond rated company (TECO's current rating) and an A rated company could not possibly make up the difference in ROEs between Mr. Herndon's recommended 8% (at the high end) and TECO's requested 12%.

Future lower borrowing costs will not outweigh the higher electric bills that customers will have to immediately pay if higher rates are approved. (Tr. 2180). As Mr. Herndon testified, a 12% ROE will cost customers much more in the long run than a 7.5% ROE and a borrowing rate pegged to TECO's current credit rating. (Tr. 2180).

This point is illustrated by some simple calculations. TECO testified that every percentage point difference in ROE equates to $30 million. (Exhibit No. 13, #61, late-filed Exhibit No. 4 to Chronister deposition). Thus, the difference between an 8% ROE and a 12% ROE is $120 million. (Tr. 2226). If TECO goes into the debt market for $250 million, as it has said it intends to do, (Tr. 441-442), and the difference between a BBB company and an A company in terms of borrowing is 2%, the company would save $5 million in TECO borrowing costs. (Tr. 2227). If the spread is 1%, as TECO witness Abbott testified, (Tr. 620), the savings would be $2.5 million. If TECO did not come back for a rate case for 5 years, ratepayers would save $25 million in potential borrowing costs at the 2% spread or $12.5 million at the 1% spread. However, they would have paid $150 million to achieve that "savings." (FIPUG late-filed Exhibit No. 123). Such a proposal makes no economic sense for ratepayers.

It is also critical to recognize that even assuming borrowing costs would be different between the differently rated companies, such lower borrowing costs would not be reflected until TECO's next rate case. (Tr. 160, 366). While customers will see higher rates as soon as the rates go into effect in May 2009, (Tr. 161, 497, 504, 2226), they will not see lower borrowing costs (if at all) until TECO's next rate case. (Tr. 2180). Thus, while, ratepayers would see impact of the 12% ROE *immediately* in their rates, a change in debt rates – up or down – is not reflected in customers' rates until the next rate case. (Tr. 493, 497). TECO wants ratepayers to begin paying right now for a high ROE that *might* in the future result in lower borrowing costs.

It appears that TECO has increased the equity component of its capital structure in the recent past by merely sending less money to the parent holding company. It can continue to reduce investor risk and bond interest cost by keeping more of the revenue it collects from its customers rather than sending it to the parent.

<u>There Is No Guarantee What the Rating Agencies Will Do</u>

In addition, even were the Commission to agree with TECO, there is *absolutely no guarantee* regarding what action the rating agencies will take in response to a Commission decision. TECO produced no witness from any of the three rating agencies. Neither this Commission nor any of the parties know what action, if any, a particular rating agency will take as a result of this Commission's ROE decision.

Mr. Herndon testified that neither TECO nor its witnesses can guarantee that a higher credit rating will be the result of a 12% ROE. (Tr. 2179-2180). Ms. Abbott agreed that the award of a 12% ROE would not guarantee that TECO's rating would change from BBB to A. (Tr. 608; 617; 634).

Chief Financial Officer Gillette testified that no one at any of the three rating agencies has informed TECO regarding what action they will take as a result of the outcome of this rate case. (Tr. 269-271, 495). That is, even if the Commission were to accept TECO's theory regarding lower borrowing costs (which it should not), there is no evidence that TECO will be accorded an A rating if it receives a 12% ROE. TECO presented no testimony from anyone from any of the three rating agencies nor did it ask anyone from any of those rating agencies to testify. (Tr. 419-420). TECO's comments about what a particular rating agency will or will not do are nothing more than unsupported supposition and should not be accepted as a basis to award an excessive ROE.[12]

A 12% ROE is Out of Step With Other Recent ROE Decisions

The 12% ROE TECO has requested is out of line with recent ROE decisions. For example, even TECO's own witness, Dr. Murry testified that the average ROE in the southeastern states is 10.58%. (Tr. 749). In a recent case in which Dr. Murry testified in Oklahoma, the Oklahoma Public Service Commission on January 14, 2009, awarded an ROE of 10.5%, even recognizing uncertainty in the financial markets. (Exhibit No. 106 at 45; Tr. 785-786). Even Mr. Gillette testified that the evidence shows that most recently ROEs have averaged 10.35%. (Tr. 314). And since September 8, 2008, the highest ROE awarded was 11%. (Tr. 489-490). Thus, an ROE of 12% is beyond any range of reasonableness.

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[12] Mr. Gillette's own exhibit, (Exhibit No. 18, GLG-1, document 4) shows that most utilities are rated BBB. (Tr. 364). Ms. Abbott confirmed this. (Tr. 608, 621).

The ROE Mr. Herndon recommends is reasonable and appropriately takes into consideration today's financial situation. Thus, an ROE for TECO of 7.5% should be approved by the Commission.

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

POSITION: *Mr. Herndon's recommended ROE of 7.5% should be adopted and the average cost of capital adjusted accordingly.*

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. Adjustments should be made to reflect the adjustments recommended by Intervenors 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 specific adjustments FIPUG and other intervenors have recommended should be used to reduce O&M expense.*

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. Agree with Public Counsel.*

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

POSITION: *No. Agree with Public Counsel.*

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. The Commission should make the adjustments recommended by Public Counsel witness Schultz. The company's payroll should be reduced by $3,568,109; the company's 401(k) expense should be reduced by $1.991 million; and employee benefits expense should be reduced by $1,420, 208.*

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

POSITION: *Yes. Agree with Public Counsel.*

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

POSITION: *Yes. The company has overstated the number of needed employees by approximately 100 positions compared with its historical employee numbers. These positions should be deleted from the test year.*

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

POSITION: *Yes. Agree with Public Counsel.*

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

POSITION: *Yes. Incentive compensation that is contingent on or related to the parent and/or operating company achieving financial goals, such as net income, benefits shareholders not ratepayers and should be removed from the test year. Specifically, 100% of officer, key employee and general employee incentive payments contingent upon TECO or TECO Energy achieving a specific net income or other financial indicator should be disallowed as should compensation related to Performance Restricted Shares and Time-Vested Restricted Shares.*

DISCUSSION:

A portion of the incentive compensation that TECO has included in the test year is tied directly to the financial performance of TECO and its parent company, TECO Energy. Incentive compensation that is contingent on the achievement of the financial performance of the company, while beneficial to shareholders, is of no direct benefit to ratepayers and therefore such expenses should not be included in the test year. (Tr. 2240). TECO's incentive compensation program is described in Exhibit No. 89 (TECO's Response to OPC's Third Set of Interrogatories, No. 31). The incentive compensation program is applicable to three categories of employees – Officers, Key Employees, and General Employees.

As to Officers, it is clear that the entirety of their incentive compensation is tied to TECO Energy achieving a particular level of financial performance. TECO's description of the incentive plan provides:

> Regardless of the degree of achievement of each established goal, *the payout to all participants is zero if TECO Energy's income threshold set for that year by the Compensation Committee is not achieved.*[13]

As Mr. Chronister and Ms. Merrill explained, if TECO Energy does not achieve 80% of its budgeted net earnings in a particular year, officer pay out is zero. (Exhibit No. 13, #61, Chronister deposition at 101; Tr. 1171). Thus, Mr. Chronister's comment, that only 20% of officers'

[13] Exhibit No.89 at 2 (TECO Response to OPC Interrogatory No. 31), emphasis supplied.

compensation is based on TECO Energy financial targets, (Tr. 1484), is misleading at best. If TECO Energy does not make its 80% net earnings threshold, *no incentive compensation* is paid to officers. As Mr. Chronister testified, the payout is "completely contingent on net income." (Exhibit No. 13, #61, Chronister deposition at 104; Tr. 1172). Thus, one would expect the officers to be very interested in ensuring that the 80% net income threshold is met. (Tr. 1172-1173). While officers of both the parent and operating company no doubt focus much time and attention on meeting the financial goal of the parent company, such focus does not inure to the benefit of and should not be paid for by ratepayers of TECO, a subsidiary of TECO Energy.

Similarly, the incentive compensation program awards performance restricted stock shares as part of the program. The award of this stock is also based exclusively on the performance of TECO Energy stock. For example, if shareholder return is equal to the median of a group of peer companies, 100% of the target award is earned. (Exhibit No. 89, TECO's Response to OPC's Third Set of Interrogatories, No. 31 at 5). Again, focus on shareholder return inures to the benefit of shareholders, not ratepayers, and thus shareholders should be responsible for these incentives.

The incentive compensation of Key Employees is also tied, in part, to financial goals. As Mr. Chronister testified, 50% of the key employees' incentive compensation is based on achieving financial targets. Of that 50%, 15% is based on meeting TECO Energy financial targets and the remaining 35% is based on meeting TECO financial targets. (Exhibit No. 13, #61, Chronister deposition at 94; Tr. 1175). Again, a large portion of the focus of the incentive program is on the achievement of financial performance goals of TECO and TECO Energy.

Finally, the incentive compensation for general employees is based in part on financial performance related to cash flow and net income. Five percent of a possible 12% incentive compensation is related to TECO achieving its net income goals and 2% is related to TECO Energy achieving its financial goals. (Tr. 1134).

In current economic times, when executive compensation has come under great scrutiny and criticism and when even the President of the United States is taking action to limit executive compensation, this Commission must ensure that all compensation is reasonable and *directly related* to enhancing the value ratepayers receive and that it is not a windfall for executives. (Tr. 2242). Incentive compensation related to financial performance, especially financial performance of a parent company, does not meet those criteria.[14]

Other jurisdictions have disallowed incentive compensation when it was not tied directly to ratepayer value. For example, in the AEP Texas Central rate case,[15] the Public Utility Commission of Texas (PUCT) permitted inclusion of the incentive compensation only to the extent that it was tied to operational factors. The Proposal for Decision (PFD) addressed the issue initially and pointed out that the incentive compensation was predicated on both financial and operational objectives.[16] In addressing the issue of inclusion in rates, the PFD stated: "With regard to the measures themselves, the Financial Measures are of more immediate benefit to shareholders and less so to ratepayers."[17]

In reviewing the PFD and issuing its own decision, the PUCT concluded as follows:

> The financial measures are of more immediate benefit to shareholders, and the operating measures are of more immediate benefit to ratepayers.

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[14] It is telling that when it filed its rate case, TECO did not even consider scaling back any part of its incentive compensation plan. (Tr. 1180).

[15] *Application of AEP Texas Central Company for Authority to Change Rates*, Docket No. 28840.

[16] Application of AEP Texas Central Company for Authority to Change Rates, PUCT Docket No. 28840, *Proposal for Decision*, July 1, 2004 at 92.

[17] *Id.*

> Incentives to achieve operational measures are necessary and reasonable to provide T&D utility services, but those to achieve financial measures are not.[18]

The Texas Commission approved recovery of 34% of $4.4 million in requested incentive compensation, with $2.8 million being disallowed.[19]

Similarly, the Wyoming Public Service Commission disallowed 50% of PacificCorp's proposed incentive compensation because business unit and corporate incentives are primarily for the benefit of shareholders.[20] The Wyoming Commission found:

> Part of PacifiCorp's employee compensation package is made up of incentives for meeting various goals set at different levels of organization on the individual (50%), business unit (30%) and corporate (20%) levels. PacifiCorp recommended that 5% of the overall incentive package should be considered related to shareholder rather than ratepayer benefit and therefore excluded for rate making purposes. . . . WIEC recommended that half of the incentive compensation package should be excluded. . . . The exclusions are based on the premise that the business unit and corporate incentives, which total 50%, are primarily of benefit to shareholders rather than ratepayers. WIEC observed that, "[b]y tying incentive payments to financial performance, PacifiCorp made the financial success and enhanced shareholder wealth significant objectives for [its incentive plan]." . . .
>
> We adopt the WIEC adjustment as a fair and reasonable sharing of the value of the incentive program between the ratepayers and PacifiCorp's shareholders. This tracks the most prominent divisions of the plan and fairly allows for the situations in which program elements might benefit both shareholders and ratepayers.[21]

The Commission should disallow any and all incentive compensation that is tied to the financial performance of TECO or TECO Energy.

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[18] *Application of AEP Texas Central for Authority to Change Rates*, PUCT Docket No. 28440, *Final Order*, August 15, 2005 at 169-170.
[19] *Id.*
[20] *In the Matter of the Application of PacifiCorp for a Retail Electric Utility Rate Increase of $41.8 Million per Year*, Docket No. 20000-ER-03-198, *Order*, Feb. 28, 2004.
[21] *Id.*

Finally, according to Ms. Merrill, Director of Staffing and Development for TECO, goals are not driven by continuous improvement. (Tr. 149-1150). Ms. Merrill also testified that incentive compensation is "at risk" and thus is not a guarantee. (Tr. 1151). However, in 2007, 2006, and 2005 *every single* eligible employee, out of over approximately 2500 eligible employees, received incentive compensation. (Tr. 1152). In 2004, only one eligible employee, out of approximately 2400 eligible employees, did not receive incentive compensation, and in 2003, only five eligible employees, out of over 2600 eligible employees, did not receive incentive compensation. (Tr. 1152). Thus, it does not appear that incentive compensation is "at risk," as Ms. Merrill claims, or tied to improved performance.

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

POSITION: *Yes. Agree with Public Counsel.*

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

POSITION: *Yes. The company's request should be reduced by $8,173,000 as recommended by Public Counsel witness Schultz. The company failed to justify its request over historical levels.*

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

POSITION: *Yes. The adjustment recommended by Public Counsel witness Schultz should be made. TECO increased its test year levels to almost twice historical levels and three times the five year average. As Mr. Schultz testified, the company should consistently maintain its system in a safe and reliable manner.*

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

POSITION: *Yes. Agree with Public Counsel.*

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

POSITION: *Yes. Agree with Public Counsel.*

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

POSITION: *Yes. Agree with Public Counsel.*

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

POSITION: *Yes. The company's storm damage accrual should remain at $4 million annually and the reserve target should remain unchanged.*

DISCUSSION:

See discussion of 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. Agree with Public Counsel.*

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

POSITION: *Yes. The cost of this insurance should be removed from rates as recommended by Public Counsel witness Schultz. This insurance provides protection to officers and directors provides no benefit to TECO ratepayers. The entire expense, $1,605,815, should be removed.*

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

POSITION: *No position.*

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

POSITION: *TECO should be required to provide actual, rather than projected rate case expense so that actual expenditures are used to set rate case expense. Because there is generally a long period of time between rate cases, a longer amortization period is more in keeping with TECO's rate case history. Such amortization period should be five years. In addition, the Commission should reduce rate case expense as recommended by Public Counsel witness Schultz.*

DISCUSSION:

TECO seeks to recover over $3 million in rate case expense and it seeks to recover that amount in three years. FIPUG has several comments in opposition to this request.

First, TECO has projected its rate case expense. As Mr. Chronister explained in his deposition, such expenses consist mainly of fees for counsel and outside experts. (Exhibit No. 13, #61, Chronister deposition at 86). Rather than including a projection of what the expense will be, TECO should be required to file the *actual* rate case expense as part of its compliance filing. (Tr. 2239). Mr. Chronister admitted that actual invoices will be rendered in this case and that such actual invoices will be more accurate than TECO's projections. (Exhibit No. 13, #61, Chronister deposition at 89). Actual, not projected, rate case expenses should be used to set rates.

Second, TECO seeks to recover its rate case expense over a three-year period. Given TECO's rate case history, this proposed time frame is too short and TECO should be required to amortize this expense over at least five years. (Tr. 2239).

TECO's last rate case was in 1992 – over 16 years ago. *See*, Order No. PSC-93-0165-FOF-EI. There is no indication when TECO will file its next rate case, especially since TECO recovers many traditional base rate items through separate cost recovery clauses. (Tr. 2230). As the Commission's *Report to the Legislature on Utility Revenue Decoupling* (Dec. 2008) at 16 notes, in 2007, TECO recovered 64% of its annual expenses through cost recovery clauses. (This amount has steadily increased each year). Thus, TECO's need for a rate case in the next three years is highly unlikely.

Though Mr. Chronister testified that he thought TECO would be in for a rate case "sooner than five years," (Tr. 1493), he had not spoken with any upper management regarding

TECO's plans for its next rate case. (Tr. 1576). Thus, a five-year amortization period is more reasonable and should be used.

Finally, as Public Counsel witness Schultz testified, it appears that TECO's actual rate case expense is excessive. Particularly, it appears that the extra layer of review inserted by the retention of Huron Consulting Services, LLC, at a cost of $1.31 million is excessive and unnecessary. Curiously, the Huron work does not appear to have been competitively bid[22] and Huron and TECO Energy have common directors. (Tr. 1512). The amount of $1.31 million amount should be reduced. (Tr. 2102).

In addition, it appears that the fees paid to Ms. Abbott were also excessive. In this case, TECO has agreed to compensate her at a flat fee of $25,000 per month plus expenses. (Tr. 636). However, in a recent case before the Public Service Company of Oklahoma, Ms. Abbott was paid a flat fee of $25,000 to prepare her testimony and a retainer of $4,000 per month. (Tr. 37).[23] Any compensation included in rate base should be limited to what Abbott received for her Oklahoma work or significantly reduced from the requested fee of over $200,000.

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

POSITION: *Yes. The company's bad debt expense should be reduced as recommended by Public Counsel witness Larkin. TECO's increase in bad debt of 44% is unreasonable. A five-year average should be used to project uncollectible expenses.*

[22] It is unclear exactly what work was performed for this amount. Mr. Felsenthal, when asked to describe the work he performed, said: "Among other things, I attended meetings, I reviewed the MFRs, I worked with the company on responses to data requests. I, I or Huron helped or discussed various positions or ways to respond to data requests and rebuttal testimony. An assortment of items." (Tr. 1393).

[23] While Ms. Abbott testified that the $4,000 per month was a "minimum, "she did not so advise the Oklahoma Commission. (Tr.638).

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

POSITION: *Yes. The company's request for a 39% increase for office supplies should be rejected and reduced by $2,295,000 as recommended by Public Counsel witness Schultz.*

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

POSITION: *Yes. Tree trimming expense should be reduced by $3,988,568 as recommended by Public Counsel witness Schultz. This reduction accounts for lower fuel costs than the company has projected and recognizes that the company came close to a three year tree trimming cycle in 1998-2000 and should have continued at that rate.*

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 should be reduced by $236,013 as recommended by Public Counsel witness Schultz.*

ISSUE 68: Should an adjustment be made to reduce TECO's transmission inspection expense for the 2009 projected test year?

POSITION: *Yes. The company's request should be reduced by $318,846 as recommended by Public Counsel witness Schultz. TECO provided no information to support doubling 2007 historic costs.*

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. TECO has overstated its planned outages in 2009 (particularly at Big Bend) and O & M expenses should be adjusted to reflect normal outage levels as described in the testimony of FIPUG witness Pollock. TECO's outage expenses should be reduced by $8 million.*

DISCUSSION:

As the Commission is aware, the test year, in this case 2009, must be representative of normal circumstances. It should not include unusual or extraordinary costly events because that will skew upward the company's revenue requirements. However, TECO has included unusual outage events in the test year, particularly at the Big Bend station.

A review of TECO's outages shows that TECO is projecting the highest number of scheduled outages in 2009 than in any year since 2003. In 2009, the company is projecting three major outages at Big Bend. Tellingly, TECO originally planned in 2005 for only one major outage at Big Bend through 2013. (Exhibit No. 56). The planned outages at Big Bend Stations are projected to increase from 22.5 weeks in 2008 to 32 weeks in 2009 – more than a 30% increase. (Tr. 2237).

TECO's own witness, Mr. Hornick, Director of Engineering and Construction, testified that the number of Big Bend outages included in the test year are *atypical*, (Tr. 886), and are not "a normal or average situation." (Tr. 888). This is further substantiated by Exhibit No. 56 (Big Bend Station Business Plan) which demonstrates that what is "typical" for Big Bend is one major outage per year, not the three major outages included in the test year. Because the multiple outages the company has projected for Big Bend in the test year are not normal occurrences, O&M expenses must be adjusted downward to reflect normal maintenance outage levels. (Tr. 2238).

Further, such outages are not only not normal, they are also non-recurring. Two of the three outages are to install selective catalytic refiners (SCR) at Big Bend Units 1 and 2. The company's settlement with the Environmental Protection Agency and the Florida Department of Environmental Protection requires that the SCRs be installed by 2010. (Tr. 825). This one-time cost is required by the settlement agreement and will not be incurred again.

TECO incurs higher costs in years when more outages occur. For example, in 2008, there were 48.5 outage weeks that resulted in $13.7 million of O&M expenses. This is in comparison to the projected 54 weeks in 2009 at a cost of $20.2 million. This projected increase is directly related to the Big Bend outages described above. (Tr. 2238).

TECO incurred or budgeted for an average of $12.2 million per year in outage-related expenses over the 2003-2009 period. Therefore, TECO should be permitted to recover $12.2 million for planned outages during the test year. Accordingly, TECO's proposed O&M expenses should be reduced by $8 million.

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 (CIS) changes that TECO seeks to recover are routine changes done whenever rate changes are approved. Thus, the expense of this extraordinary upgrade and related depreciation expense should be denied.*

DISCUSSION:

See discussion of Issue 9.

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?

POSITION: *No. It is inappropriate to annualize these plant additions. If the Commission allows this annualization without an adjustment to recognize increased growth in sales, the company's revenue requirements will be overstated. Rate base should be reduced by $130,687.000 to reflect the actual in-service date of the CTs.*

DISCUSSION:

See discussion of Issue 5.

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

POSITION: *No. Such facilities are not scheduled to come into service until December 2009. Such facilities will be in service less than a month and the company should not collect for such facilities for the entire year. Operating expenses should be reduced by $906,000 (depreciation) and $1,039,000 (taxes other than income) to remove the annualization.*

DISCUSSION:

See discussion of Issue 7.

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: *Appropriate depreciation adjustments must be made to reflect the Commission's decision on other issues. For example, adjustments should be made to remove depreciation expense associated with the annualization of the CTs (Issue 5), annualization of the rail project (Issue 6), and the CIS upgrade (Issue 9).*

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

POSITION: *Yes. Adjustments should be made to reflect the Commission's decisions on the other issues in this case.*

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

POSITION: *Yes. Agree with Public Counsel.*

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

POSITION: *Yes. Agree with Public Counsel.*

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. FIPUG's adjustments and those of other intervenors, discussed in the other issues, should be adopted.*

REVENUE REQUIREMENTS

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

POSITION: *The appropriate multiplier is 1.633202 as recommended by Public Counsel witness Larkin.*

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

POSITION: *No. FIPUG's adjustments and those of other intervenors, discussed in the prior issues, should be adopted.*

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: *The Commission should continue to use the 12CP and 1/13 AD cost of service methodology that it has used for many years. This method appropriately allocates production investment and properly recognizes that load duration drives a utility's investment decision. TECO's proposed methodology fails to reflect the basic principle of cost causation and allocates substantial costs beyond the break-even point.*

DISCUSSION:

TECO has proposed that the Commission dramatically and drastically shift the cost of service methodology used to allocate the final revenue requirements in this case. It proposes a methodology that this Commission has never embraced. FIPUG urges the Commission to continue to use the 12 Coincident Peak (CP)-1/13 Average Demand (AD). The 12CP-1/13 AD methodology, which the Commission has traditionally employed,[24] comes much closer to recognizing the critical principles of cost causation and the economic theory which underlies generation expansion planning. (Tr. 2267). As explained below, TECO's proposal improperly allocates production costs and would triple the amount of production plant costs classified to energy. (Tr. 2319).

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[24] This method should be used in conjunction with the classification of the Big Bend scrubber and Polk gasifier classified to demand as discussed in Issue 84.

For good reason, the Commission has never used or approved the 12CP-25% AD methodology TECO now advocates, (Tr. 1736), and TECO itself has *never* before advocated this method. In TECO's last rate case, Docket No. 920324-EI, TECO proposed the 12CP-1/13 AD methodology. (Tr. 1735). In TECO's 1985 rate case, Docket No. 850246-EI, TECO proposed the 12CP-1/13 AD methodology. (Tr. 1737).[25]

As Mr. Pollock explained in his testimony, the 12CP-25% AD methodology classifies 75% of production plant costs as demand related and 25% as energy related. The 12CP method is then used to allocate those capacity costs classified to demand, while annual energy usage, or average demand, is used to allocate those capacity costs classified to energy. (Tr. 2257).

As explained below, the basis for TECO's advocacy of this method is flawed and should be rejected. In essence, TECO advocates this change in direction based on its contention that higher investment or capital costs are incurred in order to save energy costs. This is known as the theory of "capital substitution." (Tr. 2257).[26] However, TECO's use of the 12CP-25% AD allocates costs beyond the economic breakeven point between base load and peaking capacity and thus crosses the line between cost causation and cost shifting. (Tr. 2320). This results in inappropriate cost shifting because above-average plant investment is allocated to high load factor customer classes and below-average plant investment is allocated to lower load factor customer classes. (Tr. 2261; Exhibit No. 61).

The Commission has previously recognized that the concept of the breakeven point is critical. *See*, Order No. 23573 at 42. The breakeven point is the number of operating hours in which the total cost of base/intermediate and peaking capacity is the same. (Tr. 2258). Annual

[25] In the other example, TECO provides, Docket Nos. 770316-EU and 830465-EI (FPL) rate cases, Mr. Ashburn admitted the methodology was only used for a portion of FPL's nuclear unit and that this exception no longer applies. (Tr. 1737-1738).

[26] The equivalent peaker method, which the Commission rejected in Order No.23573, was a specific application of this theory.

energy usage does not cause plant investment – production capacity is added to meet peak demand. While load duration *up to* the breakeven point may influence plant investment decisions, once the breakeven point has been passed, energy usage is not a factor in what type of plant a utility decides to build. (Tr. 2258-2259).

The 12CP-25% AD methodology TECO advocates allocates substantial costs beyond the breakeven point – it would allocate 43% of production plant costs to energy. (Tr. 2319). Therefore, it is totally inconsistent with the theory of capital substitution. This methodology, which allocates costs beyond the breakeven point, simply shifts costs and is therefore inappropriate. (Tr. 2320).

Additionally, TECO proposes to use the 12CP-25% AD method to allocate all production plant costs, irrespective of the type of resource. This would include plant costs associated with the combustion turbine (CT) units. And, TECO is also proposing to apply this method to allocate the dispatchable costs recoverable in the environmental cost recovery clause, including the GSLM-2/3 payments discussed in Issue 87. However, both CTs and GSLM resources provide peaking capacity and are not incurred to achieve lower fuel costs. (Tr. 2261). Therefore, it is inappropriate to use the 12CP-25% AD methodology to allocate those costs.

In addition, if TECO's advocacy of this methodology were consistent, TECO would apply the methodology to the allocation and recovery of fuel expenses as well. That is, the treatment of fuel expense should be symmetrical with the allocation of plant investment, (Tr. 2262), given TECO's theory that investment beyond the breakeven point is made to gain fuel savings. However, TECO does not change the way fuel costs are allocated and recovered; each class pays the same average fuel cost. As Mr. Pollock explained, absent a symmetrical allocation of investment and operating costs, which would result in below-average fuel costs per kWh being assigned to those classes that are also assigned above-average investment per kW, the 12CP-25% AD is an incomplete and inaccurate representation of capital substitution theory. (Tr. 2265).

Finally, the 12CP-25% ADs method is not consistent with TECO's load and supply characteristics. TECO is essentially a summer peaking utility and may also have a brief winter peak, (Tr. 2319); that is, it has seasonal load characteristics. (Tr. 2263). Mr. Pollock summarized TECO's characteristics as follows:

- The minimum month peak is consistently below 70% of the annual system peak.
- Monthly peak demands are only 85% of the annual system peak.
- Summer peak demands are 20% (or higher) of the non-summer peak demands.
- With one exception, TECO's annual load factor is at or below 60%.

(Tr. 2263; Exhibit No. 62). Therefore, demands in the spring and fall are not relevant to determining how much capacity TECO needs in order to provide reliable service. (Tr. 2263). Thus, the 12CP method does not reflect cost causation when TECO's load and supply characteristics are analyzed. (Tr. 2264).

Because 12CP also recognizes demand throughout the year, it would be particularly inappropriate to use this method while also classifying both the scrubber and gasifer to energy. In the event that either the gasifier or the scrubber are classified to energy (which is discussed below), the Commission must also reject the 12CP method and use the summer/winter coincident peak method, as Mr. Pollock recommends, to allocate the remaining demand-related production plant costs.

Rather than either reject 12CP or accept TECO's energy cost classifications, the more appropriate action is to "stay the course." The Commission originally adopted the 12CP-1/13 AD methodology to recognize the same economic theory Mr. Ashburn discusses. While the 12CP-1/13 AD methodology allocates some investment beyond the breakeven point, it does so minimally and it recognizes that load duration is a main focus of utility investment. (Tr. 2266-2267).

For all the reasons discussed above, the Commission should reject TECO's proposed 12CP-25% AD methodology and continue to use the 12CP-1/13 AD methodology.

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: Investment and expenses for the Polk Unit 1 gasifier and the environmental costs of the Big Bend Unit scrubber should be classified as demand. The need for power plants is driven by the need to serve peak demand not by energy requirements or environmental issues. Thus, these items should be classified as demand.*

DISCUSSION:

Gasifier

Polk Unit 1 is an integrated gasified combined cycle (IGCC) plant. TECO proposes to classify to energy the gasifier equipment that converts coal into gas used in the power block. This classification should be rejected and the gasifier should be classified to demand.

Power plants are built to produce capacity to serve load and maintain reliability. Plant components are sized to provide capacity. Further, the need for new power plants is dictated by the projected peak demand *not* by annual energy requirements. (Tr. 2254). When the Commission approved the need for Polk Unit 1, it said:

> TECO's reliability criteria will not be met unless the proposed IGCC unit is completed in the time frame requested.
>
> * * *
>
> Thus, the addition of capacity from the proposed IGCC unit is needed for

TECO to maintain acceptable reliability criteria.

Order No. PSC-92-0002-FOF-EI at 4. Thus, the Polk Unit, including the gasifier, was constructed to meet peak demand and should be classified to demand, not energy.

Big Bend Scrubber

Similarly, TECO seeks to classify the Big Bend Scrubber to energy rather than demand. However, there is no reason to classify the scrubber any differently than the rest of the plant. (Tr. 2268).

While Mr. Ashburn is careful in his testimony to note that there is no *engineering* reason that Big Bend could not run without the scrubbers, (Tr. 1700), there is clearly a regulatory reason. (Tr. 1756). The scrubbers were installed to comply with a settlement that TECO entered into with the Environmental Protection Agency and the Florida Department of Environmental Protection. (Tr. 901, 1755). Once installation of the scrubbers is completed, the plants will not be able to run without them. (Tr. 903).

Order No. PSC-04-0986-PAA-EI (emphasis supplied), where the Commission permitted recovery of the scrubbers, explains:

> Tampa Electric Company ("TECO") entered into settlement agreements with the Florida Department of Environmental Protection ("FDEP") and the United States Environmental Protection Agency (EPA) which require TECO to reduce nitrogen oxides ("NOx") emissions at the Big Bend Station. The Big Bend Station is coal fired and NOx emissions are to be reduced by installing pollution control technologies, repowering, or shutting down three of the four units at the station.
>
> *TECO has decided to continue operation of the Big Bend Station using coal, and to install pollution control technologies to meet the NOx air emission limits set out in the settlement agreements.* By Petition filed on July 15, 2004, TECO explained that it will meet the NOx criteria by installing Selective Catalytic Reduction ("SCR") technology at Big Bend Units 1-4, installing pre-SCR technologies at Big Bend Units 1-3, and by installing alkali injection systems at Big Bend Units 1-4.

Mr. Hornick confirmed that the Big Bend Units will not be permitted to operate without the scrubbers. (Tr. 903).

Mr. Pollock testified that environmental requirements are a *prerequisite* to plant operation. (Tr. 2268). Clearly that is the case as to the scrubbers. As Mr. Pollock said:

> a plant could not be legally operated to provide either capacity or energy unless it was in full compliance with all applicable environmental regulations. Thus, environmental concerns do not alter the fundamental reasons that cause electric utilities to install generation capacity: namely, to meet the projected peak demand for electricity and load duration up to the break-even point.

(Tr. 2268). In addition, plant costs related to pollution control are primarily fixed and do not vary with energy usage. (Tr. 2268). Therefore, such costs should not be classified to energy.

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: *Rates for each class should be set at a level that will recover the cost of serving that class. The appropriate cost of service methodology for accomplishing this is the 12CP- 1/13 AD methodology which this Commission has historically used.*

DISCUSSION:

Base revenues should reflect the actual cost of providing service to each customer class as closely as practicable. (Tr. 2277). This Commission has long supported cost-based rates:

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

Order No. PSC-02-0787-FOF-EI at 80.

For the reasons discussed in Issue 83, the 12CP-1/13 AD methodology should be used to determine how to allocate any increase. The results of such an allocation are shown in Exhibit No. 69. The allocation shown in Exhibit No. 69 should be used to spread any revenue increase that is approved in this case. (Tr. 2280).

In contrast, using TECO's proposed 2009 interruptible credit and proposed cost of service methodology, interruptible customers would experience a base rate increase of ***35.5%*** - the second highest base rate increase of any class. (Tr. 2280; Exhibit No. 67). Such a tremendous increase – especially when coupled with the variability of the interruptible credit (see discussion in Issue 87) – is not supported by the appropriate cost of service methodology, violates principles of gradualism, and should be rejected. (Tr. 2280).[27]

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. Interruptible customers are a distinct class as their usage characteristics demonstrate. If the Commission uses a "credit" approach, the interruptible rate schedules should be designed so that interruptible customers receive a stable credit that does not change between rate cases and which properly values interruptible service. Further, the credit should not be recovered from the interruptible class. When an appropriate calculation is made, the value of the credit is $13.70/Kw.*

DISCUSSION:

The Interruptible Rate Schedules Should Not Be Eliminated

The Commission should not eliminate the interruptible rate schedules, which have been in place for decades. Interruptible tariffs are a valuable resource to TECO, its customers, and to the state as a whole. When capacity is needed to serve firm load, interruptible customers may be called upon (without notice and without limitation as to the frequency and duration of

[27] Gradualism is a concept that is applied to prevent a class from receiving an overly-large rate increase.

curtailments) to discontinue service so that firm customers will continue to receive service.

Interruptible power, a lower quality of electrical service, often causes production to be shut down resulting in losses for the interruptible customer. (Tr. 2290). The utility does not have an obligation to serve interruptible customers whenever (and without limit) capacity is needed to maintain service to firm load customers. Non-firm customers therefore relinquish their entitlement to use power and energy upon demand in exchange for a lower rate. (Tr. 2299).

As Mr. Ashburn testified, in a cost of service study, when costs are allocated to the various classes, one objective is to group customers into relatively homogeneous groups so that customers with similar service and usage characteristics are in the same group. (Tr. 1729). The interruptible class of customers is very different from customers who take firm service and the quality of service interruptible customers receive is very different from firm service.

As mentioned, TECO can cut off service to interruptible customers at any time, for any reason with no notice. (Tr. 1731). In addition, not only can the interruptible class be immediately cut off to help TECO serve its firm customers, power to this same class can also be immediately cut off to serve customers of other Florida utilities. TECO's interruptible tariff provides:

> CHARACTER OF SERVICE: The electric energy supplied under this schedule is three phase primary voltage or higher, and is subject to immediate and total interruption whenever any portion of such energy is needed by the utility for the requirements of its firm customers or to comply with requests for emergency power to serve the needs of firm customers of other utilities. Any essential needs the customer must have shall be furnished through a separate meter on a firm rate schedule.

(Tr. 2270). Thus, interruptible customers receive an inferior quality of service in comparison to firm customers, who TECO must be prepared to serve at all times. (Tr. 1730). In essence, interruptible customers receive the lowest quality of service. (Tr. 2321).

It should be noted that lower quality interruptible service is an option an electrical customer can select in exchange for reduced rates. One school in TECO's service territory decided to be placed on an interruptible tariff and receives lower rates. (Tr. 1815). The school superintendent for Hillsborough County schools addressed the Commission at the start of the hearing and asked that the Commission consider ways in which to reduce the electric bills of schools in TECO's service territory. (Tr. 9-36). The Commission should not remove an effective tool to reduce electric bills that at least one school has used successfully.

Importantly, TECO does not plan capacity additions to serve interruptible load. (Tr. 1731, 2270). Thus, the interruptible class, which TECO has had on its system for over 30 years, (Tr. 1732), has in the past permitted TECO to defer the addition of generating capacity, (Tr. 1732), and will continue to do so in the future. Thus, the interruptible class has provided and will continue to provide a benefit to TECO firm ratepayers. (Tr. 1732).

In addition, the usage characteristics of interruptible customers (as discussed in detail in Issue 88) are very distinct. For example, over half of the interruptible class takes service at the subtransmission level, while less than one half of one percent of the GSLD class takes service at subtransmission level service. (Exhibit No. 59).

Finally, policy makers, such as the Federal Energy Regulatory Commission (FERC) have recognized that interruptible power provides "insurance" in the event that a utility experiences extreme weather events, understates load growth, or sustains forced outages of a major resource.[28] (Tr. 2297). Closer to home, the necessity to have interruptible power was demonstrated in September when interruptible customers were curtailed on two consecutive days so that TECO could provide reserves to other parts of the state. (Tr. 2298).

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[28] *See*, *106* FERC ¶61,228 *at 14.*

For these reasons, as well as those discussed in Issue 88, the interruptible rate schedules should not be eliminated. Rather, the Commission should retain the current interruptible schedules and reset the interruptible rate to take into account the increasing value of interruptibility. (Tr. 2293).[29]

The Interruptible Credit Approach

If the Commission prefers the "credit" approach to interruptible service, it must ensure that such a rate design provides rate stability, is properly valued, is properly recovered, and is not reduced by a load adjustment factor.

The Interruptible Credit Must Remain Stable Between Rate Cases

Rate stability[30] is an important consideration in the design of interruptible rates for several reasons. The Commission should recognize that interruptible power is not cost free for the participating customer. It may require substantial investment in equipment and modifications to manufacturing operations, the cost of which interruptible customers expect to recover over a period of time through lower rates. Significant changes in interruptible rates that reduce a customer's expected savings are inequitable to existing customers as a matter of policy, because such changes increase the risk that the expected benefits will not outweigh the costs. (Tr. 2291).

TECO's approach to the credit subjects interruptible customers to rate instability because their base rates would change between rate cases. (Tr. 2285, 2292). This is in stark contrast to all other customers – for other customers, once base rates are set, they are not changed until the next rate case. (Tr. 2292). As Mr. Ashburn admitted, firm customers will generally know what their base rates are and that they are going to remain fixed between rate cases. (Tr. 1757); in

[29] Such interruptible rates should reflect the fact that the cost of new generation capacity has significantly increased. (Tr. 2288).
[30] Mr. Ashburn testified that rate stability is an important element of rate design. (Tr. 1756).

contrast, interruptible customers will see the credit, and hence their base rates, fluctuate between rate cases. (Tr. 1758-1759). Mr. Ashburn also testified that, this credit fluctuation will interfere with the ability of interruptible customers to predict what they will pay in any given time frame. (Tr. 1760). Finally, if TECO waits sixteen years to file another rate case, firm customers base rates will remain the same, while interruptible customers' rates could change 16 times. (Tr. 1761). To avoid the problem of rate instability, the Commission should lock in the credit and not permit it to fluctuate between rate cases.

Calculation of the Credit Amount

As described above, interruptible serve has and continues to provide great benefit to TECO, its ratepayers and the other utilities in the state. Since it represents a lower quality of service, which often requires substantial customer investment while exposing interruptible customers to substantial risk, the value of the credit provided to interruptible customers must be appropriate.

TECO has calculated the interruptible credit at $10.91 per coincident peak (CP) kW. This value is understated for two reasons. First, as Mr. Ashburn admits, the credit is based on avoiding a 2012 combustion turbine. (Tr. 1763). Therefore, the credit does not assign any value for plant that is avoided from 2009 through 2011. (Tr. 1764). That is, the analysis assumes zero avoided generation capacity benefits for 2008 through 2011, despite the fact that TECO has interruptible load on its system during that period of time. (Tr. 2295). First, it is unreasonable to assign a zero value to deferred generation capacity in 2008-2011. The existence of interruptible customers has enabled TECO to avoid building generation and without it, TECO would have had to build more generation on its system. (Tr. 2295). TECO's analysis understates the value of the credit by ignoring these capacity benefits. (Tr. 2295).

Second, the analysis is based on the net present value of the costs and benefits of interruptible power using 2008 as the base year. Because 2008 was used as the base year, the costs and benefits in 2009 were discounted. The credit is supposed to be in effect in 2009. Therefore, 2009 should be used as the base year, rather than 2008, and the corresponding 2009 costs and benefits should not be discounted by one year. (Tr. 2295).

Making these two logical changes results in a credit of $13.70/kW. (Exhibit No. 73). This is the appropriate value for the credit for interruptible customers. (Tr. 2296).

TECO asserts that the GSLM-2 and GSLM-3 credits are not at issue in this case because the Commission previously addressed the credits in Docket No. 080002-EG. (Tr. 1711-1712). However, at the time the credits were approved, they were not applicable to either interruptible or standby customers. They applied only to customers taking service on other rates.. The issue of whether Rider GSLM-2 would apply to interruptible customers and GSLM-3 to stand by customers was first raised in this base rate case.

A base rate case is a proceeding where the Commission has the latitude to determine appropriate rate designs after considering cost-of-service, customer impacts, and rate administration. For these reasons, it would be patently unfair and unreasonable to not consider appropriate changes to the GSLM-2/GSLM-3 riders in this case, if the Commission is inclined to subject IS and SBI customers to these riders for the very first time.

Recovery of the Interruptible Credit

TECO proposes to recover the cost of the credit through the Environmental Cost Recovery Clause and to allocate to customers a portion of the cost for the credit they are to receive. This approach should be rejected.

As discussed above, TECO does not install generating capacity or purchase firm power to provide interruptible service. (Tr. 1731). Payments to interruptible customers represent the value of the capacity not built or acquired to serve interruptible load. In other words, costs for generating capacity or firm power are caused by and thus should be allocated to firm customers. (Tr. 2286). These payments cannot be caused by interruptible customers because they are the ones providing the interruptible capacity. Therefore, such payments should not be allocated to interruptible customers. (Tr. 2274).

<u>A Load Factor Adjustment is Inappropriate</u>

Finally, even assuming that TECO's calculation of \$10.91/kW is correct, TECO proposes to reduce this amount in proportion to the customer's billing load factor. The credit would then be further reduced by any applicable metering voltage discount. For the reasons described in Mr. Pollock's testimony, TECO's proposed load factor adjustment should be rejected.

First, TECO's proposal uses a customer's billing load factor as a proxy for the customer's coincidence factor. This makes the unsubstantiated assumption that there is a linear relationship between load factor and coincidence factor. TECO has provided no evidence of such a linear relationship. (Tr. 2300).

Second, even if such a relationship could be demonstrated, since the amount of interruptible load is based on the average 12CP demand of the interruptible class, the adjustment should be made relative to the class average load factor or 96%. (Tr. 2300).

The definition of coincidence factor is the ratio of the customer's coincident peak demand (that is, the demand coincident with the one-hour monthly system peak) to the customer's non-coincident peak demand. The load factor adjustment erroneously implies that the amount of interruptible load is strictly a function of the demand coincident with TECO's one-hour monthly system peak. However, interruptions can occur at any time, not just coincident with the system peak or with the on-peak hours. For example, a customer could be planning to operate at its maximum demand but be unable to do so because of a curtailment. If this same customer only operated at a 50% load factor during the month, it would only get credit for half of the interruptible capacity that is provided to TECO. (Tr. 2300).

If a customer's load factor is sufficiently low in a given month, TECO's proposed adjustment could effectively cause the customer to pay a firm rate for an interruptible service of lower quality. This result could cause interruptible customers to reduce their operations in TECO's service territory or to relocate those operations to other parts of the country. (Tr. 2300).

TECO's load factor adjustment should be rejected and the credit should reasonably measure the amount of load that TECO is not obligated to serve during an interruption event. When an interruption event occurs, an interruptible customer's operating demand may immediately be reduced to zero. However, reducing existing operating demand to zero is not the only benefit of an interruption. In lieu of an interruption, a customer may have anticipated operating at a higher level of demand. The fact that the customer was prevented from imposing a higher level of demand on TECO's power supply system during an interruption period provides a benefit to the system and to TECO.

To measure this benefit, the amount of interruptible demand subject to credit should be determined by establishing each customer's normal operating demand for a defined "base line" period. This is the approach used by the Southwestern Public Service Company (SPS). (See Tr. 2301-2302). Thus, load factor is not used as a proxy for the amount of interruptible load. (Tr. 2301-2302).[31]

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[31] Another alternative would be to directly measure the amount of interruptible demand in real-time. This would require establishing a "normal" operating demand from a past period, such as on the day, week, or month that curtailments occur (excluding the curtailment periods). However, the SPS method is easier to administer. Alternatively, each customer should receive the same credit per kW of billing demand. (Tr. 2302).

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

POSITION: *No. Customer classes should be homogeneous in their usage patterns and service characteristics. The GS, GSD, GSLD and IS classes are not homogeneous in key characteristics, including size, load factor, coincidence factor and delivery voltage. Therefore, they should not be combined because to do so would put customers with very different characteristics in the same class.*

DISCUSSION:

As discussed earlier, customer classes should be homogeneous and grouped according to similar usage patterns and service characteristics. (Tr. 2251). The characteristics of the GS, GSD, GSLD and IS classes are very different[32] and should not be combined. TECO witness Ashburn admits that there are significant differences among these classes. (Tr. 1744).

The company's own load research report (Exhibit No.113) demonstrates significant differences among the classes. For example, the load research report indicates a substantial difference between the amount of energy the interruptible class consumes and the amount of energy the GSD class consumes. (Tr. 1747; Exhibit No. 113 at 22). There is a large kWh difference between average monthly energy usage of the interruptible class customers and the GSD class customers. (Tr. 1747; Exhibit No. 113 at 23). And, there is a difference as to coincident peak load factors between the interruptible class and the GSD class. (Tr. 1748; Exhibit No. 113 at 24).

In addition, Mr. Pollock provided Exhibit No. 59 which analyzes the key characteristics of the customers in each of these classes. They are summarized in the chart below:

[32] There is no connection between pricing interruptible service as TECO proposes and consolidation of the classes. (Tr. 2251).

Description	GSD	GSLD	IS
Size:			
kW per Customer	1,051	22,865	52,746
kWh per Customer	380,000	11,468,000	24,898,000
Coincident Load Factor	68.6%	79.5%	95.6%
Coincidence Factor	71.8%	86.5%	67.6%
Percent of Sales at:			
Secondary	98%	54.4%	0%
Primary	2%	45.2%	46%
Sub-transmission	0%	0.4%	54%

(Tr. 2252). This chart also demonstrates significant differences among the classes. Of critical concern is the significance of the difference in coincident load factor.[33] Coincident demand is the primary basis upon which production, transmission and distribution costs are allocated among the customer classes. (Tr. 2252). Because these classes have very different coincident demand, as the chart above illustrates, combining the classes would create inappropriate class subsidies. (Tr. 2253).

Additionally, the interruptible class is much larger than the GSD or GSLD classes. Interruptible customers take a preponderance of service at sub-transmission voltage, whereas virtually no electricity is provided to GSD or GSLD customers at this high voltage level. (Exhibit No. 59). And, interruptible customers have much higher coincident load factors than GSD or GSLD customers. The higher coincident load factor means that more energy is purchased during off-peak hours. Finally, applying the GSLD rates to the interruptible class will result in the interruptible class earning a much higher rate of return than the GSLD class. (Exhibit No. 64).

[33] Coincidence factor is the ratio of coincident demand to billing demand. It measures how much of a customer's peak demand occurs coincident with the system peak. (Tr. 2252).

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. This rate is not cost-based.*

DISCUSSION:

TECO has proposed that the Commission approve an inverted residential rate. This rate should not be approved for several reasons. First, it appears that the actual basis for this rate request is simply the fact that other utilities have such a rate. (Tr. 1662).

Second, it does not appear that the rate is cost based. As Mr. Ashburn described in his deposition (Exhibit No. 13, #60 at 89), once the cost of service study was done, a "mathematical formula" was applied to the cost-based flat rate to create the inverted rate. Thus, the rate in the cost of service study was subsequently adjusted to arrive at the inverted rate. Therefore, it cannot be based on cost and its approval would violate long-held cost of service principles.

Third, the proposed inverted rate appears to be intended to be a "conservation rate," regardless of what the company calls it. As Mr. Ashburn described it: "It's [the inverted rate] intended to give them [customers] appropriate price signals and we're hoping they have a conservation response to it, and therefore, perhaps use less energy at the higher end." The company hopes this will lead to reduced consumption. (Tr. 1766). This type of rate structure may well lead the company to come back to the Commission for further rate relief. (Tr. 1767).

Fourth, as Mr. Ashburn also admitted, though TECO used 1000 kWh in describing the impact to its customers (Exhibit No. 114), 1000 kWh is not a typical residential bill. (Tr. 1767). Not only will most customers' bills increase by more than 8% if TECO's rate request is granted because 1000 kWh is not the typical usage, the 8% increase number fails to account for fuel adjustment increases, gross receipts tax, city utility tax or franchise fees. (Tr. 1878-1788). The use of the inverted rate example may allow TECO to suggest that the rate increase it has requested will be only 8%, where that is generally not the case.

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 position.*

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 position.*

ISSUE 96: Is the proposed new meter tampering charge appropriate?

POSITION: *No position.*

ISSUE 97: Is the proposed new $5 minimum late payment charge appropriate?

POSITION: *No position.*

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

POSITION: *No position.*

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: *The appropriate demand charges are set out in Mr. Pollock's Exhibit No. 70 and recover demand – related costs through the demand charge.*

DISCUSSION:

TECO has underpriced the demand charge and overpriced the energy charge (based on TECO's proposed revenue levels), and thus its charges are inconsistent with accepted principles of cost-causation. TECO's demand-related costs should be recovered through the demand charge, and energy-related base rate costs should be collected through the energy charge. The demand and non-fuel energy charges should closely reflect the corresponding demand and non-fuel energy related costs as derived in Mr. Pollock's class cost-of-service study. (Exhibit No. 70). If the Commission approves a smaller rate increase for the interruptible class than TECO has proposed, the demand charges should be reduced accordingly.

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. TECO has understated the credit as it has failed to recognize all of the costs that are avoided when a customer takes subtransmission level service.*

DISCUSSION:

Subtransmission customers take service at 69 kV, subtransmission voltage. (Tr. 1733). TECO proposes that customers who receive service at the subtransmission level receive a discount of less than the full 100% of the cost of providing primary and secondary distribution service. (*See*, Exhibit No. 118, MFR No. E-14.)

This proposal understates the discount because it fails to recognize that the subtransmission customers allow TECO to avoid the cost of having to install a transformer, distribution lines, poles, and other facilities to serve those customers. Subtransmission customers have their own step down transformers as well as distribution system to accept the power at this level. (Tr. 1733 - 1734).

Mr. Ashburn admitted that in his cost of service study, the load of customers served at the subtransmission level was excluded from the allocation of primary and secondary distribution plant. (Tr. 1734-1735). Thus, the transformer discounts are inconsistent with the cost of service study and should be modified to reflect the totality of all costs avoided by these customers so that they are appropriately compensated.

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

POSITION: *TECO has understated the credit as it has failed to recognize all of the costs that are avoided when a customer takes subtransmission level service. The discounts should be modified should be modified to reflect the totality of all costs avoided by these customers so that they are appropriately compensated.*

DISCUSSION:

See discussion in Issue 103.

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: *The appropriate non-fuel energy charges are set out in Mr. Pollock's Exhibit No. 70.*

DISCUSSION:

TECO has underpriced the demand charge and overpriced the energy charge (based on TECO's proposed revenue levels), and thus its charges are inconsistent with accepted principles of cost-causation. TECO's demand-related costs should be recovered through the demand charge, and energy-related base rate costs should be collected through the energy charge. The demand and non-fuel energy charges should closely reflect the corresponding demand and non-fuel energy related costs as derived in Mr. Pollock's class cost-of-service study. (Exhibit No. 70).

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: *Changes in allocation and rate design made in this docket should be reflected in the clause recovery dockets.*

ISSUE 109: What are the appropriate monthly rental factors 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. TECO already has four separate cost recovery clauses and there is no need to add an additional clause which will enhance TECO's ability to change rates outside of a rate case. Transmission investment does not meet any of the criteria for a recovery clause – it is not material, volatile or beyond TECO's control. Thus, an additional recovery clause is inappropriate and should not be approved.*

DISCUSSION:

TECO seeks the Commission's approval to implement a fifth cost recovery clause – the Transmission Base Rate Adjustment Clause (TBRA). TECO contends that the purpose of the clause is to allow it to recover costs for 230 kV and above transmission projects that are submitted to the Florida Reliability Coordinating Council (FRCC) for review. (Tr. 1448). It appears to be TECO's claim that because the FRCC reviews regional transmission planning documents and because the Federal Energy Regulatory Commission (FERC) has developed a cost allocation methodology, TECO might have to incur transmission expansion costs.

As a preliminary matter, it should be noted that TECO already has four cost recovery clauses in place through which it collects over 54% of its revenue. (Tr. 2304). The addition of a fifth recovery clause is unnecessary, not supported by the evidence, and would exacerbate the current bias toward cost recovery clauses. (Tr. 2305).

In addition, the TBRA would allow TECO to raise rates to reflect changes in certain costs, while ignoring changes in other costs, (Tr. 2305), as well ignoring increases in revenue from sales. Even assuming, for the sake of argument, that TECO may have increased costs due to transmission expenditures, collection of those costs between rate cases does not take into account areas where costs may have decreased. Nor does it consider sales growth. Decreased costs and/or sales growth may offset transmission expenditures. Because the TBRA looks at expenses only, in isolation from other issues, it should not be approved.

For costs to be recovered outside a rate case, they should be material, volatile and beyond the utility's control. (Tr. 2294). Transmission investment meets none of these criteria.

As to materiality, TECO projects $68.1 million of transmission plant additions in 2009. This is less than 2% of TECO's rate base and thus is not material. (Tr. 2305). Furthermore, transmission costs are not volatile. Transmission represents fixed investment which does not vary over time. (Tr. 2305). Further, transmission facilities are planned years in advance and take years to construct. (Tr. 2008). If base rates are not sufficient to support the construction of needed transmission facilities, TECO has ample time and opportunity to file a rate case to incorporate such construction. (Tr. 2008). As Mr. Larkin testified: "There is no need for an automatic adjustment clause since the time frame in determining the need and construction of any facilities allows the utility ample time to request changes in base rates, if necessary." (Tr. 2008).

Finally, the costs for transmission facilities are clearly within TECO's control. The FRCC is an organization of utilities, including TECO. TECO is a member of the transmission planning subcommittee of the FRCC. (Exhibit No. 13, #63, Haines deposition at 35). But most importantly, the FRCC cannot direct TECO as to what transmission facilities to build. (Tr.

2005). Before TECO can build transmission facilities, it must seek a determination of need from this Commission. (Exhibit No. 13, #63, Haines at deposition at 36). *See,* section 403.537, Florida Statutes. It must also seek siting approval from the Department of Environmental Protection and the Governor and Cabinet sitting as the Siting Board for transmission lines over 230 Kv. *See*, sections 403.502-.539, Florida Statutes.

In support of its request, TECO relies upon two dockets that simply are inapposite to this case. TECO witness Chronister claims the TBRA is similar to the Generation Base Rate Adjustment approved in Docket No. 050045-EI and Docket No. 050078-EI. (Tr. 448). However, examination of this claim reveals that it is without merit as both dockets involved settlements as well as other pertinent provisions not at issue in this case. There is a large difference between a time-limited settlement and a new, on-going adjustment clause.

Docket No. 050045-EI was Florida Power and Light Company's 2005 rate case. That case was settled via a stipulation and settlement which the Commission approved. *See*, Order No. PSC-05-0902-S-EI. The stipulation resulted in the following: FPL's retail base rates and base rate structure were frozen for four years; no petition for any new surcharges to recover costs traditionally recovered in base rates was permitted; a revenue sharing plan between FPL and its customers above a threshold level was put in place as well as other terms and conditions. No such stipulations or agreements are at issue in this docket. (Tr. 1582-1583).

Similarly, Docket No. 050078-EI, involved Progress Energy Florida's 2005 rate case. In Order No. PSC-05-0945-S-EI, the Commission approved a stipulation and settlement between the parties. The stipulation froze Progress' base rates for four years, included a revenue sharing plan between the company and customers, and applied the generation adjustment only to the Hines plant.

This case has not been settled. The reliance by TECO on two settlement stipulations, which inherently involve negotiations and give and take, is misplaced.

Therefore, the two dockets upon which TECO attempts to rely to support the TBRA are simply inapposite. The TBRA TECO seeks 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?

POSITION: *Yes.*

ISSUE 114: Should this docket be closed?

POSITION: *Not at this time. Tampa Electric should be required to file the necessary tariffs to conform to the Commission's decision in this docket.*

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Late-Filed Exhibit #123

Return on Equity vs. Reduced Interest Costs

("Bang for the Buck")

	Return on Equity Percentage		
	12%	10%	8%
Cost to ratepayers[1]	$360 million	$300 million	$240 million
Savings to ratepayers	0	$60 million	$120 million

Assume $250 million[2] to be financed	Financing Costs Differential
Rate Spread of ½% between A & BBB	$1.25 million
Rate Spread of 1% between A & BBB[3]	$2.5 million
Rate Spread of 2% between A & BBB	$5 million

[1]TECO witness Gillette confirmed each percentage point of return on equity represents an additional $30 million in rates charged to consumers. (Tr. 365).

[2]TECO witness Gillette testified that the amount to be financed by TECO for 2009 was $125 million (Tr. p. 441) and the amount to be financed for 2010 was $125 million. (Tr. 442).

[3]TECO witness Abbott testified that the spread between A rated bonds and BBB rated bonds is 1%. (Tr. 620).

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true and correct copy of the foregoing FIPUG Post-Hearing Statement of Issues and Positions and Post-Hearing Brief has been furnished by (*) hand delivery or U.S. Mail this 17th day of February, 2009 to the following:

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