BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for Rate Increase by Tampa Electric Company	DOCKET NO. 080317-EI Filed: November 26, 2008

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DIRECT TESTIMONY AND EXHIBITS OF JEFFRY POLLOCK

ON BEHALF OF THE FLORIDA INDUSTRIAL POWER USERS GROUP AND THE MOSAIC COMPANY

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1. INTRODUCTION, QUALIFICATIONS, AND PURPOSE

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Jeffry Pollock; 12655 Olive Blvd., Suite 335, St. Louis, MO 63141.

Q WHAT IS YOUR OCCUPATION AND BY WHO ARE YOU EMPLOYED?

A I am an energy advisor and President of J. Pollock, Incorporated.

Q PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A I have a Bachelor of Science Degree in Electrical Engineering and a Masters in Business Administration from Washington University. Since graduation in 1975, I have been engaged in a variety of consulting assignments, including energy procurement and regulatory matters in both the United States and several Canadian provinces. I have participated in regulatory matters before this Commission since 1976. More details are provided in Appendix A to this testimony.

Q ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?

A I am testifying on behalf of the Florida Industrial Power Users Group (FIPUG) and The Mosaic Company (Mosaic).[1]

Q WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A I am testifying on TECO's proposed revenue requirements, retail class cost-of-service study, class revenue allocation, firm and non-firm rate design, and the Transmission Base Rate Adjustment (TBRA).

Q ARE YOU SPONSORING ANY EXHIBITS?

A Yes. I am sponsoring **Exhibits ___(JP-1)** through **___(JP-19)**. Many of these exhibits are based on TECO's claimed revenue requirements in this proceeding.

As such, they are for illustrative purposes only and should not be interpreted as an endorsement of TECO's proposed base rate increase.

Summary

Q PLEASE SUMMARIZE YOUR RECOMMENDATIONS.

A My recommendations are as follows:

- Reductions of $17.5 million to TECO's claim base rate revenue increase, which remove, abnormally high expenses for plant outages, to provide for a five-year amortization of actually incurred (rather than projected) rate case expenses, and exclude incentive compensation tied to achieving certain financial goals because it benefits shareholders and not TECO ratepayers;
- Revisions to TECO's class cost-of-service study that maintains the current homogeneous (GSLD and IS) customer classes, more appropriately classifies the Big Bend scrubber and Polk gasifier costs to demand, rejects the 12CP-25% AD method (which has never been approved by this Commission), applies the Commission-approved 12CP-1/13th AD method of allocation, and treats interruptible customers as firm for both pricing and costing purposes;
- A revised class revenue allocation that follows the revised class cost-of-service study and moves all rates to cost (*i.e.*, parity) while moving the lighting facilities class closer to cost;
- A firm rate design where demand and energy-related costs are recovered in demand and energy charges, respectively, and appropriate credits are provided to customers taking service at higher voltages;

- An interruptible rate design that will provide greater stability, more properly reflect the value of interruptibility, which is a cost that should be borne by firm customers, and fairly compensate interruptible customers; and
- Rejection of fifth piecemeal cost recovery clause, the Transmission Base Rate Adjustment factor, which is not needed, would unnecessarily shift risk to ratepayers and allow TECO to over-recover certain transmission rate base additions.

2. REVENUE REQUIREMENTS

Q WHAT REVENUE REQUIREMENT ISSUES ARE YOU ADDRESSING?

A I am addressing TECO's proposed test year production operation and maintenance (O&M) expenses related to scheduled outages, rate case expenses, and incentive compensation.

Q DOES THE FACT THAT YOU DO NOT DISCUSS ALL OF TECO'S REVENUE REQUESTS MEAN THAT YOU ENDORSE THE OTHER REQUESTS TECO HAS MADE?

A No. Based on the volume of material filed, as well as time constraints, I will only comment on selected revenue issues. I am sure that other parties will discuss additional revenue issues. The fact that I do not discuss such issues in my testimony does not mean that FIPUG and Mosaic endorse or support the other revenue requests TECO has made.

Q WHAT IS THE TEST YEAR THAT TECO PROPOSES TO USE FOR PURPOSES OF SETTING RATES?

A TECO is proposing to use a forecasted test year, using projected sales, revenues and expenses for 2009. In doing so TECO is apparently seeking to match rates to the time frame when those rates will be in effect.

Q EXPLAIN THE CONCEPT OF THE TEST YEAR.

A A test year is a period of time used to measure the utility's revenues and expenses for the purpose of setting base rates. In order to set rates that provide the utility a reasonable opportunity to earn a reasonable return on its used and useful investments, a test year must be representative; that is, the revenue requirements (which consist of a return on rate base plus operating expenses) should be set using sales, revenues, expenses and net investments that reflect the conditions expected to exist during the period when new base rates are in effect. Thus, non-recurring and other atypical costs should be removed.

Q IS TECO PROJECTING A CONTINUATION OF THE GROWTH IN SALES THAT HAS OCCURRED IN THE MOST RECENT 10-YEAR PERIOD?

A No. In the short run, 2008 and 2009, TECO is projecting sales increases. However, the increase in test year sales is below the TECO's projected average 2008-2017 sales growth.[2] Specifically, projected growth in total sales for 2008 is approximately 0.8% and for 2009 growth is approximately 1.5% -- both below the projected 2% average used for the remainder of the time period.

Q DOES THE SLOWER PROJECTED GROWTH RAISE ANY CONCERNS?

A Yes. Base rates reflect a utility's test year costs divided by test year sales. The higher the costs (*i.e.,* the numerator) and/or the lower the sales (*i.e.,* the denominator), the higher the rate. All things being equal, the higher rate will provide the utility the opportunity to cover increased costs and provide increased returns to shareholders. Given that TECO is forecasting a slower growth in sales – particularly in the Test Year – and higher O&M expenses, the Commission should thoroughly "scrub" the filing and remove unnecessary and unreasonable costs.

Q. WHAT GROWTH RATE HAS TECO USED TO DETERMINE WHAT GENERATION AND PLANT IT NEEDS?

A TECO has procured generation capacity and added plant in service in anticipation of continued 2% per year sales growth. This includes the addition of five new combustion turbine (CT) units in the test year, totaling 285 MW. With slower sales growth, the proposed base rates will be higher. All other things being equal, the resumption of normal sales growth would result in lower per unit costs. This would allow TECO to absorb higher base rate costs, such as additional transmission investment, without the need for additional rate relief, as discussed later in this testimony.

Scheduled Outages

Q **HAVE YOU REVIEWED THE O&M EXPENSES FOR SCHEDULED PRODUCTION PLANT OUTAGES?**

A Yes. As part of my review of TECO's projected test year O&M expenses, I have determined that these expenses are overstated because they reflect an abnormal number of scheduled (or planned) outages. Thus, I recommend that test year O&M expenses be adjusted to reflect a more normal level of scheduled outages.

Q **WHAT DID YOUR REVIEW OF PLANT OUTAGES REVEAL?**

A TECO is projecting the highest number of scheduled outages in 2009 than in any other year since 2003. TECO's projections are provided in **Exhibit __(JP-1)**. Specifically, the planned outages at Big Bend Station are shown on page 1, while total planned outages are shown on page 2. As can be seen on page 1, TECO projects the duration of planned Big Bend outages to increase from 22.5 weeks in 2008 to 32 weeks in 2009, a more 30% increase. Overall plant outages would increase from 43 weeks in 2008 to 54 weeks in 2009 (page 2).

Q **WOULD YOU CHARACTERIZE THE TEST YEAR OUTAGES AS NON-RECURRING?**

A Yes. The last time two major Big Bend outages occurred in the same year was in 2006 when Units 1 and 3 were both down for major inspection outages.[3] In 2009, there are three outages. Two of the three 2009 scheduled outages are to install selective catalytic refiners (SCR) at Units 1 and 2.[4] TECO has also scheduled a maintenance overhaul of most of the operating equipment and boiler of Unit 4.[5] Further, the SCR-related outages are non-recurring. As TECO witness, Mr. Hornick, points out, the Company's settlement with the

Environmental Protection Agency and the Florida Department of Environmental Protection require that these alterations be in place by 2010[6].

Q DID TECO ORIGNALLY PLAN FOR TWO MAJOR BIG BEND OUTAGES IN 2009?

A No. **Exhibit ___(JP-2)** is a document provided in discovery that shows the planned outages for Big Bend for the period 2007-2013. The document shows that the Company originally planned only one major outage per year at Big Bend through 2013.

Q IS THERE ANY RELATIONSHIP BETWEEN THE NUMBER OF PLANNED OUTAGES AND THE COSTS ASSOCIATED WITH THESE OUTAGES?

A Yes. **Exhibit __(JP-3)** shows the outage costs for the period 2003-2009. As can be seen, TECO incurs higher costs in those years when more outages occur. This is particularly evident when comparing the test year to prior years. For example, in 2008, there were 43 outage weeks that resulted in $13.7 million of O&M expenses. This compares to 54 outage weeks at a projected cost of $20.2 million for the test year. The projected increase can be attributed to Big Bend.

Q SHOULD AN ADJUSTMENT BE MADE TO TEST YEAR O&M EXPENSE?

A Yes. The test year should be representative of normal circumstances. Using past history and TECO's planning document as a guide, it is simply not normal to have multiple major outages at the Big Bend Plant. For that reason, I recommend that Test Year O&M expenses be adjusted to reflect normal maintenance outage levels in terms of costs.

The recommended adjustment is quantified in **Exhibit __ (JP-3).** Specifically, TECO has incurred or budgeted for an average of $12.2 million per year in outage-related expenses over the period 2003 – 2009. Thus, TECO should be allowed $12.2 million for planned outages during the test year and

TECO's proposed expense should be reduced by $8 million.

Rate Case Expenses

Q HOW DOES TECO PROPOSE TO RECOVER RATE CASE EXPENSE?

A TECO proposes to recover $3.15 million in rate case expenses amortized over three years.

Q DO YOU HAVE ANY RECOMMENDATIONS WITH REGARD TO TECO'S PROPOSED RECOVERY OF RATE CASE EXPENSE?

A Yes. I have two recommendations. First, rather than including a projection of what the expense will be, upon completion of the proceeding, and as part of the compliance filing, TECO should be required to provide actual rate case expenditures, with the actual expenditures being used to set the level of rate case expense to be recovered from customers. Second, the amortization period for rate case expenses should be at least five years rather than the three years TECO requests.

Q WHY DO YOU RECOMMEND A LONGER AMORTIZATION PERIOD FOR RATE CASE EXPENSE?

A TECO's last rate case was in 1992. There is no indication when TECO will file its next case following this case. Since 1992 TECO has begun to use cost recovery clauses to recover carrying costs for items that would normally fall in base rates. The most significant is the costs related to environmental capital expenditures. As discussed later, TECO is proposing to shift $22 million from base rates to the conservation clause by terminating Schedules IS and SBI. If history is any guide, there will be an extended period of time between this rate case and TECO's next rate case. A longer amortization period is much more in line with TECO's rate case history. Adjusting the amortization period from three to five years would reduce TECO's revenue requirement by $420,000.

Incentive Compensation

Q HAVE YOU REVIEWED THE TEST YEAR EXPENSES FOR INCENTIVE COMPENSATION?

A Yes.

Q. ARE THERE PORTIONS OF THE REQUEST THAT RAISE AN ISSUE?

A Yes. A portion of TECO's total compensation is tied directly to the financial performance of the operating company and the parent company. The issue is whether compensation tied to financial performance should be included as an expense for ratemaking purposes.

Q SHOULD INCENTIVE COMPENSATION THAT IS TIED TO FINANCIAL PERFORMANCE BE ALLOWED IN RATES?

A No. Incentive compensation that is contingent upon the parent and/or operating company achieving certain financial goals, such as net income, cash flow, or other (stand-alone or comparative) measures, is beneficial to shareholders but not of direct benefit to ratepayers. For this reason, incentives to achieve financial goals are appropriately borne by shareholders not ratepayers.

Q WHAT FINANCIALLY-BASED PERFORMANCE INCENTIVES ARE REFLECTED IN TECO'S TEST YEAR EXPENSES?

A TECO witness Merrill describes two components of TECO's annual pay program. First, there is an annual merit increase which is predicated upon individual performance and overall salary position relative to the market.[7] The second component of the annual pay program is the "variable incentive pay program known as 'Success Sharing'. It provides an annual one-time payment based on the achievements of the team member and company against pre-established goals".[8] TECO has included the expected payouts under the Success Sharing Plan in the gross payroll reflected on Schedule C-31. Incentive compensation is not separately broken down in the filing or the Company's Testimony.

Q **WHAT IS YOUR UNDERSTANDING OF THE SUCCESS SHARING PLAN?**

A There are three levels of participation – Officers, Key Employees and General Employees. Under the Officer Short Term Incentive portion of the plan, goals are established at the corporate, operating and individual levels and payout is based on level of achievement. However, "the payout to all participants is zero if TECO Energy's income threshold set for that year by the Compensation Committee is not achieved." [9]

The Key Employee Short-Term Annual Incentive Plan is administered "virtually identical to the incentive plan for officers" with goals based 50% on financial and 50% on individual.

The general employee short term incentive program is available to all non-officer/key employees and is based upon five non-financial goals and two financial goals, cash flow and net income. The maximum payout under the plan is 12% of either the higher of the employee's total earnings or the job market value for the calendar year.[10]

Finally, there is a separate officer/key employee long-term incentive program which awards shares to employees. There are two classes of awards, performance restricted shares, for which total shareholder return must exceed the bottom quartile of a group of peer companies for there to be any award, and a time-restricted award, for which the officer/key employee must remain with the company for a given period of time.

Q **HAS TECO PAID ITS EXECUTIVES AND OTHER EMPLOYEES INCENTIVE COMPENSATION IN THE PAST?**

A Yes. **Exhibit ___(JP-4)** is a copy of TECO's Response to OPC's Third Set of Interrogatories No. 29. It shows that TECO has paid Incentive Compensation in each year since 2003. In all but 2003, employees received payments in excess of the targeted level of incentive compensation. The most recent actual payment made was for 2007, in which employees received $12.9 million in incentive compensation.

Q **HAVE YOU BEEN ABLE TO DETERMINE WHAT INCENTIVE COMPENSATION WAS RECEIVED BY ANY OF THE OFFICERS OF TECO DURING 2007?**

A No. However, published information reveals that two TECO officers, the President and CFO, received approximately $1.5 million in incentive compensation including stock awards worth approximately $810,000 and non-equity incentive payments of approximately $690,000 for 2007[11].

Q **WHAT IS TECO'S JUSTIFICATION FOR SEEKING RECOVERY OF 100% OF THE INCENTIVE COMPENSATION FROM RATEPAYERS?**

A According to TECO witness Merrill, the purpose of the Success Sharing Plan is "to attract, retain and motivate high performing goal-oriented team members." However, as explained above, the portion of the compensation to executives and key employees is predicated upon the corporate parent, TECO Energy attaining certain financial goals. Further, even the general plan for all non-executive/key employees rewards the individuals predicated upon financial goals of not only the operating company (TECO) but also is upon certain financial goals for the parent company, TECO Energy.[12] In current economic times, when executive compensation has come under great scrutiny and criticism, this Commission must ensure that all compensation is directly related to enhancing the value ratepayers receive and is not a windfall for executives.

Q HAVE OTHER JURISDICTIONS DISALLOWED INCENTIVE COMPENSATION TIED TO FINANCIAL PERFORMANCE?

A Yes. Texas, a jurisdiction in which I have testified with regularity, has disallowed the portion of incentive compensation tied to corporate financial objectives.[13] Specifically, in the AEP Texas Central rate case, 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, pointing out that the incentive compensation was predicated on both financial and operational objectives.[14] In addressing the issue of inclusion in rates, the PFD addressed the issue as follows:

> With regard to the measures themselves, the Financial Measures are of more immediate benefit to shareholders and less so to ratepayers. Conversely, the Operating Measures are of more immediate benefit to ratepayers and less so to shareholders. The question is whether these various interests satisfy the regulatory scheme by which expenses may be included as part of a proposed rate change. By statute, the Commission may not consider for ratemaking purposes an "expenditure, including an executive salary, . . . [that the Commission] finds to be unreasonable, unnecessary, or not in the public interest." By rule, the Commission has interpreted the "public interest" requirement to mean that an expense is "reasonable and necessary *to provide service to the public*."[15]

The PFD went on to conclude that the operational goals and related incentive compensation were reasonable and necessary expenses in the setting of rates:

> The Applicant makes a plausible case for including in the cost of service the 34% portion of the incentive expense that is related to Operational Measures. By their very nature, Operational Measures reflect goals that relate to the public interest. Indeed, many are required to be considered as independent issues in this proceeding. Although the Operational Measures relate to AEP as a corporate holding company rather than to the Applicant, the Applicant shares in those Operational Measures on an allocated basis. The ALJs find that the goals of the Operational Measures are in the public interest and reasonable and necessary to provide service to the public.[16]

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.
>
> Incentives to achieve operational measures are necessary and reasonable to provide T&D utility services, but those to achieve financial measures are not.[17]

The Commission approved recovery of 34% of $4.4 million in requested incentive compensation, with $2.8 million being disallowed.[18]

Likewise, 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.[19] 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 rate payer 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 rate payers. 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 rate payers 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.[20]

Q SPECIFICALLY WHAT EXPENSES SHOULD BE DISALLOWED FOR RATEMAKING PURPOSES?

A TECO's Response to OPC's Third Set of Interrogatories No. 31, indicates that Performance Restricted Shares are awarded based on TECO Energy total shareholder return. No factors related to the operation of TECO are identified as being relevant to the awarding of Time-Vested Restricted Shares. Therefore, I recommend that 100% of the cost of those two awards be removed from test year expenses. Stock compensation on Schedule C-35, line 15 for 2009 is shown as $2.6 million and that amount should be excluded.

I would also recommend the disallowance of 100% of officer and key employee cash payments because those payments are contingent upon TECO Energy achieving a specific level of net income. Additionally, a portion of the general employee-based incentive pay also should be excluded from allowable operating expenses because it is based upon financial goals of both TECO and TECO Energy, the parent. I recommend that 50% of the incentive compensation be disallowed. Based upon the 2007 incentive compensation payout of $12.9 million, the additional disallowance would be $6.45 million. In total, I recommend a reduction of $9.05 million in the allowance of incentive compensation on the basis that such compensation is for the benefit of shareholders rather than ratepayers.

3. CLASS COST-OF-SERVICE STUDY

Q **WHAT IS A CLASS COST-OF-SERVICE STUDY?**

A A cost-of-service study is an analysis used to determine each class's responsibility for the utility's costs. Thus, it determines whether the revenues a class generates cover the class's cost-of-service. A class cost-of-service study separates the utility's total costs into portions incurred on behalf of the various customer groups. Most of a utility's costs are incurred to jointly serve many customers. For purposes of rate design and revenue allocation, customers are grouped into homogeneous classes according to their usage patterns and service characteristics.

Q **WHAT PROCEDURES ARE USED IN A COST-OF-SERVICE STUDY?**

A The basic procedure for conducting a class cost-of-service study is fairly simple. First, we identify the different types of costs (*functionalization*), determine their primary causative factors (*classification*), and then apportion each item of cost among the various rate classes (*allocation*). Adding up the individual pieces gives the total cost for each class.

Identifying the utility's different levels of operation is a process referred to as functionalization. The utility's investments and expenses are separated into production, transmission, distribution, and other functions. To a large extent, this is done in accordance with the Uniform System of Accounts developed by the Federal Energy Regulatory Commission.

Once costs have been functionalized, the next step is to identify the primary causative factor (or factors). This step is referred to as *classification*. Costs are classified as demand-related, energy-related or customer-related. Demand (or capacity) related costs vary with peak demand, which is measured in kilowatts (or kW). This includes production, transmission, and some distribution investment and related fixed operation and maintenance (O&M) expenses. As explained later, peak demand determines the amount of capacity needed for reliable service. Energy-related costs vary with the production of energy (or kWh). Energy-related costs include fuel and variable O&M expense. Customer-related costs vary directly with the number of customers, and include expenses such as meters, service drops, billing, and customer service.

Each functionalized and classified cost must then be *allocated* to the various customer classes. This is accomplished by developing allocation factors that reflect the percentage of the total cost that should be paid by each class. The allocation factors should reflect *cost-causation*; that is, the degree to which each class caused the utility to incur the cost.

Q WHAT KEY PRINCIPLES ARE RECOGNIZED IN A CLASS COST-OF-SERVICE STUDY?

A A properly conducted class cost-of-service study recognizes two key cost-causation principles. First, customers are served at different delivery voltages. This affects the amount of investment the utility must make to deliver electricity to the meter. Second, since cost-causation is also related to how electricity is used, both the timing and rate of energy consumption (*i.e.*, demand) are critical. Because electricity cannot be stored for any significant time period, a utility must acquire sufficient generation resources and construct the required transmission facilities to meet the maximum projected demand, including a reserve margin as a contingency against forced and unforced outages, severe weather, and load forecast error. Customers that use electricity during the critical peak hours cause the utility to invest in generation and transmission facilities.

Q WHAT FACTORS CAUSE THE PER-UNIT COSTS TO DIFFER BETWEEN CUSTOMER CLASSES?

A Factors that affect the per-unit cost include whether a customer's usage is constant or fluctuating (load factor), whether the utility must invest in transformers and distribution systems to provide the electricity at lower voltage levels, and the amount of electricity that a customer uses. In general, industrial consumers are less costly to serve on a per unit basis because they:

(1) Operate at higher load factors;

(2) Take service at higher delivery voltages; and

(3) Use more electricity per customer.

These three factors explain why some customers pay higher average rates than others.

For example, the difference in the losses incurred to deliver electricity at the various delivery voltages is a reason why the per-unit energy cost to serve is not the same for all customers. More losses occur to deliver electricity at distribution voltage (either primary or secondary) than at transmission voltage, which is generally the level at which industrial customers take service. This means that the cost per kWh is lower for a transmission customer than a distribution customer. The cost to deliver a kWh at primary distribution, though higher than the per-unit cost at transmission, is also lower than the delivered cost at secondary distribution.

In addition to lower losses, transmission customers do not use the distribution system. Instead, transmission customers construct and own their own distribution systems. Thus, distribution system costs are not allocated to transmission level customers who do not use that system. Distribution customers, by contrast, require substantial investments in these lower voltage facilities to provide service. Secondary distribution customers require more investment than do primary distribution customers. This results in a different cost to serve each type of customer.

Two other cost drivers are efficiency and size. These drivers are important because most fixed costs are allocated on either a demand or customer basis.

Efficiency can be measured in terms of load factor. Load factor is the ratio of average demand (*i.e.*, energy usage divided by the number of hours in the period) to peak demand. A customer that operates at a high load factor is more efficient than a lower load factor customer because it requires less capacity for the same amount of energy. For example, assume that two customers purchase the same amount of energy, but one customer has an 80% load factor and the other has a 40% load factor. The 40% load factor customers would have twice the peak demand of the 80% load factor customers, and the utility would therefore require twice as much capacity to serve the 40% load factor customer as the 80% load factor. Said differently, the fixed costs to serve a high load factor customer are spread over more kWh usage than for a low load factor customer.

Q **HAVE YOU REVIEWED THE CLASS COST-OF-SERVICE STUDY TECO FILED IN THIS PROCEEDING?**

A Yes.

Q **DOES TECO'S CLASS COST-OF-SERVICE STUDY COMPORT WITH ACCEPTED INDUSTRY PRACTICES?**

A With the exceptions I will discuss below, yes. TECO's class cost-of-service study recognizes the different types of costs as well as the different ways electricity is used by various customers.

Q **DO YOU AGREE WITH ALL OF TECO'S PROPOSED ALLOCATION METHODS?**

A No. I disagree with the following TECO proposals:

- The consolidation of the GSD, GSLD, and IS classes;
- Classifying the Big Bend scrubber and Polk Unit 1 gasifier investments to energy, rather than demand; and
- The 12 Coincident Peak and 25% Average Demand (12CP-25%AD) method of allocating production plant.

Finally, even though the Commission approved TECO's proposal to increase the Energy Conservation Cost Recovery (ECCR) surcharge in Docket No. 08802 EI to allow the recovery of Rider GSLM-2 and GSLM-3 credits, these credits are not allocable to interruptible customers. I will explain later in this section why interruptible customers should not be charged for any of these credits.

Q **WHAT PORTION OF PRODUCTION PLANT COSTS WOULD BE ALLOCATED TO ENERGY UNDER TECO'S CLASSIFICATION/ALLOCATION PROPOSALS?**

A Taking all production plant costs into account, including costs recovered through the ECRC, TECO's proposals in this base rate case would result in allocating 43% of these costs to energy.

Q. **IS THIS ALLOCATION APPROPRIATE?**

A No. TECO is placing undue emphasis on year-round energy, or annual average demand, rather than peak demand. As explained later, peak demand drives the need to install operable generation capacity. Annual average demand is not a cost driver.

__GSD, GSLD, IS Class Consolidation__

Q WHY IS TECO PROPOSING TO CONSOLIDATE THE GSD, GSLD, AND IS CLASSES?

A TECO bases its request to consolidate these classes on two proposed rate design changes. First, TECO proposes to eliminate Schedule IS (Interruptible Service) and to price this service under Rider GSLM-2 (GSLM-3 for standby service). It asserts that the GSLM are riders to Schedule GSD. Second, TECO asserts that the present GSD and GSLD base rate charges for energy and demand are nearly identical, with the only real difference being the customer charge that reflects the different percentage of customers taking service at a higher voltage level, and the application of a power factor clause for GSLD.

Q. IS CONSOLIDATION OF THESE CLASSES APPROPRIATE?

A No. As previously explained, customer classes should be homogeneous according to their usage patterns and service characteristics. While TECO asserts that there are minimal differences between the current GSD and GSLD prices, it fails to show that there are no significant differences in either usage patterns or service characteristics among GSD, GSLD, and IS customers.

Q DOES TECO'S PROPOSED CHANGE (WHICH FIPUG AND MOSAIC OPPOSE) IN THE PRICING OF INTERRUPTIBLE SERVICE JUSTIFY TRANSFERRING SCHEDULE IS CUSTOMERS TO SCHEDULE GSD?

A No. The design of riders GSLM-2 and GSLM-3 is not tied to a specific firm rate design, such as GSD. Thus, there is no connection whatsoever between pricing interruptible service on these riders and the proposed consolidation of the GSD, GSLD, and IS classes.

Q ARE THE GSD, GSLD, AND IS CLASSES HOMOGENEOUS?

A No. **Exhibit ___(JP-5)** is an analysis of the characteristics of GSD, GSLD, and

IS classes. The key characteristics include: size, load factor, coincidence factor, and delivery voltage. The analysis is summarized in the table below. As can be seen, there are significant differences in each of the key characteristics.

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%

Q WHAT IS COINCIDENCE FACTOR?

A 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.

Q HOW IS COINCIDENCE FACTOR RELEVANT IN DETERMINING WHETHER CUSTOMER CLASSES ARE HOMOGENEOUS?

A Differences in coincidence factor have important rate design implications. Specifically, a lower coincidence factor means that it is less costly to serve a customer on a per kW basis. The higher the coincidence factor, the higher the demand charge when the charge is based on maximum demand. This result is illustrated on the next page. Coincident demand is the primary basis upon which production, transmission and distribution costs are allocated among the customer classes. Billing or non-coincident demand is the maximum metered demand during the billing month.

Relationship Between Coincidence Factor and Demand Charges					
Customer Class	Coincident Demand (kW)	Billing or Non-Coincident Demand (kW)	Coincidence Factor[(a)]	Allocated Demand Costs[(b)]	Demand Charge[(c)]
	(1)	(2)	(3)	(4)	(5)
1	1,000	2,000	50%	$10,000	$5.00
2	1,000	1,430	70%	$10,000	$6.99
3	1,000	1,175	85%	$10,000	$8.51
(a) Column (1) ÷ Column (2)					
(b) Assume that costs are allocated in proportion to Column (1).					
(c) Column (4) ÷ Column (2)					

As can be seen, the lower the coincidence factor, the lower per unit demand charge, all other things being equal. This is because there are more billing units (Column 2) over which to spread the allocated demand-related costs (Column 4).

Q **WHAT IS THE IMPLICATION OF THE DIFFERENT COINCIDENCE FACTORS IN DETERMINING WHETHER THE GSD, GSLD, AND IS CLASSES SHOULD BE COMBINED?**

A As shown previously, the GSD, GSLD, and IS classes have very different coincidence factors. Ignoring all of the other differences, combining these three classes would result in inappropriate cross subsidies.

Q **ARE THERE OTHER REASONS THE GSD, GSLD, AND IS CLASSES SHOULD NOT BE COMBINED?**

A Yes. The IS class is much larger than either the GSD or GSLD classes. IS 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. Further, IS 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. And finally, as explained later, applying the

GSLD rates to the IS class will result in the IS class earning a much higher rate of return than the GSLD class.

Q **PLEASE SUMMARIZE YOUR RECOMMENDATION ON TECO'S PROPOSAL TO CONSOLIDATE THE GSD, GSLD, AND IS CLASSES.**

A The Commission should not consolidate these classes. The proposed class consolidation is not supported because there are dramatic differences in class load and service characteristics. While this is one of the criteria that Mr. Ashburn references in describing a proper rate design,[21] he has failed to follow his own criterion in this instance. The IS class should remain intact regardless of how interruptible service is priced.

Polk Unit 1 Gasifier

Q **HOW DOES TECO PROPOSE TO CLASSIFY THE INVESTMENT AND RELATED EXPENSES OF THE GASIFIER AT POLK UNIT 1?**

A TECO proposes to classify the gasifier train equipment (gasifier) to energy. Polk Unit 1 is an integrated gasified combined cycle (IGCC) facility. In explaining this treatment, Mr. Ashburn states that the gasifier converts coal as the fuel feedstock into gas used in the power block and thus performs a fuel conversion function.

Q **SHOULD THE POLK UNIT 1 FUEL CONVERSION EQUIPMENT BE CLASSIFIED TO ENERGY?**

A No. All power plants are built to produce capacity when it is needed to serve load and maintain reliability. However, the need for power plants is dictated by the projected peak demand, not the annual energy requirements. This is no less true for Polk Unit 1. In approving a determination of need for this unit, the Commission found that:

> 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.
>
> * * *
>
> TECO's proposed 220 MW IGCC unit is also needed to contribute to the reliability and integrity of the electric system of the State as a whole.[22]

In other words, the entire plant (including the gasifier) is needed to meet projected peak load growth and maintain reliability. Thus, it was peak demand, not year-round energy that caused the capacity of Polk Unit 1 and the rest of TECO's generation fleet to be built. Without the growth in peak demand, Polk Unit 1 and other capacity would not be needed. Therefore, the gasifier should be classified to demand and not to energy.

Q. WOULD CLASSIFYING THE GASIFIER TO DEMAND BE CONSISTENT WITH THE COST OF SERVICE PRINCIPLES YOU DISCUSSED ABOVE?

A. Yes. Mr. Ashburn has selectively chosen only one component of Polk Unit 1 for this special, and inappropriate, treatment. It can be said that the land, turbine generators, step-up transformers, and structures of every TECO power plant have all been sized to provide the capacity needed to meet peak demand. Yet, Mr. Ashburn proposes to allocate 25% of these costs to energy. Further, most of the remaining costs would be allocated to spring and fall months as a consequence of using the 12CP method. As explained later, TECO experiences its annual system peaks during the summer and winter months. These are the demands that drive TECO's capacity planning process. The 12CP method, on the other hand, allocates production plant costs to each of the twelve months in a calendar year.

Thus, it is improper and inconsistent with cost of service principles to selectively choose one component of one plant, the Polk Unit 1 gasifier, without also recognizing that other plants and plant components are caused by the need to meet annual peak demands.

Q DOES IT FOLLOW THAT THE INVESTMENT IN THOSE POWER PLANT COMPONENTS DESIGNED TO CONVERT FUEL INTO ENERGY SHOULD BE CLASSIFIED TO ENERGY?

A No. All power plants physically convert fuel into energy. For example, coal is received, processed and transported into the boilers to produce steam (another form of energy) at the Big Bend Units. It is this steam that is used to provide the energy to rotate the turbine generator, which in turn generates electricity. Despite this similarity to the Polk Unit 1 gasifier, there is no debate that the individual components of a power plant are *sized* to provide the capacity need for TECO to meet peak demand and provide reliable service. Thus, they should not be classified to energy.

For all of the above reasons, the Polk gasifier should be classified to demand.

12CP-25% AD Method

Q WHAT METHOD DOES TECO ASK THE COMMISSION TO APPROVE TO ALLOCATE PRODUCTION PLANT COSTS?

A TECO asks this Commission to approve the 12CP-25% AD methodology for allocating production plant costs to the retail customer classes.

Q HAS THIS COMMISSION EVER APPROVED THE 12CP-25% AD METHOD ?

A No.

Q WHAT METHOD HAS THE COMMISSION PREVIOUSLY APPROVED?

A In past rate cases, the Commission has approved the 12CP-1/13th AD method. The Commission used this method in TECO's most recent base rate case (with the exception of the Big Bend scrubbers) and uses this method in both the ECCR and Capacity Cost Recovery (CCR) clauses.

Q WHAT IS THE 12CP-25% AD METHOD?

A The 12CP-25% AD method 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.

Q WHAT REASON DOES TECO OFFER FOR ASKING THE COMMISSION TO CHANGE TO THE 12CP-25% AD METHOD TO SET RATES IN THIS PROCEEDING?

A TECO argues that the 25% weighting to average demand represents a "balance" between the "inadequate" 12 CP-1/13th AD and Equivalent Peaker (EP) methodologies. Specifically, Mr. Ashburn cites the substantial base load and intermediate generation that TECO has built to serve load. TECO's investment in base load and intermediate capacity is generally higher in cost on a per kW basis than the corresponding investment in peaking capacity. He further argues that TECO has significant production plant investment related to environmental concerns, which he asserts is incurred more as a function of the energy utilization of a production facility than its peak capability. The bottom line of Mr. Ashburn's contention is that higher investment or capital costs are incurred to save energy costs. The notion that a utility is said to "substitute" capital investment for fuel savings is often referred to as the theory of "Capital Substitution." The EP method was a specific application of Capital Substitution theory.

Q HAS THIS COMMISSION PREVIOUSLY ADDRESSED THE EQUIVALENT PEAKER (EP) METHOD?

A Yes. This Commission has previously rejected the EP method. Specifically, the Commission stated that:

> The equivalent peaker methodology implies a refined knowledge of costs which is misleading, particularly as to the allocation of the plant costs to hours past the break-even point.[23]

Thus, the Commission recognized that allocating the extra plant investment associated with generating units that provide fuel cost savings (*e.g.,* base load and intermediate capacity) to energy usage beyond the economic break-even point is at odds with the utility planning process. This is because <u>all</u> production from a specific plant (*i.e.*, kWh sales) is not the critical factor in deciding what type of capability to install. I will explain why this is so below.

Q WHAT IS MEANT BY THE "BREAK-EVEN POINT?"

A The break-even point is the number of operating hours in which the total cost of base/intermediate and peaking capacity is the same. The illustration is based on a break-even point of 1,000 hours. This reflects the fact that peaking units rarely operate more than 1,000 hours per year on a recurring basis.

Q WHAT IS THE SIGNIFICANCE OF THE BREAK-EVEN POINT?

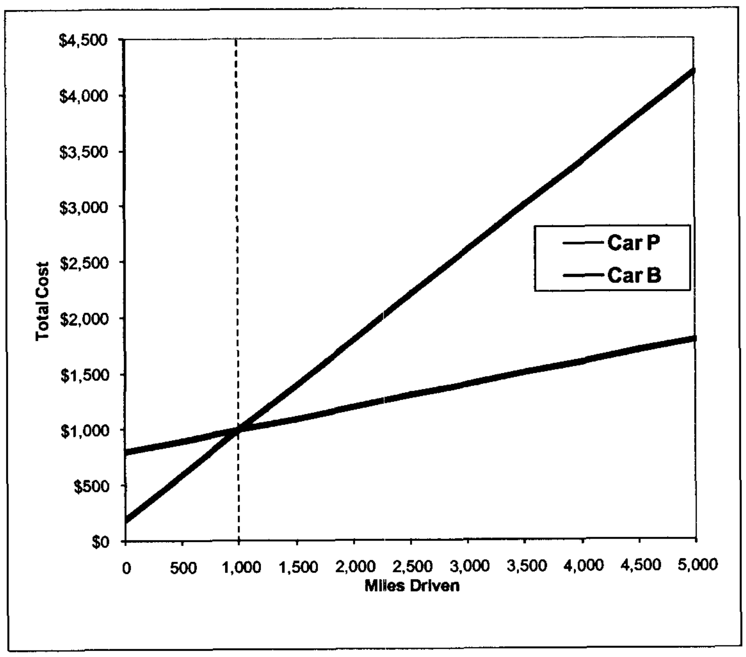
A Once a utility decides that additional production capacity is needed to meet peak demand, if that new capacity is expected to run only a limited number of hours, total costs are minimized by the choice of a peaker. On the other hand, if it is projected that a unit will run for a sufficient number of hours, then the intermediate or base load unit will be more economical.

Therefore, annual energy usage does not cause plant investment. However, load duration up to the break-even point may influence plant investment decisions. Beyond the break-even point, energy utilization is no longer a factor in the decision to select base load capacity or peaking capacity.

To provide an analogy, suppose two different customers are required to rent cars from a fleet that contains only two types of cars, "Car P" and "Car B":

	[redacted]	Car B
Fixed Charge	$200	$800
Mileage Charge	80¢	20¢

Car B has a high fixed charge and gets high mileage (like a base load plant), while the Car P has a low fixed charge but gets poor mileage (like a peaking unit). The graph below shows total cost of both cars over a range of miles driven.



The total cost is also calculated in the table below.

Miles Driven	Total Cost		Best Choice
		Car B	
0	$200	$800	
500	$600	$900	
1,000	$1,000	$1,000	P or B
1,500	$1,400	$1,100	B
2,000	$1,800	$1,200	B
2,500	$2,200	$1,300	B
3,000	$2,600	$1,400	B
3,500	$3,000	$1,500	B
4,000	$3,400	$1,600	B
4,500	$3,800	$1,700	B
5,000	$4,200	$1,800	B

As can be seen, the break-even point between Car P and Car B is 1,000 miles. That is, the higher mileage Car B has a lower total cost per mile than the Car P if it operated more than 1,000 miles. If one customer needed to drive 1,500 miles and a second customer needed to drive a car 4,500 miles, both customers would choose the same car, Type B. The 12CP-25% AD, however, would charge the second customer about 47% more solely because that customer needed to drive three times as many miles. This result is arbitrary and inequitable because the Type B car was the more economical choice for both customers.

Q **DOES THE 12CP-25% AD METHOD REFLECT COST-CAUSATION CONSISTENT WITH THE BREAK-EVEN POINT CONCEPT?**

A No. As previously stated, TECO is proposing to classify and/or allocate 43% of production plant costs to energy. The 25% AD portion is shown in **Exhibit ___(JP-6)**. As can be seen, the 25% AD has the effect of allocating substantial costs beyond the break-even point. Further, some of the 12CPs fall outside of the hours that peaker units operate. Thus, the 12CP-25% AD is totally contrary to capital substitution theory. The Commission should (once again) not endorse a cost allocation method which, on its face, is inconsistent with system planning principles, the underlying theory of capital substitution, and past precedent.

Q **DOES THE 12CP-25% AD METHOD HAVE ANY OTHER FLAWS?**

A Yes. The 12CP-25% AD method would be used to allocate all production plant costs, irrespective of the type of resource. This would include plant costs associated with the combustion turbine (CT) units. Further, TECO is also proposing to apply this method to allocate the dispatchable costs recoverable in the ECCR. This would include GSLM-2/3 payments as discussed below. Both CTs and GSLM resources provide peaking capacity and are not incurred to achieve lower fuel costs. Finally, this method is not consistent with TECO's load and supply characteristics.

Q **IS THE 12CP-25% AD CONSISTENT WITH CAPITAL SUBSTITUTION THEORY?**

A No. In addition to allocating costs beyond the break-even point, TECO's proposed application would fail to fully reflect capital substitution theory.

Q **WHY DO YOU CONTEND THAT THE 12CP-25% AD FAILS TO FULLY REFLECT CAPITAL SUBSTITUTION THEORY?**

A Mr. Ashburn implements capital substitution theory by altering the method in which production plant-related costs are allocated among the retail customer classes. The result of applying capital substitution in this fashion is to allocate above-average plant investment to high load factor customer classes and below-average investment to lower load factor customers. This is shown in **Exhibit ____ (JP-7)**. As can be seen, TECO's average production investment is $553 per 12CP kW. The RS and GS classes have been allocated net investment less than $530 per kW, while the allocations to other classes would range from $561 per kW to over $1,300, which is above the average.

However, Mr. Ashburn fails to apply capital substitution theory to allocate production operating expense. That is, the 12CP-25% AD erroneously assumes that customers should be charged average or "slice of the system" fuel costs. A slice of the system means that each class is served from the same mix of base load and peaking capacity. Thus, each class would pay the same average fuel charge, or 5.93¢ per kWh

Q **WHY IS THIS APPROACH INCONSISTENT WITH CAPITAL SUBSTITUTION THEORY?**

A There is a symmetrical relationship between plant investment and operating expense. This relationship is shown in **Exhibit ____ (JP-7)**, page 2. On average, TECO's net production investment is $442 per kW of winter capacity. The average fuel expense associated with this investment is $5.46¢ per kWh. As can be seen, the capacity that TECO classifies as base load (line 1) has a net plant investment of $558 per kW and associated fuel expense of $3.95¢ per kWh. The corresponding costs for peaking capacity are $309 per kW, and 14.88¢ per kWh. The base load capacity, thus, has a higher plant investment but a lower operating expense, on a per unit basis. The opposite is true for TECO's peaking capacity (line 3).

Given the symmetrical relationship, the application of capital substitution theory would not be complete unless the allocation and recovery of fuel expense was consistent (symmetrical) with the corresponding allocation of plant investment. This means that a class that is allocated a larger share of production plant investment should also receive more of the associated benefits of the lower operating costs of base/intermediate capacity. Stated differently, if a class is allocated above-average plant investment per kW, then consistency demands that this same class be allocated below average operating expense (fuel and variable O&M) per MWh. This would explicitly recognize the symmetrical relationship between plant investment and operating expense.

Consider again the analogy of the two cars (P and B) with different fuel efficiencies and fixed costs. The customer who drives the car only a few miles (low load factor) would incur a higher average mileage charge than the customer that drives many miles per day (high load factor). This symmetrical relationship is consistent with capital substitution theory.

Q **DO TECO'S LOAD CHARACTERISTICS SUPPORT USE OF THE 12CP-25% AD METHOD?**

A No. TECO experiences its maximum annual demand for electricity in either the summer or winter months. This is shown in **Exhibit ____ (JP-8_)**, page 1, which is an analysis of TECO's monthly firm peak demands as a percent of the annual system peak for the years 2003 through 2007. The peak demands in the other months are typically well below the summer and winter peak demands.

These characteristics are further summarized in **Exhibit ____ (JP-8)**, page 2. As can be seen:

- 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.
- And with one exception, TECO's annual load factor is at or below 60%.

These ratios confirm that TECO has seasonal load characteristics. Thus, electricity demands in the spring and fall months are not relevant in determining the amount of capacity needed for TECO to provide reliable service.

Q ARE THE MONTHLY PEAKS IN THE SPRING/FALL MONTHS IMPORTANT BECAUSE TECO HAS TO REMOVE GENERATION FOR SCHEDULED MAINTENANCE?

A No. Although TECO does schedule most planned outages during the spring and fall months, this does not make these months important from a cost-causation perspective. Specifically, despite planned outages, TECO generally has higher reserve margins during the non-summer months than during the summer months. This is shown in **Exhibit ___(JP-9)**. The reserve margins were calculated as the margin (available capacity less scheduled outages less firm peak demand) divided by firm peak demand. As can be seen, the summer month reserve margins, adjusted for scheduled outages, have been well below the corresponding non-summer month reserve margins.

Q WHAT DO THE PEAK DEMAND AND RESERVE MARGIN ANALYSES DEMONSTRATE?

A The analyses demonstrate that the summer peak demands, and to a lesser extent the winter peak demand, determine TECO's capacity requirements. The spring and fall months are irrelevant. Thus, the 12CP method does not reflect cost-causation when measured by TECO's load and supply characteristics.

Q PLEASE SUMMARIZE THE REASONS THAT IT IS INAPPROPRIATE TO USE THE 12CP-25% AD METHOD TO ALLOCATE PRODUCTION CAPITAL COSTS TO THE VARIOUS RATE CLASSES.

A First, the 12CP-25% AD method results in 43% of production plant costs being allocated based on year-round energy usage, taking into account costs recovered in base rates and through the ECRC. The assumption that year-round energy usage causes higher production capital investment is totally inaccurate and flawed. As discussed above, investment decisions are not caused by energy usage. At most, they are influenced by load duration but only up to the break-even point between different types of capacity. Therefore, allocating production investment on energy utilization, as is the case under the 12CP-25% AD, is a flawed application of capital substitution theory.

Second, there is no symmetrical allocation of fuel costs which is required because the 12CP-25% AD allocates a larger share of base load plants, which have both above-average investment and below-average fuel costs. TECO's cost study makes no effort to change the way that fuel costs are allocated and recovered from customer classes. Currently, each class pays the same average fuel costs, which is the same allocation as in methodologies that do not explicitly recognize system planning principles. 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.

Finally, TECO has seasonal load characteristics, and it experiences its lowest reserve margins during the summer and winter peak months rather than during the spring and fall months. For these reasons, the 12CP method cannot be justified solely on the basis of the summer and winter peak months that are driving TECO's capacity needs.

Q **YOU STATED EARLIER THAT THE COMMISSION HAS PREVISOULY APPROVED THE 12CP-1/13TH AD METHOD. WHY DID THE COMMISSION SELECT THIS METHOD?**

A It is my understanding that the Commission originally adopted the 12CP-1/13th AD method to recognize the same economic theory that Mr. Ashburn associates with the 12CP-25% AD. Although the 12CP-1/13th AD allocates production investment beyond the break-even point, it does so only minimally. It also recognizes that load duration is a driver that determines utility investment decisions.

Q **WHICH OF THE TWO METHODS, 12CP-1/13TH AD OR 12CP-25% AD, COMES CLOSER TO REFLECTING UTILITY SYSTEM PLANNING PRINCIPLES?**

A While neither method perfectly reflects system planning principles, the 12CP-1/13th AD method (with the Big Bend Scubber and Polk gasifier costs classified to demand) would come much closer to recognizing cost-causation and the economic theory underlying generation expansion planning (i.e., capital substitution). TECO's proposed production plant classification/allocation methodology is nothing more than an unsupported "compromise" between the currently approved 12CP-1/13th AD method and the previously discredited Equivalent Peaker method. For this and all of the above reasons, the Commission should reject the 12CP-25% AD method in this proceeding.

Environmental Costs

Q **IS TECO PROPOSING TO RECOVER ANY ENVIRONMENTAL COSTS IN BASE RATES?**

A Yes. TECO proposes to recover the scrubber portion of the Big Bend Unit 4 environmental equipment in base rates.

Q **HOW DOES TECO PROPOSE TO ALLOCATE THE BIG BEND 4 SCRUBBER COSTS?**

A TECO proposes to classify and allocate the entirety of these costs to energy.

Q MR. ASHBURN ARGUES THAT CLASSIFYING ENVIRONMENTAL COSTS TO ENERGY CAPTURES THE PRODUCTION COST IMPACT OF HIGHER LOAD FACTOR AND INTERRUPTIBLE CUSTOMERS WHO BENEFIT FROM THE LOWER VARIABLE COSTS OF BASE AND INTERMEDIATE LOAD UNITS. DO YOU AGREE?

A No. This argument is inconsistent with well-known principles of cost-causation. The proper application of cost-causation is to identify the specific usage characteristics that cause the utility to incur production plant and related expenses. While environmental concerns may be reflected in the investment in production equipment and may influence production operating expenses, they are a prerequisite to plant operation. In other words, 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.

In addition to being directly related to production plant, pollution control investments are primarily fixed. They vary directly in proportion to the size (*i.e.*, the capacity) of a generating unit. More importantly, other than some operation and maintenance expenses, these costs do not vary with energy usage. Therefore, the cost characteristics of pollution control equipment do not support the classification of production plant costs to the energy function.

Q DID THE COMMISSION ORDER THAT THE BIG BEND SCRUBBERS BE CLASSIFIED TO ENERGY IN TECO'S LAST RATE CASE?

A No. The ratemaking treatment of the Big Bend scrubbers was stipulated to in TECO's last rate case, Docket No. 92-0314.[24]

Q HOW SHOULD THE BIG BEND SCRUBBER COSTS BE CLASSIFIED AND ALLOCATED IN THIS PROCEEDING?

A The Big Bend scrubber costs should be classified 100% to demand and allocated to retail customer classes using the 12CP-1/13th AD method. In other words, the scrubber should not be classified and allocated any differently than the plant.

Q SHOULD THE COMMISSION ALSO CHANGE THE WAY THAT ENVIRONMENTAL COSTS ARE ALLOCATED IN THE ECRC?

A Yes. The 12CP-1/13th AD method should also be used to allocate environmental investments and related costs and fixed operating expenses that are currently recovered in the ECRC.

Q IS THERE ANY PRECEDENT FOR ALLOCATING ENVIRONMENTAL COSTS ON A BASIS OTHER THAN ENERGY?

A Yes. Progress Energy Florida (PEF) and Florida Power & Light Company (FPL) have agreed to allocate some environmental costs on a demand basis.[25] Further, Alabama Power Company and Georgia Power Company allocate environmental costs relative to base rate (non-fuel) revenues.

<u>Revised Class Cost-of-Service Study</u>

Q HAVE YOU REVISED THE CLASS COST-OF-SERVICE STUDY TO INCORPORATE THE ADJUSTMENTS YOU HAVE DISCUSSED?

A Yes. A summary of the revised class cost-of-service study at present is presented in **Exhibit ___(JP-10)**. A complete copy of the revised cost-of-service study is provided in my workpapers which will be provided in response to a discovery request.

Q WHAT CHANGES DID YOU MAKE TO TECO'S COST OF SERVICE STUDY?

A I have made three changes:

1. Production plant costs were allocated using the 12CP-1/13th AD method.

2. Big Bend scrubber and Polk Unit 1 gasifier costs were classified 100% to demand.

3. The IS class was treated as firm for both costing and pricing purposes.

__Treatment of the Schedule IS Class__

Q **PLEASE DESCRIBE THE INTERRUPTIBLE CLASS.**

A The interruptible class consists of rate schedules IS (interruptible service) and SBI (standby interruptible service). Under these rate schedules, service may be interrupted at TECO's sole discretion when capacity is needed to maintain service to its firm customers.

Q **IS INTERRUPTIBLE LOAD THE SAME QUALITY OF SERVICE AS FIRM LOAD?**

A No. In addition to the fact that TECO does not plan its capacity additions to serve interruptible load, TECO can cut-off service to interruptible customers at any time for any reason. Schedule IS provides as follows:

> __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.[26]

Q **PLEASE EXPLAIN THE TREATMENT OF THE SCHEDULE IS CLASS IN YOUR COST OF SERVICE STUDY.**

A The interruptible loads were included in the 12CP demands used to develop the class allocation factors. Because this treatment assumes for costing purposes that Schedule IS customers are receiving firm service, it is both logical and consistent to re-state the Schedule IS revenues at the firm service rates. In this instance, I re-priced IS at the current Schedule GSLD rate. This is shown in **Exhibit___(JP-11)**. The difference between the restated and actual current Schedule IS revenues reflects the amount of interruptible "credits" currently being paid to Schedule IS customers. As can be seen, current Schedule IS/SBI rates are $22.9 million below the corresponding firm (Schedule GSLD/SBF) rates.

Q WHY SHOULD THE INTERRUPTIBLE CREDITS BE ALLOCATED ONLY TO THE FIRM CUSTOMER CLASSES?

A Production capacity costs should not be allocated to interruptible customers because they do not cause such costs to be incurred. There are two basic ways to accomplish this. The first is to exclude interruptible load from the cost-of-service study. The second method, which is the approach I have taken, is to include interruptible load as if it were firm, but then to spread the amount of the interruptible credits to the firm classes in the cost-of-service study. The two treatments are mathematically equivalent, as illustrated in **Exhibit ___(JP-12)**.

The illustration shows the allocation of $10,000 in production capacity costs to two equal size classes: A and B. Class A is comprised of only firm load, while Class B's load is 50% firm and 50% interruptible. The interruptible load provides $1,500 in revenue. Method 1 allocates zero production capacity costs to interruptible customers (line 8). The revenues provided by interruptible customers are used to lower the cost to provide firm service (line 9). This results in allocating the $10,000 as follows: Class A $5,667; Class B $4,333 ($2,833 plus $1,500), of which the firm load would be charged $2,833.

Method 2 treats interruptible load as firm, but allocates the interruptible credits only to firm load. The interruptible credits are the difference between the revenues at firm rates (or $2,500) and the revenues paid by the interruptible customers (or $1,500). Thus, in the illustration, the interruptible credits are $1,000. As can be seen on line 13, the $10,000 of production capacity costs is allocated as follows: Class A $5,667; Class B $4,333 ($2,833 plus $1,500), of which firm Class B customers are allocated $2,833. However, this is the same allocation as if no production capacity costs were allocated to interruptible customers in the first place (*i.e.,* Method 1).

Q **WHAT DOES THIS EXAMPLE DEMONSTRATE?**

A The example demonstrates that the costs of providing interruptible service should be allocated in proportion to *firm* loads. It would be inappropriate to allocate the credits to total loads, including interruptible load, because that would effectively charge interruptible customers for the production plant they avoid. This would be contrary to the principle of cost-causation and regulatory precedent. Yet, TECO is proposing to spread these costs to all customers, including interruptible customers, in the ECCR.

Q **WHY IS TECO'S PROPOSAL TO REQUIRE INTERRUPTIBLE CUSTOMERS TO PAY FOR A PORTION OF THEIR OWN CREDITS CONTRARY TO ACCEPTED REGULATORY PRACTICE?**

A TECO's proposal would, in effect, be identical to allocating production capacity costs to interruptible customers. This proposition was recently considered and unequivocally rejected by the Federal Energy Regulatory Commission (FERC). The FERC has traditionally excluded interruptible load from the allocation of production capacity-related costs. This long-standing practice is described in the following excerpt from the recent FERC order rejecting a proposal by Entergy to allocate capacity costs to interruptible load:

> 61. The Initial Decision overlooks that Entergy bases the recovery of its costs on the coincident peak recovery method, in which Entergy allocates its costs among its customers according to each

customer's share of the System load at the time of the System peak. **It assesses its capacity costs to peak period users because it is peak demand that determines how much Entergy will invest in capacity.** [FN116] In Kentucky Utilities, the Commission explained the theory behind this method of cost allocation. A utility builds its bulk power facilities, i.e., generating units and transmission lines, to meet the maximum or peak demand of its firm customers. **Because the utility incurs the cost of these facilities to meet the peak demand of its firm customers, those customers should pay for the facilities. The peak responsibility method accomplishes this by allocating the cost of the facilities among the firm customers in the same proportion as each customer's demand bears to the system peak. [FN117] In contrast, as explained below, a utility need not build to meet its interruptible demand.**

62. **The Commission thus traditionally has not "allocated" the cost of facilities to interruptible load**.

* * *

63. Since Entergy can curtail interruptible service so that it does not contribute to the System peak, **interruptible load does not determine how much Entergy must invest in capacity to meet the System peak, i.e., its customers' needs. Therefore, under the peak load responsibility cost allocation method, Entergy should not include interruptible load in its calculations**.

67. Thus, as explained above, because Entergy did not and does not have to construct capacity to serve interruptible load at the time of its System peak (and thus can and does offer interruptible service at a lower rate), the Initial Decision cannot stand. [FN121] Moreover, the cost recovery system that the Initial Decision adopts [FN122] is without foundation. There is no evidence that Entergy built capacity to serve interruptible load. While Entergy may have considered interruptible capacity in its planning before 1995, [FN123] it then already had sufficient capacity to meet its load and did not need to construct additional capacity; its most recent capacity additions occurred in the mid-1980's. [FN124] So reference to interruptible load in Entergy's planning documents does not demonstrate that Entergy actually built capacity to serve interruptible load. [FN125]

69. Also, it is uncontroverted that Entergy does not now acquire capacity, and, since at least 1995 has not acquired capacity, to serve interruptible loads. [FN131] The Presiding Judge so found, [FN132] and no one disputes this finding. [FN133] Since it is clear, then, that firm load currently drives Entergy's capacity acquisitions, there is no credible basis to allocate the cost of capacity to interruptible loads that existed in 1995. For example, in 2000, Entergy needed all of its existing generating capacity, plus 2950 MW, to meet firm load. [FN134] When all capacity is needed

> to serve firm load, **there is no logical reason to allocate the cost of this capacity based, in part, on interruptible load - - either pre-1995 or post-1995.**[27]

Q **WOULD ALLOCATING PRODUCTION CAPACITY COSTS TO INTERRUPTIBLE CUSTOMERS BE COMPATIBLE WITH TECO'S OWN SYSTEM PLANNING PRACTICES?**

A No. TECO does not plan to install generating capacity or purchase firm power to provide interruptible service. TECO specifically removes interruptible loads in assessing the need for new capacity.[28] Since TECO does not incur production capacity costs to serve interruptible customers, no such costs should be allocated to them. The fundamental principal of utility cost allocation is that costs are allocated to those customers that cause them to be incurred. Interruptible customers do not cause capacity costs to be incurred, and thus those costs should not be allocated to them.

Q **SHOULD THE COSTS INCURRED TO SUSTAIN INTERRUPTIBLE LOAD BE ALLOCATED DIFFERENTLY IF THESE COSTS ARE RECOVERED IN BASE RATES OR THROUGH A COST RECOVERY CLAUSE?**

A No. Payments to interruptible customers represent the value of the capacity not built or acquired to serve interruptible load. Thus, they are not caused by or allocable to interruptible customers. This treatment should apply irrespective of whether the cost of providing interruptible service is recovered in base rates or through the ECCR, as TECO is proposing.

<u>Revised Class Cost-of-Service Study Results</u>

Q **PLEASE EXPLAIN HOW THE COST-OF-SERVICE STUDY RESULTS ARE EVALUATED.**

A Cost-of-service study results shown in my revised study (**Exhibit ___(JP-10)** are measured in three ways: (1) rate of return, (2) relative rate of return, and (3) interclass subsidies.

Rate of return (line 29) is the ratio of net operating income (revenues less allocated operating expenses as shown in line 18) to the allocated rate base (line 27). Net operating income is the difference between operating revenues at current rates (line 6) and allocated operating expenses (line 16). If a class is presently providing revenues sufficient to recover its cost-of-service (at the current system rate of return), it will have a rate of return equal to or greater than the total system return of 5.00%.

Relative rate of return (RROR), which is shown on line 31, is the ratio of each class' rate of return to the Florida Retail average rate of return. A relative rate of return above 100 means that a class is providing a rate of return higher than the system average, while a relative rate of return below 100 indicates that a class is providing a below-system average rate of return.

Subsidy (line 33) measures the difference between the revenues required from each class to achieve the system rate of return and the revenues actually being recovered. A negative amount indicates that a class is being subsidized each year (*i.e.*, revenues are below cost at the system rate of return), while a positive amount indicates that a class is providing a subsidy each year (*i.e.*, revenues are above cost).

Q WHAT DO THE RESULTS OF YOUR REVISED CLASS COST-OF-SERVICE STUDY SHOW?

A The IS class is producing the highest ROR (nearly twice the system average) of any customer class *before* TECO's proposed base rate increase.

Q WHAT IMPLICATIONS DO THESE RESULTS HAVE IN THIS CASE?

A Even with no base rate increase, this class is currently providing a higher ROR than TECO is requesting in this proceeding. Thus:

- The cost of providing firm service to Schedule IS customers is below the current Schedule GSLD pricing; and

- It is not appropriate to consolidate the IS and GSLD/GSD classes because it would result in Schedule IS customers subsidizing the firm service rates of Schedule GSLD/GSD customers.

4. CLASS REVENUE ALLOCATION

Q WHAT IS CLASS REVENUE ALLOCATION?

A Class revenue allocation is the process of determining how any base revenue change the Commission approves should be spread to each customer class the utility serves.

Q HOW SHOULD ANY CHANGE IN BASE REVENUES APPROVED IN THIS DOCKET BE SPREAD AMONG THE VARIOUS CUSTOMER CLASSES TECO SERVES?

A Base revenues should reflect the actual cost of providing service to each customer class as closely as practicable. Regulators sometimes limit the immediate movement to cost based on principles of gradualism and rate administration.

Q PLEASE EXPLAIN THE PRINCIPLE OF GRADUALISM.

A *Gradualism* is a concept that is applied to prevent a class from receiving an overly-large rate increase. That is, the movement to cost-of-service should be made gradually rather than all at once because it would result in rate shock to the affected customers.

Q PLEASE EXPLAIN HOW RATE ADMINISTRATION IS RELATED TO RATE CHANGE.

A. *Rate administration* is a concept that applies when the design of a rate may be tied to the design of other rates to minimize revenue losses when customers migrate from a more expensive to a less expensive rate.

Q SHOULD THE RESULTS OF THE COST-OF-SERVICE STUDY BE THE PRIMARY FACTOR IN DETERMINING HOW ANY BASE REVENUE CHANGE SHOULD BE ALLOCATED?

A Yes. Cost-based rates will send the proper price signals to customers. This will allow customers to make rational consumption decisions.

Q ARE THERE OTHER REASONS TO APPLY COST-OF-SERVICE PRINCIPLES WHEN CHANGING RATES?

A Yes. The other reasons for adhering to cost-of-service principles are equity, engineering efficiency (cost-minimization), stability and conservation.

Q WHY ARE COST-BASED RATES EQUITABLE?

A Rates which primarily reflect cost-of-service considerations are equitable because each customer pays what it actually *costs* the utility to serve the customer – no more and no less. If rates are not based on cost, then some customers must pay part of the cost of providing service to other customers, which is inequitable.

Q HOW DO COST-BASED RATES PROMOTE ENGINEERING EFFICIENCY?

A With respect to engineering efficiency, when rates are designed so that demand and energy charges are properly reflected in the rate structure, customers are provided with the proper incentive to minimize their costs, which will, in turn, minimize the costs to the utility.

Q HOW CAN COST-BASED RATES PROVIDE STABILITY?

A When rates are closely tied to cost, the utility's earnings are stabilized because changes in customer use patterns result in parallel changes in revenues and expenses.

Q HOW DO COST-BASED RATES ENCOURAGE CONSERVATION?

A By providing balanced price signals against which to make consumption decisions, cost-based rates encourage conservation (of both peak day and total usage), which is properly defined as the avoidance of wasteful or inefficient use (not just *less use*). If rates are not based on a class cost-of-service study, then consumption choices are distorted.

Q **DOES COMMISSION POLICY SUPPORT THE MOVEMENT OF UTILITY RATES TOWARD ACTUAL COST?**

A Yes. The Commission's support for cost-based rates is longstanding and unequivocal. For example,

> 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.[29]

Therefore, moving TECO's rates closer to cost would be consistent with Commission policy.

Q **HOW IS TECO PROPOSING TO ALLOCATE THE PROPOSED BASE REVENUE INCREASE IN THIS PROCEEDING?**

A TECO's proposed base revenue increase is shown in **Exhibit ___(JP-13)**. As can be seen on page 1, TECO is proposing a 26.4% base rate increase. The increases by rate would range from 7.9% for Lighting Facilities to 134.3% for the interruptible (Schedule IS/SBI) class.

Q **WOULD INTERRUPTIBLE CUSTOMERS EXPERIENCE 134% BASE RATE INCREASES?**

A The answer depends on the level and structure of the interruptible credits that will be provided under the GSLM-2 and GSLM-3 riders. As discussed later, TECO's proposal to provide interruptible service under these riders will subject interruptible customers to periodic base rate changes. Based on the riders that

TECO proposes for 2009, interruptible customers would experience an "effective" base revenue increase of 35.5%. The corresponding increases for all rate classes is shown on page 2 of **Exhibit ___(JP-13)**. The difference between page 2 and page 1 is the assumption that Rider GSLM-2 & 3 payments would be recovered in the ECCR (see Column 3). As can be seen, interruptible customers would receive the second highest base rate increase of any rate class.

Q HOW SHOULD ANY RATE INCREASES OR DECREASES RESULTING FROM THIS CASE BE ALLOCATED AMONG THE VARIOUS CLASSES?

A Consistent with Commission policy and precedent, rates for each class should be set at a level that will recover the cost of serving that class. Under my revised class cost-of-service study, interruptible base rates should be reduced. The same is true of Lighting Facility rates.

To avoid rate shock and to reflect gradualism considerations, I propose that no rate class should receive a base rate decrease. This is reflected in **Exhibit ___ (JP-14)** using TECO's proposed revenue requirement.

Q WOULD YOUR RECOMMENDED REVENUE ALLOCATION MOVE ALL CLASSES CLOSER TO COST?

A Yes. This is shown in **Exhibit ___(JP-15)**, which shows the cost-of-service study results under my recommended class revenue allocation. As can be seen, all but one class would be moved very close to cost. The lighting facility class would move 63% closer to cost.

5. FIRM RATE DESIGN

Q WHAT RATE DESIGN ISSUES WILL YOU ADDRESS?

A In this section, I will discuss the appropriate design of the firm rates. Non-firm rate design is addressed in Part 5. Specifically, I will discuss:

- The Demand and Non-Fuel Energy charges; and
- The Transformer Ownership Discounts.

<u>**Demand and Non-Fuel Energy Charges**</u>

Q DESCRIBE THE DEMAND AND NON-FUEL ENERGY CHARGES.

A These charges are designed to recover base rate (non-fuel) costs. Demand charges are billed relative to a customer's maximum metered (kW) demand in the billing month, while the non-fuel energy charges are billed on the kWh purchased.

Q DO YOU AGREE WITH HOW TECO HAS PROPOSED TO DEVELOP THE DEMAND AND NON-FUEL ENERGY CHARGES?

A No. Consistent with 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. TECO has underpriced the demand charge and overpriced the energy charge (based on TECO's proposed revenue levels). The demand and non-fuel energy charges should closely reflect the corresponding demand and non-fuel energy related costs as derived in the class cost-of-service study.

Q WHAT ARE THE UNIT ENERGY COSTS DERIVED FROM YOUR REVISED CLASS COST-OF-SERVICE STUDY?

A The unit costs from the revised class cost-of-service study are shown in **Exhibit ___ (JP-16)**. As can be seen, the Schedule IS non-fuel energy costs would be

0.75¢ per kWh. TECO's proposed non-fuel energy charge would be 1.06¢ per kWh, which is substantially above the actual unit cost. Accordingly, I recommend that the non-fuel energy charge be set at the per unit energy cost, or 0.75¢ per kWh.

<u>**Transformer Ownership Discounts**</u>

Q EXPLAIN THE CONCEPT OF TRANSFORMER OWNERSHIP DISCOUNTS.

A TECO's current rates apply to customers that take service at different delivery voltages. However, the base demand and energy charges in Schedules GSD and GSLD are designed to reflect the cost to serve at secondary distribution, while the corresponding Schedule IS base rate charges are designed for service at primary distribution. Thus, to prevent intra-class subsidies, there must be a mechanism to adjust the base charges to reflect the lower cost of providing primary and sub-transmission service.

Q WHAT MECHANISMS ARE APPROPRIATE TO ACCOMPLISH THIS?

A There are two such mechanisms to reflect voltage-differentiated costs in the current tariffs: (1) the Metering Level Discount and (2) the Transformer Ownership Discount. Though the term "discount" is sometimes interpreted as a below-cost rate, both the Metering Level and the Transformer Ownership Discounts are cost-based; that is, they reflect differences in the cost of providing service by delivery voltage. Whereas the Metering Level Discount reflects the differences in losses where electricity is metered (*i.e.,* the utility incurs lower losses to deliver electricity at sub-transmission than distribution voltage), the Transformer Ownership Discount reflects the differences in the cost of the facilities used to provide service.

For example, Schedule GSLD customers served at primary voltage receive a 36¢ per kW credit, which reflects the costs of providing secondary distribution service, which are avoided when the customer supplies the necessary equipment. A GSLD customer served at sub-transmission receives a 59¢ per kW credit. The corresponding credit for a Schedule IS customer is 23¢ per kW. The lower credit is due to the fact that the base rate Schedule IS charges are designed for service at primary, rather than secondary, distribution service. In both cases, however, the latter credits reflect the cost of distribution facilities avoided when a customer takes sub-transmission service.

In summary, the Metering Service and Transformer Ownership Discounts are consistent with cost-of-service principles. They prevent intra-class subsidies by providing lower rates to customers that take service at higher delivery voltages. This is appropriate because the utility does not invest in distribution facilities and it also incurs lower losses to serve sub-transmission customers.

Q **WHAT CONCERNS DO YOU HAVE ABOUT THE PROPOSED TRANSFORMER OWNERSHIP DISCOUNT?**

A The proposed credits are understated because TECO divided the avoided cost by "ratcheted" rather than actual billing demand. The ratcheted demands were assumed to be 22% higher than the billing demand. However, there are no demand ratchets in TECO's tariffs. Thus, a cost-based credit should reflect actual billing demands.

Q **HOW WOULD USING BILLING DEMANDS AFFECT THE PROPOSED TRANSFORMER OWNERSHIP DISCOUNT?**

A The analysis is shown in **Exhibit ___(JP-17)**. The calculation is identical to TECO's, as found in TECO's response to FIPUG's Production of Document Request No. 20, but for substituting actual rather than ratcheted billing demands on lines 21 and 48.

6. INTERRUPTIBLE RATES

Q WHAT IS INTERRUPTIBLE POWER?

A Interruptible power is a tariff option that allows a utility to curtail interruptible load when resources are needed to maintain system reliability; that is, when there are insufficient resources to meet customer demand, a utility can curtail interruptible load. This allows the utility to maintain service to firm (i.e., non-interruptible) customers. Interruptible power, thus, is a lower quality of service than firm power. TECO does not include interruptible load in determining the need for additional capacity. Thus, TECO does not plan capacity additions to serve interruptible load.

Q DOES INTERRUPTIBLE POWER PROVIDE ANY OTHER BENEFITS?

A Yes. The Florida Reliability Coordinating Council (FRCC) requires that all reserve sharing groups and balancing authorities maintain adequate Contingency Reserves to cover the FRCC's most severe single contingency, which is currently 910 MW. Of this amount, TECO's contingency reserve requirement is currently 86.4 MW. TECO must supply this reserve when called upon to replace reserve capacity that is no longer available due to sudden forced outages of major generating facilities or the loss of transmission facilities.

Contingency reserves may be comprised of those generating resources and Interruptible Load that are available within 15 minutes. Thus, TECO counts interruptible power in meeting its contingency reserve obligations.[30]

Q PLEASE SUMMARIZE TECO'S PROPOSED REVISIONS TO ITS INTERRUPTIBLE TARIFFS.

A TECO proposes to continue to change the design of its interruptible tariffs, which it began in 1999 following Order No. PSC-99-1778-FOF-EI.

First, TECO asks this Commission to allow it to eliminate Schedules IS-1, IS-3, and SBI. The customers currently on these tariffs would be transferred to other rates. IS-1 and IS-3 customers would be transferred to Schedule GSD for firm service and Rider GSLM-2 for interruptible service. (As previously discussed, Schedule IS customers should not be transferred to Schedule GSD because the IS class load and service characteristics substantially differ from the GSD and GSLD classes.) Interruptible standby (SBI) customers would be transferred to Schedule SBF for firm supplemental and standby service and Rider GSLM-3 for standby interruptible service. Thus, all interruptible customers would pay firm rates and receive a credit that is supposed to reflect the value of interruptibility.

Second, the interruptible credit in the GSLM-2 and GSLM-3 Riders would be based on the Contracted Credit Value (CCV). The CCV approximately reflects TECO's avoided cost and is designed to provide a 1.2 benefit-to-cost ratio using the ratepayer impact measure (RIM) test. This is the same treatment accorded to demand-side management (DSM) programs. As discussed later, TECO has understated the capacity benefits Schedule IS customers provide, thereby understating the CCV.

Third, Riders GSLM-2 and GSLM-3 would be re-filed annually based on the then estimate of TECO's avoided costs. If TECO's avoided costs change, the CCV will change. This would subject interruptible customers to continual changes in their base rates. Under TECO's proposal, the CCV would only remain constant for up to three years thus making the rate highly unstable.

Fourth, by transferring all interruptible service to Riders GSLM-2 and GSLM-3, the interruptible credits would be removed from base rates and collected in the ECCR. Thus, TECO would be guaranteed dollar-for-dollar recovery of all capacity payments, including past over- (under) collections.

Fifth, the capacity payments recovered through the ECCR would be allocated to all customers, including the interruptible customers. As previously discussed, payments to interruptible customers are caused by and should be allocated to firm service customers only.

Q **HOW WOULD TECO'S PROPOSALS IMPACT INTERRUPTIBLE CUSTOMERS TAKING SERVICE ON SCHEDULES IS AND SBI?**

A As a consequence of TECO's proposals, Schedule IS/SBI customers would experience a 134% base rate increase, before the application of Riders GSLM-2 and GSLM-3. These Riders will offset some portion of the base rate increase. The amount of the offset will depend on (1) the CCV and (2) the customer's monthly billing load factor.

For 2009, the (CCV) would be $10.91 per monthly coincident peak (CP) kW. This would result in net annual payments of about $25.4 million. However, this would be offset by higher ECCR charges of $1 million. The net non-fuel rate increase for 2009 for IS/SBI customers would be 35%. These calculations are shown in **Exhibit ___ (JP-18)**. If TECO's proposals are approved, the IS class would receive the second highest base rate increases. This is despite the fact that the IS class is currently subsidizing other customer classes and is providing a return higher than TECO is seeking in this case.

Q **CAN INTERRUPTIBLE CUSTOMERS RELY ON RECEIVING A $10.91 PER KW CREDIT?**

A No. Under TECO's proposal, the CCV changes over time due to (1) changes in the CCV and (2) variations in the customer's monthly billing load factor.

The first change is addressed in Paragraph 5 of the Special Provisions paragraph in Riders GSLM-2 and GSLM-3. It states:

> When the customer's Initial Term of service runs out, that customer shall have a new CCV applied then for a new 36 month period. The credit applied shall be the one on file at that time at the FPSC. At any time, at the customer's discretion, the customer may request a new 36 month commitment whereupon their CCV shall be changed to the one then on file at the FPSC and a new Initial Term of 36 months shall be established.

The second change is addressed in the Monthly Credits paragraph of the GSLM-2 and GSLM-3 riders. It states:

> The Interruptible Demand Credit is the product of the Contracted Credit Value (CCV) (set forth in the Tariff Agreement for the Purchase of Industrial Load Management Rider Service) and the monthly Load Factor Adjusted Demand. The Load Factor Adjusted Demand shall be the product of the monthly Billing Demand and the monthly Billing Load Factor. The Billing Load Factor shall be the ratio of the Billing Energy to the monthly Billing Demand times the number of Billing Hours in the billing period. Billing Hours shall exclude any hours during which interruption of service occurred and no Optional Provision Energy was provided.

A customer's monthly load factor can also vary due to changing operating levels. However, as discussed later, load factor is not an appropriate proxy of the amount of load available for interruption.

Q **IS THE VARIABILITY OF THESE PAYMENTS PROBLEMATIC?**

A Yes. The variability of the capacity payments in the GSLM-2 and GSLM-3 riders is in stark contrast to the current IS/SBI structure. Currently, Schedule IS and SBI customers pay a lower rate that reflects the inferior quality of interruptible service. Thus, the capacity payment is fixed until the next general rate case and the amount of the payment does not fluctuate with a customer's monthly load factor. The changing nature of these payments would subject IS and SBI customers to rate instability.

Q **WHAT SUPPORT DOES TECO PROVIDE FOR PROPOSED RATE DESIGN CHANGES?**

A In support of its proposals, Mr. Ashburn cites Order No. PSC-93-0165-FOF-EI, the Commission Order in TECO's last rate case (Docket No. 920324-EI). This case was filed in 1992 and decided in February 1993, over 15 years ago.

Q **YOU PREVIOUSLY REFERENCED A 1999 COMMISSION ORDER ON INTERRUPTIBLE RATES. WHAT DID THE COMMISSION DECIDE?**

A The Commission granted TECO's petition to close Schedule IS-3 and to allow new interruptible service to be provided under the terms and conditions of Riders GSLM-2 and GSLM-3.[31]

Q **HAS THE WORLD CHANGED SINCE THAT 1999 ORDER WAS ISSUED?**

A Yes. The primary reason the Commission gave for closing Schedule IS-3 and creating the GSLM-2 and GSLM-3 riders was that interruptible load ceased being cost-effective due to declining equipment costs.[32] However, the cost of new generation capacity has increased significantly. The avoided unit being used to establish the $10.91 CCV is estimated to cost $871/kW.[33] By comparison, the installed cost of the Polk CTs is only $228/kW. As demonstrated later, rising equipment costs mean that Schedule IS/IS-3 is currently cost-effective.

Q HOW ELSE HAS THE WORLD CHANGED SINCE 1999?

A Interruptible power has received increasing attention from legislative and regulatory policy makers. I previously cited a FERC Order affirming that no production capacity costs should be allocated to interruptible customers. Interruptible load was also addressed in the Energy Policy Act of 2005 (EPACT 2005). Specifically:

> "(d) DEMAND RESPONSE.—The Secretary shall be responsible for—
> "(1) educating consumers on the availability, advantages, and benefits of advanced metering and communications technologies, including the funding of demonstration or pilot projects;
> "(2) working with States, utilities, other energy providers and advanced metering and communications experts to identify and address barriers to the adoption of demand response programs; and
> "(3) not later than 180 days after the date of enactment of the Energy Policy Act of 2005, providing Congress with a report that identifies and quantifies the national benefits of demand response and makes a recommendation on achieving specific levels of such benefits by January 1, 2007."
> (e) DEMAND RESPONSE AND REGIONAL COORDINATION.—
> (1) IN GENERAL.—It is the policy of the United States to encourage States to coordinate, on a regional basis, State energy policies to provide reliable and affordable demand response services to the public.
> (2) TECHNICAL ASSISTANCE.—The Secretary shall provide technical assistance to States and regional organizations formed by two or more States to assist them in—
> (A) identifying the areas with the greatest demand response potential;
> H. R. 6—373
> (B) identifying and resolving problems in transmission and distribution networks, including through the use of demand response;
> (C) developing plans and programs to use demand response to respond to peak demand or emergency needs; and
> (D) identifying specific measures consumers can take to participate in these demand response programs.

Following enactment, the FERC issued Order No. 693 in which it directed NERC to submit a modification to BAL-002 that includes a requirement that explicitly allows demand-side management (DSM) to be used as a resource for contingency reserves provided that it is treated on a comparable basis and meets similar technical requirements as other resources providing this service.[34]

Last February, the FERC issued an Advanced Notice of Proposed Rulemaking (ANOPR) to improve the operation of organized wholesale electric power markets. One of the improvements discussed in the ANOPR is in the area of demand response and the use of market prices to elicit demand response. In particular, the reforms would further eliminate barriers to demand response.[35]

Demand response is already providing certain ancillary services in various organized markets, including the PJM Interconnection and Electric Reliability Council of Texas (ERCOT). Thus, it is clear that promoting demand response (of which interruptible power is a primary option) is now a preferred policy.

Q IS INTERRUPTIBLE POWER AN IMPORTANT RESOURCE FOR THE STATE OF FLORIDA?

A Yes. The interruptible tariffs have been in place for decades. They have been and currently are a valuable resource to TECO and to the state as a whole. When capacity is needed to serve firm load customers, interruptible customers, statewide, may be called upon (with or without notice and without limitation as to the frequency and duration of curtailments) to discontinue service so that the lights will stay on for the firm customer base. Such interruption often causes production to be shut down resulting in losses for the interruptible customer.

Q **HOW CAN THE COMMISSION NURTURE THIS VALUABLE RESOURCE?**

A The Commission should not approve any changes that would discourage the continued use of this valuable resource. Rate designs that create instability, such as TECO's proposed rate structure, should be rejected.

Q **WHY IS A STABLE RATE DESIGN IMPORTANT TO MAINTAIN THE VIABILITY OF INTERRUPTIBLE POWER?**

A 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. Thus, rate stability is an important consideration in the design of interruptible rates. Significant changes in interruptible rates that reduce a customer's expected savings are inequitable to the existing customers as a matter of policy, because such changes increase the risk that the expected benefits will not outweigh the costs.

Further, for some customers, interruptible service is the only viable option. This is particularly the case for firms that produce commodity products, such as phosphate and industrial gases. Electricity is a significant operating cost in producing these products. Firms operating in these industries continue to face increasing global and domestic competition. An arbitrary change in cost allocation policy and drastic rate design changes could further raise their manufacturing costs and seriously hamper the continued operation of these firms.

Q **WHAT CONCERNS DO TECO'S RATE DESIGN PROPOSALS RAISE?**

A TECO's proposals raise several policy concerns. Specifically:

- Should payments to interruptible customers be subject to

- periodic changes outside of a base rate case?
- Is it reasonable and necessary for TECO to recover the cost of providing interruptible service through the ECCR?
- Is TECO properly valuing interruptible service?
- Is interruptible service the same as DSM?
- Should the interruptible credit be reduced by the customer's monthly load factor?

I address each of these important questions below.

Subjecting the CCV to Periodic Changes

Q DOES TECO'S PROPOSAL TO TRANSFER SCHEDULE IS/SBI CUSTOMERS TO THE GSLM RIDERS SUBJECT THESE CUSTOMERS TO PERIODIC BASE RATE CHANGES?

A Yes. The CCV is updated in the annual ECCR filings. The most recent update was filed in Docket No. 080002-EG. In that filing, TECO proposed a CCV of $10.91 for the period January through December 2009.[36] Prior years' CCVs have ranged from $3.71 in 2001 to $7.78 in 2007.[37] Thus, unlike firm customers, interruptible rates would be subject to change (up or down).

Q ARE RETAIL CUSTOMERS THAT PURCHASE FIRM POWER FROM TECO SUBJECT TO BASE RATE CHANGES OUTSIDE OF A BASE RATE CASE?

A No. Once the Commission sets base rates, they are not changed until the next rate case.

Q IS IT REASONABLE TO SUBJECT SCHEDULE IS/SBI CUSTOMERS TO PERIODIC BASE RATE CHANGES OUTSIDE A FULL RATE CASE?

A No. Among the rate design criteria TECO says it has considered in this proceeding are revenue stability and continuity.[38] Subjecting customers to potentially unstable rate designs, by pegging the CCV to ever changing measures of avoided cost, is fundamentally incompatible with these criteria.

Q **HOW CAN THIS PROBLEM BE AVOIDED WITHOUT CAUSING HARM TO TECO'S CUSTOMERS?**

A The easiest solution is to maintain the current Schedule IS/SBI structure but reset the rate to reflect the increasing value of interruptibility. As with TECO's other rates, no further changes would be made until the next rate case. With rising equipment costs, this more traditional rate-making approach would provide the necessary stability without causing harm to other customers.

Should the Commission prefer the approach that TECO proposes in this case, then an interruptible customer should have the option of locking-in the current CCV for an extended period of time, say five or ten years, at the customer's option. This alternative would also provide a more stable rate design. Further, other customers would not be harmed even if equipment costs were to suddenly (and unexpectedly) decline. This is because, as discussed later, interruptible load has allowed and (if properly nurtured) will continue to allow TECO to defer capacity additions.

Recovery through the ECCR

Q **IS IT REASONABLE AND NECESSARY TO RECOVER INTERRUPTIBLE CREDITS FROM SCHEDULE IS/SBI CUSTOMERS THROUGH THE ECCR?**

A No. The purpose of cost recovery clauses is to allow more timely recovery of costs outside of a general rate case when the failure to adjust rates would otherwise have an adverse financial impact on the utility. Thus, the costs subject to change in between general rate cases should be:

1. **Material**—that is, the particular expense is large in relation to the utility's overall revenue requirement,

2. **Volatile**—that is, the level of a particular expense is subject to wide fluctuations over a relatively short time-period; and

3. **Beyond the utility's direct control**—that is, a particular expense is subject to the impact of global and domestic commodity markets.

Fuel and purchased power energy costs meet these criteria. These costs account for over 48% of TECO's overall revenue requirements. As the Commission is well-aware, fuel costs reflect volatile changes in commodity costs. And, coal and natural gas prices affected by global markets are largely beyond TECO's direct control.

Q DO THE CAPACITY CREDITS PAID TO INTERRUPTIBLE CUSTOMERS MEET ALL THREE CRITERIA NECESSARY FOR SPECIAL COST RECOVERY TREATMENT?

A No. These payments constitute less than 1% of TECO's overall revenue requirements. Fixing interruptible rates based on the current value of interruptibility is well within TECO's direct control. Further, it would provide greater stability both for interruptible customers and the Company. Rates that fluctuate due to ever changing avoided cost estimates would make the capacity credits unnecessarily volatile.

<u>Value of Interruptibility</u>

Q HAS TECO CALCULATED THE LEVEL OF INTERRUPTIBLE SERVICE CREDIT?

A Yes. TECO filed a cost-effectiveness test in Docket No. 080002-EG that shows that the resulting credit for interruptible customers should be $10.91 per coincident peak (CP) kW.[39]

Q DO YOU AGREE WITH THE $10.91 VALUE AS DETERMINED BY TECO?

A No. The $10.91 CCV is understated for two reasons. First, the analysis assumed zero avoided capacity costs for the period 2008 through 2011. This assumption is based on a further assumption that the capacity avoided by interruptible power would be a 2012 combustion turbine (CT). Second, the analysis is based on the net present value of the costs and benefits of interruptible power with 2008 as the base year. As a consequence, the costs and benefits in 2009 were discounted. The CCV 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.

Q WHY WOULD USING A 2012 AVOIDED UNIT UNDERSTATE THE VALUE OF INTERRUPTIBILITY?

A TECO's cost-effectiveness analysis assigns *costs* to interruptible service in the form of incentive payments beginning in 2008 and for each year over the model's 25-year time horizon. However, the corresponding *benefits*, which primarily consist of avoided generation capacity costs, do not commence until 2012. In other words, the analysis assumes zero avoided generation capacity *benefits* for the period 2008 through 2011.

Q IS IT REASONABLE TO ASSIGN ZERO VALUE TO DEFERRED GENERATION CAPACITY IN THE YEARS 2008 THROUGH 2011?

A No. The interruptible tariffs have been in existence for decades. Their existence has allowed TECO to avoid building unneeded generation capacity (because capacity additions are based on projected firm loads). It should be noted that TECO is including the cost of five new CTs in its test year revenue requirements. Without interruptible load, TECO could have added six or more CTs. By specifically ignoring the capacity benefits provided by interruptible loads in the past, which continue to accrue benefits in the years 2008 through 2011, TECO's cost-effectiveness analysis understates the CCV.

Q **WHAT CHANGES SHOULD BE MADE TO TECO'S APPLICATION OF THE COST-EFFECTIVENESS MODEL TO MORE APPROPRIATELY MEASURE THE COSTS AND BENEFITS OF INTERRUPTIBLE POWER?**

A First, the base year of the model should be 2009 to recognize that the rates approved in this case will not become effective until May 2009, and the CCV would remain in effect for up to 36 months.

Second, since the incentive payments are principally made to recognize the avoided capacity cost benefits of interruptible service, the model should include avoided generation capacity costs for each year of the model's time horizon. It would be reasonable to set these avoided generation capacity benefits based on the installed cost of the Baytown and Polk CTs that TECO is proposing to include in rate base in this proceeding.

Q **HAVE YOU RE-RUN THE COST-EFFECTIVENESS MODEL WITH THE TWO CHANGES DESCRIBED ABOVE?**

A Yes. **Exhibit ___(JP-19)** is a revised cost-effectiveness analysis, which is based on the same analysis TECO presented in Docket No. 080002-EG, with the two recommended changes. As can be seen, the two changes would result in a CCV of over $13.70/kW, which is 25% higher than the $10.91/kW CCV derived by TECO and much more representative of the value of interruptible power.

Q YOU PREVIOUSLY STATED THAT THE CCV IS BASED ON ACHIEVING A 1.2 BENEFIT-TO-COST RATIO USING THE RIM TEST. IS THERE ANY ECONOMIC REASON WHY THE CCV NEEDS TO ACHIEVE A 1.2 BENEFIT-TO-COST RATIO?

A No. Other ratepayers would be no worse off if the CCV were set at full avoided cost (*i.e.,* a 1.0 benefit-to-cost ratio). Interruptible power offsets the need for additional generating capacity, thereby reducing total capacity costs from what they would have otherwise been without the presence of interruptible service.

The obvious analogy is with a fire insurance policy. Even though many years may pass without incident, the homeowner will continue to pay the insurance company to maintain the appropriate coverage. At a minimum, the cost that the system pays for this insurance coverage (in the form of interruptible demand credits) should reflect the avoided cost associated with deferring the installation of new peaking generation capacity on the TECO system. This is the case because peaking capacity is the type of generation that is most likely to be avoided through the continued presence of interruptible load on the utility's system.

Q HAVE POLICY MAKERS ALSO RECOGNIZED THIS INTRINSIC VALUE OF INTERRUPTIBLE POWER?

A Yes. Interruptible power provides "insurance" in the event that the utility experiences extreme weather, understates load growth, or sustains forced outages of a major resource. As the FERC has found:

> *61804 **[E]ven a limited right of interruption**, if it enables the Company to keep a customer from imposing demands on the system during peak periods, **gives a Company the ability to control its capacity costs.** Therefore, that customer shares no responsibility for capacity costs under a peak

> responsibility method. [FN145]
>
> It is, thus, the right to interrupt that is critical to the analysis, and not the actual interruptions or even the number or length of such interruptions. If a Company can keep a customer from imposing its load on the system at system peak, as Entergy can do here, then, under the peak responsibility method of cost allocation that Entergy uses, "that customer shares no responsibility for capacity costs...." [FN146]
>
> 75. Second, the distinction that the initial decision draws between "reliability" and "economic" considerations is also unclear. When a utility makes a commitment to serve firm load, it commits to serve that load at all times (absent a force majeure event on the system). When a utility makes a commitment to serve interruptible load, it does not commit to serve that load at all times. **To the contrary, it expressly reserves the right to interrupt (even if there is no force majeure event on its system).** Moreover, when it curtails interruptible load, it does so to protect its service to its firm load. That is, it curtails interruptible load precisely because it has not undertaken to construct or otherwise acquire the necessary facilities to serve interruptible load at all times and most particularly when use of the system is peaking; for firm load, in contrast, it has undertaken to construct or otherwise acquire such facilities.[40]

Q HAS THE INTRINSIC VALUE OF INTERRUPTIBLE POWER RECENTLY BEEN DEMONSTRATED?

A Yes. This past September, interruptible customers were curtailed twice, on two consecutive days, so that TECO could provide contingency reserves to assist other utilities in the state.[41]

<u>**Interruptible Service is Not the Same as DSM**</u>

Q SHOULD INTERRUPTIBLE SERVICE BE TREATED THE SAME AS DSM PROGRAMS FOR THE PURPOSE OF DESIGNING INTERRUPTIBLE RATES?

A No. The utility's obligation to serve customers who participate in DSM programs distinguishes DSM programs from interruptible service. A utility that funds a DSM program, such as home insulation, continues to provide firm service to its customers. The capacity and energy savings associated with such programs are merely a substitute for the power and energy sales that have been the traditional services provided by a regulated utility. Thus, DSM programs maintain or enhance the quality of firm service that customers receive.

By contrast, interruptible power is a lower quality of service. 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.

Further, as previously explained, interruptible loads are used to satisfy TECO's contingency reserve requirements as determined by the FRCC.

These characteristics clearly distinguish interruptible power from passive DSM programs.

<u>**Load Factor Adjustment**</u>

Q UNDER TECO'S PROPOSAL, WOULD ALL INTERRUPTIBLE CUSTOMERS RECEIVE THE $10.91 PER CP KW CCV?

A No. Under TECO's proposal, the $10.91 per kW CCV would be reduced in proportion to the customer's billing load factor. These credits would, in turn, be further reduced by any applicable metering voltage adjustment. For example, a primary distribution level customer having a maximum kW demand of 5,000 kW at a 70% load factor would have an effective interruptible credit of only $7.48 per kW ($10.91 per CP kW x 70% x 98% to account for the metering voltage adjustment).

Q **IS THIS LOAD FACTOR ADJUSTMENT A VALID APPROACH FOR ALLOCATING THE INTERRUPTIBLE CREDITS WITHIN THE IS CLASS?**

A No. First, TECO's proposal uses a customer's billing load factor as a proxy for the customer's coincidence factor. This approach assumes that there is a linear relationship between load factor and coincidence factor. However, TECO has provided no evidence of such a linear relationship.

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

Also, recall that 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. Thus, 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. In reality, 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 his 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, he would only get credit for half of the interruptible capacity that he is providing to TECO.

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.

Q HOW SHOULD THE MONTHLY CREDIT BE STRUCTURED?

A The Monthly 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 during an interruption period provides a benefit to the system.

To measure this benefit, it is my recommendation that the amount of interruptible demand subject to credit be determined by establishing each customer's normal operating demand for a defined "base line" period. For example, Southwestern Public Service Company (SPS) uses the following definition of interruptible demand:

> MONTHLY CREDIT
> The customer's Monthly Credit shall be calculated by multiplying the Monthly Credit Rate (MCR) by the lesser of the customer's CIL or the actual Interruptible Demand during the billing month.

The CIL or Contract Interruptible Load is defined as:

> The median of the customer's maximum daily thirty (30) minute integrated kW demands occurring between the hours of 12:00 noon and 8:00 p.m. Monday through Friday, excluding federal holidays, during the period June 1 through September 30 of the prior year, less the Contract Firm Demand, if any. If customer has no history in the prior year or customer anticipates that its CIL for the upcoming year will exceed the prior year's CIL by one hundred (100) kW or more, at customer's request, Company may, in its sole discretion, estimate the CIL. In extraordinary circumstances, Company may calculate CIL using load data from the year one year prior to the year normally used to calculate the CIL, if the customer has shown that, due to extraordinary circumstances, the load

> data that would normally be used to calculate its CIL is less representative of what the customer's load is likely to be in the upcoming year than its load data from the year one year prior to the period normally used.
>
> For existing customers, Company shall calculate the customer's CIL to be used in the upcoming year by December 31st of the then current year. If the Company determines that the customer's CIL to be used in the upcoming year is less than 500 kW, then the Agreement shall terminate at the end of the then current year. If the Company determines that the combined CIL of all existing customers to be used in the upcoming year exceeds 85MW, then those existing customers whose CIL is greater than the prior year's CIL may be required to reduce their CIL (by increasing their Contract Firm Demand) proportionally in order that total CIL does not exceed 85MW.[42]

Thus, SPS does not use load factor as a proxy for the amount of interruptible load.

Q **IS THERE ANOTHER ALTERNATIVE TO DETERMINE THE AMOUNT OF INTERRUPTIBLE LOAD?**

A Yes. 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).

Q **WHICH OF THESE TWO ALTERNATIVES DO YOU RECOMMEND?**

A While the real-time method would be the most accurate, I recommend using the SPS method as described above. This method would be easier to administer.

Q **IS THERE ANOTHER REASONABLE ALTERNATIVE APPROACH IF THE COMMISSION REJECTS THE SPS METHOD?**

A Yes. In lieu of the two alternatives discussed earlier, the credit could be applied as a reduction to the maximum demand charge as is presently the case. In other words, each customer should receive the same credit per kW of billing demand. Finally, in no event should load factor be used to adjust the amount of the credit unless the load factor is based on the class average load factor, not the 100% load factor that the Company proposes to use.

7. COST RECOVERY CLAUSES

Q IS TECO PROPOSING TO IMPLEMENT A NEW COST RECOVERY CLAUSE?

A Yes. TECO is proposing to add a fifth cost recovery clause, the Transmission Base Rate Adjustment (TBRA). As described by TECO witness, Jeffrey Chronister, the purpose of the TBRA would be to allow TECO to timely recover the costs associated with 230 kV and above transmission projects submitted for FRCC review, which are not already being recovered through base rates or a cost recovery clause.[43]

Q HOW WOULD THE TBRA WORK?

A The details are sketchy because TECO did not provide a written tariff. However, Mr. Chronister states that the TBRA would be similar to the Capacity Cost Recovery (CCR) clause. The Company would seek cost recovery for transmission plant additions that TECO projects will be substantially complete by calculating a revenue requirement using the authorized cost of equity and capital structure. A true up would be made to account for differences between estimated and actual expenditures.

Q HOW WOULD THE TBRA DETERMINE TRANSMISSION PLANT COSTS THAT ARE NOT ALREADY BEING RECOVERED THROUGH BASE RATES OR A COST RECOVERY CLAUSE?

A Assuming the design of the TBRA is similar to the CCR, recovery would include 100% of the costs of all new 230 kV transmission investment related to the specific FRCC-approved projects that are not already in rate base.

Q SHOULD THE PROPOSED TBRA BE IMPLEMENTED?

A No. TECO already has four separate cost recovery clauses that account for over 54% of its total revenue requirements. Adding a fifth clause would only exacerbate the current bias (that favors cost-recovery clauses) and would not provide a balanced regulatory framework. The Commission must balance the interests of ratepayers with the interests of the regulated utility. That balance would be thwarted by yet another new piecemeal rate rider. This is because piecemeal rate riders shift the risks that are normally the responsibility of utility shareholders between rate cases to ratepayers. Ratepayers would see their non-fuel rates rise and fall without a rate case. This represents piecemeal or single-issue ratemaking.

Q WHAT DO YOU MEAN BY *PIECEMEAL* OR *SINGLE-ISSUE* RATEMAKING?

A Piecemeal ratemaking would allow a utility to raise rates to reflect changes in certain specified costs, while ignoring potentially offsetting changes in other costs not subject to the rider. For example, the proposed TBRA would allow TECO to reflect changes in certain transmission capital costs. However, these changes would be made in isolation because they would ignore any potentially offsetting rate base reductions due to plant retirements or depreciation. Thus, even if TECO's rate base decreases, TECO would be allowed to increase rates solely based on incremental transmission investment.

Q WHAT OTHER CONCERNS DO YOU HAVE ABOUT THE TBRA?

A As previously stated, costs that are subject to recovery outside of a general rate case should be *material*, *volatile,* and *beyond the utility's control.* Transmission investment does not meet any of these criteria. Specifically, the projected $68.1 million of transmission plant additions in 2009 is less than 2% of TECO's rate base. Once a transmission facility commences service, the revenue requirement is fixed and does not vary over time. Further, as a member of the FRCC and as the party responsible for constructing new facilities, TECO has some control over the both the timing and cost.

Q WOULD THE ABSENCE OF A TBRA PREVENT TECO FROM HAVING A REASONABLE OPPORTUNITY TO RECOVER THE COST OF TRANSMISSION CAPACITY ADDITIONS?

A No. As TECO sells more energy, base rate revenues will also grow. Thus, TECO will have more revenue with which to recover increasing costs, including future plant additions. Stated differently, transmission plant additions will be offset to some degree by the growth in revenues stemming from growing electricity sales. The offset would be more significant because, as previously discussed, the base rates in this case are being set with an assumption of much slower sales growth during the test year.

Finally, if TECO is unable to earn a reasonable return, then it always has the option of filing a general rate case.

Q IF ANOTHER PIECEMEAL RATE RIDER IS ADOPTED, WHAT IMPACT SHOULD THIS HAVE IN DETERMINING TECO'S REVENUE REQUIREMENTS IN THIS PROCEEDING?

A Dollar-for-dollar recovery of costs, with interest, not only reduces regulatory lag but lowers TECO's regulatory risk. Thus, if the piecemeal rate riders are adopted, this lower risk should be considered in determining TECO's authorized return on equity. All other things being equal, adopting the proposed riders should result in a lower authorized return on common equity.

Q DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A Yes.

APPENDIX A
Qualifications of Jeffry Pollock

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Jeffry Pollock. My business mailing address is 12655 Olive Blvd, Suite 335, St. Louis, Missouri 63141.

Q WHAT IS YOUR OCCUPATION AND BY WHOM ARE YOU EMPLOYED?

A I am an energy advisor and President of J.Pollock Incorporated.

Q PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A I have a Bachelor of Science Degree in Electrical Engineering and a Masters in Business Administration from Washington University. At various times prior to graduation, I worked for the McDonnell Douglas Corporation in the Corporate Planning Department; Sachs Electric Company; and L. K. Comstock & Company. While at McDonnell Douglas, I analyzed the direct operating cost of commercial aircraft.

Upon graduation, in June 1975, I joined Drazen-Brubaker & Associates, Inc. (DBA). DBA was incorporated in 1972 assuming the utility rate and economic consulting activities of Drazen Associates, Inc., active since 1937. From April 1995 to November 2004, I was a managing principal at Brubaker & Associates (BAI).

During my tenure at both DBA and BAI, I have been engaged in a wide range of consulting assignments including energy and regulatory matters in both the United States and several Canadian provinces. This includes preparing financial and economic studies of investor-owned, cooperative and municipal utilities on revenue requirements, cost-of-service and rate design, and conducting site evaluation. Recent engagements have included advising clients on electric restructuring issues, assisting clients to procure and manage electricity in both competitive and regulated markets, developing and issuing request for proposals (RFPs), evaluating RFP responses and contract negotiation. I was also responsible for developing and presenting seminars on electricity issues.

I have worked on various projects in over 20 states and in two Canadian provinces, and have testified before the Federal Energy Regulatory Commission and the state regulatory commissions of Alabama, Arizona, Colorado, Delaware, Florida, Georgia, Illinois, Iowa, Louisiana, Minnesota, Mississippi, Missouri, Montana, New Jersey, New Mexico, Ohio, Pennsylvania, Texas, Virginia and Washington. I have also appeared before the City of Austin Electric Utility Commission, the Board of Public Utilities of Kansas City, Kansas, the Bonneville Power Administration, Travis County (Texas) District Court, and the U.S. Federal District Court. A list of my appearances since 1994 is attached.

Q **PLEASE DESCRIBE J.POLLOCK INCORPORATED.**

A J.Pollock assists clients to procure and manage energy in both regulated and competitive markets. The J.Pollock team also advises clients on energy and regulatory issues. Our clients include commercial, industrial and institutional energy consumers. Currently, J.Pollock has offices in St. Louis, Missouri and Austin and Houston, Texas.

ENDNOTES

[1] Mosaic filed a petition to intervene in this case on November 25, 2008.

[2] *Direct Testimony of Lorraine L Cifuentes*, Exhibit __, (LLC-1) Document No. 6.

[3] TECO's Response to FIPUG First Set of Interrogatories, No. 1.

[4] TECO's Response to FIPUG First Set of Interrogatories, No. 2.

[5] TECO's Response to FIPUG First Set of Interrogatories, No. 2.

[6] *Direct Testimony of Mark J. Hornick* at 15.

[7] *Direct Testimony of Dianne S. Merrill* at 10.

[8] *Id.*

[9] TECO Response to OPC's Third Set of Interrogatories, Interrogatory No. 31.

[10] *Id.*

[11] Source: SNL Financial

[12] TECO Response to OPC's Third Set of Interrogatories, Interrogatory No. 30.

[13] *See,* Application of AEP Texas Central Company for Authority to Change Rates, PUCT Docket No. 28840, *Final Order* issued August 15, 2005 at paragraphs 164 – 170.

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

[15] *Id,* at 95.

[16] *Id,* at 96.

[17] *See,* Application of AEP Texas Central Company for Authority to Change Rates, PUCT Docket No. 28840, *Final Order* issued August 15, 2005 at paragraphs 169 – 170.

[18] *Id.*

[19] *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* issued February 28, 2004 at pp. 30-31.

[20] *Id.*

[21] *Direct Testimony of William R. Ashburn* at 38.

[22] Order No. PSC-92-0002-FOF-EI at 4.

[23] Gulf Power Company, Florida Public Service Commission Docket No. 891345-EI, *Order No. 23573* at 42 (Oct. 3, 1990).

[24] *Order No. PSC-93-0165-FOF-EI* at 74.

[25] *Order No. PSC-05-0945-5-S-EI*; *Order No. PSC-05-0902-S-EI* at 4.

[26] Tampa Electric Company Nineteenth Revised Sheet No.6.090.

[27] 106 FERC ¶61,228, at 14 (emphasis added).

[28] Tampa Electric Company, *Ten Year Site Plan, 2008* at 51.

[29] Docket No. 010949-EI, *Order No. PSC-02-0787-FOF-EI* at 80.

[30] Florida Reliability Coordinating Council, *Handbook*, FRCC Contingency (Operating) Reserve Policy, November 2008.

[31] *Order No. PSC-99-1778-FOF-EI* at 8.

[32] *Id.* at 2.

[33] Docket No. 080002-EG, *Testimony of Howard T. Bryant* at Bates 60.

[34] FERC Docket No. RM06-16-000, Order No. 693 at 102.

[35] 122 FERC P 61167,2008 WL 469319 (FERC).

[36] Docket No. 080002-EG, *Testimony of Howard T. Bryant* at 9.

[37] TECO's Response to FIPUG's POD 20 at Bates 1507.

[38] *Direct Testimony of William J. Ashburn* at 38.

[39] Docket No. 080002-EG, *Testimony of Howard T.* Bryant at 9.

[40] 106 FERC ¶61,228, at 14 (emphasis added).

[41] TECO's Reply to FIPUG Interrogatory No. 38.

[42] Southwestern Public Service Company, *Electric Tariff*, Section No. IV, Sheet No. IV-177.

[43] *Direct Testimony of Jeffrey S. Chronister* at 44.

Appendix A
Testimony Filed in Regulatory Proceedings
by Jeffry Pollock

PROJECT	UTILITY	ON BEHALF OF	Docket	TYPE	Regulatory Jurisdiction	Subject	DATE
80601	SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	35763	Supplemental Direct	TX	Recovery of Energy Efficiency Costs	11/6/2008
80601	SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	35763	Cross-Rebuttal	TX	Cost Allocation, Demand Ratchet, Renewable Energy Certificates (REC)	10/28/2008
80601	SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	35763	Direct	TX	Revenue Requirements, Fuel Reconciliation Revenue Allocation, Cost-of-Service and Rate Design Issues	
50106	ALABAMA POWER COMPANY	Alabama Industrial Energy Consumers	18148	Direct	AL	Energy Cost Recovery Rate (WITHDRAWN)	9/16/2008
50701	ENTERGY TEXAS, INC.	Texas Industrial Energy Consumers	35269	Direct	TX	Allocation of rough production costs equalization payments	7/9/2008
70703	ENTERGY GULF STATES UTILITIES, TEXAS	Texas Industrial Energy Consumers	34800	Direct	TX	Non-Unanimous Stipulation	6/11/2008
50103	TEXAS PUC STAFF	Texas Industrial Energy Consumers	33672	Supplemental Rebuttal	TX	Transmission Optimization and Ancillary Services Studies	6/3/2008
50103	TEXAS PUC STAFF	Texas Industrial Energy Consumers	33672	Supplemental Direct	TX	Transmission Optimization and Ancillary Services Studies	5/23/2008
60104	SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Industrial Energy Consumers	33891	Supplemental Direct	TX	Certificate of Convenience and Necessity	5/8/2008
70703	ENTERGY GULF STATES UTILITES, TEXAS	Texas Industrial Energy Consumers	34800	Cross-Rebuttal	TX	Cost Allocation and Rate Design and Competitive Generation Service	4/18/2008
70703	ENTERGY GULF STATES UTILITES, TEXAS	Texas Industrial Energy Consumers	34800	Direct	TX	Eligible Fuel Expense	4/11/2008
70703	ENTERGY GULF STATES UTILITES, TEXAS	Texas Industrial Energy Consumers	34800	Direct	TX	Competitive Generation Service Tariff	4/11/2008
70703	ENTERGY GULF STATES UTILITES, TEXAS	Texas Industrial Energy Consumers	34800	Direct	TX	Revenue Requirements	4/11/2008
70703	ENTERGY GULF STATES UTILITES, TEXAS	Texas Industrial Energy Consumers	34800	Direct	TX	Cost of Service study, revenue allocation, design of firm, interruptible and standby service tariffs; interconnection costs	4/11/2008
41229	TEXAS-NEW MEXICO POWER COMPANY	Texas Industrial Energy Consumers	35038	Rebuttal	TX	Over $5 Billion Compliance Filing	4/14/2008
71202	SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Periman Ltd.	07-00319-UT	Rebuttal	NM	Revenue requirements, cost of service study, rate design	3/28/2008
61101	AEP TEXAS CENTRAL COMPANY	Texas Industrial Energy Consumers	35105	Direct	TX	Over $5 Billion Compliance Filing	3/20/2008
51101	CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC	Texas Industrial Energy Consumers	32902	Direct	TX	Over $5 Billion Compliance Filing	3/20/2008
71202	SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Periman Ltd.	07-00319-UT	Direct	NM	Revenue requirements, cost of service study (COS); rate design	3/7/2008
50701	ENTERGY GULF STATES UTILITIES TEXAS	Texas Industrial Energy Consumers	34724	Direct	TX	IPCR Rider increase and interim surcharge	11/28/2007
70601	GEORGIA POWER COMPANY	Georgia Industrial Group/Georgia Traditional Manufacturers Group	25060-U	Direct	GA	Return on equity; cost of service study; revenue allocation; ILR Rider; spinning reserve tariff; RTP	10/24/2007
70303	ONCOR ELECTRIC DELIVERY COMPANY & TEXAS ENERGY FUTURE HOLDINGS LTD	Texas Industrial Energy Consumers	34077	Direct	TX	Acquisition; public interest	9/14/2007
60104	SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Industrial Energy Consumers	33891	Direct	TX	Certificate of Convenience and Necessity	8/30/2007
61201	ALTAMAHA ELECTRIC MEMBERSHIP CORPORATION	SP Newsprint Company	25226-U	Rebuttal	GA	Discriminatory Pricing; Service Territorial Transfer	7/17/2007
61201	ALTAMAHA ELECTRIC MEMBERSHIP CORPORATION	SP Newsprint Company	25226-U	Direct	GA	Discriminatory Pricing; Service Territorial Transfer	7/6/2007

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by Jeffry Pollock

PROJECT	UTILITY	ON BEHALF OF	Docket	TYPE	Regulatory Jurisdiction	Subject	DATE
70502	PROGRESS ENERGY FLORIDA	Florida Industrial Power Users Group	070052-EI	Direct	FL	Nuclear uprate cost recovery	6/19/2007
70603	ELECTRIC TRANSMISSION TEXAS LLC	Texas Industrial Energy Consumers	33734	Direct	TX	Certificate of Convenience and Necessity	6/8/2007
60601	TEXAS PUC STAFF	Texas Industrial Energy Consumers	32795	Rebuttal Remand	TX	Interest rate on stranded cost reconciliation	6/15/2007
60601	TEXAS PUC STAFF	Texas Industrial Energy Consumers	32795	Remand	TX	Interest rate on stranded cost reconciliation	6/8/2007
50103	TEXAS PUC STAFF	Texas Industrial Energy Consumers	33672	Rebuttal	TX	CREZ Nominations	5/21/2007
50701	ENTERGY GULF STATES UTILITES, TEXAS	Texas Industrial Energy Consumers	33687	Direct	TX	Transition to Competition	4/27/2007
50103	TEXAS PUC STAFF	Texas Industrial Energy Consumers	33672	Direct	TX	CREZ Nominations	4/24/2007
61101	AEP TEXAS CENTRAL COMPANY	Texas Industrial Energy Consumers	33309	Cross-Rebuttal	TX	Cost Allocation,Rate Design, Riders	4/3/2007
50701	ENTERGY GULF STATES UTILITIES TEXAS	Texas Industrial Energy Consumers	32710	Cross-Rebuttal	TX	Fuel and Rider IPCR Reconcilation	3/16/2007
61101	AEP TEXAS NORTH COMPANY	Texas Industrial Energy Consumers	33310	Direct	TX	Cost Allocation,Rate Design, Riders	3/13/2007
61101	AEP TEXAS CENTRAL COMPANY	Texas Industrial Energy Consumers	33309	Direct	TX	Cost Allocation,Rate Design, Riders	3/13/2007
50701	ENTERGY GULF STATES UTILITIES TEXAS	Texas Industrial Energy Consumers	32710	Direct	TX	Fuel and Rider IPCR Reconcilation	2/28/2007
41219	AEP TEXAS CENTRAL COMPANY	Texas Industrial Energy Consumers	31461	Direct	TX	Rider CTC design	2/15/2007
50701	ENTERGY GULF STATES UTILITIES TEXAS	Texas Industrial Energy Consumers	33586	Cross-Rebuttal	TX	Hurricane Rita reconstruction costs	1/30/2007
60104	SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Industrial Energy Consumers	32898	Direct	TX	Fuel Reconciliation	1/29/2007
50701	ENTERGY GULF STATES UTILITIES TEXAS	Texas Industrial Energy Consumers	33586	Direct	TX	Hurricane Rita reconstruction costs	1/18/2007
60303	GEORGIA POWER COMPANY	Georgia Industrial Group/Georgia Textile Manufacturers Group	23540-U	Direct	GA	Fuel Cost Recovery	1/11/2007
60503	SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	32766	Cross Rebuttal	TX	Cost allocation, Cost of service, Rate design	1/8/2007
60503	SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	32766	Direct	TX	Cost allocation, Cost of service, Rate design	12/22/2006
60503	SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	32766	Direct	TX	Revenue Requirements,	12/17/2006
60503	SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	32766	Direct	TX	Fuel Reconcilation	12/17/2006
50701	ENTERGY GULF STATES UTILITIES TEXAS	Texas Industrial Energy Consumers	32907	Cross Rebuttal	TX	Hurricane Rita reconstruction costs	10/12/06
50701	ENTERGY GULF STATES UTILITIES TEXAS	Texas Industrial Energy Consumers	32907	Direct	TX	Hurricane Rita reconstruction costs	10/09/06
60601	TEXAS PUC STAFF	Texas Industrial Energy Consumers	32795	Cross Rebuttal	TX	Stranded Cost Reallocation	09/07/06
60101	COLQUITT EMC	ERCO Worldwide	23549-U	Direct	GA	Service Territory Transfer	08/10/06
60601	TEXAS PUC STAFF	Texas Industrial Energy Consumers	32795	Direct	TX	Stranded Cost Reallocation	09/07/06
60104	SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Industrial Energy Consumers	32672	Direct	TX	ME-SPP Transfer of Certificate to SWEPCO	8/23/2006

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50503	AEP TEXAS CENTRAL COMPANY	Texas Industrial Energy Consumers	32758	Direct	TX	Rider CTC design and cost recovery	08/24/06
60503	SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	32685	Direct	TX	Fuel Surcharge	07/26/06
60301	PUBLIC SERVICE ELECTRIC AND GAS COMPANY	New Jersey Large Energy Consumers	171406	Direct	NJ	Gas Delivery Cost allocation and Rate design	06/21/06
60303	GEORGIA POWER COMPANY	Georgia Industrial Group/Georgia Textile Manufacturers Group	22403-U	Direct	GA	Fuel Cost Recovery Allowance	05/05/06
50503	AEP TEXAS CENTRAL COMPANY	Texas Industrial Energy Consumers	32475	Cross-Rebuttal	TX	ADFIT Benefit	04/27/06
50503	AEP TEXAS CENTRAL COMPANY	Texas Industrial Energy Consumers	32475	Direct	TX	ADFIT Benefit	04/17/06
41229	TEXAS-NEW MEXICO POWER COMPANY	Texas Industrial Energy Consumers	31994	Cross-Rebuttal	TX	Stranded Costs and Other True-Up Balances	3/16/2006
41229	TEXAS-NEW MEXICO POWER COMPANY	Texas Industrial Energy Consumers	31994	Direct	TX	Stranded Costs and Other True-Up Balances	3/10/2006
50303	SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Periman Ltd. Occidental Power Marketing	ER05-168-001	Direct	NM	Fuel Reconciliation	3/6/2006
50701	ENTERGY GULF STATES UTILITIES TEXAS	Texas Industrial Energy Consumers	31544	Cross-Rebuttal	TX	Transition to Competition Costs	01/13/06
50701	ENTERGY GULF STATES UTILITIES TEXAS	Texas Industrial Energy Consumers	31544	Direct	TX	Transition to Competition Costs	01/13/06
50601	PUBLIC SERVICE ELECTRIC AND GAS COMPANY AND EXELON CORPORATION	New Jersey Large Energy Consumers Retail Energy Supply Association	BPU EM05020106 OAL PUC-1874-05	Surrebuttal	NJ	Merger	12/22/2005
50705	SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Periman Ltd. Occidental Power Marketing	EL05-19-002; ER05-168-001	Responsive	FERC	Fuel Cost adjustment clause (FCAC)	11/18/2005
50601	PUBLIC SERVICE ELECTRIC AND GAS COMPANY AND EXELON CORPORATION	New Jersey Large Energy Consumers Retail Energy Supply Association	BPU EM05020106 OAL PUC-1874-05	Direct	NJ	Merger	11/14/2005
50102	PUBLIC UTILITY COMMISSION OF TEXAS	Texas Industrial Energy Consumers	31540	Direct	TX	Nodal Market Protocols	11/10/2005
50701	ENTERGY GULF STATES UTILITIES TEXAS	Texas Industrial Energy Consumers	31315	Cross-Rebuttal	TX	Recovery of Purchased Power Capacity Costs	10/4/2005
50701	ENTERGY GULF STATES UTILITIES TEXAS	Texas Industrial Energy Consumers	31315	Direct	TX	Recovery of Purchased Power Capacity Costs	9/22/2005
50705	SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Periman Ltd. Occidental Power Marketing	EL05-19-002; ER05-168-001	Responsive	FERC	Fuel Cost Adjustment Clause (FCAC)	9/19/2005
50503	AEP TEXAS CENTRAL COMPANY	Texas Industrial Energy Consumers	31056	Direct	TX	Stranded Costs and Other True-Up Balances	9/2/2005
50705	SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Periman Ltd. Occidental Power Marketing	EL05-19-00; ER05-168-00	Direct	FERC	Fuel Cost adjustment clause (FCAC)	8/19/2006
50203	GEORGIA POWER COMPANY	Georgia Industrial Group/Georgia Textile Manufacturers Group	19142-U	Direct	GA	Fuel Cost Recovery	4/8/2005
41230	CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC	Texas Industrial Energy Consumers	30706	Direct	TX	Competition Transition Charge	3/16/2005
41230	CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC	Texas Industrial Energy Consumers	30485	Supplemental Direct	TX	Financing Order	1/14/2005
41230	CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC	Texas Industrial Energy Consumers	30485	Direct	TX	Financing Order	1/7/2005
8201	PUBLIC SERVICE COMPANY OF COLORADO	Colorado Energy Consumers	04S-164E	Cross Answer	CO	Cost of Service Study, Interruptible Rate Design	12/13/2004
8201	PUBLIC SERVICE COMPANY OF COLORADO	Colorado Energy Consumers	04S-164E	Answer	CO	Cost of Service Study, Interruptible Rate Design	10/12/2004

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PROJECT	UTILITY	ON BEHALF OF	Docket	TYPE	Regulatory Jurisdiction	Subject	DATE
8244	GEORGIA POWER COMPANY	Georgia Industrial Group/Georgia Textile Manufacturers Group	18300-U	Direct	GA	Revenue Requirements, Revenue Allocation, Cost of Service, Rate Design, Economic Development	10/8/2004
8195	CENTERPOINT, RELIANT AND TEXAS GENCO	Texas Industrial Energy Consumers	29526	Direct	TX	True-Up	6/1/2004
8156	GEORGIA POWER COMPANY/SAVANNAH ELECTRIC AND POWER COMPANY	Georgia Industrial Group	17687-U/17688-U	Direct	GA	Demand Side Management	5/14/2004
8148	TEXAS-NEW MEXICO POWER COMPANY	Texas Industrial Energy Consumers	29206	Direct	TX	True-Up	3/29/2004
8095	CONECTIV POWER DELIVERY	New Jersey Large Energy Consumers	ER03020110	Surrebuttal	NJ	Cost of Service	3/18/2004
8111	AEP TEXAS CENTRAL COMPANY	Texas Industrial Energy Consumers	28840	Rebuttal	TX	Cost Allocation and Rate Design	2/4/2004
8095	CONECTIV POWER DELIVERY	New Jersey Large Energy Consumers	ER03020110	Direct	NJ	Cost Allocation and Rate Design	1/4/2004
7850	RELIANT ENERGY HL&P	Texas Industrial Energy Consumers	26195	Supplemental Direct	TX	Fuel Reconciliation	9/23/2003
8045	VIRGINIA ELECTRIC AND POWER COMPANY	Virginia Committee for Fair Utility Rates	PUE-2003-00285	Direct	VA	Stranded Cost	9/5/2003
8022	GEORGIA POWER COMPANY	Georgia Industrial Group/Georgia Textile Manufacturers Group	17066-U	Direct	GA	Fuel Cost Recovery	7/22/2003
8002	AEP TEXAS CENTRAL COMPANY	Flint Hills Resources, LP	25395	Direct	TX	Delivery Service Tariff Issues	5/9/2003
7857	PUBLIC SERVICE ELECTRIC AND GAS COMPANY	New Jersey Large Energy Consumers	ER02050303	Supplemental	NJ	Cost of Service	3/14/2003
7850	RELIANT ENERGY HL&P	Texas Industrial Energy Consumers	26195	Direct	TX	Fuel Reconciliation	12/31/2002
7857	PUBLIC SERVICE ELECTRIC AND GAS COMPANY	New Jersey Large Energy Consumers	ER02050303	Surrebuttal	NJ	Revenue Allocation	12/16/2002
7836	PUBLIC SERVICE COMPANY OF COLORADO	Colorado Energy Consumers	02S-315EG	Answer	CO	Incentive Cost Adjustment	11/22/2002
7857	PUBLIC SERVICE ELECTRIC AND GAS COMPANY	New Jersey Large Energy Consumers	ER02050303	Direct	NJ	Revenue Allocation	10/22/2002
7863	DOMINION VIRGINIA POWER	Virginia Committee for Fair Utility Rates	PUE-2001-00306	Direct	VA	Generation Market Prices	8/12/2002
7718	FLORIDA POWER CORPORATION	Florida Industrial Power Users Group	000824-EI	Direct	FL	Rate Design	1/18/2002
7633	GEORGIA POWER COMPANY	Georgia Industrial Group/Georgia Textile Manufacturers Group	14000-U	Direct	GA	Cost of Service Study, Revenue Allocation, Rate Design	10/12/2001
7555	TAMPA ELECTRIC COMPANY	Florida Industrial Power Users Group	010001-EI	Direct	FL	Rate Design	10/12/2001
7658	SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Industrial Energy Consumers	24468	Direct	TX	Delay of Retail Competition	9/24/2001
7647	ENTERGY GULF STATES, INC.	Texas Industrial Energy Consumers	24469	Direct	TX	Delay of Retail Competition	9/22/2001
7608	RELIANT ENERGY HL&P	Texas Industrial Energy Consumers	23950	Direct	TX	Price to Beat	7/3/2001
7593	GEORGIA POWER COMPANY	Georgia Industrial Group/Georgia Textile Manufacturers Group	13711-U	Direct	GA	Fuel Cost Recovery	5/11/2001
7520	GEORGIA POWER COMPANY SAVANNAH ELECTRIC & POWER COMPANY	Georgia Industrial Group/Georgia Textile Manufacturers Group	12499-U,13305-U, 13306-U	Direct	GA	Integrated Resource Planning	5/11/2001
7303	ENTERGY GULF STATES, INC.	Texas Industrial Energy Consumers	22356	Rebuttal	TX	Allocation/Collection of Municipal Franchise Fees	3/31/2001

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PROJECT	UTILITY	ON BEHALF OF	Docket	TYPE	Regulatory Jurisdiction	Subject	DATE
7309	SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	22351	Cross-Rebuttal	TX	Energy Efficiency Costs	2/22/2001
7305	CPL, SWEPCO, and WTU	Texas Industrial Energy Consumers	22352, 22353, 22354	Cross-Rebuttal	TX	Allocation/Collection of Municipal Franchise Fees	2/20/2001
7423	GEORGIA POWER COMPANY	Georgia Industrial Group/Georgia Textile Manufacturers Group	13140-U	Direct	GA	Interruptible Rate Design	2/16/2001
7305	CPL, SWEPCO, and WTU	Texas Industrial Energy Consumers	22352, 22353, 22354	Supplemental Direct	TX	Transmission Cost Recovery Factor	2/13/2001
7310	TEXAS-NEW MEXICO POWER COMPANY	Texas Industrial Energy Consumers	22349	Cross-Rebuttal	TX	Rate Design	2/12/2001
7308	TXU ELECTRIC COMPANY	Texas Industrial Energy Consumers	22350	Cross-Rebuttal	TX	Unbundled Cost of Service	2/12/2001
7303	ENTERGY GULF STATES, INC.	Texas Industrial Energy Consumers	22356	Cross-Rebuttal	TX	Stranded Cost Allocation	2/6/2001
7308	TXU ELECTRIC COMPANY	Texas Industrial Energy Consumers	22350	Direct	TX	Rate Design	2/5/2001
7303	ENTERGY GULF STATES, INC.	Texas Industrial Energy Consumers	22356	Supplemental Direct	TX	Rate Design	1/25/2001
7307	RELIANT ENERGY HL&P	Texas Industrial Energy Consumers	22355	Cross-Rebuttal	TX	Stranded Cost Allocation	1/12/2001
7303	ENTERGY GULF STATES, INC.	Texas Industrial Energy Consumers	22356	Direct	TX	Stranded Cost Allocation	1/9/2001
7307	RELIANT ENERGY HL&P	Texas Industrial Energy Consumers	22355	Direct	TX	Cost Allocation	12/13/2000
7375	CENTRAL POWER AND LIGHT COMPANY	Texas Industrial Energy Consumers	22352	Cross-Rebuttal	TX	CTC Rate Design	12/1/2000
7375	CENTRAL POWER AND LIGHT COMPANY	Texas Industrial Energy Consumers	22352	Direct	TX	Cost Allocation	11/1/2000
7308	TXU ELECTRIC COMPANY	Texas Industrial Energy Consumers	22350	Direct	TX	Cost Allocation	11/1/2000
7308	TXU ELECTRIC COMPANY	Texas Industrial Energy Consumers	22350	Cross-Rebuttal	TX	Cost Allocation	11/1/2000
7305	CPL, SWEPCO, and WTU	Texas Industrial Energy Consumers	22352, 22353, 22354	Direct	TX	Excess Cost Over Market	11/1/2000
7315	VARIOUS UTILITIES	Texas Industrial Energy Consumers	22344	Direct	TX	Generic Customer Classes	10/14/2000
7308	TXU ELECTRIC COMPANY	Texas Industrial Energy Consumers	22350	Direct	TX	Excess Cost Over Market	10/10/2000
7315	VARIOUS UTILITIES	Texas Industrial Energy Consumers	22344	Rebuttal	TX	Excess Cost Over Market	10/1/2000
7310	TEXAS-NEW MEXICO POWER COMPANY	Texas Industrial Energy Consumers	22349	Cross-Rebuttal	TX	Generic Customer Classes	10/1/2000
7310	TEXAS-NEW MEXICO POWER COMPANY	Texas Industrial Energy Consumers	22349	Direct	TX	Excess Cost Over Market	9/27/2000
7307	RELIANT ENERGY HL&P	Texas Industrial Energy Consumers	22355	Cross-Rebuttal	TX	Excess Cost Over Market	9/26/2000
7307	RELIANT ENERGY HL&P	Texas Industrial Energy Consumers	22355	Direct	TX	Excess Cost Over Market	9/19/2000
7334	GEORGIA POWER COMPANY	Georgia Industrial Group/Georgia Textile Manufacturers Group	11708-U	Rebuttal	GA	RTP Petition	3/24/2000
7334	GEORGIA POWER COMPANY	Georgia Industrial Group/Georgia Textile Manufacturers Group	11708-U	Direct	GA	RTP Petition	3/1/2000
7232	PUBLIC SERVICE COMPANY OF COLORADO	Colorado Industrial Energy Consumers	99A-377EG	Answer	CO	Merger	12/1/1999

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7258	TXU ELECTRIC COMPANY	Texas Industrial Energy Consumers	21527	Direct	TX	Securitization	11/24/1999
7246	CENTRAL POWER AND LIGHT COMPANY	Texas Industrial Energy Consumers	21528	Direct	TX	Securitization	11/24/1999
7089	VIRGINIA ELECTRIC AND POWER COMPANY	Virginia Committee for Fair Utility Rates	PUE980813	Direct	VA	Unbundled Rates	7/1/1999
7090	AMERICAN ELECTRIC POWER SERVICE CORPORATION	Old Dominion Committee for Fair Utility Rates	PUE980814	Direct	VA	Unbundled Rates	5/21/1999
7142	SHARYLAND UTILITIES, L.P.	Sharyland Utilities	20292	Rebuttal	TX	Certificate of Convenience and Necessity	4/30/1999
7060	PUBLIC SERVICE COMPANY OF COLORADO	Colorado Industrial Energy Consumers Group	98A-511E	Direct	CO	Allocation of Pollution Control Costs	3/1/1999
7039	SAVANNAH ELECTRIC AND POWER COMPANY	Various Industrial Customers	10205-U	Direct	GA	Fuel Costs	1/1/1999
6945	TAMPA ELECTRIC COMPANY	Florida Industrial Power Users Group	950379-EI	Direct	FL	Revenue Requirement	10/1/1998
6873	GEORGIA POWER COMPANY	Georgia Industrial Group	9355-U	Direct	GA	Revenue Requirement	10/1/1998
6729	VIRGINIA ELECTRIC AND POWER COMPANY	Virginia Committee for Fair Utility Rates	PUE960036,PUE960296	Direct	VA	Alternative Regulatory Plan	8/1/1998
6713	CENTRAL POWER AND LIGHT COMPANY	Texas Industrial Energy Consumers	16995	Cross-Rebuttal	TX	IRR	1/1/1998
6582	HOUSTON LIGHTING & POWER COMPANY	Lyondell Petrochemical Company	96-02867	Direct	COURT	Interruptible Power	1997
6758	SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Industrial Energy Consumers	17460	Direct	TX	Fuel Reconciliation	12/1/1997
6729	VIRGINIA ELECTRIC AND POWER COMPANY	Virginia Committee for Fair Utility Rates	PUE960036,PUE960296	Direct	VA	Alternative Regulatory Plan	12/1/1997
6713	CENTRAL POWER AND LIGHT COMPANY	Texas Industrial Energy Consumers	16995	Direct	TX	Rate Design	12/1/1997
6646	ENTERGY TEXAS	Texas Industrial Energy Consumers	16705	Rebuttal	TX	Competitive Issues	10/1/1997
6646	ENTERGY TEXAS	Texas Industrial Energy Consumers	16705	Rebuttal	TX	Competition	10/1/1997
6646	ENTERGY TEXAS	Texas Industrial Energy Consumers	473-96-2285/16705	Direct	TX	Rate Design	9/1/1997
6646	ENTERGY TEXAS	Texas Industrial Energy Consumers	16705	Direct	TX	Wholesale Sales	8/1/1997
6744	TAMPA ELECTRIC COMPANY	Florida Industrial Power Users Group	970171-EU	Direct	FL	Interruptible Rate Design	5/1/1997
6632	MISSISSIPPI POWER COMPANY	Colonial Pipeline Company	96-UN-390	Direct	MS	Interruptible Rates	2/1/1997
6558	TEXAS-NEW MEXICO POWER COMPANY	Texas Industrial Energy Consumers	15560	Direct	TX	Competition	11/11/1996
6508	TEXAS UTILITIES ELECTRIC COMPANY	Texas Industrial Energy Consumers	15195	Direct	TX	Treatment of margins	9/1/1996
6475	TEXAS UTILITIES ELECTRIC COMPANY	Texas Industrial Energy Consumers	15015	DIRECT	TX	Real Time Pricing Rates	8/8/1996
6449	CENTRAL POWER AND LIGHT COMPANY	Texas Industrial Energy Consumers	14965	Direct	TX	Quantification	7/1/1996
6449	CENTRAL POWER AND LIGHT COMPANY	Texas Industrial Energy Consumers	14965	Direct	TX	Interruptible Rates	5/1/1996
6449	CENTRAL POWER AND LIGHT COMPANY	Texas Industrial Energy Consumers	14965	Rebuttal	TX	Interruptible Rates	5/1/1996

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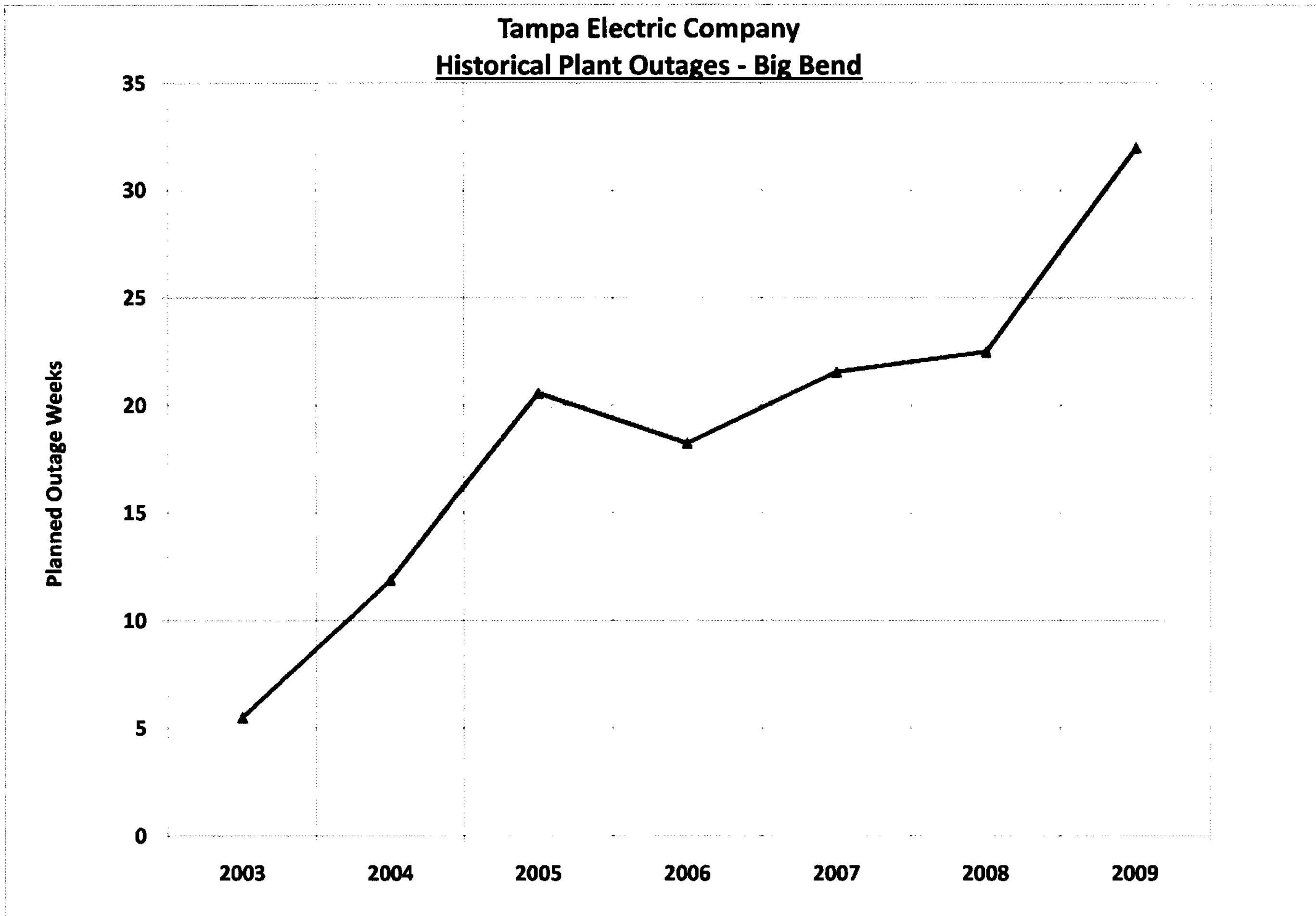
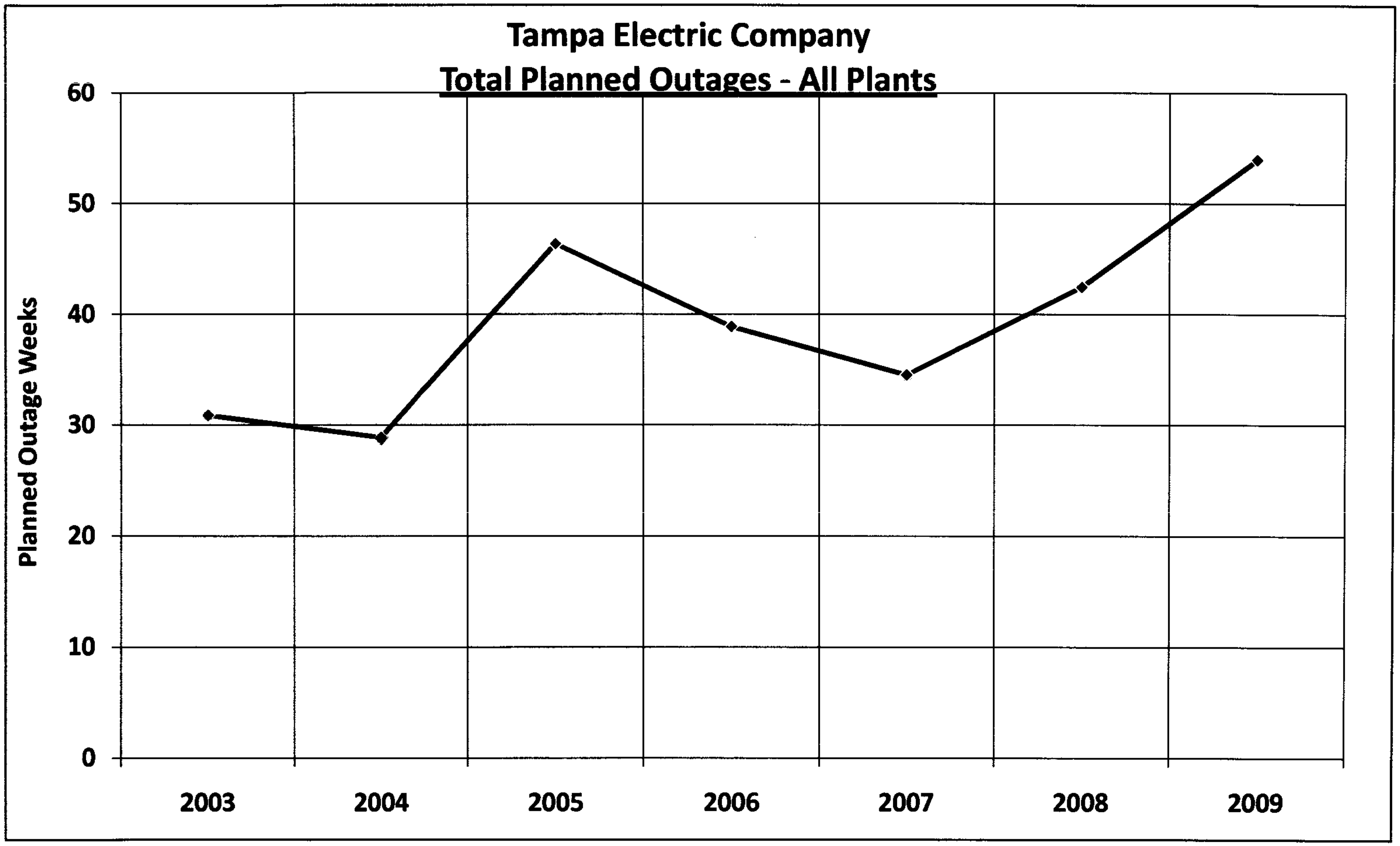
6523	PUBLIC SERVICE COMPANY OF COLORADO	Multiple Intervenors	95A-531EG	Answer	CO	Merger	4/1/1996
6235	TEXAS UTILITIES ELECTRIC COMPANY	Texas Industrial Energy Consumers	13575	Direct	TX	Competitive Issues	4/1/1996
6435	SOUTHWESTERN PUBLIC SERVICE COMMISSION	Texas Industrial Energy Consumers	14499	Direct	TX	Acquisition	11/1/1995
6391	HOUSTON LIGHTING & POWER COMPANY	Grace, W.R & Company	13988	Rebuttal	TX	Rate Design	8/1/1995
6353	SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	14174	Direct	TX	Costing of Off-System Sales	8/1/1995
6157	WEST TEXAS UTILITIES COMPANY	Texas Industrial Energy Consumers	13369	Rebuttal	TX	Cancellation Term	8/1/1995
6391	HOUSTON LIGHTING & POWER COMPANY	Grace, W.R & Company	13988	Direct	TX	Rate Design	7/1/1995
6157	WEST TEXAS UTILITIES COMPANY	Texas Industrial Energy Consumers	13369	Direct	TX	Cancellation Term	7/1/1995
6296	GEORGIA POWER COMPANY	Georgia Industrial Group	5601-U	Rebuttal	GA	EPACT Rate-Making Standards	5/1/1995
6296	GEORGIA POWER COMPANY	Georgia Industrial Group	5601-U	Direct	GA	EPACT Rate-Making Standards	5/1/1995
6278	COMMONWEALTH OF VIRGINIA	VCFUR/ODCFUR	PUE940067	Rebuttal	VA	Integrated Resource Planning	5/1/1995
6295	GEORGIA POWER COMPANY	Georgia Industrial Group	5600-U	Supplemental	GA	Cost of Service	4/1/1995
6063	PUBLIC SERVICE COMPANY OF COLORADO	Multiple Intervenors	94I-430EG	Rebuttal	CO	Cost of Service	4/1/1995
6063	PUBLIC SERVICE COMPANY OF COLORADO	Multiple Intervenors	94I-430EG	Reply	CO	DSM Rider	4/1/1995
6295	GEORGIA POWER COMPANY	Georgia Industrial Group	5600-U	Direct	GA	Interruptible Rate Design	3/1/1995
6278	COMMONWEALTH OF VIRGINIA	VCFUR/ODCFUR	PUE940067	Direct	VA	EPACT Rate-Making Standards	3/1/1995
6125	SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	13456	Direct	TX	DSM Rider	3/1/1995
6235	TEXAS UTILITIES ELECTRIC COMPANY	Texas Industrial Energy Consumers	13575|13749	Direct	TX	Cost of Service	2/1/1995
6063	PUBLIC SERVICE COMPANY OF COLORADO	Multiple Intervenors	94I-430EG	Answering	CO	Competition	2/1/1995
6061	HOUSTON LIGHTING & POWER COMPANY	Texas Industrial Energy Consumers	12065	Direct	TX	Rate Design	1/1/1995



Outage Data	Actual*					Budget*	Projected**
	2003	2004	2005	2006	2007	2008	2009
Total Planned Outages (Weeks)	5.5	11.9	20.6	18.3	21.6	22.5	32.0

* - Source: TECO Reply to FIPUG 1st Set of Interrogatories, No. 1
** - Source: TECO Reply to FIPUG 1st Set of Interrogatories, No. 2



	Actual*					Budgeted*	Projected**
	2003	2004	2005	2006	2007	2008	2009
Total Planned Outages (Weeks)	30.9	28.9	46.39	38.91	34.54	42.5	54

* - Source: TECO Reply to FIPUG 1st Set of Interrogatories, No. 1
** - Source: TECO Reply to FIPUG 1st Set of Interrogatories, No. 2

Big Bend Station Business Plan (2007-2013)
Outage Summary

Planned Outages

Units	2005A	2006F	2007P	2008P	2009P	2010P	2011P	2012P	2013P
Unit #1	FS 23-Day	MO 56-Day	FS 14-Day	FS 21-Day	FS 14-Day	MO 98-Day	FS 14-Day	FS 21-Day	FS 21-Day
Unit #2	MO 56-Day	deferred	FS 21-Day	FS 14-Day	MO 98-Day	FS 14-Day	FS 21-Day	FS 21-Day	MO 56-Day
Unit #3	FS 25-Day	FS 28-Day	FS 14-Day	MO 98-Day	FS 14-Day	FS 21-Day	FS 21-Day	MO 56-Day	FS 14-Day
Unit #4	FS 26-Day	FS 32-Day	MO 90-Day	FS 14-Day	FS 21-Day	FS 21-Day	MO 56-Day	FS 14-Day	FS 21-Day

37017

Major Drivers:
- Major Outage in 2005 was turbine, boiler and condenser related
- Major Outage in 2006 is turbine, boiler and condenser related
- Major Outages in 2007 thru 2010 are SRC tie-in outages
  - 2007 & 2008 are boiler related; 2009 is feed water heater & condensate polisher; 2010 is turbine related

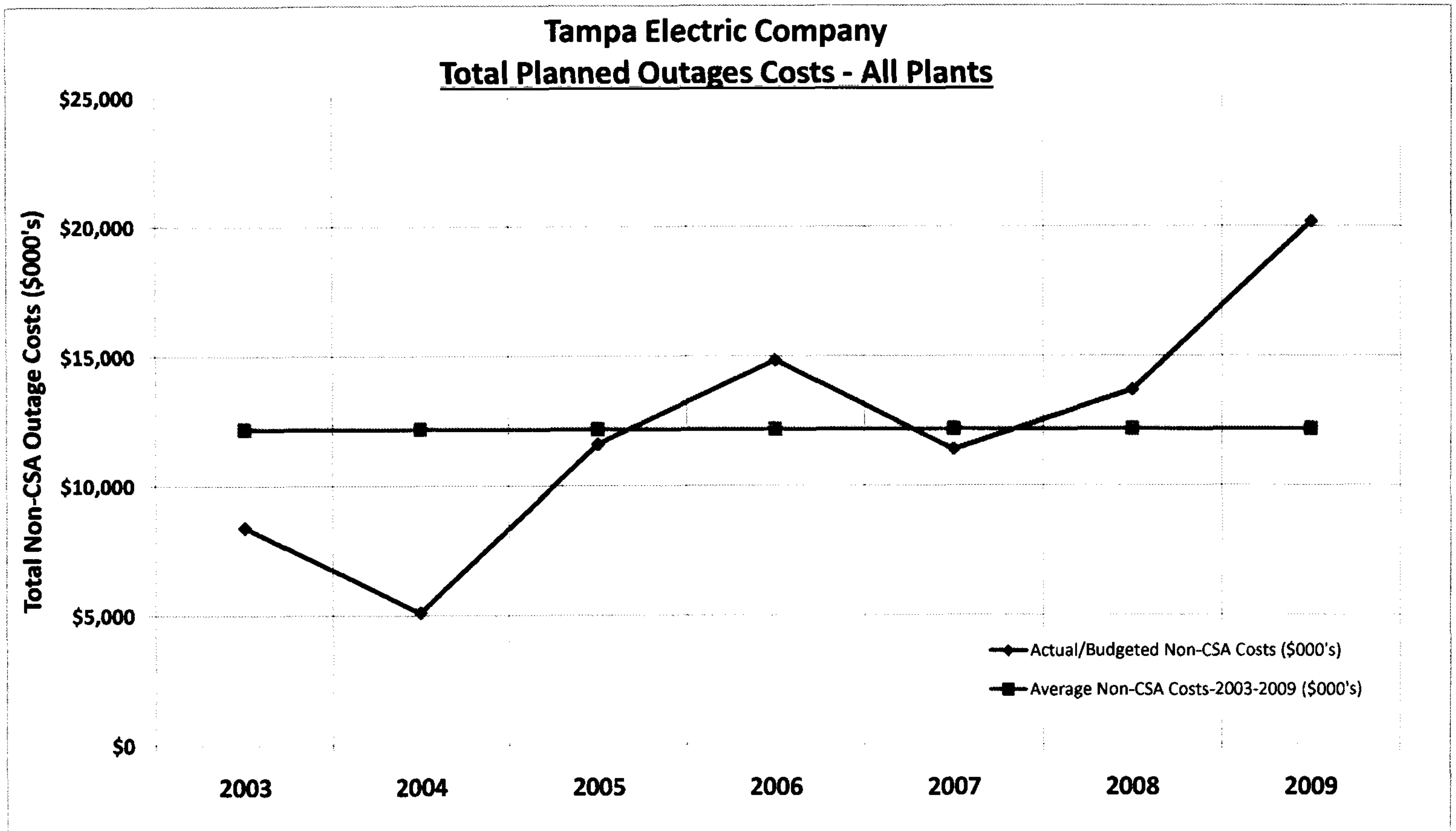
Dollars / Day	2005A	2006F	2007P	2008P	2009P	2010P	2011P	2012P	2013P
Fuel System	$50,554	$68,312	$75,000	$77,300	$79,600	$82,000	$84,500	$87,000	$89,600
Major	$60,845	$75,066	$100,000	$103,000	$106,100	$109,300	$112,600	$116,000	$119,500

Major Drivers:
- 2005's fuel system dollars per day were budgeted at $27,667; $1.7 million of additional funding was received and $534 thousand of Station funds were reallocated to complete 2005's outages as listed above.
- 2007 thru 2010 fuel system dollars per day is 2005's "standard" per day ($50,000) escalated 3% per year for inflation.
- 2007 thru 2010 major dollars per day is 115% of the fuel system; funding is limited to 56 days, not the full 90 or 98 days.

TAMPA ELECTRIC COMPANY
DOCKET NO. 080317-EI
OPC'S FIRST REQUEST FOR PODS
FILED: SEPTEMBER 29, 2008

Docket No. 080317-EI
TECO Planned Big Bend Outage Weeks
Exhibit JP-2

Docket No. 080317-EI
Planned Outage Costs
Exhibit JP-3



	Actual*					Budgeted*	Projected**
	2003	2004	2005	2006	2007	2008	2009
Actual/Budgeted Non-CSA Costs ($000's)	$8,406	$5,105	$11,620	$14,855	$11,401	$13,705	$20,204
Average Non-CSA Costs-2003-2009 ($000's)	$12,185	$12,185	$12,185	$12,185	$12,185	$12,185	$12,185

* - Source: TECO Reply to FIPUG 1st Set of Interrogatories, No. 1
** - Source: TECO Reply to FIPUG 1st Set of Interrogatories, No. 2

TAMPA ELECTRIC COMPANY
Comparison of Incentive Compensation Paid vs. Targeted

Line	Category	2003	2004	2005	2006	2007
	(1)	(2)	(3)	(4)	(5)	(6)
1	Target Incentive	$12,907,073	$8,915,750	$7,842,388	$8,648,081	$10,062,634
2	Actual Paid (1)	$7,523,283	$10,423,489	$10,889,364	$9,749,805	$12,909,356
3	Actual Expensed	$5,560,138	$10,480,885	$11,653,924	$10,296,670	$12,762,948
4	Incentive Paid percent of Targeted	58%	117%	139%	113%	128%

(1) Represents payouts for the plan year as indicated; some payments were made in the subsequent calendar year.

Source: TECO response to OPC 3rd set of Interrogatories No. 29

Docket No. 080317-EI
Class Load Analysis
Exhibit JP-5

TAMPA ELECTRIC COMPANY

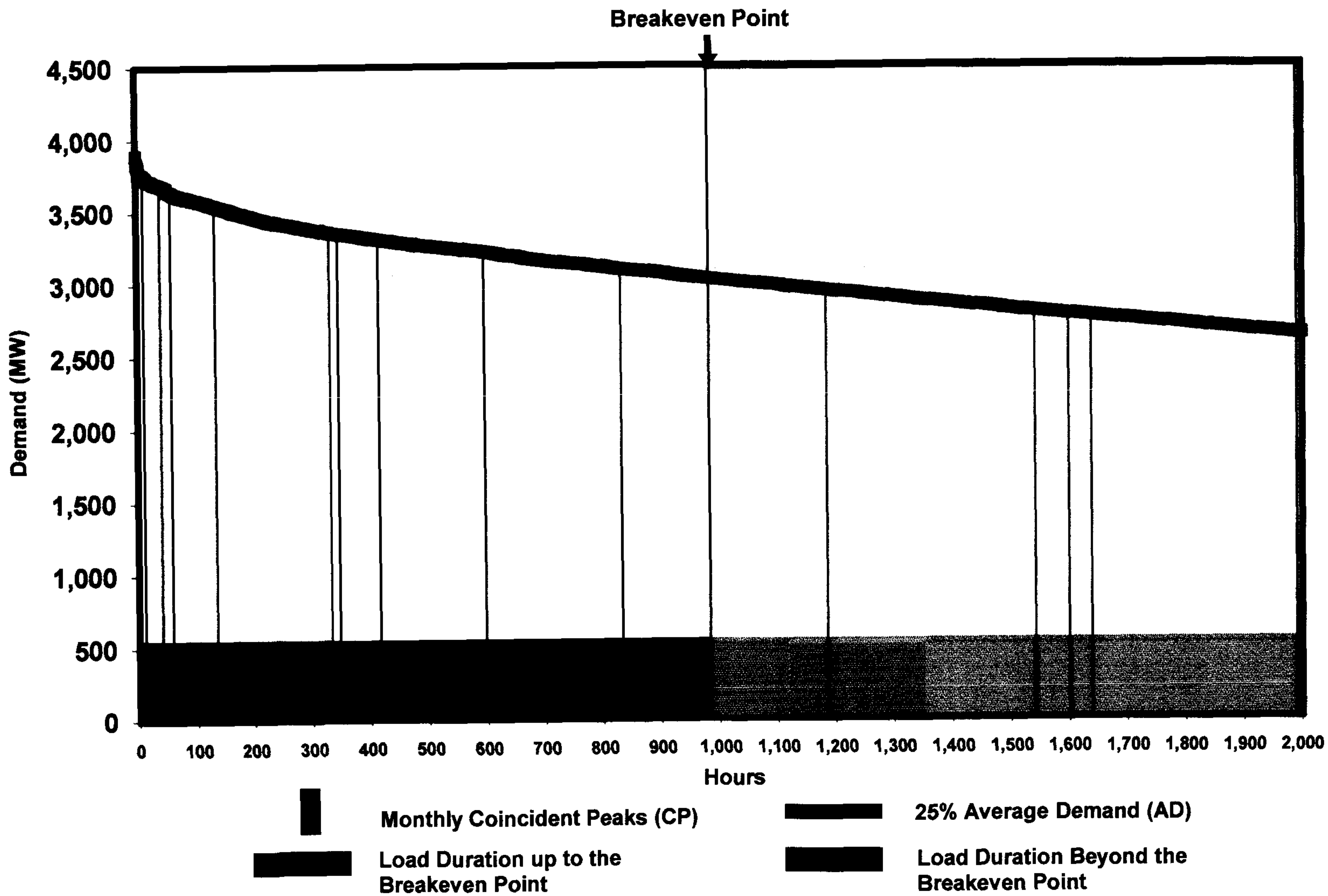
Comparison of GSD, GSLD, and IS Class Characteristics
Projected Test Year Ending December 31, 2009

					GSD		GSLD			IS	
Line	Description	GSD	GSLD	IS	Secondary	Primary	Secondary	Primary	SubTrans	Primary	SubTrans
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	**Energy Sold (MWh)**	5,621,820	2,580,205	1,394,270	5,484,319	137,501	1,388,036	1,180,119	12,049	639,090	755,180
2	**Energy at Generation (MWh)**	5,935,284	2,697,049	1,424,672	5,793,298	141,986	1,466,236	1,218,612	12,202	659,935	764,737
3	Percent of Total				97.6%	2.4%	54.4%	45.2%	0.5%	46.3%	53.7%
4	**12CP Demand (MW)**	930.8	370.9	166.3	916.7	14.2	229.7	141.0	0.2	49.3	117.1
5	Load Factor	68.6%	79.5%	95.6%	69%	74%	69%	97%	164%	148%	74%
6	**Class NCP Demand (MW)**	1,085.1	431.9	229.8							
7	Load Factor	58.9%	68.3%	69.2%							
8	Coincidence Factor	85.8%	85.9%	72.4%							
9	**Winter CP MW)**	802.6	308.7	143.0							
10	Load Factor	79.6%	95.5%	111.2%							
11	**Summer CP (MW)**	1,052.6	404.2	147.6							
12	Load Factor	60.7%	73.0%	107.7%							
13	**Billing Demand (MW)**	15,549	5,145	2,954	15,237	312	2,868	2,272	5	1,616	1,338
14	Load Factor	49.3%	68.8%	64.6%	49.5%	40.1%	66.0%	72.4%	71.4%	54.1%	77.3%
15	Coincidence Factor	71.8%	86.5%	67.6%	72.2%	54.5%	96.1%	74.5%	43.6%	36.6%	105.0%

Docket No. 080317-EI
Cost Allocation
Exhibit JP-6

TAMPA ELECTRIC COMPANY

Cost Allocation Using The 12CP-25%AD Method



TAMPA ELECTRIC COMPANY

Allocation of Production Plant and Fuel Costs
Under the 12CP-25%AD Method
Test Year Ending December 31, 2009

		Allocated Net Production Plant			Recovery of Fuel and Purchased Power Expense		
Line	Rate Class	Amount (000)	12CP (MW)	$ Per kW	Amount (000)	Energy (GWh)	¢ Per kWh
		(1)	(2)	(3)	(4)	(5)	(6)
1	RS	1,080,580	2,041	$530	567,196	9,566	5.93
2	GS	123,569	234	528	68,214	1,150	5.93
3	GSD	517,619	923	561	351,926	5,935	5.93
4	GSLD	212,686	370	576	159,918	2,697	5.93
5	IS	99,541	115	864	84,405	1,424	5.93
6	SL/OL ENERGY	6,729	5	1,381	14,102	238	5.93
7	Fl Juris	2,040,724	3,687	$553	1,245,761	21,010	5.93

TAMPA ELECTRIC COMPANY

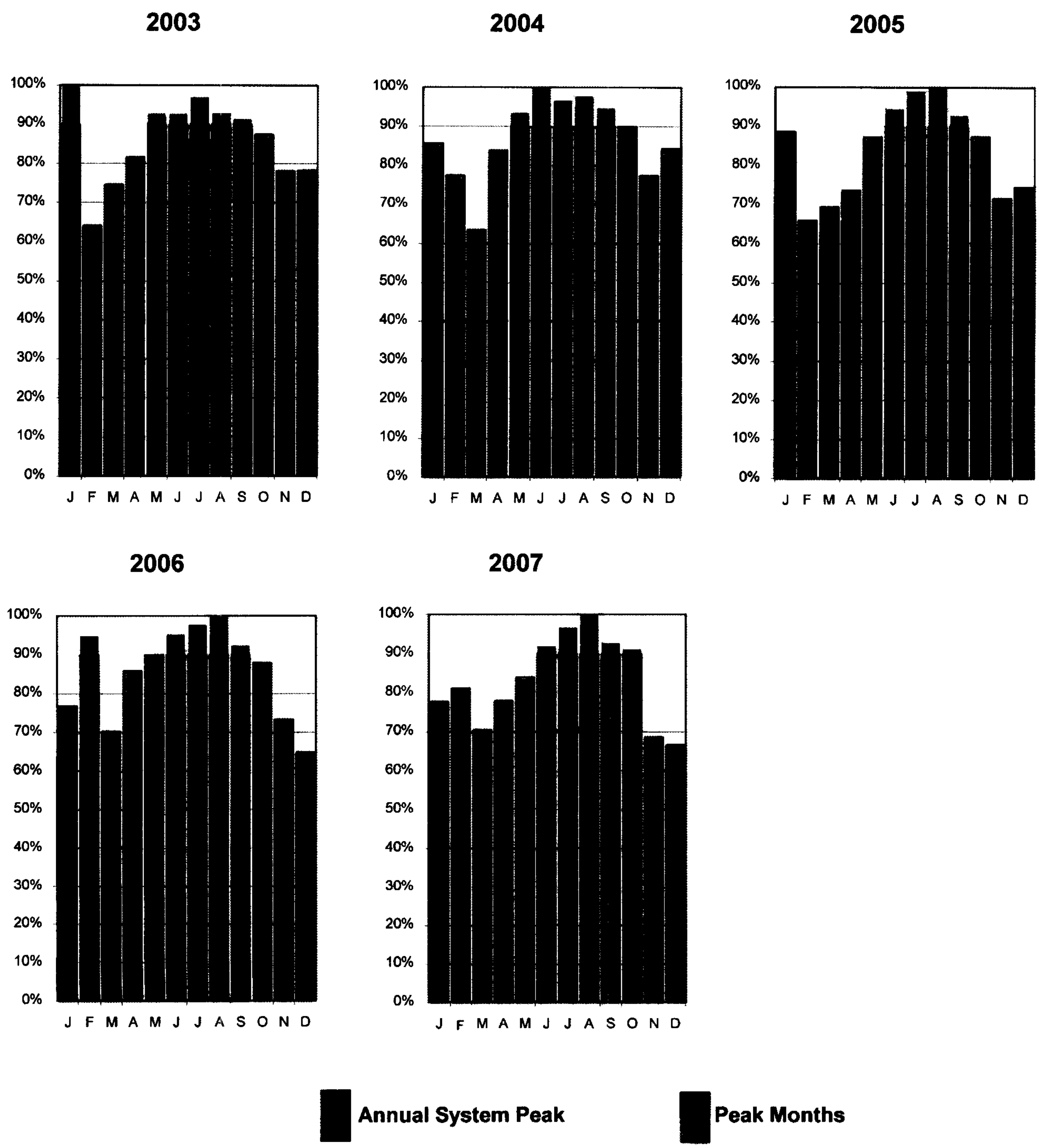
Comparison of Net Plant Investment and Fuel Costs By Capacity Type
Forecast Year Ending December 31, 2009

Line	Capacity Type	Net Investment ($/kW)	Fuel Costs (¢/kWh)
		(1)	(2)
1	Base Load	$558	3.95
2	Intermediate	$403	7.17
3	Peaking	$309	14.88
4	System Average	$442	5.46

Docket No. 080317-EI
TECO Load Analysis
Exhibit JP-8
Page 1 of 2

TAMPA ELECTRIC COMPANY

Analysis of Monthly Peak Demands
As a Percentage of the Annual System Peak
<u>for the Years 2003-2007</u>



TAMPA ELECTRIC COMPANY

Analysis of TECO's System Load Characteristics

2003-2007 (Actual)

Year	Peak Demand	Minimum Demand	Average Demand	Average Summer Demand	Average Non-Summer Demand	Winter Peak Demand
	(1)	(2)	(3)	(4)	(5)	(6)
	Firm Demand (MW)					
2003	3,455	2,219	2,969	3,229	2,839	3,455
2004	3,563	2,262	3,103	3,465	2,922	3,054
2005	3,852	2,537	3,223	3,718	2,975	3,413
2006	3,893	2,525	3,338	3,749	3,133	3,690
2007	4,035	2,687	3,359	3,846	3,116	3,275

Ratio Analysis

	Minimum to Annual Peak	Average to Annual Peak	Avg Summer % More Than Avg Non-Sum	Avg Summer Peak to Peak Demand	Avg Non-Sum Peak to Peak Demand	Annual Load Factor
2003	64%	86%	14%	93%	82%	60%
2004	63%	87%	19%	97%	82%	66%
2005	66%	84%	25%	97%	77%	57%
2006	65%	86%	20%	96%	80%	57%
2007	67%	83%	23%	95%	77%	57%

TAMPA ELECTRIC COMPANY

Reserve Margins as a Percent of Firm Peak Demand

Line	Year	Data	Average Summer Months	Average Non-Summer Months	Ratio of Summer to Non-Summer Margins
			(1)	(2)	(3)
1	2003	Actual	40%	62%	65%
2	2004	Actual	33%	61%	54%
3	2005	Actual	24%	56%	44%
4	2006	Actual	22%	44%	51%
5	2007	Actual	23%	58%	40%

PRESENT RATE STRUCTURE
PROD. CAP. ALLOC. METHOD: 12CP & 1/13th AD
DATA: PROJECTED 2009,
FULLY ADJUSTED (000's)

TAMPA ELECTRIC COMPANY
Cost of Service Study at Present Rates
With Interruptible Priced at Firm
Polk Gasifier and Environmental Costs Classified to Demand
RATE OF RETURN SUMMARY - ROR

Docket No. 080317-EI
Cost of Service Study
Exhibit JP-10

LINE NO.		FPSC JURIS	RS	GS	GSD	GSLD	IS	SL/OL ENERGY	SL/OL FACILITIES
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	OPERATING REVENUES								
2	Sales Revenue (incl. Transmission Firm Whsl)	837,851	454,812	53,970	192,520	73,686	21,915	4,683	36,265
3	Reprice Interruptible at Firm Rates	(0)	(12,940)	(1,488)	(5,998)	(2,430)	22,907	(50)	-
4	Other Revenues	27,507	19,187	2,357	3,882	1,463	439	163	17
5									
6	TOTAL OPERATING REVENUES	865,358	461,059	54,838	190,404	72,719	45,261	4,796	36,282
7									
8	OPERATING EXPENSES								
9	Power Transactions	7,615	3,467	417	2,151	978	516	86	-
10	O&M Expense	370,923	215,556	24,075	76,370	30,553	13,093	2,151	9,123
11	Deprec & Amortiz Expense	194,608	108,096	12,093	41,690	15,622	6,079	817	10,211
12	Taxes Other than Income	62,272	35,170	3,898	13,501	5,152	2,043	266	2,242
13	Income Taxes	48,499	12,514	2,783	14,517	5,692	8,711	660	3,620
14	Gain/(Loss) on Disp	(1,534)	(857)	(96)	(341)	(129)	(51)	(6)	(54)
15									
16	TOTAL OPERATING EXPENSES	682,382	373,947	43,170	147,889	57,868	30,391	3,974	25,143
17									
18	NET OPERATING INCOME	182,977	87,112	11,668	42,514	14,851	14,870	822	11,139
19									
20	RATE BASE								
21	Plant in Service	5,483,474	3,062,641	343,320	1,219,029	462,121	180,832	22,961	192,571
22	Plant Held for Future Use	37,330	20,874	2,280	9,036	3,603	1,381	156	-
23	Working Capital	(30,585)	(26,966)	(2,659)	(1,035)	1,618	2,295	547	(4,386)
24	Construction Work in Progress	101,071	55,042	6,227	24,814	9,962	4,503	217	306
25	Less: Depreciation Reserve	1,934,488	1,076,009	120,211	422,379	158,715	60,773	8,465	87,935
26									
27	TOTAL RATE BASE	3,656,802	2,035,582	228,957	829,464	318,589	128,238	15,416	100,556
28									
29	RATE OF RETURN (%)	5.00	4.28	5.10	5.13	4.66	11.60	5.33	11.08
30									
31	RELATIVE RATE OF RETURN	1.00	0.86	1.02	1.02	0.93	2.32	1.07	2.21
32									
33	SUBSIDY	2	(24,101)	346	1,652	(1,782)	13,820	82	9,985

PRESENT RATE STRUCTURE
PROD. CAP. ALLOC. METHOD: 12CP & 1/13th AD
DATA: PROJECTED 2009,
FULLY ADJUSTED (000's)

TAMPA ELECTRIC COMPANY
Cost of Service Study at Present Rates
With Interruptible Priced at Firm
Polk Gasifier and Environmental Costs Classified to Demand
RATE OF RETURN SUMMARY - ROR

LINE NO.		FPSC JURIS	RS	GS	GSD	GSLD	IS	SL/OL ENERGY	SL/OL FACILITIES
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
34	DEVELOPMENT OF REVENUE REQUIREMENTS								
35	Total Rate Base	3,656,802	2,035,582	228,957	829,464	318,589	128,238	15,416	100,556
36	Total Cost of Capital	8.82%	8.82%	8.82%	8.82%	8.82%	8.82%	8.82%	8.82%
37	(@ 12.00% ROE)								
38	Total Required Net Operating Income	322,530	179,538	20,194	73,159	28,100	11,311	1,360	8,869
39									
40	Less: Achieved Net Operating Income	182,977	87,112	11,668	42,514	14,851	14,870	822	11,139
41									
42	Equals: Return Deficiency/(Surplus)	139,553	92,426	8,526	30,644	13,248	(3,559)	538	(2,270)
43	Times: Expansion Factor	1.6349	1.6349	1.6349	1.6349	1.6349	1.6349	1.6349	1.6349
44									
45	Equals: Revenue Deficiency/ (Surplus)	228,154	151,106	13,939	50,100	21,659	(5,818)	879	(3,712)
46									
47	Plus: Revenues @ Present Rates	865,358	461,059	54,838	190,404	72,719	45,261	4,796	36,282
48									
49	Equals: Total Revenue Requirements	1,093,512	612,165	68,777	240,504	94,378	39,442	5,676	32,570
50	Less: Other Revenues	(27,507)	(19,187)	(2,357)	(3,882)	(1,463)	(439)	(163)	(17)
51									
52	Equals: Total Sales Revenue Requirements	1,066,005	592,978	66,421	236,622	92,915	39,004	5,512	32,554
53									
54	Sales Revenue Requirements Index	0.79	0.75	0.79	0.79	0.77	1.15	0.84	1.11

TAMPA ELECTRIC COMPANY

Current Interruptible Credits
Test Year Ending December 31, 2009

Line	Non-Firm Rate	Firm Rate	Base Revenue at Present Rates	Base Revenue at Firm Rates Rates	Interruptible Credit Amount (3) - (4)	Interruptible Credit Percent (5) ÷ (4)
	(1)	(2)	(3)	(4)	(5)	(6)
1	IS	GSLD	$17,825	$34,429	$16,604	48.2%
2	SBI	SBF	4,090	10,393	6,303	60.6%
3	Total		$21,915	$44,821	$22,906	51.1%

Mathematical Equivalence Between Allocating No Production Capacity Costs to Interruptible Loads and Allocating the Interruptible Credits on Firm Demand

				Class B	
Line	Description	Total	Class A	Firm	Interruptible
		(1)	(2)	(3)	(4)
	Assumptions				
1	Peak Demand	1,000	500	250	250
2	Percent of Total		50%	25%	25%
3	Firm Peak Demand	750	500	250	-
4	Percent of Total		67%	33%	0%
5	Production Capacity Revenues				$ 2,500
6	Interruptible Credits				$ (1,000)
7	Net Revenue				$ 1,500
	***Method 1:* Allocate No Production Capacity Costs to Interruptible**				
8	Production Capacity Costs	$ 10,000	$ 6,667	$ 3,333	$ -
9	Less: Interruptible Revenue	$ -	$ (1,000)	$ (500)	$ 1,500
10	Revenue Requirement	$ 10,000	$ 5,667	$ 2,833	$ 1,500
	***Method 2:* Treat Interruptible Load as Firm and Allocate the Interrruptible Credit to Firm Load**				
11	Production Capacity Costs	$ 10,000	$ 5,000	$ 2,500	$ 2,500
12	Interruptible Credits	$ -	$ 667	$ 333	$ (1,000)
13	Revenue Requirement	$ 10,000	$ 5,667	$ 2,833	$ 1,500

TAMPA ELECTRIC COMPANY

Proposed Base Revenue Increase
Test Year Ending December 31, 2009
(Dollar Amounts in Thousands)

Line	Rate	Base Revenue at Present Rates	Base Revenue at Proposed Rates	Increase Amount (2) - (1)	Increase Percent (3) ÷ (1)
		(1)	(2)	(3)	(4)
1	RS	$454,811	$567,758	$112,947	24.8%
2	GS	53,601	67,558	13,957	26.0%
3	GSD	192,892	238,358	45,466	23.6%
4	GSLD/SBF	73,683	88,291	14,607	19.8%
5	IS/SBI	21,915	51,347	29,433	134.3%
6	Lighting Energy	4,683	6,768	2,085	44.5%
7	Lighting Facilities	36,265	39,144	2,878	7.9%
8	TOTAL	$837,851	$1,059,224	$221,374	26.4%

TAMPA ELECTRIC COMPANY

Net Base Revenue Increase
Test Year Ending December 31, 2009
(Dollar Amounts in Thousands)

Line	Rate	Base Revenue at Present Rates	Proposed Base Rate Increase	Proposed GSLM-2/3 Credits	Proposed Net Revenue Increase	
					Amount	Percent (4) ÷ (1)
		(1)	(2)	(3)	(4)	(5)
1	RS	$454,811	$112,947	$11,964	$124,912	27.5%
2	GS	53,601	13,957	1,372	15,329	28.6%
3	GSD	192,892	45,466	5,823	51,289	26.6%
4	GSLD/SBF	73,683	14,607	2,410	17,017	23.1%
5	IS/SBI	21,915	29,433	(21,656)	7,777	35.5%
6	Lighting Energy	4,683	2,085	87	2,172	46.4%
7	Lighting Facilities	36,265	2,878	-	2,878	7.9%
8	TOTAL	$837,851	$221,374	($0)	$221,374	26.4%

Docket No. 080317-EI
FIPUG Revenue
Allocation
Exhibit JP-14

TAMPA ELECTRIC COMPANY

FIPUG Recommended Base Revenue Allocation
Test Year Ending December 31, 2009
(Dollar Amounts in Thousands)

Line	Rate	Base Revenue at Present Rates	Recommended Class Revenue Allocation Amount (2) - (1)	Recommended Class Revenue Allocation Percent (3) ÷ (1)
		(1)	(2)	(3)
1	RS	$454,811	$131,044	28.8%
2	GS	53,601	11,510	21.5%
3	GSD	192,892	43,304	22.5%
4	GSLD/SBF	73,683	18,948	25.7%
5	IS/SBI	21,915	15,722	71.7%
6	Lighting Energy	4,683	781	16.7%
7	Lighting Facilities	36,265	-	0.0%
8	TOTAL	$837,851	$221,309	26.4%

PRESENT RATE STRUCTURE
PROD. CAP. ALLOC. METHOD:
12CP & 1/13th AD
DATA: PROJECTED 2009,
FULLY ADJUSTED (000's)

TAMPA ELECTRIC COMPANY
Summary of Cost of Service Study Results at FIPUG'S
Recommended Rates
With Interruptible Priced at Firm
Polk Gasifier and Environmental Costs Classified to Demand

Docket No. 080317-EI
Cost of Service Study
Exhibit JP-15

LINE NO.		FPSC JURIS (1)	RS (2)	GS (3)	GSD (4)	GSLD (5)	IS (6)	SL/OL ENERGY (7)	SL/OL FACILITIES (8)
1	Present Operating Revenues	865,358	461,059	54,838	190,404	72,719	45,261	4,796	36,282
	Recommended Increase:								
2	Base Revenues	221,309	143,008	12,882	49,127	21,358	(5,934)	867	-
3	Other Revenues	6,816	5,957	818	99	(36)	(20)	(3)	-
4	Total Increase	228,125	148,965	13,701	49,226	21,322	(5,954)	864	-
5	Divided By: Expansion Factor	1.6349	1.6349	1.6349	1.6349	1.6349	1.6349	1.6349	1.6349
6	Additional Operating Income	139,536	91,116	8,380	30,110	13,042	(3,642)	529	-
7	Net Operating Income at Present Rates	182,977	87,112	11,668	42,514	14,851	14,870	822	11,139
8	Net Operating Income at Recommended Rates	322,512	178,229	20,048	72,624	27,893	11,228	1,350	11,139
9	Total Rate Base	3,656,802	2,035,582	228,957	829,464	318,589	128,238	15,416	100,556
10	RATE OF RETURN (%)	8.82	8.76	8.76	8.76	8.76	8.76	8.76	11.08
11	RELATIVE RATE OF RETURN	1.00	0.99	0.99	0.99	0.99	0.99	0.99	1.26
12	SUBSIDY	0	(2,125)	(236)	(867)	(335)	(134)	(15)	3,712

PRESENT RATE STRUCTURE
PROD. CAP. ALLOC. METHOD: 12CP & 1/13th AD
DATA: PROJECTED 2009,
FULLY ADJUSTED (000's)

TAMPA ELECTRIC COMPANY
Cost of Service Study at Present Rates
With Interruptible Priced at Firm
Big Bend Scrubber and Polk Gasifier Costs Classified to Demand
DERIVATION OF UNIT COSTS - UNTCST

PROPOSED ROR

LINE NO.			FPSC JURIS	RS	GS	GSD	GSLD	IS	SL/OL ENERGY	SL/OL FACILITIES
1	FUNCTIONALIZED REVENUE REQUIREMENTS									
2	Production	DEM	489,393	264,770	30,069	121,953	49,187	22,406	1,009	-
3	Production	EGY	149,166	67,928	8,168	42,140	19,151	10,091	1,688	-
4	Transmission	DEM	18,878	10,348	1,170	4,652	1,854	830	24	-
5	Subtransmission	DEM	49,480	27,123	3,068	12,193	4,858	2,175	64	-
6	Distribution Primary	DEM	136,813	81,566	7,988	31,123	12,389	1,984	1,764	-
7	Distribution Secondary	DEM	83,743	57,138	5,826	16,664	3,424	-	691	-
8	Distribution: Mtrs,Svcs,IS Equip,Ligl	CUST	88,222	43,317	6,706	4,676	335	965	15	32,209
9	Other: Mtr. Reading, Billing, Cust Sr	CUST	50,308	40,789	3,426	3,221	1,717	552	257	345
10	TOTAL BASE REVENUE REQUIREMENTS		1,066,005	592,978	66,421	236,622	92,915	39,004	5,512	32,554
11										
12	BILLING UNITS (ANNUAL)									
13	MWh Sales Related To:									
14	Production & Transmission (Factor 404)			9,055,662	1,089,086	5,620,445	2,568,162	1,371,644	225,147	
15	Distribution Primary (Factor 408)			9,055,662	1,089,086	5,620,445	2,556,354	401,957	225,147	
16	Distribution Secondary (Factor 410)			9,055,662	1,089,086	5,521,998	1,549,134	-	225,147	
17										
18	Billing kW Related To:									
19	Production & Transmission (Factor 401)					15,545,527	5,191,932	3,356,134		
20	Distribution Primary (Factor 402)					15,545,527	5,243,554	902,684		
21	Distribution Secondary (Factor 403)					15,328,378	3,265,587	-		
22										
23	Annual Bills (Factor 405)			7,182,972	797,112	177,528	2,700	672	n/a	

PRESENT RATE STRUCTURE
PROD. CAP. ALLOC. METHOD: 12CP & 1/13th AD
DATA: PROJECTED 2009,
FULLY ADJUSTED (000's)

TAMPA ELECTRIC COMPANY
Cost of Service Study at Present Rates
With Interruptible Priced at Firm
Big Bend Scrubber and Polk Gasifier Costs Classified to Demand
DERIVATION OF UNIT COSTS - UNTCST

PROPOSED ROR

LINE NO.		FPSC JURIS	RS	GS	GSD	GSLD	IS	SL/OL ENERGY	SL/OL FACILITIES
24									
25	FUNCTIONALIZED UNIT COSTS								
26	Customer Related - $/Bill								
27	Meters, Svcs, IS Equip		$ 6.03	$ 8.41	$ 26.34	$ 124.05	$ 1,436.02	$ -	
28	Mtr. Reading, Billing, Cust Srvc		$ 5.68	$ 4.30	$ 18.14	$ 636.07	$ 822.17	$ -	
29	TOTAL CUSTOMER		$ 11.71	$ 12.71	$ 44.48	$ 760.13	$ 2,258.19	$ -	
30									
31	Production Energy (cents/kWh)		0.75	0.75	0.75	0.75	0.74	0.75	
32									
33	Capacity Related								
34	Based on MWH Sales - (cents/kWh)								
35	Production		2.92	2.76	2.17	1.92	1.63	0.45	
36	Transmission		0.41	0.39	0.30	0.26	0.22	0.04	
37	Distribution Primary		0.90	0.73	0.55	0.48	0.49	0.78	
38	Distribution Secondary		0.63	0.53	0.30	0.22	0.00	0.31	
39									
40	Based on Billing KW Demand - ($kW/month)								
41	Production Demand				$ 7.84	$ 9.47	$ 6.68		
42	Transmission Demand				$ 1.08	$ 1.29	$ 0.90		
43	Distribution Primary Demand				$ 2.00	$ 2.36	$ 2.20		
44	Distribution Secondary Demand				$ 1.09	$ 1.05	$ -		

Docket No. 080317-EI
Transformer Discount
Exhibit JP-17

TAMPA ELECTRIC COMPANY
Development of Transformer Ownership Discounts (Revised)
Dollars in Thousands

Line		GSD	GSLD/SBF	IS/SBI
1	I. Distribution Primary/ Secondary Transformation Costs			
2				
3	EPIS - Jurisdictional Separation Study	GSD	GSLD/SBF	IS/SBI
4	a. Line Transformers	$ 77,344	$ 15,892	$ -
5	b. Total Distribution Secondary Delivery	$ 104,988	$ 21,572	$ -
6				
7	Ratio a/b	73.7%	73.7%	
8				
9	Distribution Secondary Revenue Requirements:	$ 16,663	$ 3,424	$ -
10				
11	Sum of Monthly Effective Billing KW	15,328,378	3,265,587	-
12	Weighted Average Unit Cost - $ per KW-Month (Line 9/ Line 11)	$ 1.09	$ 1.05	
13	Times Ratio	73.7%	73.7%	
14	Equals Transformation Unit Cost	$ 0.80	$ 0.77	
15				
16	Sum of Monthly KWH	5,521,998	1,549,134	-
17	Weighted Average Unit Cost - $ per MWh	$ 3.02	$ 2.21	
18	Times Ratio	73.7%	73.7%	
19	Equals Transformation Unit Cost for GSD Option Rate	$ 2.22	$ 1.63	
20				
21	Sum of Monthly Ratcheted Demand KW	15,328,378	3,265,587	-
22	Weighted Average Unit Cost - $ per KW-Month	$ 1.09	$ 1.05	
23	Times Ratio	73.7%	73.7%	
24	Equals Transformation Unit Cost (Stand-by Unit Cost)	$ 0.80	$ 0.77	
25				
26				
27	II. Transmission/Distribution Primary Transformation Costs			
28				
29	EPIS - Jurisdicitional Separation Study	GSD	GSLD/SBF	IS/SBI
30	a. Distribution Substation	$ 41,772	$ 16,627	$ 2,667
31	b. Total Distribution Primary Delivery	$ 187,045	$ 74,450	$ 11,940
32				
33	Ratio a/b	22.3%	22.3%	22.3%
34				
35	Distribution Primary Revenue Requirements			
36	Class Cost of Service Study	$ 31,122	$ 12,390	$ 1,989
37				
38	Sum of Monthly Effective Billing KW	15,545,527	5,243,555	902,684
39	Weighted Average Unit Cost - $ per KW Month	2.00	2.36	2.20
40	Times Ratio	22.3%	22.3%	22.3%
41	Equal Transformation Unit Cost	$ 0.45	$ 0.53	$ 0.49
42				
43	Sum of Monthly MWH	5,620,445	2,556,354	401,957
44	Weighted Average Unit Cost - $ per MWh	$ 5.54	$ 4.85	$ 4.95
45	Times Ratio	22.3%	22.3%	22.3%
46	Equals Transformation Unit Cost for GSD Option Rate $/MWh	$ 1.24	$ 1.08	$ 1.11
47				
48	Sum of Monthly Ratcheted Demand KW	15,545,527	5,243,555	902,684
49	Weighted Average Unit Cost - $ per KW Month	2.00	2.36	2.20
50	Times Ratio	22.3%	22.3%	22.3%
51	Equal Transformation Unit Cost (Stand-by Unit Cost)	$ 0.45	$ 0.53	$ 0.49
52				
53	Summary Proposed Transformer Ownership Discount ($/kW-mo)			
54	Distribution Primary Delivery ($/kW-mo) (Line 14)	$ 0.80	$ 0.77	$ -
55	Distribution Primary Delivery (¢/kWh) (Line 19)	0.222	0.163	-
56	Distribution Primary Delivery - Standby ($/kW-mo) (Line 24)	$ 0.80	$ 0.77	$ -
57	Subtransmission Delivery ($/kW-mo) (Line 14 + Line 41)	1.25	1.30	0.49
58	Subtransmission Delivery (¢/kWh) (Line 19 + Line 46)	$ 0.346	$ 0.271	$ 0.111
59	Subtransmission Delivery - Standby ($/kW-mo) (Line 22 + Line 51)	1.53	1.58	0.49

Docket No. 080317-EI
Non-Firm Increase
Exhibit JP-18

TAMPA ELECTRIC COMPANY

Proposed Net Increase to the Non-Firm Rates

Test Year Ending December 31, 2009

Line	Rate	Base Revenue at Present Rates	Base Revenue at Proposed Rates	Proposed Increase	Estimated GSLM Payment	12CP 25%AD Allocation Factor	ECCR Cost	Net Increase Amount (2)-(1)+(4)+(6)	Net Increase Percent (7) ÷ (1)
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	IS	$17,825	$40,314	126.2%	($17,588)		$973	$5,874	33.0%
2	SBI	4,090	11,033	169.8%	(5,206)		166	1,903	46.5%
3	Total	$21,915	$51,347	134.3%	($22,794)	4.9960%	$1,139	$7,777	35.5%

TAMPA ELECTRIC COMPANY

Derivation of Revised Contracted Capacity Value

Line	Description	Amount (1)		
	Program Demand Savings and Line Losses			
1	Customer KW reduction at the meter	3,071.00	KW/Cust	
2	Generator KW reduction per customer	3,161.21	KW Gen/Cust	
3	KW Line Loss Percentage	6.5%		
4	Generation KWH Reduction per customer	745,512	KWH/Cust/Yr	
5	KWH line loss percentage	5.80%		
6	Group Line Loss Multiplier	1		
7	Customer KWH Program Increase at Meter	0	KWH/Cust/Yr	
8	Customer KWH Reduction at Meter	704,643	KWH/Cust/Yr	
	Economic Life and K Factors			
1	Study Period for Conservation Program	25		
2	Generator Economic Life	25		
3	T & D Economic Life	25		
4	K Factor for Generation	1.612		
5	K Factor for T & D	1.612		
	Utility & Customer Costs			
1	Utility Non-recurring cost per customer	$ 106,743.00	$ per cust	
2	Utility Recurring cost per customer	$ 1,396.16	$ per cust / yr	
3	Utility Cost Escalation Rate	2.30%		
4	Utility Discount Rate	7.89%		
5	Utility AFUDC Rate	7.79%		
6	Utility Non-recurring rebate / incentive	$ -	$ per cust	
7	Utility Recurring rebate / incentive	**482,596**	$ per cust / yr	
8	Utility rebate / incentive ESCAL Rate	0%		
9	**CCV**	**$ 13.70**		
	Avoided Generator, Trans, & Dist Costs			
1	Base Year	2009		
2	In-service Year for Avoided Generating Unit	2009		2012
3	Base Year Avoided Generating Unit Cost ($/kW)	$ 650.00	$	870.34
4	In-service Year for Avoided T & D	2012		
5	Base Year Avoided Transmission Unit Cost	$ -	$/KW	
6	Base Year Avoided Distribution Unit Cost	$ -	$/KW	
7	Gen, Tran, Dist Cost Escalation Rate	2.3%		
8	Generator Fixed O&M Cost	21.45	$/KW/Yr	
9	Generator Fixed O&M Escalation Rate	2.3%		
10	Transmission Fixed O&M Cost	0	$/KW/Yr	
11	Distribution Fixed O&M Cost	0	$/KW/Yr	
12	Trans & Dist Fixed O&M Escalation Rate	2.3%		
13	Avoided Gen Unit Variable O&M cost	0.00364	$/KWH	
14	Generator Variable O&M Cost Escalation Rate	2.3%		
15	Generator Capacity Factor	2.2%		
16	Avoided Generating Unit Fuel Cost	0.0749	$/KWH	
17	Avoided Gen Unit Fuel Escalation Rate	3.66%		
18	Avoided Purchase Capacity Cost /KW	0	$/KW/Yr	
19	Capacity Cost Escalation Rate	0%		

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true and correct copy of the foregoing Testimony and Exhibits of Jeffry Pollock has been furnished by U.S. Mail and (*) hand delivery this 26th day of November, 2008 to the following:

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